NEMS Overview and Brief Description of Cases

The National Energy Modeling System

The projections in the *Annual Energy Outlook 2006* (*AEO2006*) are generated from the National Energy Modeling System (NEMS) [*1*], developed and maintained by the Office of Integrated Analysis and Forecasting (OIAF) of the Energy Information Administration (EIA). In addition to its use in the development of the *AEO* projections, NEMS is also used in analytical studies for the U.S. Congress, the White House, and other offices within the Department of Energy. The *AEO* projections are also used by analysts and planners in other government agencies and outside organizations.

The projections in NEMS are developed with the use of a market-based approach to energy analysis. For each fuel and consuming sector, NEMS balances energy supply and demand, accounting for economic competition among the various energy fuels and sources. The time horizon of NEMS is the long-term period through 2030, approximately 25 years into the future. In order to represent regional differences in energy markets, the component modules of NEMS function at the regional level: the nine Census divisions for the end-use demand modules; production regions specific to oil, gas, and coal supply and distribution; the North American Electric Reliability Council (NERC) regions and subregions for electricity; and the Petroleum Administration for Defense Districts (PADDs) for refineries.

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. The primary flows of information between each of these modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The delivered fuel prices encompass all the activities necessary to produce, import, and transport fuels to the end user. The information flows also include other data on such areas as economic activity, domestic production, and international petroleum supply.

The integrating module controls the execution of each of the component modules. To facilitate modularity, the components do not pass information to each other directly but communicate through a central data file. This modular design provides the capability to execute modules individually, thus allowing decentralized development of the system and independent analysis and testing of individual modules, and permits the use of the methodology and level of detail most appropriate for each energy sector. NEMS calls each supply, conversion, and end-use demand module in sequence until the delivered prices of energy and the quantities demanded have converged within tolerance, thus achieving an economic equilibrium of supply and demand in the consuming sectors. Solution is reached annually through the long-term horizon. Other variables are also evaluated for convergence, such as petroleum product imports, crude oil imports, and several macroeconomic indicators.

Each NEMS component represents the impacts and costs of legislation and environmental regulations that affect that sector and reports key emissions. NEMS represents current legislation and environmental regulations as of October 31, 2005, such as the Energy Policy Acts of 2005 [*2*] and 1992 [*3*], the Clean Air Act Amendments (CAAA), and the costs of compliance with regulations, such as the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR), both of which were finalized and published on the U.S. Environmental Protection Agency web page in March 2005 and in the *Federal Register* in May 2005.

In general, the historical data used for the *AEO2006* projections were based on EIA's *Annual Energy Review 2004*, published in August 2005 [*4*]; however, data were taken from multiple sources. In some cases, only partial or preliminary data were available for 2004. Carbon dioxide emissions were calculated by using carbon dioxide coefficients from the EIA report, *Emissions of Greenhouse Gases in the United States 2004*, published in December 2005 [*5*].

Historical numbers are presented for comparison only and may be estimates. Source documents should be consulted for the official data values. Some definitional adjustments were made to EIA data for the projections. For example, the transportation demand sector in *AEO2006* includes electricity used by railroads, which is included in the commercial sector in EIA's consumption data publications. Footnotes in the appendix tables of this report indicate the definitions and sources of historical data.

The *AEO2006* projections for 2005 and 2006 incorporate short-term projections from EIA's September 2005 *Short-Term Energy Outlook* (*STEO*). For short-term energy projections, readers are referred to monthly updates of the *STEO* [*6*].

Component Modules

The component modules of NEMS represent the individual supply, demand, and conversion sectors of domestic energy markets and also include international and macroeconomic modules. In general, the modules interact through values representing the prices or expenditures of energy delivered to the consuming sectors and the quantities of end-use energy consumption.

Macroeconomic Activity Module

The Macroeconomic Activity Module provides a set of essential macroeconomic drivers to the energy modules and a macroeconomic feedback mechanism within NEMS. Key macroeconomic variables include gross domestic product (GDP), industrial output, interest rates, disposable income, prices, new housing starts, new light-duty vehicle sales, and employment. The module uses the following models from Global Insight, Inc. (GII): Macroeconomic Model of the U.S. Economy, national Industry Model, and national Employment Model. In addition, EIA has constructed a Regional Economic and Industry Model to project regional economic drivers and a Commercial Floorspace Model to project 13 floorspace types in 9 Census divisions. The accounting framework for industrial output uses the North American Industry Classification System (NAICS).

International Module

The International Module represents world oil markets, calculating the average world oil price and computing supply curves for 5 categories of imported crude oil for the Petroleum Market Module (PMM) of NEMS. The module allows changes in U.S. import requirements. In addition, 17 international petroleum product supply curves, including supply curves for oxygenates and unfinished oils, are also calculated and provided to the PMM. A world oil supply/demand balance is created, including estimates for 16 oil consumption regions and 19 oil production regions. The oil production estimates include both conventional and nonconventional supply recovery technologies.

Residential and Commercial Demand Modules

The Residential Demand Module projects energy consumption in the residential sector by housing type and end use, based on delivered energy prices, the menu of equipment available, the availability of renewable sources of energy, and housing starts. The Commercial Demand Module projects energy consumption in the commercial sector by building type and nonbuilding uses of energy and by category of end use, based on delivered prices of energy, availability of renewable sources of energy, and macroeconomic variables representing interest rates and floorspace construction.

Both modules estimate the equipment stock for the major end-use services, incorporating assessments of advanced technologies, including representations of renewable energy technologies and effects of both building shell and appliance standards. The Commercial Demand Module incorporates combined heat and power (CHP) technology. The modules also include projections of distributed generation. Both modules incorporate changes to "normal" heating and cooling degree-days by Census division, based on State-level population projections. The Residential Demand Module projects that the average square footage of both new construction and existing structures is increasing based on trends in the size of new construction and the remodeling of existing homes.

Industrial Demand Module

The Industrial Demand Module projects the consumption of energy for heat and power and for feedstocks and raw materials in each of 16 industry groups, subject to the delivered prices of energy and macroeconomic variables representing employment and the value of shipments for each industry. As noted in the description of the Macroeconomic Module, the value of shipments is based on NAICS. The industries are classified into three groups—energy-intensive manufacturing, non-energy-intensive manufacturing, and nonmanufacturing. Of the 8 energy-intensive industries, 7 are modeled in the Industrial Demand Module, with components for boiler/steam/cogeneration, buildings, and process/assembly use of energy. Bulk chemicals are further disaggregated to organic, inorganic, resins, and agricultural chemicals. A representation of cogeneration and a recycling component are also included. The use of energy for petroleum refining is modeled in the Petroleum Market

Module, and the projected consumption is included in the industrial totals.

Transportation Demand Module

The Transportation Demand Module projects consumption of fuels in the transportation sector, including petroleum products, electricity, methanol, ethanol, compressed natural gas, and hydrogen, by transportation mode, vehicle vintage, and size class, subject to delivered prices of energy fuels and macroeconomic variables representing disposable personal income, GDP, population, interest rates, and the value of output for industries in the freight sector. Fleet vehicles are represented separately to allow analysis of CAAA and other legislative proposals.

The module also includes a component to assess the penetration of alternative-fuel vehicles explicitly. The air transportation module explicitly represents the industry practice of parking aircraft to reduce operating costs and the movement of aircraft from passenger to cargo markets as aircraft age [7]. For air freight shipments, the model employs narrow-body and wide-body aircraft only. The model also uses an infrastructure constraint that limits growth in air travel to levels commensurate with industry-projected infrastructure expansion and capacity growth.

Electricity Market Module

The Electricity Market Module (EMM) represents generation, transmission, and pricing of electricity, subject to delivered prices for coal, petroleum products, natural gas, and biofuels; costs of generation by all generation plants, including capital costs; macroeconomic variables for costs of capital and domestic investment; enforced environmental emissions laws and regulations; and electricity load shapes and demand. There are three primary submodules—capacity planning, fuel dispatching, and finance and pricing. Nonutility generation, distributed generation, and transmission and trade are modeled in the planning and dispatching submodules. The levelized cost of uranium fuel for nuclear generation is incorporated directly in the EMM.

All specifically identified CAAA compliance options that have been promulgated by the EPA are explicitly represented in the capacity expansion and dispatch decisions; those that have not been promulgated are not incorporated (e.g., fine particulate proposal). All specifically identified EPACT2005 financial incentives for power generation expansion and dispatch have been implemented. Several States, primarily in the Northeast, have recently enacted air emission regulations that affect the electricity generation sector. Where firm State compliance plans have been announced, regulations are represented in *AEO2006*.

Renewable Fuels Module

The Renewable Fuels Module (RFM) includes submodules representing renewable resource supply and technology input information for central-station, grid-connected electricity generation technologies, including conventional hydroelectricity, biomass (wood, energy crops, and biomass co-firing), geothermal, landfill gas, solar thermal electricity, solar photovoltaics, and wind energy. The RFM contains renewable resource supply estimates representing the regional opportunities for renewable energy development. Investment tax credits for renewable fuels are incorporated, as currently legislated in the EPACT1992 and EPACT2005. EPACT1992 provides a 10-percent tax credit for business investment in solar energy (thermal non-power uses as well as power uses) and geothermal power. EPACT2005 increases the tax credit to 30 percent for solar energy systems installed before January 1, 2008. The credits have no expiration dates.

Production tax credits for wind, geothermal, landfill gas, and some types of hydroelectric and biomass-fueled plants are also represented. They provide a tax credit of up to 1.9 cents per kilowatthour for electricity produced in the first 10 years of plant operation. New plants that come on line before January 1, 2008, are eligible to receive the credit. Significant changes made for *AEO2006* in the accounting of new renewable energy capacity resulting from State renewable portfolio standards, mandates, and goals are described in *Assumptions to the Annual Energy Outlook 2006* [8].

Oil and Gas Supply Module

The Oil and Gas Supply Module represents domestic crude oil and natural gas supply within an integrated framework that captures the interrelationships among the various sources of supply: onshore, offshore, and Alaska by both conventional and nonconventional techniques, including natural gas recovery from coalbeds and low-permeability formations of sandstone and shale. This framework analyzes cash flow and profitability to compute investment and drilling for each of the supply sources, based on the prices for crude oil and natural gas, the domestic recoverable resource base, and the state of technology. Oil and gas production functions are computed at a level of 12 supply regions, including 3 offshore and 3 Alaskan regions. This module also represents foreign sources of natural gas, including pipeline imports and exports to Canada and Mexico, and liquefied natural gas (LNG) imports and exports.

Crude oil production quantities are input to the Petroleum Market Module in NEMS for conversion and blending into refined petroleum products. Supply curves for natural gas are input to the Natural Gas Transmission and Distribution Module for use in determining natural gas prices and quantities. International LNG supply sources and options for regional expansions of domestic regasification capacity are represented, based on the projected regional costs associated with international gas supply, liquefaction, transportation, and regasification and world natural gas market conditions.

Natural Gas Transmission and Distribution Module

The Natural Gas Transmission and Distribution Module represents the transmission, distribution, and pricing of natural gas, subject to end-use demand for natural gas and the availability of domestic natural gas and natural gas traded on the international market. The module tracks the flows of natural gas in an aggregate domestic pipeline network, connecting the domestic and foreign supply regions with 12 demand regions. This capability allows the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of pipeline capacity expansion requirements. The flow of natural gas is determined for both a peak and off-peak period in the year. Key components of pipeline and distributor tariffs are included in separate pricing algorithms.

Petroleum Market Module

The Petroleum Market Module (PMM) projects prices of petroleum products, crude oil and product import activity, and domestic refinery operations (including fuel consumption), subject to the demand for petroleum products, the availability and price of imported petroleum, and the domestic production of crude oil, natural gas liquids, and alcohol and biodiesel fuels. The module represents refining activities in the five Petroleum Administration for Defense Districts (PADDs), using the same crude oil types represented in the International Energy Module. It explicitly models the requirements of CAAA and the costs of automotive fuels, such as conventional and reformulated gasoline, and includes biofuels production for blending in gasoline and diesel.

AEO2006 reflects State legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Maine, Michigan, Minnesota, Missouri, Montana, Nebraska, New Hampshire, New Jersey, New York, North Carolina, Ohio, Rhode Island, South Dakota, Vermont, Washington, and Wisconsin. Furthermore, MTBE is assumed to be phased out by the end of 2008 as a result of EPACT2005, which allows refiners to discontinue use of oxygenates in reformulated gasoline, and because of concern about MTBE contamination of surface water and groundwater resources.

The nationwide phase-in of gasoline with an annual average sulfur content of 30 ppm between 2005 and 2007, regulations that limit the sulfur content of highway diesel fuel to 15 ppm starting in mid-2006 and of all nonroad and locomotive/marine diesel to 15 ppm by mid-2012, and the renewable fuels standard of 7.5 billion gallons by 2012 are represented in *AEO2006*. Growth in demand and the costs of the regulations lead to capacity expansion for refinery-processing units, assuming a financing ratio of 60 percent equity and 40 percent debt, with a hurdle rate and an after-tax return on investment of about 9 percent [*9*]. End-use prices are based on the marginal costs of production, plus markups representing product and distribution costs and State and Federal taxes [*10*]. Expansion of refinery capacity at existing sites is permitted in all of the five refining regions modeled.

Fuel ethanol and biodiesel are included in the PMM, because they are commonly blended into petroleum products. The module allows ethanol blending into gasoline at 10 percent by volume or less, as well as limited quantities of E85, a blend of up to 85 percent ethanol by volume. Ethanol is produced primarily in the Midwest from corn or other starchy crops, and it is expected to be produced from cellulosic material in other regions in the future. Biodiesel is produced from soybean oil or yellow grease (primarily, recycled cooking oil). Both soybean oil biodiesel and yellow grease biodiesel are assumed to be blended into highway diesel.

Alternative fuels such as coal-to-liquids (CTL) and gas-to-liquids (GTL) are modeled in the PMM, based on their economics relative to competing feedstocks and products. CTL facilities are likely to be built at locations close to coal supply sources, where liquid products and electricity could also be distributed to nearby demand regions. GTL facilities may be built on the North Slope of Alaska but would compete with the Alaska Natural Gas Transportation System (ANGTS) for available natural gas resources. Both CTL and GTL are discussed in more detail in "Issues in Focus."

Coal Market Module

The Coal Market Module (CMM) simulates mining, transportation, and pricing of coal, subject to the end-use demand for coal differentiated by heat and sulfur content. U.S. coal production is represented in the CMM using 40 separate supply curves—differentiated by region, mine type, coal rank, and sulfur content. The coal supply curves include a response to capacity utilization of mines, mining capacity, labor productivity, and factor input costs (mining equipment, mining labor, and fuel requirements). Projections of U.S. coal distribution are determined in the CMM through the use of a linear programming algorithm that determines the least-cost supplies of coal for a given set of coal demands by demand region and sector, accounting for minemouth prices, transportation costs, existing coal supply contracts, and sulfur and mercury allowance costs. Over the projection horizon, coal transportation costs in the CMM are projected to vary in response to changes in railroad productivity and the user cost of rail transportation equipment.

The CMM produces projections of U.S. steam and metallurgical coal exports and imports, in the context of world coal trade. The CMM's linear programming algorithm determines the pattern of world coal trade flows that minimizes the production and transportation costs of meeting a pre-specified set of regional world coal import demands, subject to constraints on export capacities and trade flows. The international coal market component of the module computes trade in 3 types of coal for 16 export and 20 import regions. U.S. coal production and distribution are computed for 14 supply and 14 demand regions.

Annual Energy Outlook 2006 Cases

Table E1 provides a summary of the cases used to derive the *AEO2006* projections. For each case, the table gives the name used in this report, a brief description of the major assumptions underlying the projections, a designation of the mode in which the case was run in NEMS (either fully integrated, partially integrated, or standalone), and a reference to the pages in the body of the report and in this appendix where the case is discussed. The following sections describe the cases listed in Table E1. The reference case assumptions for each sector are described at web site www.eia.doe.gov/oiaf/aeo/assumption/. Regional results and other details of the projections are available at web site www.eia.doe.gov/oiaf/aeo/supplement/.

Macroeconomic Growth Cases

In addition to the *AEO2006* reference case, the *low economic growth* and *high economic growth cases* were developed to reflect the uncertainty in projections of economic growth. The alternative cases are intended to show the effects of alternative growth assumptions on energy market projections. The cases are described as follows:

- The low economic growth case assumes lower growth rates for population (0.5 percent per year), nonfarm employment (0.7 percent per year), and productivity (1.8 percent per year), resulting in higher prices and interest rates and lower growth in industrial output. In the low economic growth case, economic output increases by 2.4 percent per year from 2004 through 2030, and growth in GDP per capita averages 1.9 percent per year.
- The high economic growth case assumes higher growth rates for population (1.1 percent per year), nonfarm employment (1.4 percent per year), and productivity (2.7 percent per year). With higher productivity gains and employment growth, inflation and interest rates are lower than in the reference case, and consequently economic output grows at a higher rate (3.5 percent per year) than in the reference case (3.0 percent). GDP per capita grows by 2.4 percent per year, compared with 2.2 percent in the reference case.

Price Cases

The world oil price in *AEO2006* is represented by the average U.S. refiners acquisition costs of imported low-sulfur light crude oil, in order to be more consistent with prices typically reported in the media. The low-sulfur light crude oil price is similar to the West Texas Intermediate (WTI) crude oil price. *AEO2006* also includes a projection of the annual average U.S.

Table E1. Summary of the *AEO2006* cases

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Reference	Baseline economic growth (3.0 percent per year), world oil price, and technology assumptions. Complete projection tables in Appendix A.	Fully integrated	—	—
Low Economic Growth	Gross domestic product grows at an average annual rate of 2.4 percent from 2004 through 2030. Subset of projection tables in Appendix B.	Fully integrated	p. 62	p. 203
High Economic Growth	Gross domestic product grows at an average annual rate of 3.5 percent from 2004 through 2030. Subset of projection tables in Appendix B.	Fully integrated	p. 62	p. 203
Low Price	More optimistic assumptions for worldwide crude oil and natural gas resources than in the reference case. World oil prices are $28 per barrel in 2030, compared with $50 per barrel in the reference case, and lower 48 wellhead natural gas prices $4.96 per thousand cubic feet in 2030, compared with $5.92 in the reference case. Subset of projection tables in Appendix C.	Fully integrated	p. 64	p. 206
High Price	More pessimistic assumptions for worldwide crude oil and natural gas resources than in the reference case. World oil prices are about $90 per barrel in 2030 and lower 48 wellhead natural gas prices $7.72 per thousand cubic feet in 2030. Subset of projection tables in Appendix C.	Fully integrated	p. 64	p. 206
Residential: 2005 Technology	Future equipment purchases based on equipment available in 2005. Existing building shell efficiencies fixed at 2005 levels. Partial projection tables in Appendix D.	With commercial	p. 68	p. 206
Residential: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Building shell efficiencies increase by 22 percent from 2003 values by 2030. Partial projection tables in Appendix D.	With commercial	p. 68	p. 207
Residential: Best Available Technology	Future equipment purchases and new building shells based on most efficient technologies available. Building shell efficiencies increase by 26 percent from 2003 values by 2030. Partial projection tables in Appendix D.	With commercial	p. 68	p. 207
Commercial: 2005 Technology	Future equipment purchases based on equipment available in 2005. Building shell efficiencies fixed at 2005 levels. Partial projection tables in Appendix D.	With residential	p. 70	p. 207
Commercial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Building shell efficiencies for new and existing buildings increase by 10.4 and 7.4 percent, respectively, from 1999 values by 2030. Partial projection tables in Appendix D.	With residential	p. 70	p. 207
Commercial: Best Available Technology	Future equipment purchases based on most efficient technologies available. Building shell efficiencies for new and existing buildings increase by 12.4 and 8.9 percent, respectively, from 1999 values by 2030. Partial projection tables in Appendix D.	With residential	p. 70	p. 207
Industrial: 2005 Technology	Efficiency of plant and equipment fixed at 2005 levels. Partial projection tables in Appendix D.	Standalone	p. 73	p. 207
Industrial: High Technology	Earlier availability, lower costs, and higher efficiencies assumed for more advanced equipment. Partial projection tables in Appendix D.	Standalone	p. 73	p. 207
Transportation: 2005 Technology	Efficiencies for new equipment in all modes of travel fixed at 2005 levels. Partial projection tables in Appendix D.	Standalone	p. 76	p. 208

Table E1. Summary of the *AEO2006* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Transportation: High Technology	Reduced costs and improved efficiencies assumed for advanced technologies. Partial projection tables in Appendix D.	Standalone	p. 76	p. 208
Transportation: Alternative CAFE	Assumes that manufacturers adhere to the proposed fleetwide increases in light truck CAFE standards to 24 miler per gallon for model year 2011.	Standalone	p. 24	p. 208
Integrated 2005 Technology	Combination of the residential, commercial, industrial, and transportation 2005 technology cases, electricity low fossil technology case, and assumption of renewable technologies fixed at 2005 levels. Partial projection tables in Appendix D.	Fully integrated	p. 60	—
Integrated High Technology	Combination of the residential, commercial, industrial, and transportation high technology cases, electricity high fossil technology case, high renewables case, and advanced nuclear cost case. Partial projection tables in Appendix D.	Fully integrated	p. 60	—
Electricity: Advanced Nuclear Cost	New nuclear capacity assumed to have 20 percent lower capital and operating costs in 2030 than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 84	p. 208
Electricity: Nuclear Vendor Estimate	New nuclear capacity assumed to have lower capital costs based on vendor goals. Partial projection tables in Appendix D.	Fully integrated	p. 84	p. 208
Electricity: Low Fossil Technology	New advanced fossil generating technologies assumed not to improve over time from 2006. Partial projection tables in Appendix D.	Fully integrated	p. 83	p. 209
Electricity: High Fossil Technology	Costs and efficiencies for advanced fossil-fired generating technologies improve by 10 percent in 2030 from reference case values. Partial projection tables in Appendix D.	Fully integrated	p. 83	p. 208
Electricity: Mercury Control Technologies	Cost and performance for halogenated activated carbon injection technology used to determine its impact on mercury removal requirements from coal-fired power plants.	Fully integrated	p. 59	p. 209
Renewables: Low Renewables	New renewable generating technologies assumed not to improve over time from 2006. Partial projection tables in Appendix D.	Fully integrated	p. 84	p. 209
Renewables: High Renewables	Levelized cost of energy for nonhydropower renewable generating technologies declines by 10 percent in 2030 from reference case values. Lower capital cost for cellulose ethanol plants. Partial projection tables in Appendix D.	Fully integrated	p. 84	p. 209
Oil and Gas: Slow Technology	Cost, finding rate, and success rate parameters adjusted for 50-percent slower improvement than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 88	p. 210
Oil and Gas: Rapid Technology	Cost, finding rate, and success rate parameters adjusted for 50-percent more rapid improvement than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 88	p. 209
Oil and Gas: Low LNG	LNG imports exogenously set to 30 percent less than the results from the high price case, with remaining assumptions from the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 90	p. 210

Table E1. Summary of the *AEO2006* cases (continued)

Case name	Description	Integration mode	Reference in text	Reference in Appendix E
Oil and Gas: High LNG	LNG imports exogenously set to 30 percent more than the results from the low price case, with remaining assumptions from the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 90	p. 210
Oil and Gas: ANWR	Federal oil and gas leasing permitted in the Arctic National Wildlife Refuge starting in 2005. Partial projection tables in Appendix D.	Fully integrated	p. 94	p. 210
Coal: Low Cost	Productivity for coal mining and coal transportation assumed to increase more rapidly than in the reference case. Coal mining wages, mine equipment and coal transportation equipment costs assumed to be lower than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 102	p. 210
Coal: High Cost	Productivity for coal mining and coal transportation assumed to increase more slowly than in the reference case. Coal mining wages, mine equipment and coal transportation equipment costs assumed to be higher than in the reference case. Partial projection tables in Appendix D.	Fully integrated	p. 102	p. 210

refiners acquisition cost of imported crude oil (IRAC), which is more representative of the average cost of all crude oil used by refiners.

The historical record shows substantial variability in world oil prices, and there is arguably even more uncertainty about future prices in the long term. *AEO2006* considers three price cases (*reference* case, *low price case*, and *high price case*) to allow an assessment of alternative views on the course of future oil and natural gas prices. In the reference case, world oil prices moderate from current levels through 2015 before beginning to rise to $57 per barrel in 2030 (2004 dollars). The low and high price cases define a wide range of potential price paths (from $34 to $96 per barrel in 2030). The two cases reflect different assumptions about the availability of world oil and natural gas resources and production costs; they do not assume changes in OPEC behavior. Because the low and high price cases are not directly integrated with a world economic model, the impact of world oil prices on international economies is not directly accounted for in this analysis.

- The reference case represents EIA's current judgment regarding the expected behavior of OPEC producers in the long term, adjusting production to keep world oil prices in a range of $40 to $50 per barrel, in keeping with OPEC's stated goal of keeping potential competitors from eroding its market share. Because OPEC (and particularly the Persian Gulf nations) is expected to be the dominant supplier of oil in the international market over the long term, its production choices will significantly affect world oil prices.
- The low price case assumes greater world crude oil and natural gas resources which are less expensive to produce and a future market where all oil and natural gas production becomes more competitive and plentiful than the reference case.
- The high price case assumes that world crude oil and natural gas resources, including OPEC's, are lower and require greater cost to produce than assumed in the reference case.

Buildings Sector Cases

In addition to the *AEO2006* reference case, three standalone technology-focused cases using the Residential and Commercial Demand Modules of NEMS were developed to examine the effects of changes to equipment and building shell efficiencies.

For the residential sector, the three technology-focused cases are as follows:

- The *2005 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2005. Existing building shell efficiencies are assumed to be fixed at 2005 levels.

- The *high technology case* assumes earlier availability, lower costs, and higher efficiencies for more advanced equipment [*11*]. Building shell efficiency in 2030 is assumed to be 22 percent higher than the 2003 level.
- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. Building shell efficiency in 2030 is assumed to be 26 percent higher than the 2003 level.

For the commercial sector, the three technology-focused cases are as follows:

- The *2005 technology case* assumes that all future equipment purchases are based only on the range of equipment available in 2005. Building shell efficiencies are assumed to be fixed at 2005 levels.
- The *high technology case* assumes earlier availability, lower costs, and/or higher efficiencies for more advanced equipment than in the reference case [*12*]. Building shell efficiencies for new and existing buildings in 2030 are assumed to be 10.4 percent and 7.4 percent higher, respectively, than their 1999 levels—a 25-percent improvement relative to the reference case.
- The *best available technology case* assumes that all future equipment purchases are made from a menu of technologies that includes only the most efficient models available in a particular year, regardless of cost. Building shell efficiencies for new and existing buildings in 2030 are assumed to be 12.4 percent and 8.9 percent higher, respectively, than their 1999 values—a 50-percent improvement relative to the reference case.

Two additional integrated cases were developed, in combination with assumptions for electricity generation from renewable fuels, to analyze the sensitivity of the projections to changes in generating technologies that use renewable fuels and in the availability of renewable energy sources. For the Residential and Commercial Demand Modules:

- The *high renewables case* assumes greater improvements in residential and commercial photovoltaic systems than in the reference case. The high renewables assumptions result in capital cost estimates for 2030 that are approximately 10 percent lower than reference case costs for distributed photovoltaic technologies.
- The *low renewables case* assumes that costs and performance levels for residential and commercial photovoltaic systems remain constant at 2005 levels through 2030.

Industrial Sector Cases

In addition to the *AEO2006* reference case, two standalone cases using the Industrial Demand Module of NEMS were developed to examine the effects of less rapid and more rapid technology change and adoption. The Industrial Demand Module was also used as part of an integrated high renewables case. For the industrial sector:

- The *2005 technology case* holds the energy efficiency of plant and equipment constant at the 2005 level over the projection period. In this case, delivered energy intensity falls by 0.9 percent annually. Because the level and composition of industrial output are the same in the reference, 2005 technology, and high technology cases, any change in primary energy intensity in the two technology cases is attributable to efficiency changes. The 2005 technology case was run with only the Industrial Demand Module, rather than in fully integrated NEMS runs. Consequently, no potential feedback effects from energy market interactions were captured.
- The *high technology case* assumes earlier availability, lower costs, and higher efficiency for more advanced equipment [*13*] and a more rapid rate of improvement in the recovery of biomass byproducts from industrial processes (0.7 percent per year, as compared with 0.4 percent per year in the reference case). The same assumption is also incorporated in the integrated high renewables case, which focuses on electricity generation. While the choice of 0.7 percent recovery is an assumption of the high technology case, it is based on the expectation that there would be higher recovery rates and substantially increased use of CHP in that case. Changes in aggregate energy intensity result both from changing equipment and production efficiency and from changing composition of industrial output. Because the composition of industrial output remains the same as in the reference case, delivered energy intensity falls by 1.4 percent annually in the high technology case. In the reference case, delivered energy intensity falls by 1.2 percent annually between 2004 and 2030.

Transportation Sector Cases

In addition to the *AEO2006* reference case, two standalone cases using the Transportation Demand Module of NEMS were developed to examine the effects of less rapid technology change and adoption and more rapid technology change and adoption. For the transportation sector:

- The *2005 technology case* assumes that new vehicle fuel efficiencies remain constant at 2005 levels through the projection horizon, unless emissions and/or efficiency regulations require the implementation of technology that affects vehicle efficiency. For example, the new light truck corporate average fuel economy (CAFE) standards require an increase in fuel economy through 2007, and increases in heavy truck emissions standards are required through 2010. As a result, the technology available for light truck efficiency improvement is frozen at 2007 levels, and the technology available to heavy trucks is frozen at 2010 levels.
- In the *high technology case*, the characteristics of light-duty conventional and alternative-fuel vehicles reflect more optimistic assumptions about incremental improvements in fuel economy and costs [*14*]. In the air travel sector, the high technology case reflects lower costs for improved thermodynamics, advanced aerodynamics, and weight-reducing materials, providing a 25-percent improvement in new aircraft efficiency relative to the reference case in 2025. In the freight truck sector, the high technology case assumes more incremental improvement in fuel efficiency for engine and emissions control technologies [*15*]. More optimistic assumptions for fuel efficiency improvements are also made for the rail and shipping sectors.

Both cases were run with only the Transportation Demand Module rather than as fully integrated NEMS runs. Consequently, no potential macroeconomic feedback on travel demand was captured, nor were changes in fuel prices incorporated.

In addition to these standalone cases, EIA also developed an *alternative CAFE case* designed to examine the potential energy impacts of proposed reforms to the structure of CAFE standards for light trucks and increases in light truck CAFE standards for model years 2008 through 2011 [*16*]. The alternative CAFE case assumes that manufacturers will adhere to the proposed fleet-wide increases in light truck CAFE standards, to 24 miles per gallon for model year 2011.

Electricity Sector Cases

In addition to the reference case, four integrated cases with alternative electric power assumptions were developed to analyze uncertainties about the future costs and performance of new generating technologies. Two of the cases examine alternative assumptions for nuclear power technologies, and two examine alternative assumptions for fossil fuel technologies. Reference case values for technology characteristics are determined in consultation with industry and government specialists; however, there is always uncertainty surrounding newer, untested designs. The electricity cases analyze what could happen if costs of advanced designs are either higher or lower than assumed in the reference case. The cases are fully integrated to allow feedback between the potential shifts in fuel consumption and fuel prices.

Nuclear Technology Cases

- The cost assumptions for the *advanced nuclear cost case* reflect a 20-percent reduction in the capital and operating costs for advanced nuclear technology in 2030, relative to the reference case. The reference case, which assumes that some learning occurs regardless of new orders and construction, projects a 14-percent reduction in the capital costs of nuclear power plants between 2006 and 2030. The advanced nuclear cost case assumes a 31-percent reduction between 2006 and 2030.
- The *nuclear vendor estimate case* uses assumptions that are consistent with estimates from British Nuclear Fuels Limited (Westinghouse) for the manufacture of its AP1000 advanced pressurized-water reactor. In this case, the overnight capital cost of a new advanced nuclear unit is assumed to be 18 percent lower initially than assumed in the reference case and 44 percent lower in 2030. In both of the alternative nuclear cases, cost and performance characteristics for all other technologies are as assumed in the reference case.

Fossil Technology Cases

- In the *high fossil technology case*, capital costs, heat rates, and operating costs for advanced coal and natural gas generating technologies are assumed to be 10 percent lower than reference case levels in 2030. Because learning is assumed to occur in the reference case, costs and performance in the high case are reduced from initial levels by more than 10 percent. Heat rates in the *high fossil technology case* fall to between 16 and 22 percent below initial levels, and capital costs are reduced by 22 to 26 percent between 2006 and 2030, depending on the technology.

- In the *low fossil technology case*, capital costs and heat rates for coal gasification combined-cycle units and advanced combustion turbine and combined-cycle units do not decline during the projection period but remain fixed at the 2006 values assumed in the reference case.

Details about annual capital costs, operating and maintenance costs, plant efficiencies, and other factors used in the high and low fossil technology cases are described in the detailed assumptions, which are available at web site www.eia.doe.gov/oiaf/aeo/assumption/.

An additional integrated case was also run to analyze the potential impacts of improved mercury control technologies to comply with CAMR. A detailed description of the rule is included in "Legislation and Regulations."

- In the *mercury control technology case*, the cost and performance for halogenated activated carbon injection technology are used to determine its impact on mercury removal requirements from coal-fired power plants. Conventional activated carbon injection has not been effective in achieving high mercury removal rates from subbituminous and lignite coals, but preliminary tests show that high levels of mercury removal can be achieved with relatively low rates of brominated activated carbon injection. If brominated activated carbon becomes commercially available by 2018, it could have significant impacts on the cost of achieving mercury removal targets.

Renewable Fuels Cases

In addition to the *AEO2006* reference case, two integrated cases with alternative assumptions about renewable fuels were developed to examine the effects of less aggressive and more aggressive improvement in renewable technologies. The cases are as follows:

- In the *low renewables case*, capital costs, operations and maintenance costs, and performance levels for wind, solar, biomass, and geothermal resources are assumed to remain constant at 2006 levels through 2030.
- In the *high renewables case*, the levelized costs of energy for nonhydroelectric generating technologies using renewable resources are assumed to decline to 10 percent below the reference case costs for the same resources in 2030. For most renewable resources, lower costs are accomplished by reducing the capital costs of new plant construction. To reflect recent trends in wind energy cost reductions, however, it is assumed that wind plants ultimately achieve the 10-percent cost reduction through a combination of performance improvement (increased capacity factor) and capital cost reductions. Biomass supplies are also assumed to be 10 percent greater for each supply step. Annual limits are placed on the development of geothermal sites, because they require incremental development to assure that the resource is viable. In the high renewables case, the annual limits on capacity additions at geothermal sites are raised from 25 megawatts per year through 2015 to 50 megawatts per year for all projection years. All other cases are assumed to retain the 25-megawatt limit through 2015. Other generating technologies and projection assumptions remain unchanged from those in the reference case. In the high renewables case, the rate of improvement in recovery of biomass byproducts from industrial processes is also increased. More rapid improvement in cellulosic ethanol production technology is also assumed, resulting in lower cost for cellulose ethanol at any level of output than in the reference case.

Oil and Gas Supply Cases

Two alternative technology cases were created to assess the sensitivity of the projections to changes in the assumed rates of progress in oil and natural gas supply technologies. In addition, high and low LNG supply cases were developed to examine the impacts of variations in LNG supply on the domestic natural gas market.

- In the *rapid technology case*, the parameters representing the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates for conventional oil and natural gas drilling in the reference case were increased by 50 percent. A number of key exploration and production technologies for unconventional natural gas were also increased by 50 percent in the rapid technology case. Key Canadian supply parameters were also modified to simulate the assumed impacts of more rapid oil and natural gas technology penetration on the Canadian supply potential. All other parameters in the model were kept at the reference case values, including technology parameters for other modules, parameters affecting foreign oil supply, and assumptions about imports and exports of LNG and natural gas trade between the United States and Mexico. Specific detail by region and fuel category is presented in *Assumptions to the Annual Energy Outlook 2006*, available at web site www. eia.doe.gov/oiaf/aeo/assumption/.

- In the *slow technology case*, the parameters representing the effects of technological progress on finding rates, drilling, lease equipment and operating costs, and success rates for conventional oil and natural gas drilling in the *AEO2006* reference case were reduced by 50 percent. A number of key exploration and production technologies for unconventional natural gas were also reduced by 50 percent in the slow technology case. Key Canadian supply parameters were also modified to simulate the assumed impacts of slow oil and natural gas technology penetration on Canadian supply potential. All other parameters in the model were kept at the reference case values.
- The *high LNG case* exogenously specifies LNG imports at levels 30 percent higher than projected in the low price case. The intent is to project the potential impact on domestic markets if LNG imports turn out to be higher than projected in the reference case.
- The *low LNG case* exogenously specifies LNG imports at levels 30 percent lower than projected in the high price case. The intent is to project the potential impact on domestic markets if LNG imports turn out to be lower than projected in the reference case.
- The *ANWR case* assumes that the U.S. Congress will approve leasing in the 1002 Area Federal lands in the Arctic National Wildlife Refuge for oil and natural gas exploration and production.

Petroleum Market Cases

In addition to the *AEO2006* reference case, a case that is part of the integrated high renewable case evaluates the impact of more optimistic assumptions about biomass supplies on the production and use of cellulosic ethanol.

- The *high renewables case* uses more optimistic assumptions about the availability of renewable energy sources. The supply curve for cellulosic ethanol is shifted in each projection year relative to the reference case, making larger quantities available at any given price earlier than in the reference case. More rapid improvement in cellulosic ethanol production technology is also assumed, resulting in lower cost for cellulose ethanol at any level of output than in the reference case.

Coal Market Cases

Two alternative coal cost cases examine the impacts on U.S. coal supply, demand, distribution, and prices that result from alternative assumptions about mining productivity, labor costs, and mine equipment costs on the production side, and railroad productivity and rail equipment costs on the transportation side. For the coal cost cases, adjustments to the reference case assumptions for coal mining and railroad productivity were based on variations in growth rates observed in the data for these industries since 1980. The low and high coal cost cases represent fully integrated NEMS runs, with feedback from the macroeconomic activity, international, supply, conversion, and end-use demand modules.

- In the *low coal cost case*, average annual productivity growth rates for coal mining and railroad productivity are 2.5 percent and 2.6 percent higher, respectively, than in the *AEO2006* reference case. On the mining side, adjustments to reference case productivity are applied at the supply curve level, while adjustments to railroad productivity are made at the regional level. Coal mining wages and mine equipment costs, which remain constant in real dollars in the reference case, are assumed to decline by 1.0 percent per year in real terms in the low coal cost case. Railroad equipment costs, which are projected to increase by 2.1 percent per year in constant dollars in the reference case, are assumed to increase at a slower rate of 1.1 percent per year.
- In the *high coal cost case*, average annual productivity growth rates for coal mining and railroad productivity are 2.5 percent and 2.6 percent lower, respectively, than in the *AEO2006* reference case. Coal mining wages and mine equipment costs are assumed to increase by 1.0 percent per year in real terms. Railroad equipment costs are assumed to increase by 3.1 percent per year.

Additional details about the productivity, wage, and equipment cost assumptions for the reference and alternative coal cost cases are provided in Appendix D.

Notes

[1]Energy Information Administration, The *National Energy Modeling System: An Overview 2003*, DOE/EIA-0581(2003) (Washington, DC, March 2003).

[2]Energy Policy Act of 2005, P.L. 109-58.

[3]Energy Policy Act of 1992, P.L. 102-486, Title III, Section 303, and Title V, Sections 501 and 507.

[4]Energy Information Administration, *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005).

[5]Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2004*, DOE/EIA-0573(2004) (Washington, DC, December 2005).

[6]Energy Information Administration, *Short-Term Energy Outlook*, web site www.eia.doe.gov/emeu/steo/pub/contents.html. Portions of the preliminary information were also used to initialize the NEMS Petroleum Market Module projection.

[7]Jet Information Services, Inc., *World Jet Inventory Year-End 2003* (Woodinville, WA, March 2004), and personal communication from Bill Francoins (Jet Information Services) and Thomas C. Hoang (Boeing).

[8]Energy Information Administration, *Assumptions to the Annual Energy Outlook 2006*, DOE/EIA-0554 (2006) (Washington, DC, to be published).

[9]The hurdle rate for a coal-to-liquids (CTL) plant is assumed to be 12.3 percent because of the higher economic risk involved in this technology.

[10]For gasoline blended with ethanol, the tax credit of 51 cents (nominal) per gallon of ethanol is assumed to be extended through 2030, based on the fact that the ethanol tax credit has been continuously in force for the past 25 years and was recently extended from 2007 to 2010 by the American Jobs Creation Act of 2004.

[11]High technology assumptions are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004).

[12]High technology assumptions are based on Energy Information Administration, *EIA—Technology Forecast Updates—Residential and Commercial Building Technologies—Advanced Adoption Case* (Navigant Consulting, Inc., September 2004).

[13]These assumptions are based in part on Energy Information Administration, *Industrial Technology and Data Analysis Supporting the NEMS Industrial Model* (FOCIS Associates, October 2005).

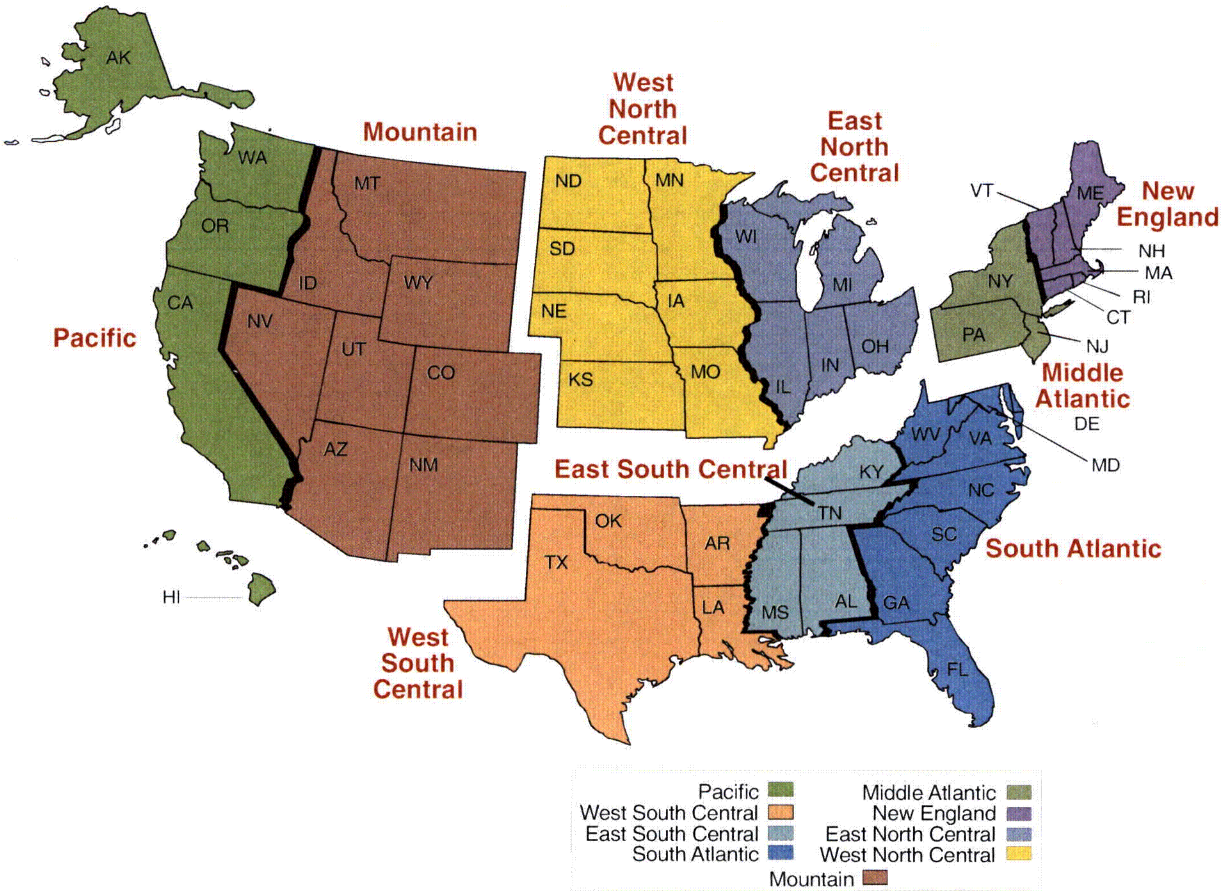
[14]Energy Information Administration, *Documentation of Technologies Included in the NEMS Fuel Economy Model for Passenger Cars and Light Trucks* (Energy and Environmental Analysis, September 2003).

[15]A. Vyas, C. Saricks, and F. Stodolsky, *Projected Effect of Future Energy Efficiency and Emissions Improving Technologies on Fuel Consumption of Heavy Trucks* (Argonne, IL: Argonne National Laboratory, 2001).

[16]National Highway Traffic Safety Administration, *Average Fuel Economy Standards for Light Trucks Model Years 2008-2011*, 49 CFR Parts 523, 533, and 537, Docket No. 2005-22223, RIN 2127-AJ61 (Washington, DC, August 2005).

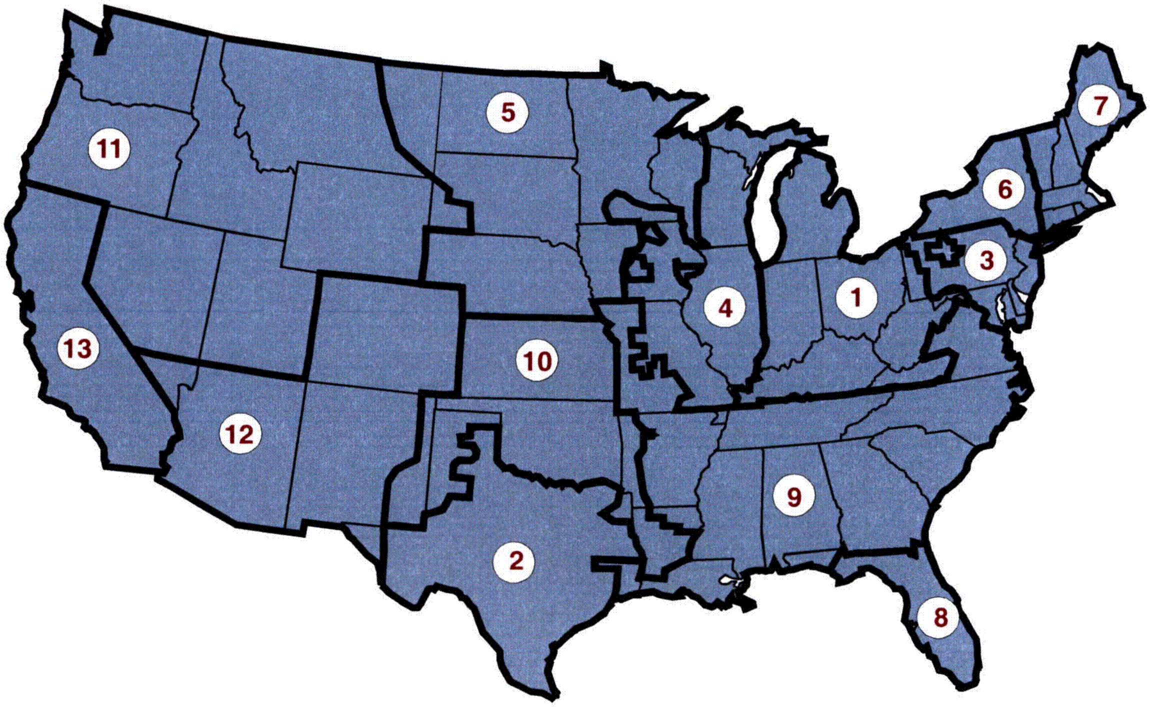
Regional Maps

F1. United States Census Divisions



Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

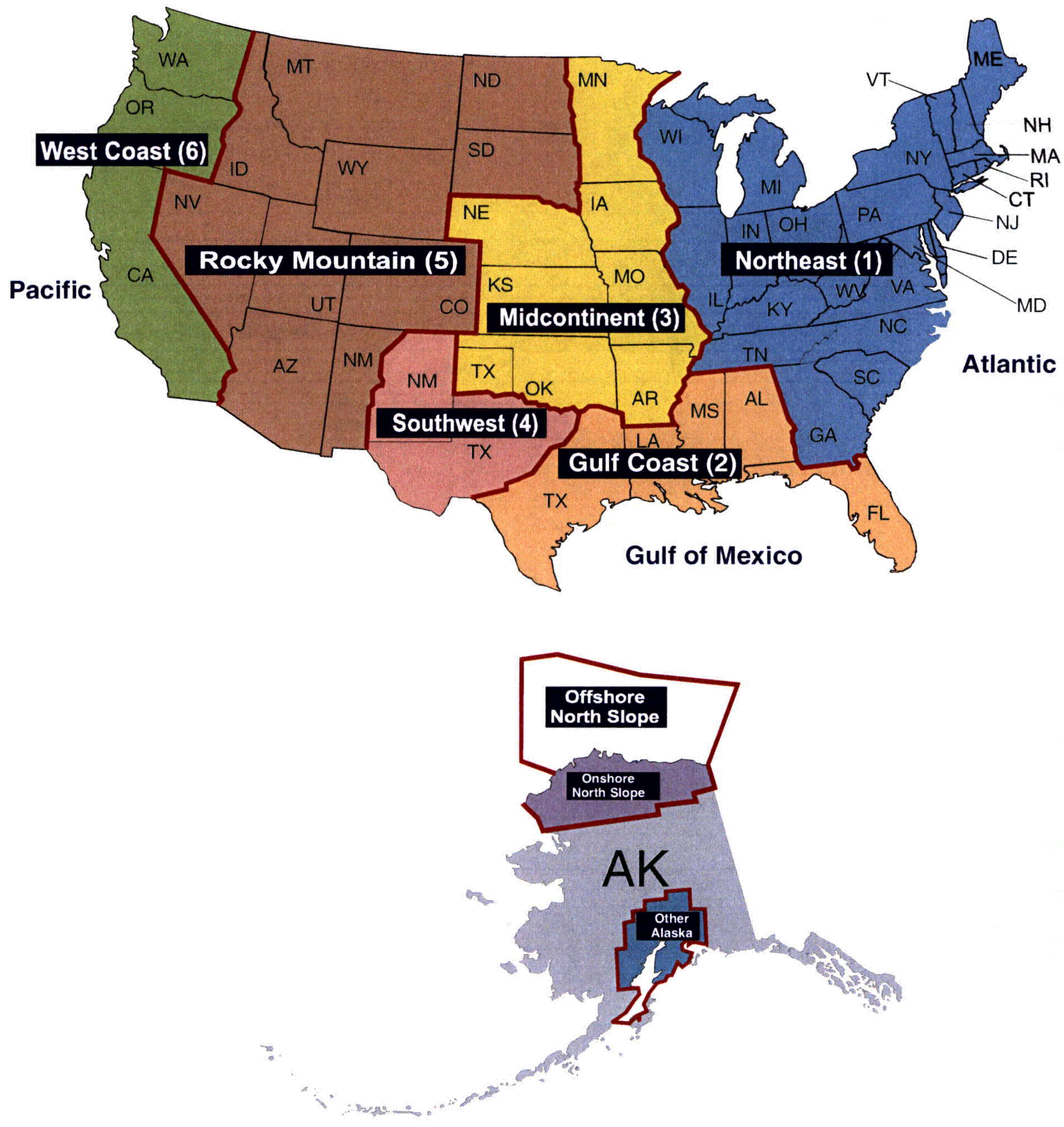
F2. Electricity Market Module Regions



1 East Central Area Reliability Coordination Agreement (ECAR)
2 Electric Reliability Council of Texas (ERCOT)
3 Mid-Atlantic Area Council (MAAC)
4 Mid-America Interconnected Network (MAIN)
5 Mid-Continent Area Power Pool (MAPP)
6. New York (NY)
7. New England (NE)
8. Florida Reliability Coordinating Council (FL)
9. Southeastern Electric Reliability Council (SERC)
10. Southwest Power Pool (SPP)
11. Northwest Power Pool (NWP)
12. Rocky Mountain Power Area, Arizona, New Mexico, and Southern Nevada (RA)
13. California (CA)

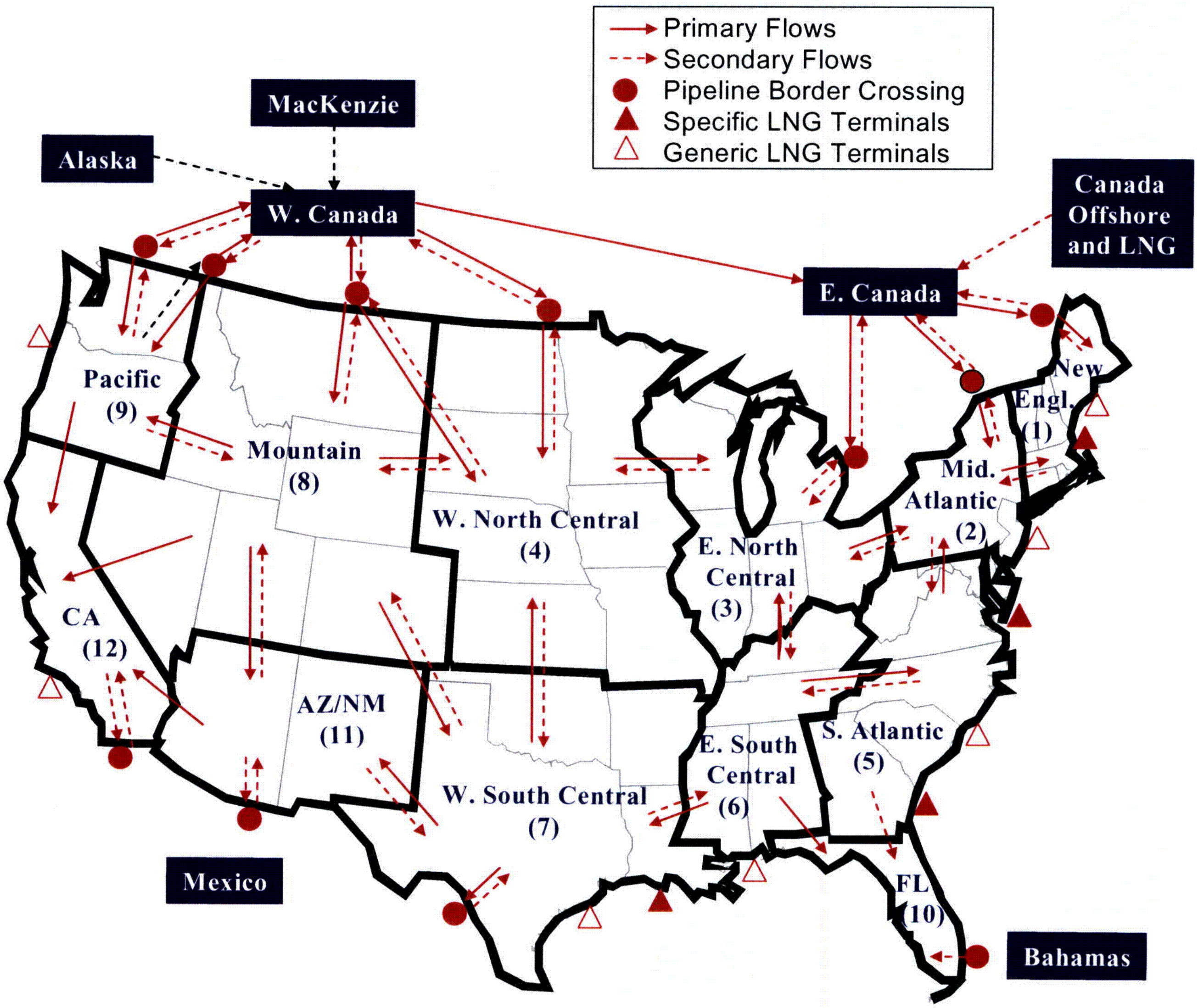
Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F3. Oil and Gas Supply Model Regions



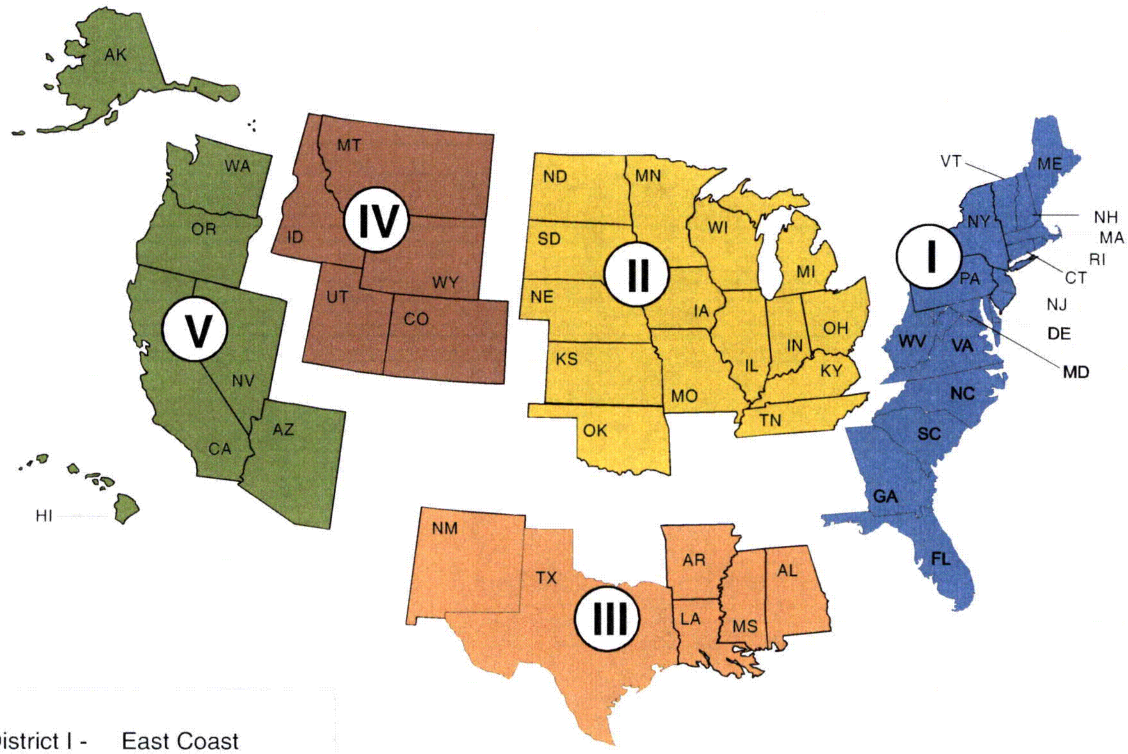
Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F4. Natural Gas Transmission and Distribution Model Regions



Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

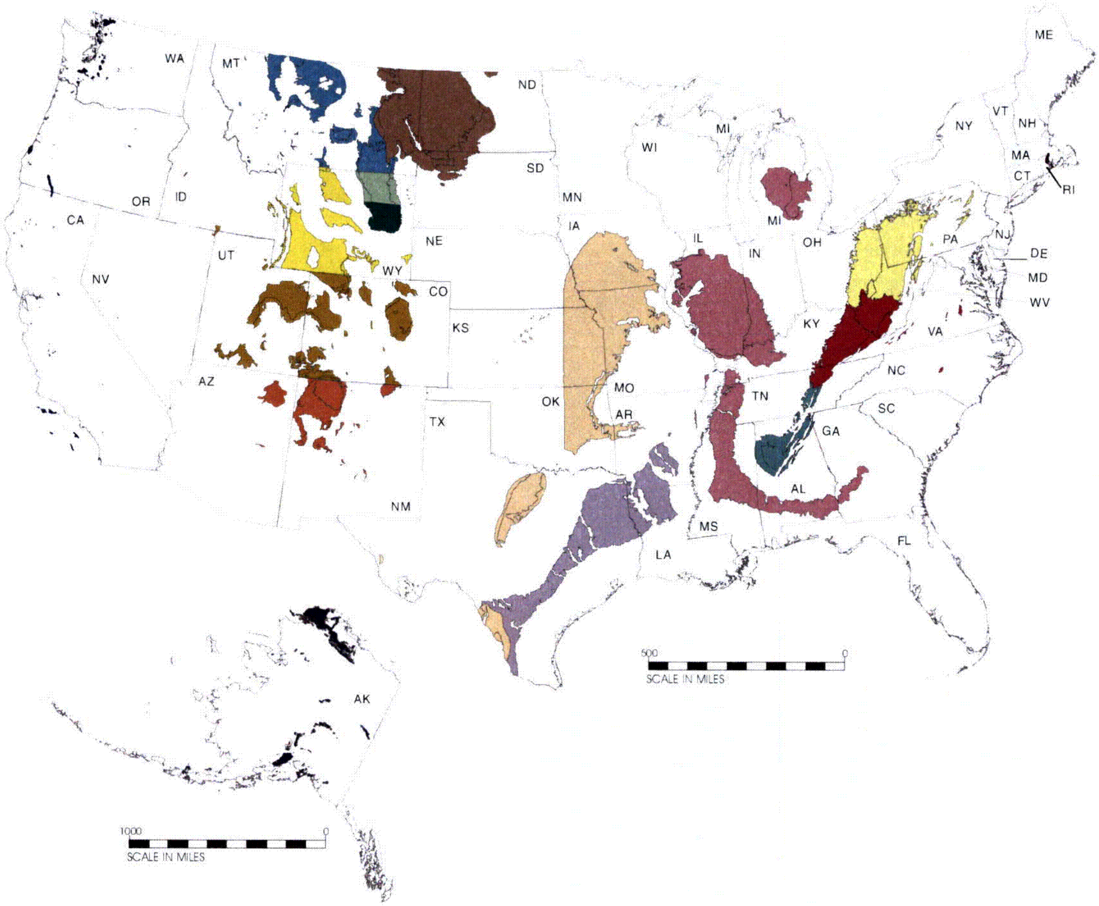
F5. Petroleum Administration for Defense Districts



PAD District I - East Coast
PAD District II - Midwest
PAD District III - Gulf Coast
PAD District IV - Rocky Mountain
PAD District V - West Coast

Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F6. Coal Supply Regions



NORTHERN GREAT PLAINS
- Dakota Lignite
- Western Montana
- Wyoming, Northern Powder River Basin
- Wyoming, Southern Powder River Basin
- Western Wyoming

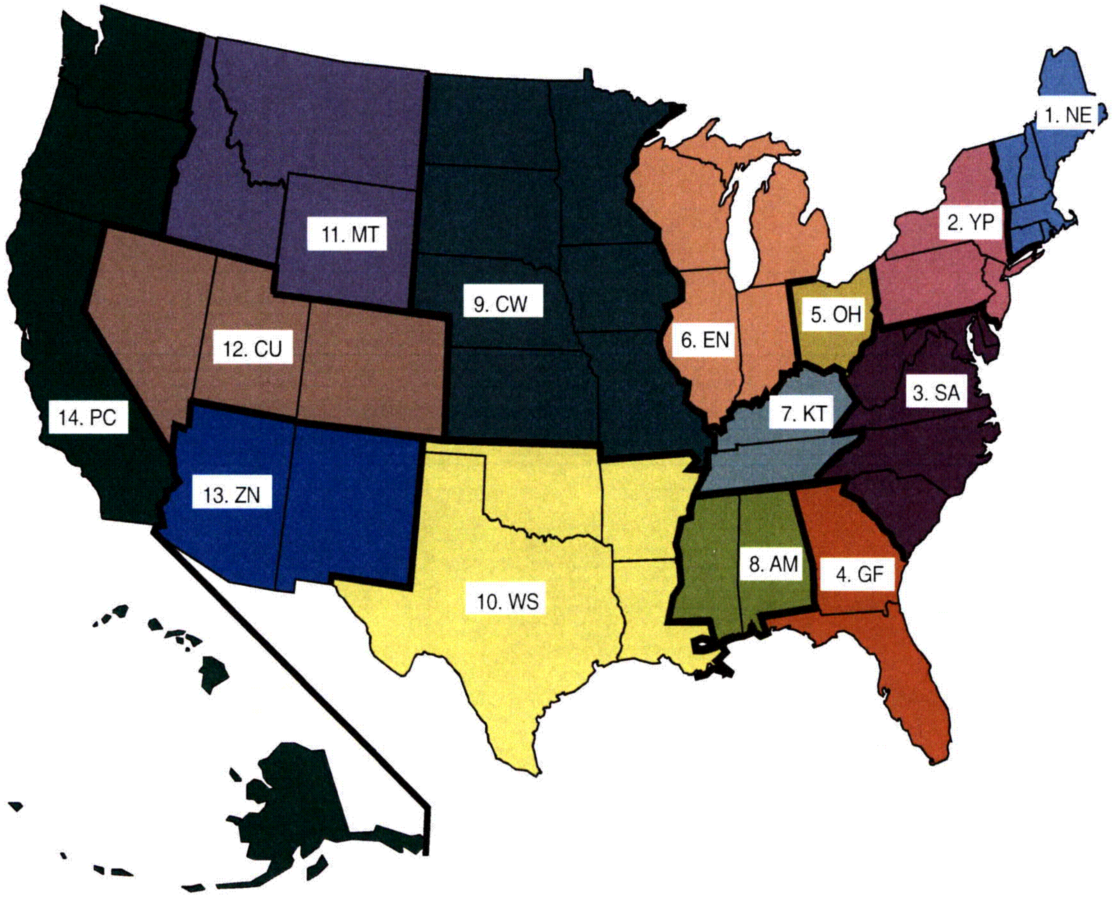
APPALACHIA
- Northern Appalachia
- Central Appalachia
- Southern Appalachia

INTERIOR
- Eastern Interior
- Western Interior
- Gulf Lignite

OTHER WEST
- Rocky Mountain
- Southwest
- Northwest

Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

F7. Coal Demand Regions



Region Code	Region Content
1. NE	CT,MA,ME,NH,RI,VT
2. YP	NY,PA,NJ
3. SA	WV,MD,DC,DE,VA,NC,SC
4. GF	GA,FL
5. OH	OH
6. EN	IN,IL,MI,WI
7. KT	KY,TN
8. AM	AL,MS
9. CW	MN,IA,ND,SD,NE,MO,KS
10. WS	TX,LA,OK,AR
11. MT	MT,WY,ID
12. CU	CO,UT,NV
13. ZN	AZ,NM
14. PC	AK,HI,WA,OR,CA

Source: Energy Information Administration. Office of Integrated Analysis and Forecasting.

Conversion Factors

Table G1. Heat Rates

Fuel	Units	Approximate Heat Content
Coal[1]		
Production	million Btu per short ton	20.411
Consumption	million Btu per short ton	20.276
Coke Plants	million Btu per short ton	27.426
Industrial	million Btu per short ton	22.473
Residential and Commercial	million Btu per short ton	22.948
Electric Power Sector	million Btu per short ton	19.966
Imports	million Btu per short ton	25.000
Exports	million Btu per short ton	26.108
Coal Coke	million Btu per short ton	24.800
Crude Oil		
Production	million Btu per barrel	5.800
Imports[1]	million Btu per barrel	5.980
Petroleum Products		
Consumption[1]	million Btu per barrel	5.357
Motor Gasoline[1]	million Btu per barrel	5.215
Jet Fuel	million Btu per barrel	5.670
Distillate Fuel Oil[1]	million Btu per barrel	5.799
Residual Fuel Oil	million Btu per barrel	6.287
Liquefied Petroleum Gas[1]	million Btu per barrel	3.618
Kerosene	million Btu per barrel	5.670
Petrochemical Feedstocks[1]	million Btu per barrel	5.527
Unfinished Oils	million Btu per barrel	5.825
Imports[1]	million Btu per barrel	5.473
Exports[1]	million Btu per barrel	5.753
Natural Gas Plant Liquids		
Production[1]	million Btu per barrel	3.724
Natural Gas[1]		
Production, Dry	Btu per cubic foot	1,027
Consumption	Btu per cubic foot	1,030
End-Use Sectors	Btu per cubic foot	1,031
Electric Power Sector	Btu per cubic foot	1,025
Imports	Btu per cubic foot	1,023
Exports	Btu per cubic foot	1,009
Electricity Consumption	Btu per kilowatthour	3,412

Btu = British thermal unit.
[1]Conversion factors vary from year to year. Values correspond to those published by EIA for 2004 and may differ slightly from model results.
Sources: Energy Information Administration (EIA), *Annual Energy Review 2004*, DOE/EIA-0384(2004) (Washington, DC, August 2005), and EIA, AEO2006 National Energy Modeling System run AEO2006.D111905A.

The Energy Information Administration
2006 EIA Energy Outlook and Modeling Conference

Renaissance Hotel, Washington, DC *March 27, 2006*

8:30 a.m. - 8:45	**Opening Remarks - *Guy F. Caruso,*** *Administrator*, Energy Information Administration
8:50 a.m. - 9:20	**Overview of the *Annual Energy Outlook 2006* - *John Conti,*** *Director*, Office of Integrated Analysis and Forecasting, Energy Information Administration
9:25 a.m. - 10:25	**Keynote Address: International Oil Markets - *Speaker to be announced***
10:40 a.m. - 12:10	**Concurrent Sessions A** **1. Global Oil Market Outlook: Short-Term Issues** **2. The Future Relationship of Oil and Natural Gas Prices in the U.S.** **3. Nuclear—Is EPACT Enough?**
1:40 p.m. - 3:10	**Concurrent Sessions B** **1. World Outlook for Unconventional Oil Production** **2. Globalization of the Natural Gas Market** **3. Return to Coal—From Where and at What Price?**
3:25 p.m. - 4:55	**Concurrent Sessions C** **1. How Far Ethanol?** **2. Unconventional Natural Gas: Industry Savior or Bridge?** **3. If Not Natural Gas Then . . . ?**

Hotel

The conference will be held at the *Renaissance Hotel*, (202) 898-9000. The *Renaissance Hotel* is located at 999 Ninth Street, NW, Washington, DC 20001, near the Gallery Place Metro station.

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Fax: ______________________
E-mail: ______________________

Please indicate which sessions you will be attending:

- ❐ Opening Remarks/Overview/Keynote Address

Concurrent Sessions A

- ❐ Global Oil Market Outlook: Short-Term Issues
- ❐ The Future Relationship of Oil and Natural Gas Prices in the U.S.
- ❐ Nuclear—Is EPACT Enough?

Concurrent Sessions B

- ❐ World Outlook for Unconventional Oil Production
- ❐ Globalization of the Natural Gas Market
- ❐ Return to Coal—From Where and at What Price?

Concurrent Sessions C

- ❐ How Far Ethanol?
- ❐ Unconventional Natural Gas: Industry Savior or Bridge?
- ❐ If Not Natural Gas Then . . . ?

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Section 8.1 Ref 3

2006
Long-Term Reliability Assessment

The Reliability of the Bulk Power Systems In North America

North American Electric Reliability Council
October 2006

TABLE OF CONTENTS

INTRODUCTION

Mission of the Electric Reliability Organization

NERC's mission is to improve the reliability and adequacy of the bulk power system in North America. To achieve that, NERC develops and enforces reliability standards; monitors the bulk power system; assesses future adequacy; audits owners, operators, and users for preparedness; and educates and trains industry personnel. NERC is a self-regulatory organization that relies on the diverse and collective expertise of industry participants. As the Electric Reliability Organization (ERO), NERC is subject to audit by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada.

On July 20, 2006, the Federal Energy Regulatory Commission (FERC) approved NERC's application to become the ERO for the United States. As the ERO, NERC will have legal authority to enforce reliability standards on all owners, operators, and users of the bulk power system, rather than relying on voluntary compliance. NERC is working to gain similar recognition by governmental authorities in Canada, including eight provinces and the National Energy Board, before the end of this year, and will seek recognition in Mexico once the necessary legislation is adopted there.

Section 39.11(b) of the Commission's regulations provide that: "The Electric Reliability Organization shall conduct assessments of the adequacy of the Bulk-Power System in North America and report its findings to the Commission, the Secretary of Energy, each Regional Entity, and each Regional Advisory Body annually or more frequently if so ordered by the Commission." The *2006 Long-Term Reliability Assessment* is the first assessment filed by NERC in its capacity as the ERO.

How This Assessment was Prepared

NERC, through its Reliability Assessment Subcommittee of the NERC Planning Committee, prepared this *2006 Long-Term Reliability Assessment* based on data and information provided by the eight regional reliability organizations. While the report is based on these data and information and on summaries of regional self-assessments, its key findings, actions needed, and assessment summary represent NERC's independent judgment of the reliability and adequacy of the bulk power systems in North America as existing and as planned, and what is needed to effect improvement.

The assessment was prepared by conducting a peer review of the data and information submitted by the eight regional reliability organizations based on their member systems' projections as of March 24, 2006. Where possible, updates to the data and information have been incorporated. The subcommittee reviewed regional summaries of projected peak electric demand, energy, and capacity resources; appraised regional plans for new electric generation resources and transmission facilities; and assessed the potential effects of changes in technology, market forces, legislation, regulations, and governmental policies on the reliability of future electricity supplies. Neither NERC nor the subcommittee makes any projections or draws any conclusions in this report regarding expected electricity prices for the assessment period.

The data and information submitted by the regional reliability organizations was based on their member systems' projections as of March 24, 2006. Where possible, updates to the data and information have been incorporated. Additional supporting documentation is available through NERC and the regional reliability organizations. While the subcommittee did not independently verify all of the information contained in the individual regional assessments, it did investigate and verify information where conflicting or confusing information was presented. Summaries of the supporting data are contained in the tables and figures throughout the report.

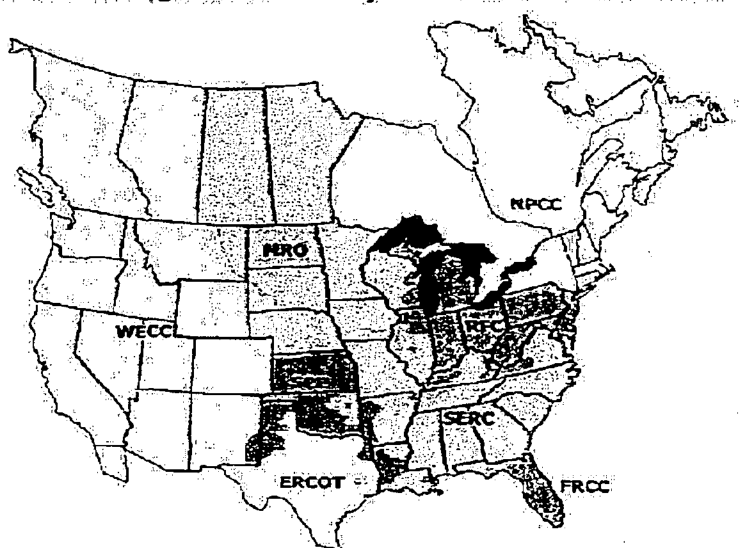
This assessment is based on several assumptions:

- Weather will be normal.
- Economic activity will occur as assumed in the demand forecasts.
- Generating and transmission equipment will perform at average availability levels.
- Generating units that are undergoing planned outages will return to service as scheduled.
- Generating unit and transmission additions and upgrades will be in service as scheduled.
- Demand reductions expected from direct control load management and interruptible demand contracts will be effective, if and when they are needed.
- Electricity transfers will occur as projected.

Summer 2006 Heat Wave

The widespread heat wave experienced in late July and early August 2006 caused peak demands to exceed forecasts and required utility system operators, customers, and government agencies to implement emergency procedures in some areas. While some localized distribution outages did occur, no bulk power system involuntary customer load interruptions were needed, mainly because generating capacity performed extremely well during this period.

Figure 1: NERC Regional Reliability Councils as of October 16, 2006



ERCOT
Electric Reliability Council of Texas, Inc.

FRCC
Florida Reliability Coordinating Council

MRO
Midwest Reliability Organization

NPCC
Northeast Power Coordinating Council

RFC
Reliability*First* Corporation

SERC
SERC Reliability Corporation

SPP
Southwest Power Pool, Inc.

WECC
Western Electricity Coordinating Council

Key Findings and Actions Needed[1]

Electric Capacity Margins Continue to Decline — Action Needed to Avoid Shortages

- Electric capacity margins will decline over the 2006–2015 period in most regions.
- The projected decline in margins reflects a short-term resource acquisition strategy that has been the norm for most of the past ten years.
- Electric utilities forecast demand to increase over the next ten years by 19 percent (141,000 MW) in the United States and 13 percent (9,500 MW) in Canada, but project committed resources to increase by only 6 percent (57,000 MW) in the U.S. and by 9 percent (9,000 MW) in Canada.
- The projected increase in committed resources assumes that all resource additions that are in various stages of planning, licensing, or construction will come into service on schedule.
- Available capacity margins, which include only committed resources, are projected to drop below minimum regional target levels in ERCOT, MRO, New England, RFC, and the Rocky Mountain and Canada areas of WECC in the next 2–3 years, with other portions of the Northeastern U.S. Southwest, and Western U.S. reaching minimum levels later in the ten-year period.
- Over 50,000 MW of uncommitted resources exist today NERC-wide that either do not have firm contracts or a legal or regulatory requirement to serve load, lack firm transmission service or a transmission study to determine availability for delivery, are designated or classified as energy only resources, or are in mothballed status because of economic considerations.
- Over the next ten years, uncommitted resources will more than double with the inclusion of generation currently under construction or in the planning stage, but which is not yet under contract to serve load.
- In many cases, these uncommitted resources represent a viable source of incremental resources that can be used to meet minimum regional target levels.
- The lack of adequate transmission emergency transfer capability or transmission service agreements could limit the ability to deliver available resources from areas of surplus to areas of need.
- Demand reductions have been achieved through various demand response programs. Direct control load management and interruptible demand programs represent about 2.5 percent of summer peak demand (20,000 MW) in the U.S. and about 2.5 percent of winter peak demand (2,500 MW) in Canada. New or expanded demand response programs and initiatives can further reduce peak demands.[2]

[1] The "Actions Needed" do not represent mandatory requirements, but rather NERC's independent judgment of those steps that will help improve reliability and adequacy of the bulk power systems of North America.
[2] Demand response programs include: direct-control load management, interruptible demand contracts, peak demand pricing, energy efficiency standards and improvements, etc.

- Long-term electricity supply adequacy requires a broad and balanced portfolio of generation and fuel types, transmission, demand response, renewables, and distributed generation; all supply-side and demand-side options need to be available.

Actions Needed:

- Electric utilities[3] need to commit to add sufficient supply-side or demand-side resources, either through markets, bi-lateral contracts, or self supply, to meet minimum regional target levels.
- Electric utilities, with support from state, federal, and provincial government agencies, need to actively pursue effective and efficient demand response programs.
- Electric utilities and resource providers need to coordinate long-term resource plans with transmission providers to ensure sufficient transmission capacity is available to deliver resources to load areas.
- NERC, in conjunction with regional reliability organizations and electric utilities, will evaluate the implications of the 2006 summer heat wave on future demand forecasts.
- NERC, in conjunction with regional reliability organizations, electric utilities, resource planning authorities, and resource providers, will address the issue of "uncommitted resources" by establishing more specific criteria for counting resources toward supply requirements.
- NERC will expedite the development of its new reliability standard on resource adequacy assessment that will establish parameters for taking into account various factors, such as: fuel deliverability; energy-limited resources; supply/demand uncertainties; environmental requirements; transmission emergency import constraints and objectives; capability to share generation reserves to maintain reliability, etc.

Construction of New Transmission is Still Slow — Continues to Face Obstacles

- Expansion and strengthening of the transmission system continues to lag demand growth and expansion of generating resources in most areas.[4]
- While peak demand is projected to increase over the next ten years by 19 percent in the U.S. and by 13 percent in Canada, total transmission miles are projected to increase by less than 7 percent in the U.S. and 3.5 percent in Canada.
- The transmission system requires additional investment to address reliability issues and economic impacts.
- Without expanded transmission system investment, grid congestion will increase, making it more difficult for available supply to meet demands and to allow full utilization of capacity/demand

[3] "Electric utilities" in this context refers to load-serving entities whose responsibility it is to secure energy, transmission, and related interconnected operations services to serve the electrical demand and energy requirements of its end-use customers.

[4] Several new transmission projects within the PJM portion of the RFC region and planned for service in the next five to fifteen years, were not included in the data submitted for this assessment. These proposed long-lead-time projects are currently in the PJM Siting Feasibility Study stage to evaluate which projects or portions thereof will move forward.

diversity; in some situations, this can lead to supply shortages and involuntary customer interruptions.

- With a few exceptions, the present transmission planning horizon is five years or less. Proposed solutions tend to address short term problems without looking to longer lead time facility requirements.

- Obstacles to the siting and certification of new transmission in the U.S. may be eased and transmission development enhanced by several actions: U.S. Department of Energy (DOE) designation of National Interest Electric Transmission Corridors (NIETC) and the associated FERC backstop siting authority; DOE designation of multipurpose energy corridors; and DOE serving as the lead agency for federal authorizations, permits, and approvals for interstate transmission projects.

- Although there has been a recent upturn in planned transmission investment in several regions, growth in peak demand and generation additions will pose new challenges.

- FERC's recently issued transmission pricing rule offers a wide range of incentives and pricing reforms to stimulate needed investment in new transmission facilities to projects that qualify in both RTO/ISO and non-RTO/ISO regions.

- Bulk power system reliability and adequacy depends on close coordination of generation and transmission planning and demand response programs..

Actions Needed:

- Based on the congestion study released on August 8, 2006, the U.S. DOE, in conjunction with transmission owners and planning authorities, needs to complete the designation of NIETCs.

- RTOs and transmission owners need to address other areas of congestion and emergency transfer capability that could impact reliability, and create a long-term vision for a high capacity grid system.

- State and federal government agencies in the United States. need to work on removing obstacles to expedited siting and certification of transmission lines independent of the recommendations by DOE.

- Canadian federal and provincial government agencies need to work diligently to remove similar obstacles in Canada.

- Transmission owners, planning authorities, and other stakeholders need to engage in long-term, robust, and comprehensive regional planning for transmission infrastructure, including infrastructure needed for new sources of generation.

- Federal, state, and provincial regulators need to reduce regulatory barriers and encourage investment in transmission infrastructure improvements.

- NERC will expedite the development of its new reliability standard that will establish requirements for assessing the performance of planned bulk power transmission systems and the requirements for documenting plans to remedy reliability inadequacies identified in the process of conducting such assessments.

Fuel Supply and Delivery for Electric Generation Important to Reliability

- The adequacy of electricity supplies depends, in part, on the adequacy of fuel supply and delivery systems, not just the installed capacity of generators.
- Gas-fired generating capacity additions are projected to account for almost half of the resource additions over the 2006–2015 period.
- Dependence on natural gas for electric generation is projected to increase in ERCOT, FRCC, the U.S. portions of MRO, NPCC, and WECC.
- The supply and delivery of gas to electric generators can be disrupted when electric generation demands for gas coincide with high gas demands for other customers. In some cases, even firm gas contracts for electric generation can be curtailed in favor of residential heating needs during extreme cold weather.
- Strengthening fuel delivery infrastructures and firming up gas supply and delivery contracts will reduce the potential for shortages in electricity supplies due to fuel disruptions.
- Coal delivery infrastructure was an issue in 2005 and early 2006, but the situation is improving.

Actions Needed:

- Electric utilities, resource planning authorities, and resource providers need to evaluate the reliability of fuel supply and delivery systems when determining electricity supply adequacy.
- Entities that purchase fuel for electric generators need to review and strengthen fuel supply and delivery contracts to ensure that fuel disruptions do not limit generator operation during critical electric supply situations.
- System operators and planners need to evaluate the consequences of unexpected fuel transportation contingencies on the reliability and adequacy of the bulk power system.
- Communications and emergency operating procedures between electric system operators and gas pipeline operators need to be in place to address extreme cold weather events.
- Federal, state, and provincial agencies, along with fuel supply and delivery industries, need to evaluate the adequacy of these critical infrastructures for supporting an adequate electricity supply system.
- NERC and regional reliability organizations will include in their regional reliability assessment programs a review of the impact of any fuel transportation infrastructure interruption that could adversely impact electric system reliability.

Aging Workforce a Challenge to Future Reliability

- The reliability of the North American electric utility grid is dependent on the accumulated experience and technical expertise of those who design and operate the system.
- As the rapidly aging workforce leaves the industry over the next five to ten years, the challenge to the electric utility industry will be to fill this void.

Actions Needed:

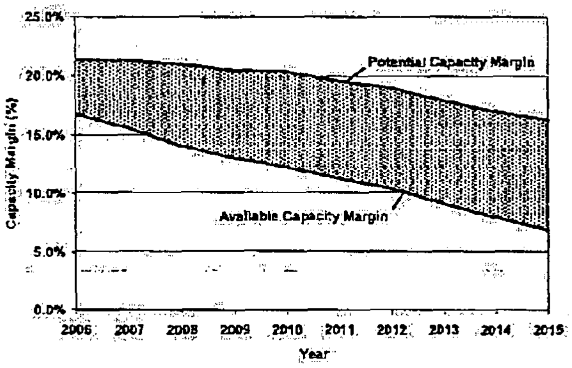
- Electric utilities need to identify key personnel approaching retirement and establish mentoring programs to impart the experience realized by these individuals.
- Electric utilities need to reassess compensation and benefits packages to attempt to retain aging personnel, either on a full-time or part-time basis.
- The electric utility industry as a whole needs to establish cooperative programs with academia to reinvigorate the power engineering education in North America.

ASSESSMENT SUMMARY

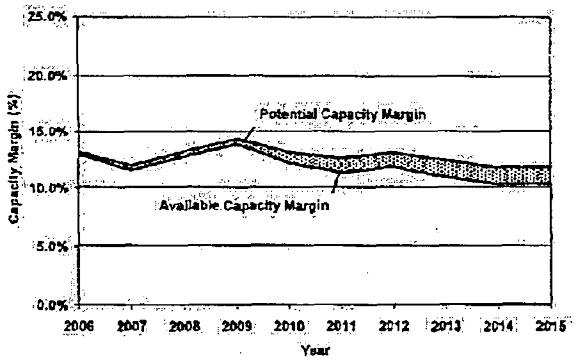
Action Needed to Ensure Resource Adequacy Over the 2006–2015 Period

Available capacity margins in the U.S. and Canada are projected to decline over the 2006–2015 period. Margins vary from region to region, as does the amount of *uncommitted resources* reported.

Capacity margins in United States decline throughout ten-year period. Uncommitted resources offer significant potential.



Capacity margins in Canada steady in short term; decline in long term.



Capacity Margin — Capacity that could be available to cover random factors such as forced outages of generating equipment, demand forecast errors, weather extremes, and capacity service schedule slippage.

Available Capacity Margin — The difference between ***committed*** capacity resources and peak demand, expressed as a percentage of capacity resources.

Potential Capacity Margin — The difference between ***committed*** plus ***uncommitted*** capacity resources and peak demand, expressed as a percentage of capacity resources.

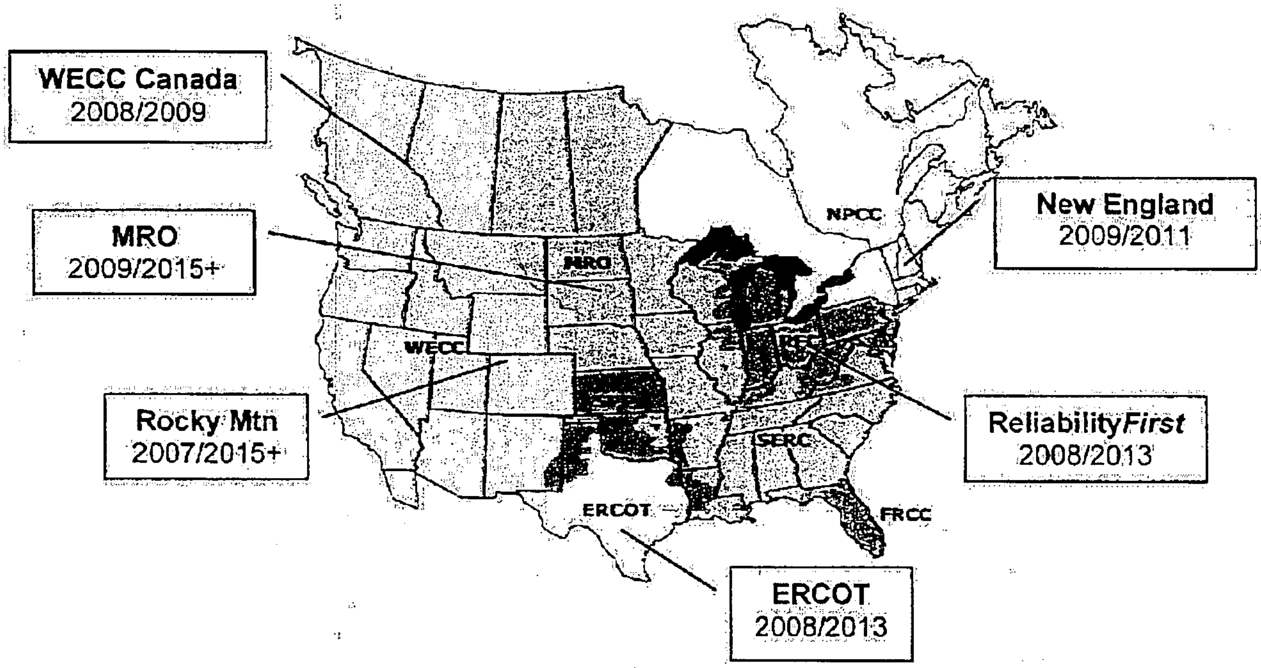
Committed Capacity Resources — Generating capacity resources that are existing, under construction, or planned that are considered available, deliverable, and committed to serve demand, plus the net of capacity purchases and sales.

Uncommitted Capacity Resources — Capacity resources that include one or more of the following:

- Generating resources that have not been contracted nor have legal or regulatory obligation to deliver at time of peak.
- Generating resources that do not have or do not plan to have firm transmission service reserved (or its equivalent) or capacity injection rights to deliver the expected output to load within the region.
- Generating resources that have not had a transmission study conducted to determine the level of deliverability.
- Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources.
- Transmission-constrained generating resources that have known physical deliverability limitations to load within the region.

Available capacity margins drop below minimum target levels in ERCOT, MRO, New England[5], RFC, and Rocky Mountain and Canada areas of WECC in the next 2–3 years, with many other areas reaching minimum levels later in the ten-year period. However, all regions have some additional resources potentially available in the form of *uncommitted resources* that exist, are under construction, or are in the planning stage, which offer the potential to meet minimum target levels. Actions needed to make these resources available when required include returning "mothballed" units to active service, entering into power purchase agreements for existing or new resources, upgrading transmission to provide access to resources that would not otherwise be deliverable, and developing and bringing into service projects that are in generator interconnection queues.

Electricity Supply Margins Projected to Fall Below Minimum Target Levels in Some Areas of North America in Next 2–3 Years



Areas Needing Additional Resources
XXXX/YYYY – 1st year additional resources needed
XXXX – beyond current projections
YYYY – beyond uncommitted resources

For example, in ERCOT, available capacity margins will drop below the 11 percent minimum target level by 2008. The ERCOT potential capacity margins, which include the effects of uncommitted resources, remain above the required minimum through 2013. In the case of ERCOT, the uncommitted resources comprise generators that are in "mothballed" status, but which could be returned to active service if needed.

[5] The FERC recently approved a forward capacity market for ISO New England, is expected to result in additional resources in the next three years.

In some cases, areas that require additional resources to meet minimum target levels can purchase those resources from neighboring regions or subregions.

Even if additional resources are added, the possibility remains that above average resource unavailability, coupled with high demands caused by extreme weather, could create localized supply problems.

Reliability Will Depend on Close Coordination of Generation and Transmission Planning and Construction

Electric utilities forecast demand to increase over the next ten years by 19 percent (141,000 MW) in the U.S. and 13 percent (9,500 MW) in Canada, but project committed resources to increase by only 6 percent (57,000 MW) in the U.S. and by 9 percent (9,000 MW) in Canada. Given the short lead-time for developing some types of generation, this difference could be offset by assignment or development of capacity that has not yet been committed or announced.

More than 9,000 miles of new transmission (230 kV and above) are proposed to be added through 2010, with a total of about 12,873 miles added over the 2006–2015 time frame[6]. The increase represents a 6.1 percent increase in the total miles of installed extra high voltage (EHV) transmission lines (230 kV and above) in North America over the 2006–2015 assessment period. Furthermore, upgrading or replacing existing lower capacity transmission lines also increases the capacity and reliability of the existing transmission network, but does not increase the reported miles of transmission lines.

North American transmission systems are expected to meet reliability requirements in the near term. However, as customer demand increases and transmission systems experience increased power transfers, portions of these systems will be operated at or near their reliability limits more of the time. Under these conditions, coincident unavailability of generating units, transmission lines, or transformers, while improbable, can degrade bulk power system reliability.

Even though NERC expects the transmission systems to be operated reliably, some portions of the grid will not be able to deliver available resources to areas needing additional resources to meet minimum target levels for adequacy, or be able to support all desired electricity market transactions. Some well-known transmission constraints are recurring, while new constraints appear as electricity flow patterns change.

In the long term, reliable transmission will depend upon the close coordination of generation and transmission planning and construction and the adoption of longer term planning horizons (ten or more years). This coordination activity must now be accomplished through different means than in the past and involves coordination among many different market participants. A combination of market signals and regulatory decisions will dictate the location and timing of generating capacity additions, and also influence the siting and construction of new transmission facilities.

Fuel Supply Will be a Bigger Factor in Meeting Capacity Margins

Most regions do not anticipate any long-term problems with fuel supplies for the 2006–2015 assessment period. However, if short-term interruptions of supply occur, affected generators will need to implement contingency plans to manage the operation of their facilities. For example, beginning in 2005 and over the course of 2006, deliveries of western coal from the Powder River Basin (PRB) were curtailed due to rail track maintenance. These deliveries are improving but are not yet meeting all desired delivery

[6] Several new transmission projects planned for service in the next five to fifteen years within the PJM portion of the RFC region were not included in the data submitted for this assessment. These proposed long-lead-time projects are currently in the PJM Siting Feasibility Study stage to evaluate which projects or portions thereof will move forward.

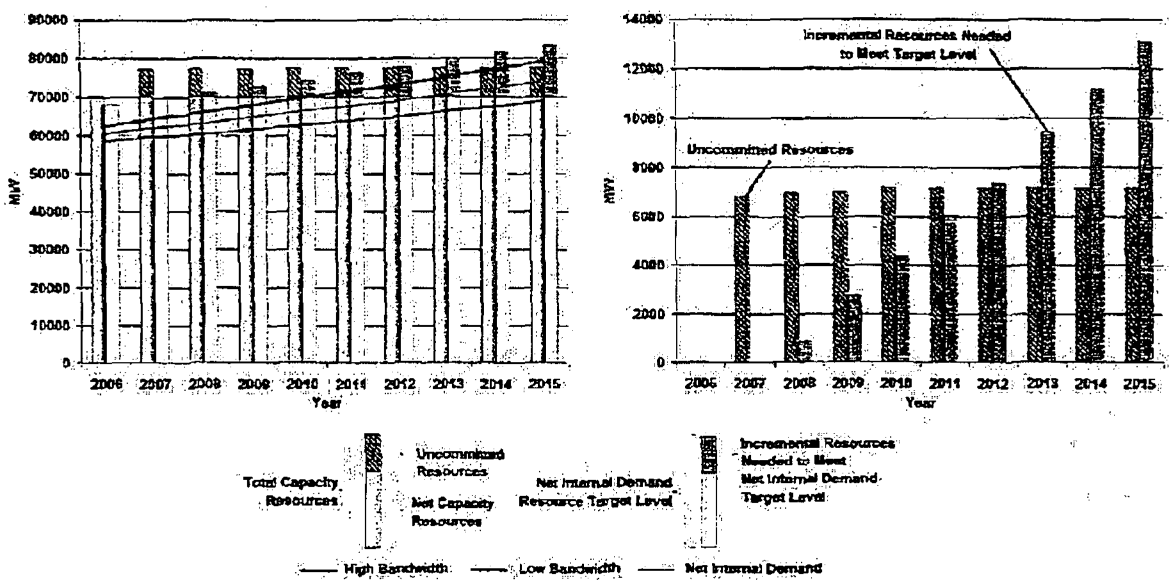
requests. Close review of natural gas supply and delivery issues will also be required in some regions due to the increasing reliance on natural gas for electric generation. This issue becomes particularly critical during the winter or following major storms or hurricanes as experienced during the winter of 2005/2006 following hurricanes Katrina and Rita.

Hydroelectric resources will be affected by the amount of precipitation each year, which cannot be accurately predicted very far into the future. This long-term assessment relies on historical average rainfall levels when considering the availability of hydroelectric resources. These assumptions are addressed more specifically during seasonal assessments.

Regional Assessment Highlights

ERCOT

The Electric Reliability Council of Texas, Inc. (ERCOT) is projecting about 2,000 MW less installed capacity over the assessment period than in last year's assessment due to wind generation deratings from last year's assessment and additional unit mothballing. Along with an increased load forecast, this results in lower capacity margins than last year's assessment. The assessment indicates capacity margins should remain close to, but above, the 11 percent target until 2008 (compared to 2010 in last year's assessment). However, approximately 7,000 MW of existing mothballed generating capacity is not included as available capacity that could potentially be brought back into service in a short time frame. In order to meet the capacity margin target in 2008, ERCOT may need to commit some of the mothballed generation.



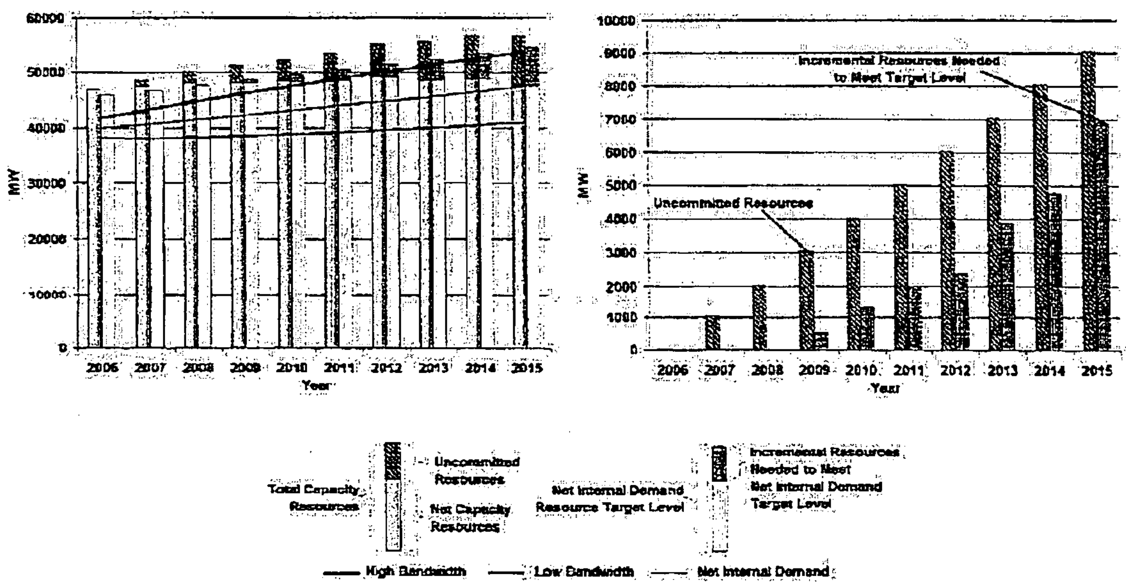
Approximately 6,100 MW of publicly announced new generation is also scheduled to come on-line between 2006 and 2011, without signed interconnection agreements, that is not included in ERCOT's capacity forecast. Many of these facilities are coal-fired and will not be available until 2009–2010. The Public Utility Commission of Texas is in the process of considering rules to maintain capacity adequacy in ERCOT going forward.

FRCC

The Florida Reliability Coordinating Council (FRCC) expects to have adequate generating capacity reserves and for the transmission system to operate reliably throughout 2006–2015. However, the transmission lines between southwestern central Florida generation and the greater Orlando load area will continue to be heavily loaded and will require extensive operational procedures. Permanent solutions are under review to resolve these deficiencies with new transmission projects. Based on the committed projects and expected generation dispatch, it is expected that these operational procedures will continue in this area until 2010. Remedial operation strategies have been developed to address these conditions and will continue to be evaluated to ensure system reliability. Utilities have announced plans for 5,524 MW of new coal-fired plants, which will increase fuel diversity.

MRO

Sufficient generating capacity is expected within the entire Midwest Reliability Organization (MRO) to meet its reserve capacity obligations through 2009. The MRO-Canada region has adequate generating capability throughout the assessment period. Currently, planned capacity reported in the MRO-U.S. region is below MRO requirements for reserve capacity obligations from 2010–2015. However, the MRO does not expect any capacity deficits to occur during the assessment period because capacity margins are expected to be higher than reported based on significant new generation identified in the regional ten-year plan for the period of 2004–2013.



Through the 2015 planning horizon, the MRO expects its transmission system to perform adequately assuming proposed reinforcements are completed on schedule. Continued power market activity will continue to fully utilize the capability of the system, which may not meet all market needs.

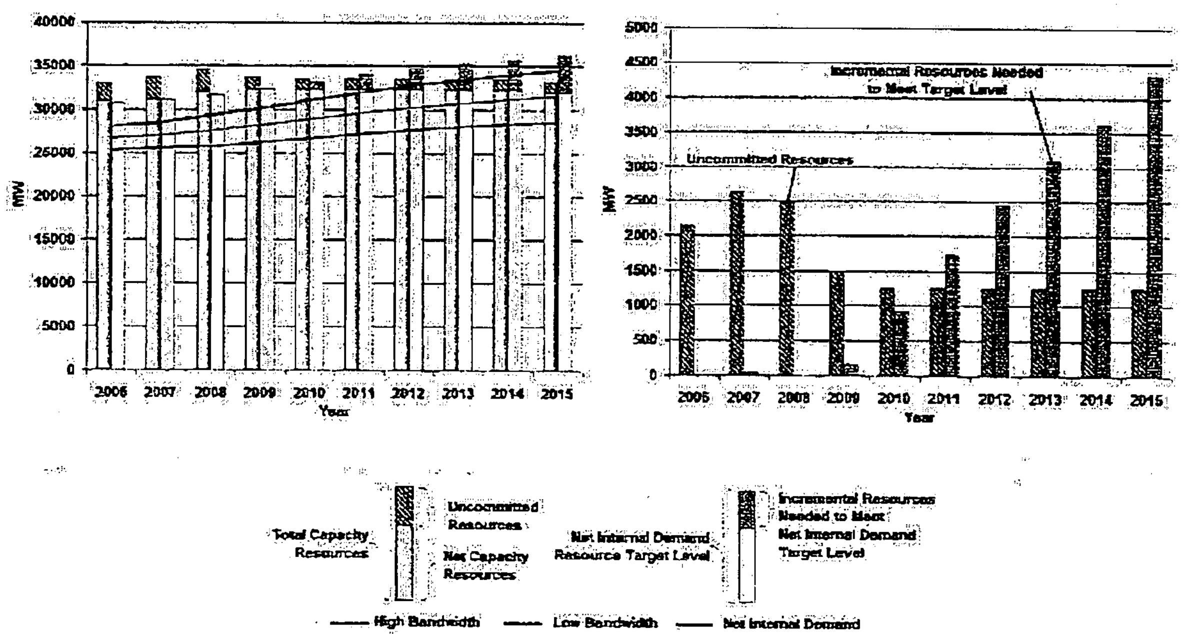
NPCC

New England

Installed reserve margins will be declining throughout the study period from a high of 15 percent in 2008 to almost 0 percent in 2015. The installed reserve margins reflect firm capacity purchases of approximately 400 MW per year through 2012, approximately 330 MW purchase in 2013–2014, and approximately 110 MW in 2015. There are no generating unit retirements assumed throughout the study period and new generation totaling approximately 1,390 MW (capabilities include projects that have received proposed plan approval) is assumed to commercialize by the end of 2009.

With respect to the regional requirement, ISO New England anticipates that New England will meet the NPCC resource adequacy criterion of one-day-in-ten-years loss-of-load expectation through 2008 assuming forecasted loads and capacity materialize and 2,000 MW of tie reliability benefits are available. This is made up of 600 MW from New York, 1,200 MW from Hydro Québec, and 200 MW from New Brunswick. Existing transfer capability study results indicate that there is sufficient transfer capability with surrounding areas to receive this assistance when needed. New capacity will be needed beyond that year in order to meet the reliability criterion. This assessment is based on estimated requirements calculated in the 2006 Regional System Plan.

To meet NPCC criteria, and assuming 2,000 MW of tie reliability benefits are available from neighboring control areas, approximately 170 MW are needed in 2009, increasing annually and requiring a total of 4,300 MW by 2015.



New York

Given current demand projections, New York would need the addition of 4,030 MW of new resources in order to meet a projected 18 percent level through 2015. This projection assumes the continuation of the current level of external purchases of approximately 2,500 MW and the continuation of special case resources of approximately 1,080 MW. It is anticipated that the resources necessary to meet this projected requirement would be procured through the NYISO ICAP market. Currently, new capacity totaling 2,940 MW is under construction in New York. The generation currently under construction in conjunction with the approximately 2,500 MW of allowable external purchases will be sufficient for New York to meet an 18 percent reserve margin through 2015 even if no new projects are proposed.

Ontario

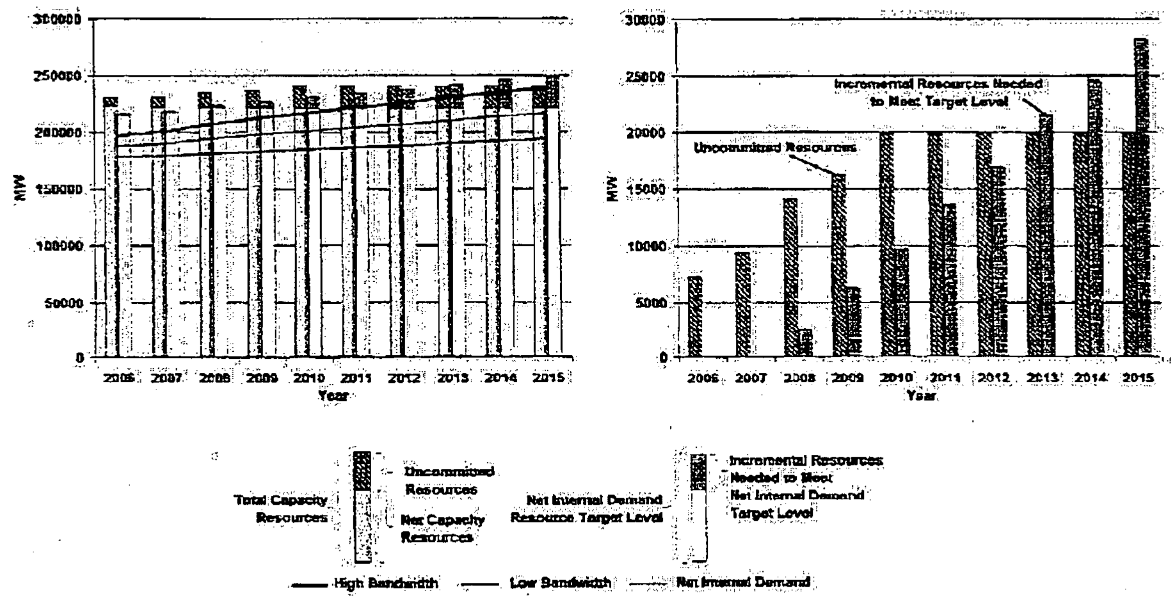
Since last summer, more than 600 MW of new supply has been added to the Ontario power system, which has improved Ontario's supply outlook in the short term. Under median demand growth assumptions, resources that are currently available within Ontario, together with the contracted new generation and imports, are sufficient to meet the NPCC resource adequacy criterion from 2006–2015.

Québec

In the *2005 Québec Area Triennial Review of Resource Adequacy*, Québec demonstrated that the installed reserve margin requirement was about 10 percent over the annual peak load to comply with the NPCC adequacy criterion. For the whole period, the expected installed reserve margin will be over this percentage. Even in the case of a high load scenario, Québec still meets the NPCC resource adequacy criterion (lost of load expectation less than 0.1 day/year).

RFC

The Reliability*First* Corporation (RFC) region is expected to have sufficient resources to satisfy a 15 percent reserve margin through at least 2007. Proposed capacity additions and existing capacity that is undeliverable, uncommitted, or energy-only resources, could satisfy the 15 percent reserve margin through 2012, if the transmission system is capable of fully delivering those resources. Additional capacity resources will still be needed beyond 2012 to maintain a 15 percent reserve margin. No commitments to resource development beyond 2011 are known at this time.



SERC

Capacity resources in SERC are expected to be adequate to reliably supply the forecast firm peak demand and energy requirements throughout the long-term assessment period. Significant generation development has occurred in the SERC region during the past few years, resulting in thousands of MW of uncommitted generating capacity. Some of this generation can be made available as short-term nonfirm or potential future resources to SERC members and others.

SPP

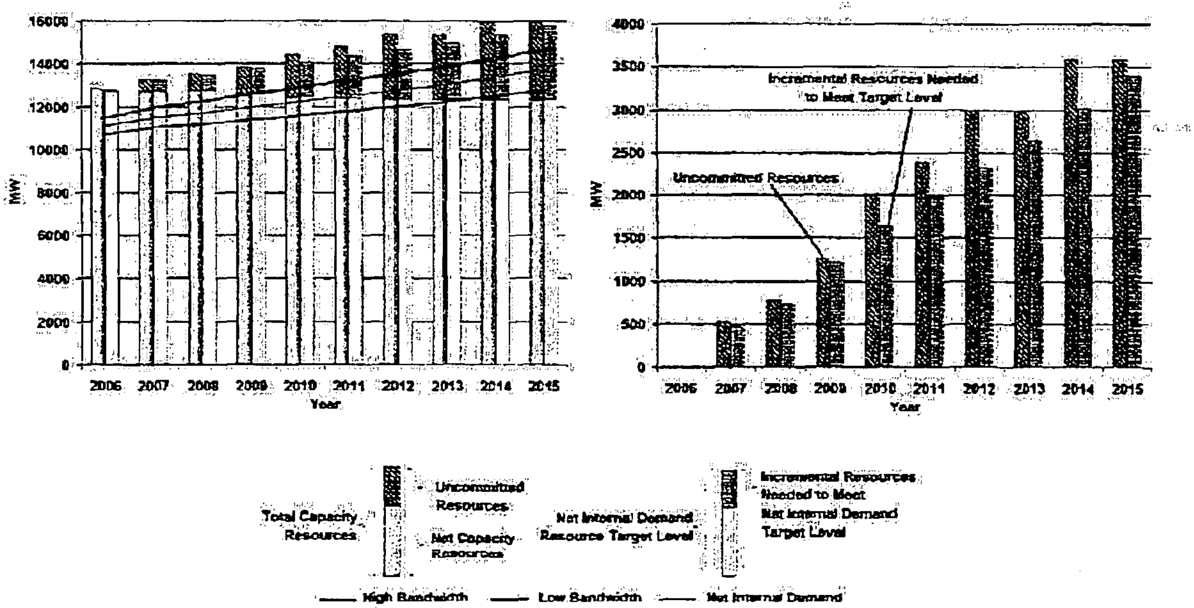
Southwest Power Pool (SPP) anticipates consistent growth in demand and energy consumption over the next ten years. Adequate generation capacity is forecasted in SPP to be available over the planning horizon to meet native network load needs with committed generation resources meeting minimum capacity margins.

Expansion of the existing transmission system to address the reliability and economic needs of the market is a top priority for SPP. SPP is in the process of implementing several initiatives that will result in transmission expansion and better utilization of the existing assets in the footprint. The existing bulk power system is expected to reliably serve the needs of native network load for the short-term while incremental system flows from commercial transmission reservations will most likely utilize any remaining transmission capacity.

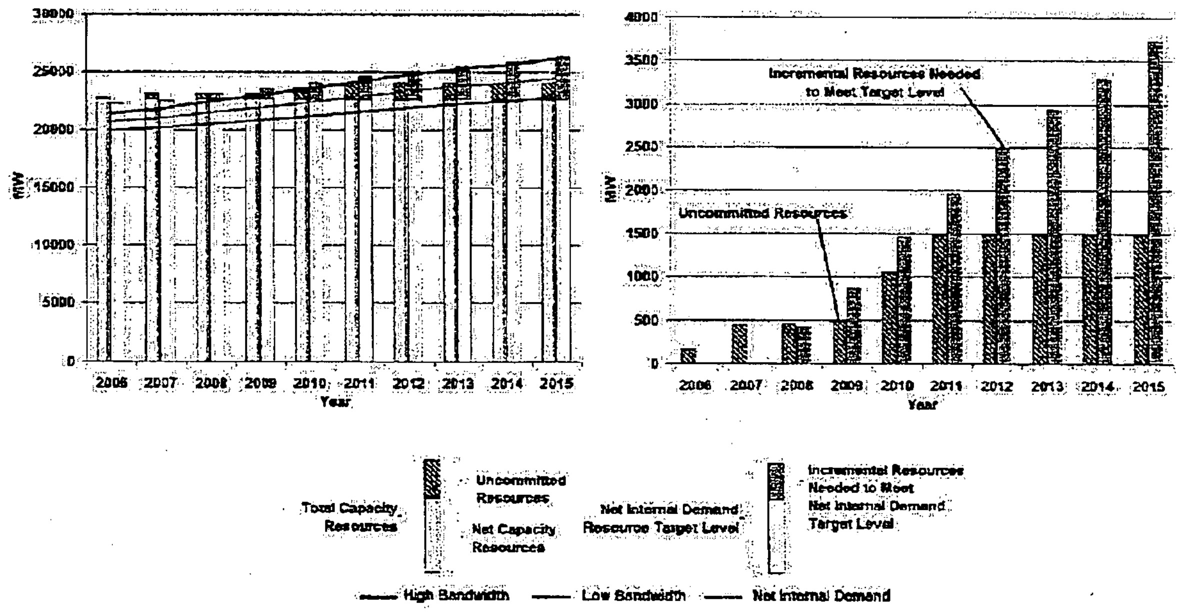
WECC

Due to a slight decrease in existing generating capacity and a significant decrease in reported generation additions, capacity margins for the Western Electricity Coordinating Council (WECC) are reported as declining throughout the ten-year assessment period. The capacity margin declines occur in multiple subregions. WECC's *2006 Power Supply Assessment Report* (PSA) indicates that summer electricity supply shortages relative to study planning margins could occur as early as 2009 and winter electricity supply shortages could occur as early as 2008–2009 in Canada, assuming normal weather, adverse hydroelectric conditions, and no resource additions beyond those presently under active construction with expected in-service dates prior to July 2007 (or July 2008 if coal-fired).

The Rocky Mountain Power Area (RMPA) summer 2007 capacity margin is 9.8 percent without uncommitted resources and 13.2 percent with uncommitted resources. By the summer of 2011, those margins become -0.8 percent and 15.5 percent, respectively. A significant portion of the expected uncommitted resources has received state utility commission approval and is under active development.



The WECC-Canada winter 2008–2009 capacity margin is 5.1 percent without uncommitted resources and 7.1 percent with uncommitted resources. By the winter of 2011, those margins become -1.1 percent and 5.1 percent, respectively.



The PSA reports that by 2009, summer transfer capability limitations between the winter peaking northern portion and summer peaking southern portion of WECC result in a 1,000 MW resource shortfall. The southern portion resource needs increase to roughly 20,000 MW by 2015, even though the northern portion is capacity surplus throughout the period. Although the transmission limitations represented in the PSA analysis are conservative, they are not unreasonable and the report clearly establishes that WECC has insufficient transmission to fully utilize seasonal capacity/demand diversity within the Western Interconnection.

The PSA report is available at:
(http://www.wecc.biz/modules.php?op=modload&name=Downloads&file=index&req=getit&lid=2330). Plans have been announced for 5,951 miles of 230-, 345- and 500-kV transmission line construction and upgrades during 2006–2015. These additions will not significantly reduce the northwest-to-southwest transfer capability constraint.

Transmission rated at 230 kV and above increased by about 140 miles in 2005. Proposed transmission facility additions reported for 2006–2015 include 2,276 miles of 230-kV lines, 1,075 miles of 345-kV lines, and 2,600 miles of 500-kV lines. Depending on transmission and resource addition in-service dates and locations, the transmission system may be adequate to satisfy firm transmission interconnection requirements but may not be adequate to allow full utilization of capacity/demand diversity throughout 2006–2015.

Emerging Reliability and Adequacy Issues

Significant Transmission Expansion Project Plans

Over the course of the last couple of years, several large scale transmission expansion projects have been proposed by a number of entities across North America. The main objectives of these projects include:

- eliminating regional transmission system congestion,
- promoting fuel diversity, and
- access to renewable resources.

These projects typically involve large scale transmission lines connecting generation-rich areas to areas that need those resources. Some of these projects are proposed within the footprint of established RTOs with established transmission expansion processes, and others are proposed in regions not operated by RTOs or ISOs making the approval of project need unique to each project. Although the typical attribute of these projects is that they are intended to enhance the economic efficiency of the bulk power system or to access renewables, they will also have a reliability benefit by increasing operational flexibility.

While not all inclusive, the following is a listing of examples of the type of projects discussed in this section:

Project Name	Proposed Capacity	Description
I-765	5000 MW	Line from West Virginia to New Jersey to access lower cost coal and gas resources
Frontier Line	6,000 MW	Line from Wyoming to Utah, Nevada, Arizona and California to access clean coal and wind resources
Transwest Express	3,000 MW	Line from Wyoming to Arizona to access clean coal and wind resources
Northern Lights	3,000 MW	Line to access tar sands in Alberta
Sea Breeze	1,600 MW	Undersea dc cable from northern Oregon to northern California to access renewable resources
Neptune	790 MW	A merchant HVdc line between Sayreville (New Jersey) and Newbridge Road (New York) substations
Clear Springs–Salado Project	3,300 MW	Line from economic generation in central Texas through several load centers to the north
Houston Area Constraint Mitigation Project	3,600 MW	Several new lines, line upgrades, and a switching station that increase import capability into the Houston area
Paris–Anna Line	1,600 MW	Line from economic generation in the N.E. part of Texas into the Dallas-Fort Worth metroplex
Jacksboro–West Denton Line	1,600 MW	Line that increase Dallas-Fort Worth access to wind resources

These large scale transmission projects have the potential to profoundly change the operations and planning of the transmission system in these areas. The actual development of these projects have the potential to significantly impact overall electric system reliability in a variety of ways. The potential system reliability benefits include increased generation fuel diversity reducing reliance on any one fuel to meet load requirements and reduced congestion and the associated simplification of operations.

Other impacts of these projects would be increased reliance on remote generation sources replacing less economical or less desirable generation located closer to the load center. Issues associated with replacement of generation near load centers such as reactive power and voltage support can be addressed through careful system planning. To the extent the new transmission expansion leads to integration of increased renewable resources, operational and reserve requirement issues associated with intermittent and energy limited resources discussed in the renewable resources section will also need to be addressed to assure continued system reliability.

Demand Diversity and Transmission Constraints

Peak demands often occur during different times and different seasons for the load-serving entities (LSEs) within geographically large regions. This seasonal demand diversity may be quite significant between summer peaking LSE and winter peaking LSE. In general, resource providers typically attempt to maximize plant utilization by exporting off-peak season surplus capacity among the subregions. Under normal weather conditions, this weather diversity also allows an area experiencing extreme weather to call on neighboring areas for support.

The resource data presented in this report reflects appropriate capacity reductions in cases where radially connected generation or small resource-surplus areas have limited export capability (a.k.a., "bottled capacity"). However, the data reflects primarily the expected exports based on historical diversity exchanges, excluding possible capability reductions due to local off peak load growth consuming the surplus, or potential transmission constrained utilization of the seasonal surplus capacity that may occur in the future.

For example, a very widespread heat wave may result in multiple areas experiencing simultaneous high peak demands, diminishing emergency support capability assumed available based on the historical diversity. In addition, the assumptions that past diversity exchanges will continue to occur in the future may be impacted as off-peak surpluses are being absorbed within the subregion's own growth.

Inter- and intra-region transmission constraints and increased utilizations may also reduce the ability to export all of the seasonal-surplus capacity. Addressing such transmission constraints is often problematic. For instance, hydroelectric generation may vary dramatically from year to year due to varying amounts of precipitation. As a consequence, transmission constraints can be quite significant some years and of little consequence other years.

Transmission Expansion Difficulties

Regulatory and licensing issues continue to push out the in-service dates of needed transmission projects. While most agree that new transmission lines can improve system reliability and enhance economic transfers of energy, siting of lines still runs into the same roadblocks as years past. These delays also can increase the cost significantly.

"Not In My Back Yard" (NIMBY) issues apply to many industries besides the electric power industry, but the higher public exposure to long transmission lines with wide right-of-ways seems to cause the most consternation among the public. Concerns about the health aspects of living next to a transmission line still linger.

Recovery of the extreme high cost of acquiring property and building a new line can take years or may even be uncertain. The investment in construction of a new line is considerable. In some areas, recovery of these costs is left up to case by case negotiations between the builder and, possibly multiple state utility commissions. This can be very discouraging on the builder's part. Other areas may have structured cost recovery mechanisms in place but full recovery may take several decades.

Acquiring right-of-way property can be influenced by several aspects including land prices, environmentally sensitive areas, and NIMBY issues. Land prices are increasing along with the quickly rising cost of housing. In some areas, land price inflation is averaging three or four times the general inflation rate. Some environmental groups are well organized with extremely good legal representation. All legal options to stop transmission line development are usually utilized.

Many developers are concerned about quicker development of generation in resource limited areas. Average time to plan and build a transmission line is considerably longer than the time it takes to permit and build some generation plants. The need to alleviate a congested path by building a new transmission line into a resource limited area may be made unnecessary by the addition of generation in that area.

This problem has no easy solution. Outreach and education efforts to enhance awareness of need for more transmission will help to enlighten local governments and some individuals. The culmination of the federal government helping with siting at the national level may streamline some of the possible delays. Some have even suggested sharing transmission line revenues with land owners near the right-of-ways. Integrated large scale resource planning can referee the transmission/generation fight with an overall plan that will utilize the most economic solution to the reliability problems encountered.

The Energy Policy Act of 2005 contains several provisions that could help enhance transmission siting such as DOE designation of National Interest Electric Transmission Corridors and associated FERC backstop siting authority; DOE designation of multipurpose energy corridors; and DOE coordination as lead agency of all necessary federal authorizations, permits and approvals for interstate transmission projects.

Fuels

Resource adequacy is measured by the capacity in MW of the physical "iron in the ground" represented by the generating plants, both existing and planned. However, an adequate supply of reliable electric resources to the North American electric grid is equally dependent on readily available fuel supported by a secure transportation infrastructure to deliver the fuel to the generating facility. An important element is diversity of fuel. In recent years, the electric industry has witnessed numerous events that can potentially diminish the supply of any given fuel:

- Hurricanes in the Gulf of Mexico in the summer of 2005 threatened the supply of off-shore natural gas to the United States.
- Extended droughts in the west reduced the available energy of several major hydroelectric sites in the late 1990s.
- Tensions in the Middle East continue to result in dramatic fluctuation in the price for fuel oil and could ultimately lead to major supply interruptions.
- In 2003, the political unrest in Venezuela interrupted the only production of orimulsion fuel.
- Shutting down mines due to safety issues.
- Curtailments of rail delivered/barge delivered coal.
- Short-term fuel acquisition problems driven by global markets.

The security of the supply of off-shore oil may, in future years, be dependent on the political stability of those countries exporting the majority of the world's oil, many of which are currently experiencing internal turmoil. This also includes the import of liquefied natural gas (LNG), which, although a natural gas product produced by the extreme cooling of natural gas into its liquid state, is supplied by many of the same regions of the world on which North America is dependent for its oil supply. Thus the uncertainty of both the price and availability of imported oil makes it increasingly unreliable as a utility fuel in the years ahead.

Because it is efficient and clean burning, natural gas has become the preferred fuel in North America for new generation additions, and its consumption by the electric utility industry is increasing rapidly. In addition, natural gas is also a prevalent fuel for home heating in many parts of North America, competing with the electric utility for gas supply at peak times. With this continuing growth in gas usage by the electricity sector, the adequacy and security of the natural gas supply and its infrastructure will become ever more critical to the reliability of electric supply. As a result, some utilities are looking towards clean coal-fired generation technologies for future capacity additions. Appropriate cost-recovery mechanisms will be needed to provide incentives for the construction of long-lead-time coal facilities.

Renewable energy and nuclear power are being pursued as an alternative to the ever increasing consumption of fossil-fuels in North America, with several states and provinces in North America having established standards requiring that a minimum percentage of energy consumed be derived from renewable resources. At the federal level within the United States, the Energy Policy Act of 2005:

- Encourages the renewed construction of nuclear generating plants;
- Provides loan guarantees for innovative technology that does not yield greenhouse gases as a combustion byproduct;
- Encourages increased research in clean coal burning technology;
- Requires the staged increase in the dilution of gasoline with ethanol;
- Provides subsidies for wind generation; and
- Encourages research into such renewal programs as tidal energy, biomass fuel, etc.

In the near term, renewable energy will largely be supplied by existing hydroelectric facilities and the growing numbers of wind generators entering the grid.

Although no new nuclear capacity has been constructed in about 30 years in the United States, the Energy Policy Act of 2005 hopes to provide the economic incentives to resume construction, and a number of applications for new units have been announced.

Aging Infrastructure

The North American transmission system has evolved over the last century during periods of rapid growth from the 1950s through the 1970s paralleling the technological advancements in generation. The transmission facilities installed through the 1970s are reaching the end of their projected useful life. These facilities will need to be either replaced or repaired to maintain grid reliability.

Over the past decades, the vast majority of transmission investment was directed towards constructing new facilities to meet customer load demands and comparatively little capital investment was expended for the refurbishment of the existing facilities. The aging transmission system infrastructure has many challenges such as: the availability of spare parts; the obsolesce of older equipment; the ability to maintain equipment due to outage scheduling restrictions; and the aging of the work force and lost knowledge due to personnel retirements.

The North American transmission owners must take a more proactive approach going forward in replacing obsolete and unreliable equipment including transmission lines. Chronological age is not the only condition that should be used to determine when equipment should be replaced. Potential for increased failure rates should be evaluated. These considerations should consider the diversity of equipment technologies and installation dates. However, implementation of any replacement strategy and in-depth training programs require additional capital investment, engineering and design resources, and construction labor resources, all of which are in relatively short supply.

Renewable Resources

Renewable resources will become an increasing portion of total generation resources in the future. Generation from wind, solar, biomass, geothermal, hydro, and to a lesser extent, wave/tidal, landfill gas, and municipal or biomass-based waste are generally considered renewable sources. Nearly 14,000 MW are projected to be added over the next ten years throughout North America.

Currently, a total of 21 states and the District of Columbia have adopted renewable portfolio standards (RPS) for the purchase of energy. Generally, the RPS obligation is imposed on load-serving entities and usually requires them to obtain a portion of their electricity supply from renewable resources; in some states as much as 25 percent. Wind generation is expected to provide the bulk of the energy required to meet requirements for additional generation from renewable sources. However, wind generation is often located in remote areas, which requires new transmission construction to deliver its energy to load. Because wind and some other renewable sources of electric power are intermittent in nature, actual generating capacity available at times of peak demand is less predictable than it is for capacity produced from more traditional technologies. Another characteristic of renewable sources is that typically the actual electricity produced in relation to the available capacity is relatively small. Although a large amount of capacity based on maximum output may be planned, these resources will be "energy-limited" and produce a relatively low level of MW-hours compared to their maximum capacity.

Intermittent and energy-limited renewable resources require that sufficient dispatchable resources and transmission capacity be available to assure system resource adequacy and operating security at all times. One way to take this into account in assessing a region's resource adequacy is to discount the total installed capacity from renewable sources to a level that reflects their expected operating capacity at the time of highest system demand. The appropriate level of assumed reduction is very much dependent upon regional conditions and the mix of renewable energy technologies. These characteristics might require the installation of additional thermal generation to ensure the ability to reliably serve load at the time of system peak.

Further, renewable resources have some unique characteristics that need to be analyzed to determine their ability to operate within the capacity of local transmission facilities. Specific characteristics include reactive power capability, voltage regulation, and low-voltage ride-through capability, which allows generation to remain connected to the bulk system under low-voltage conditions. These characteristics have historically been problematic for wind generation. However, as amounts of wind generation are increasing, the manufacturers are improving the capabilities of the equipment being installed. In the past year, FERC has adopted standard interconnection requirements that apply to new wind generation capacity. These new requirements should help assure that new renewable generation being added does not degrade system reliability.

Aging Work Force

While the post-war population surge has provided a young and well trained workforce for over 50 years, the baby boom generation is now entering retirement age. By 2030, the youngest baby boomers will have reached the retirement age of 66; at that point it is projected that almost 20 percent of the U. S. population will be 65 years of age or older[7]. Because of the declining birth rates since the 1960s, the workplace will not be able to replace the older baby boomer at the rate at which he or she will leave the work force.

[7] Lockwood, Nancy R.; December, 2003; The Aging Workforce; Society for Human Resource Management.

The loss of skilled and experienced technical talent is much more acute in the electric utility industry. According to a Hay Group study, 40 percent of senior electrical engineers and 43 percent of shift supervisors will be eligible for retirement by 2009. That study also found more than two-thirds of utility companies surveyed have no succession plan for supervisors and 44 percent have no plans for vice presidents. Not only does the industry not have enough professionals and managers, but the skilled labor force will be severely affected. Trying to get journeyman electricians and linemen will be more difficult than hiring the professional workforce.

At the same time, the demand for engineers with power background and other utility professionals has increased due to the advent of independent transmission companies, regional transmission organizations, and various markets. This caused the transmission dependent users, independent power producers, and other wholesale entities to increase their professional staff, particularly those with transmission planning expertise.

Aggravating the problem of sustaining the essential technical knowledge is the dwindling numbers of students in the power engineering programs of most universities. Currently, the electric power engineering programs within the United States graduate about 500 engineers per year; in the 1980s, this number approached 2,000.

The reliability of the North American electric utility grid is dependent on the accumulated experience and technical expertise of those who design and operate the system. As the rapidly aging workforce leaves the industry over the next five to ten years, the challenge to the electric utility industry will be to fill this void. Individual utilities are adopting innovative measures to bridge this emerging knowledge gap that include:

- Identifying key personnel approaching retirement and establishing mentoring programs to impart the experience realized by these individuals;
- Reassessing compensation and benefits packages to attempt to retain aging personnel, either on a full-time or part-time basis; and
- Hiring engineers and other utility professionals from outside the United States.

For those utilities where corporate consolidation and mergers occurred, the need to replace its aging workforce may not be as severe because it takes fewer people to do the same work after consolidation or merger. The electric utility industry as a whole has not, however, established the needed cooperative programs with academia to reinvigorate the power engineering education in North America.

Green House Gas Emissions

The long-term implications of greenhouse gas (GHG) emissions policies on the adequacy of future electricity supply are a function of the degree to which such policies and regulations limit or reduce the principal power plant sources of GHG emissions — carbon dioxide (CO_2) and nitrous oxide (N_2O) — and thereby limiting electricity production from fossil fuels.

The resulting influence of federal, state, and provincial regulation of GHG emissions on the combustion of fossil-fuels for power generation could restrict electricity production in the 2006–2015 assessment period. The potential reliability impacts of GHG limits on fossil-fueled power generation will depend on the transition period for coming into compliance with any new regulations.

Energy Policy Act of 2005

Two specific areas of EPACT under development in 2006 are intended to improve reliability through enhanced transmission infrastructure siting and enforcement:

1. Congestion Study and Designation of National Interest Electric Transmission Corridors (NIETCs) (Section 1221)

Section 1221 requires the Secretary of Energy to publish an electric transmission congestion study for comment by August 8, 2006. Further, the Act provides that after receiving and considering public comments, the Secretary may designate selected areas as NIETCs. Designation as a NIETC gives the Federal Energy Regulatory Commission (FERC) backstop authority under certain conditions to preempt state siting processes and approve the siting of transmission facilities within the corridors.

The congestion study, which has been completed, identifies geographic areas where electric transmission congestion is already severe, or becoming so, and where additions to transmission capacity (or suitable alternatives) could lessen the adverse impacts on consumers. The study builds upon existing transmission planning studies and other analyses prepared by regional reliability councils, regional transmission organizations (RTOs), utilities, and others. The study was also informed by congestion modeling of the Eastern and Western Interconnections.

2. Designation of energy corridors on federal lands (Section 368)

Section 368 directs the Secretaries of Agriculture, Commerce, Defense, Energy, and the Interior (the Agencies) to designate under their respective authorities corridors on Federal land in the 11 Western States (Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, and Wyoming) for oil, gas and hydrogen pipelines and electricity transmission and distribution facilities (energy corridors). The Agencies have determined that designating corridors as required by Section 368 of the Act constitutes a major federal action which may have a significant impact upon the environment within the meaning of the National Environmental Policy Act of 1969 (NEPA). For this reason, the Agencies intend to prepare a programmatic environmental impact statement (PEIS) entitled, "Designation of Energy Corridors on Federal Land in the 11 Western States" (DOE/EIS-0386) to address the environmental impacts from the proposed action and the range of reasonable alternatives. DOE and BLM will be co-lead agencies for this effort, with the U.S. Department of Agriculture's Forest Service (USFS) participating as a cooperating agency. Similar work will subsequently be conducted for Federal Lands in the eastern states.

ADEQUACY ASSESSMENT

Demand and Resource Projections

NERC expects electricity demand to grow by about 68,675 MW through the summer of 2011. Projected resource additions over this same period total about 39,937 MW, depending upon the number of merchant plants assumed to be in service. However, due to the short lead-time for developing some types of generation, this difference could be offset by assignment or development of capacity that has not yet been committed or announced.

The average annual growth in United States summer peak demand for 2006–2015 is 1.9 percent. This is slightly lower than the 2.0 percent average annual growth in actual peak demand since 1995. In Canada, average annual growth in winter peak demand over the next ten years is 1.1 percent, which is slightly higher than the 0.9 percent average annual growth in actual demand since 1995. Year-to-year demand growth rates can vary due to variations in economic conditions and weather. Also, actual demands are not corrected for weather or other conditions.

Peak demand projections shown on Figures 2 and 3 represent an aggregate of weather-normalized regional member projections. NERC has not prepared its own independent demand forecast. Individual local entities make appropriate assumptions dealing with diversity, weather, and economic conditions, which are key drivers of the demand forecast. Individual local area forecasts typically are developed using a "multi-model" approach that comprises econometric modeling using national, regional, and state/provincial economic projections, as well as end-use modeling of local service area conditions.

NERC's Load Forecasting Working Group (LFWG) develops bandwidths around the aggregate United States and Canadian demand projections to account for uncertainties inherent in demand forecasting. The average annual growth in the "high" and "low" band U.S. summer peak demands are 2.4 percent and 1.4 percent, respectively. In Canada, the "high" and "low" band growth rates in winter peak demands are 1.7 percent and 0.3 percent, respectively.

Forecast Bandwidths

Forecasts are based on probabilities and cannot precisely predict the future. Instead, forecasts typically encompass a range of possible outcomes to address future uncertainty. Each demand projection, for example, represents the most likely future outcome. Capacity resources historically have been planned to meet the most likely demand with an additional reserve to meet unusual conditions.

For planning purposes, not only is an estimate of the most likely future outcome useful, but so are those of potential variations. Accordingly, LFWG develops upper and lower confidence bands around demand projections. The confidence bands represent an 80 percent probability that future demand will occur between the upper and lower bands. Consequently, the chance that demand will be below the lower band is 10 percent and the chance that demand will be above the upper band is 10 percent. Demand projections and their associated bandwidths are updated each year to reflect the latest conditions.

The Regional Self-Assessment section of this report includes regional bandwidths to more clearly show the variability of demand within the respective regions.

Figures 2 and 3 also show overlays of projected capacity resources on the projected demand bandwidths. The NERC regions report all capacity committed to serve demand within their borders, but capacity that is not committed to serve a specific demand might not be reported to NERC through its traditional data collection process.

Accurately predicting the exact number and in-service dates of future capacity additions that merchant developers will actually construct is difficult. To supplement these traditional data sources in order to better understand the potential impacts of new generators, the RAS has enlisted the services of Energy Ventures Analysis, Inc. (EVA) to provide detailed project information[8]. Using this information, announced plans for new merchant plants were screened to establish those most likely to be built.

Figure 2 shows three resource curves: the first is based on NERC regional projections; the second adds uncommitted capacity to regional projections; and the third is the subcommittee's best estimate of future capacity resources (existing plus EVA).

[8] EVA maintains a database of all proposed new power plants in the United States and tracks various milestones associated with the completion of the projects, including applications for environmental permits, siting, acquisition of equipment, financing, and contractual arrangements to sell the output of the facilities. Using this information, announced new merchant plants were screened to establish those most likely to be built. For Canada, the RAS utilized a combination of EVA and regional data to compile comparable statistics.

Figure 2: United States Summer Capacity Versus Demand Growth

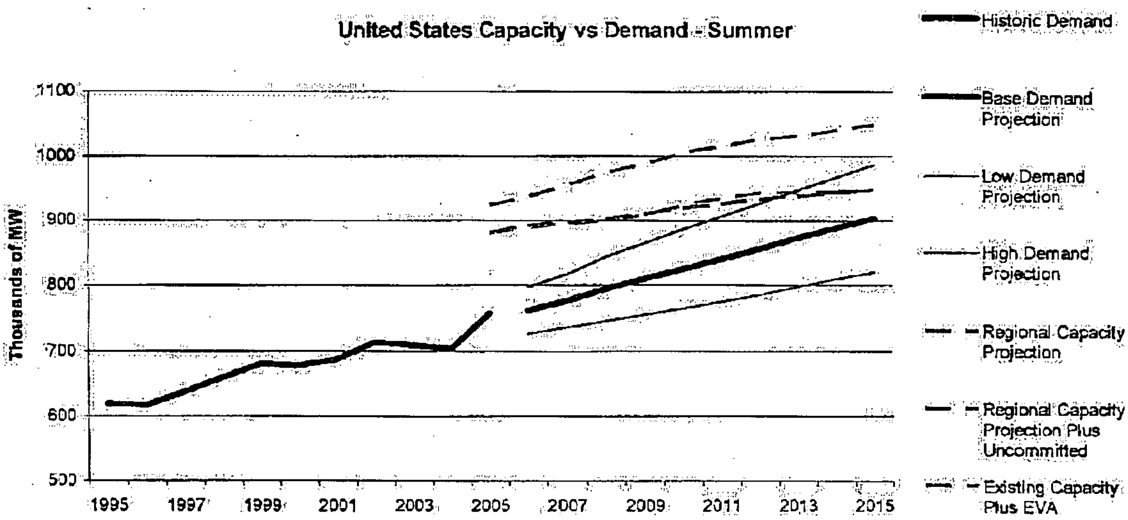
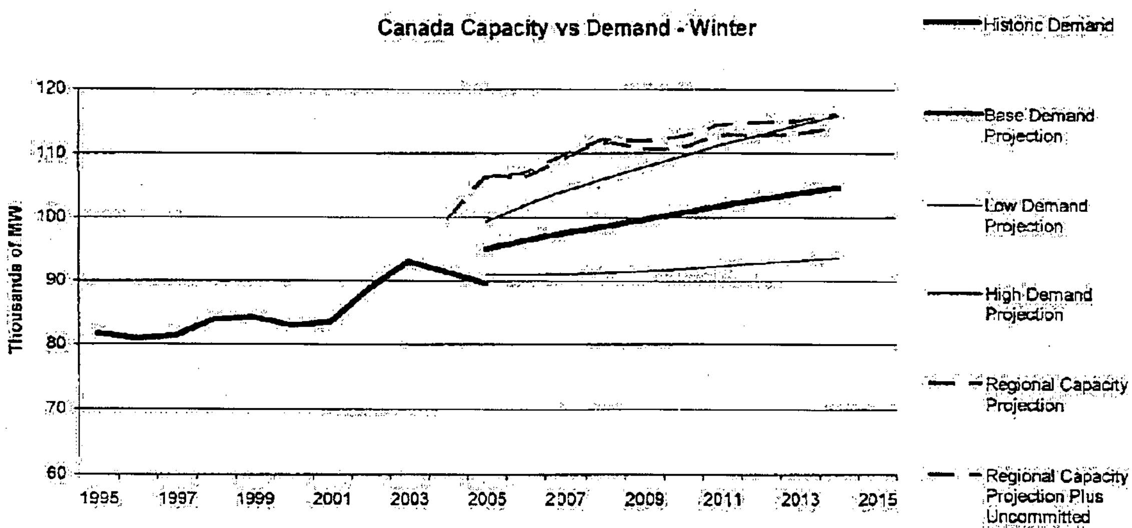


Figure 3: Canada Winter Capacity Versus Demand Growth



Capacity Additions

The overall projected amount of new generation is decreasing. In some areas, generation has been overbuilt and a decrease in new construction is an expected response to the over-supply situation. In other areas, increases in generation additions that have not yet been identified may be continuing but because of the short lead time for construction of some generating facilities, those projects may not be included in announced plans.

Table 1: Aggregate Capacity Under Development by Type

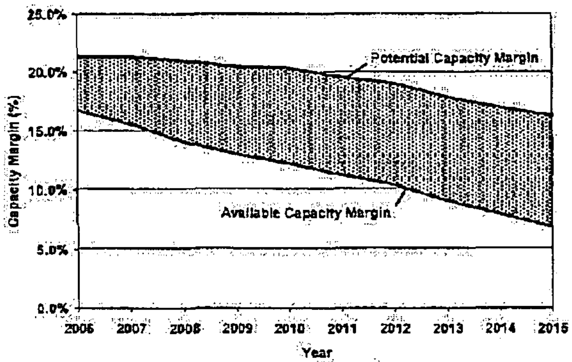
	Capacity Additions, MW			
Capacity Type	1998 to 2005	2006 to 2012	2013 to 2015	2006 to 2015
United States				
Combined Cycle	143,694	34,074	-	34,074
Simple Cycle	75,314	3,890	-	3,890
Coal	2,168	29,404	3,885	33,289
Nuclear	2,567	2,366	2,550	4,916
Wind	5,705	8,769	-	8,769
Other	1,572	3,170	-	3,170
Total U.S.	**231,019**	**81,672**	**6,435**	**88,107**
Canada				
Combined Cycle	80	-	-	-
Simple Cycle	4,740	4,653	-	4,653
Coal	490	450	-	450
Nuclear	-	-	-	-
Wind	-	1,440	-	1,440
Other	-	203	200	403
Total Canada	**5,310**	**6,746**	**200**	**6,946**

Source — EVA

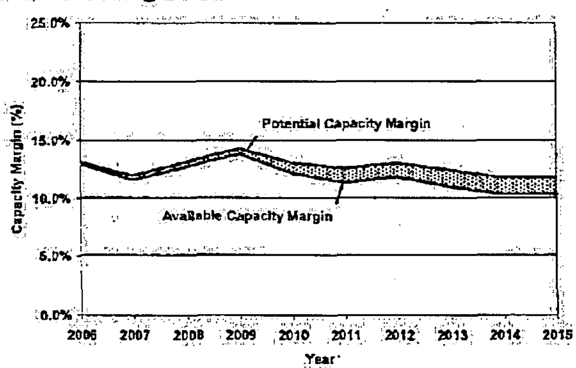
Capacity Margins

Available capacity margins in the United States and Canada are projected to decline over the 2006–2015 period. Margins vary from region to region, as does the amount of *uncommitted resources* reported.

Capacity margins in United States decline throughout ten-year period. Uncommitted resources offer significant potential.



Capacity margins in Canada steady in short term; decline in long term.



Capacity Margin — Capacity that could be available to cover random factors such as forced outages of generating equipment, demand forecast errors, weather extremes, and capacity service schedule slippage.

Available Capacity Margin — The difference between *committed* capacity resources and peak demand, expressed as a percentage of capacity resources.

Potential Capacity Margin — The difference between *committed* plus *uncommitted* capacity resources and peak demand, expressed as a percentage of capacity resources.

Committed Capacity Resources — Generating capacity resources that are existing, under construction, or planned that are considered available, deliverable, and committed to serve demand, plus the net of capacity purchases and sales.

Uncommitted Capacity Resources — Capacity resources that include one or more of the following:

- Generating resources that have not been contracted nor have legal or regulatory obligation to deliver at time of peak.
- Generating resources that do not have or do not plan to have firm transmission service reserved (or its equivalent) or capacity injection rights to deliver the expected output to load within the region.
- Generating resources that have not had a transmission study conducted to determine the level of deliverability.
- Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources.
- Transmission-constrained generating resources that have known physical deliverability limitations to load within the region.

Available capacity margins drop below minimum target levels in ERCOT, MRO, New England, RFC, and Rocky Mountain and Canada areas of WECC in the next 2–3 years, with many other areas reaching minimum levels later in the ten-year period. However, all regions have some additional resources potentially available in the form of *uncommitted resources* that exist, are under construction, or are in the planning stage, which offer the potential to meet minimum target levels. Actions needed to make these resources available when needed include: returning "mothballed" units to active service; entering into power purchase agreements for existing or new resources; upgrading transmission to provide access to resources that would not otherwise be deliverable; and developing and bringing into service projects that are in generator interconnection queues.

Energy Growth Projections

Figures 4 and 5 show ten-year projections of net energy for load for the United States and Canada along with the high and low bandwidth projections. The average annual growth in United States net energy for load is 1.8 percent, which is the same annual growth rate experienced since 1995. The "high" and "low" band growth rates for the United States are 2.2 percent and 1.4 percent, respectively. In Canada, the projected average annual growth in net energy for load is 1.2 percent, compared percent to a 1.8 percent growth rate since 1995. The "high" and "low" bands are 1.7 percent and 0.7 percent, respectively.

Figure 4: United States Net Energy for Load 2006–2015

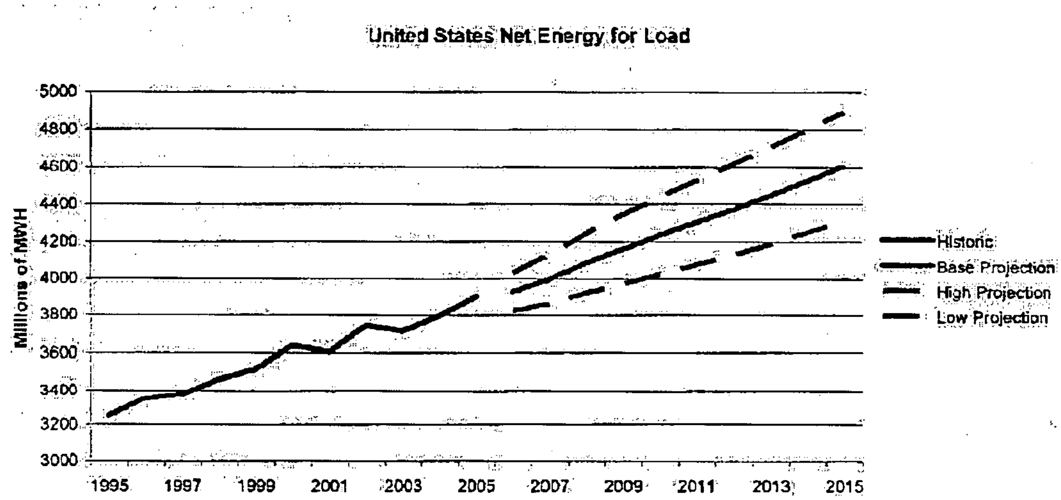
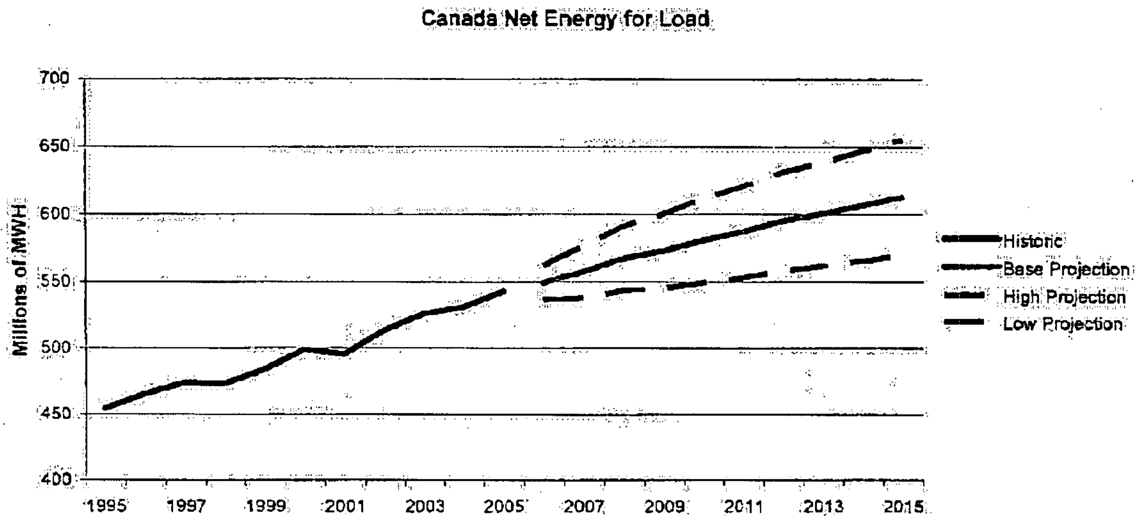


Figure 5: Canada Net Energy for Load 2006–2015



Regional Self-Assessments

Introduction

Regional Resource and Demand Projections

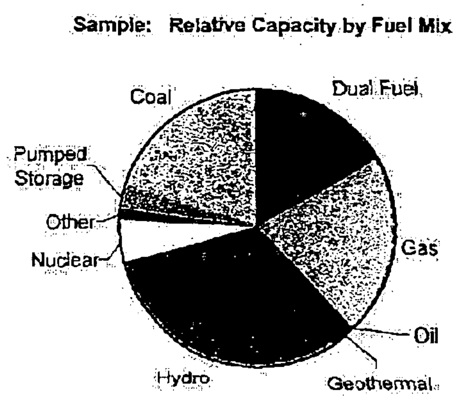
The figures in the regional self-assessment pages show the regional historical demand, projected demand growth, capacity margin projections, and generation expansion projections reported by the regions. These data are augmented by generation expansion data from EVA.

Capacity Fuel Mix

The regional capacity fuel mix charts, shown as a comparative percent of regional generating capacity between 2005 and 2011, illustrate each region's relative dependence on various fuels for its reported generating capacity. The charts for each region in the regional self-assessments are based on the most recent data available in NERC's Electricity Supply and Demand database.

Note: The category "Other" may include capacity for which a fuel type has yet to be determined.

Sample — Relative Capacity by Fuel Mix



ERCOT

Demand

ERCOT has increased its projected average annual demand growth rate over the assessment period from 1.8 percent used last year to 2.3 percent for this year's assessment. That increase is due to the effect of the historical trend and updated econometric forecasts.

ERCOT's peak demand forecasts are based on normal weather defined by a temperature normalized profile from the last 11 years of historical hourly temperatures. Unusually hot or cool weather can result in actual demands above or below the forecast. The ERCOT reserve margin of 12.5 percent was established to accommodate this demand variation along with unit forced outages.

The analysis of variability in load and weather volatility was performed with a system forecasting model that runs a Monte Carlo simulation of a median weather profile and a 90^{th} percentile profile forecast using weather and calendar variables. The 90^{th} percentile forecast is about 5.5 percent higher than the median.

Energy

The energy forecast for the assessment period indicates an average 2.1 percent growth rate. This growth rate is little changed from last year's assessment forecast. The actual growth rate from 2004 to 2005 was 3.5 percent due to milder weather in 2004 than in 2005.

Resources

ERCOT has set a minimum planning reserve margin target of 12.5 percent that equates to a capacity margin of 11 percent. This was based on a reliability study, which concluded that the margin should provide about a one-day-in-ten-years loss-of-load expectation.

Resources that are counted in determining ERCOT's margins are:

- Existing in-service capacity based on demonstrated summer net dependable capacity (except for wind generation and switchable capacity that has the capability to switch between ERCOT and other interconnections).
- Future planned generation with signed interconnection agreements.
- Fifty percent of dc tie capacity.
- Switchable capacity to the extent its owners have indicated they intend to be in the ERCOT market.
- Based on historical performance on peak, 2.6 percent of existing in-service wind capacity and future wind capacity with signed interconnection agreements.
- Mothballed capacity based on when its owners estimate it will be returned to service.

Generation owners are required to provide ERCOT at least 90 days notice of extended planned shut-downs of generation so ERCOT can enter into reliability must run (RMR) contracts for those units to keep them available if needed for system reliability. ERCOT currently has contracts with 267 MW of RMR capacity in the Laredo and Bryan areas that is needed to provide local voltage support and keep facility loadings below transmission limits. ERCOT has exit strategies to improve the transmission system so this RMR capacity can be phased out over the assessment period.

ERCOT has approximately 672 MW of new fossil-fueled generating capacity with existing signed interconnection agreements expected to come on-line between 2006 and 2011. An additional 6,100 MW of fossil-fueled, mostly coal, capacity has been publicly announced but is not included in forecasted resource capability. Almost 950 MW of new wind generation is also expected between 2006 and 2011. ERCOT does not maintain a new generation forecast beyond 2011.

A total of 820 MW of dc tie transfer capability exists between ERCOT and SPP and 36 MW of capability between ERCOT and Mexico's Comision Federal de Electricidad. Entities in ERCOT anticipate importing via the SPP dc ties 120 to 138 MW of firm purchases over the assessment period. Entities in SPP can call on 162 MW of capacity in ERCOT and it is classified as a capacity sale from ERCOT. These purchases and sales have little impact on ERCOT's ability to meet demand requirements.

Fuel

Curtailment of natural gas supply is possible during winter months, which is an issue due to the fact that over 60 percent of the generating capacity in ERCOT is fueled by natural gas. Typically, natural gas supply is not a problem for gas-fired generation in the summer months due to the absence of heating demand competition for supply. Gas generation currently has no market incentive or nonmarket mechanism to maintain dual fuel capability and storage, typically with fuel oil, which would be critical to maintaining generation adequacy during extended periods of gas curtailments. ERCOT has a procedure in place to request current status of fuel supply contracts, backup fuel supplies, and unit capabilities if severe cold weather is expected in the seven-day forecast. This information would be used to prepare operation plans.

ERCOT will initiate its Emergency Electric Curtailment Plan (EECP) (see ERCOT Protocols Section 5.6.6.1 at http://www.ercot.com/mktrules/protocols/current.html) if available capacity gets below required levels due to gas curtailments or any other reason. The EECP maintains the reliability of the interconnection by avoiding uncontrolled load shedding. During emergency conditions, ERCOT coordinates gas supply priorities with the Texas Railroad Commission.

Transmission

The existing bulk power system within ERCOT is comprised of 38,000 miles of transmission lines. ERCOT, along with its transmission owners' member systems, continues to plan for a reliable bulk power system and plans to add 1,601 miles of 138-kV, and 835 miles of 345-kV transmission lines in the 2006–2010 time period. ERCOT members invested over $345 million in new transmission lines and system upgrades in 2005, and are planning transmission capital expenditures of more than $2.2 billion over the next five years.

The major transmission constraints in ERCOT expected during the assessment period are:

- Transfers into the Dallas-Fort Worth area from northeast and central Texas
- Transfers into Houston from north and south Texas
- Transfers out of the west Texas wind generation area
- Transfers into and across the Rio Grande Valley
- Local operating reliability needs in Laredo

These constraints will require redispatch of generation by ERCOT and, in the case of Laredo, RMR contracts with generators that would have otherwise shut down as previously discussed. Their main impact is on economics as they have operational solutions to maintain reliability. Approximately 650 circuit miles of major new 345-kV lines in central, south, and north Texas are scheduled to be placed in service between 2006 and 2010 to relieve these constraints. Several lines in the Dallas-Fort Worth area are scheduled to go in service by the end of 2006 that will increase transfer capability into that area. In 2007, the new Hillje station with lines to South Texas Project and W.A. Parish will increase import capability into Houston. A line from San Miguel to Laredo scheduled for service in 2010 will allow termination of the RMR contract in Laredo.

Transmission planning is increasingly using voltage and transient stability analysis. Voltage stability has become a more pressing concern with increasing power transfers in ERCOT and lessons learned from the 2003 Northeast blackout.

Operations

No major facility outages or environmental requirements are expected during the assessment period that would significantly impact reliable operations. Ongoing operational challenges during the assessment period are expected to center around transmission congestion management and operating with reduced capacity margins.

In the short term, a number of temporary post-contingency remedial action plans (RAPs) and special protection systems (SPSs) that maximize transfer capabilities over the existing system and reduce redispatch (but require special operator attention) will be implemented as needed. Improvements to the transmission system are planned to eliminate many of the existing RAPs and SPSs over the next few years.

Capacity margins will likely be at minimum levels over the assessment period compared to the relatively high levels experienced over the last few years. This, coupled with resource vulnerability to winter gas curtailments previously discussed, will increase the likelihood that operators will need to initiate emergency procedures such as the EECP in the future. ERCOT plans to have an Operator Training Simulator available in 2007 to train operators on simulated EECP and other unusual events.

ERCOT operators are able to do real-time voltage stability analysis. This analysis addresses one of the recommendations from the report on the 2003 blackout.

The Public Utility Commission of Texas (PUCT) has approved a major market redesign that would change current congestion management procedures from a zonal to a nodal-based system. This transition, currently scheduled for January 1, 2009, would present challenges in implementing new operating systems, but should also improve the efficiency of transmission congestion management.

Assessment Process

ERCOT prepares five- and ten-year projections of capacity, demand, and reserves at least annually to evaluate whether the system will meet the reserve margin target of 12.5 percent (11 percent capacity margin). ERCOT also performs power flow analyses required to assess compliance with ERCOT Planning Criteria, which comply with NERC Planning Standards. An annual study and report is made to the PUCT highlighting congested areas of the transmission system and recommended projects to mitigate that congestion. ERCOT facilitates an open planning process through three regional planning groups made up of transmission owners and operators and other ERCOT market participants. Any party can comment on ERCOT planning studies and propose new projects or additional studies for review by the appropriate regional planning group.

ERCOT is a separate electric interconnection located entirely in the state of Texas and operated as a single balancing authority. ERCOT has 135 members that represent independent retail electric providers; generators, and power marketers; investor-owned, municipal, and cooperative utilities; and retail consumers. It is a summer-peaking region responsible for about 85 percent of the electric load in Texas. ERCOT serves a population of more than 20 million in a geographic area of about 200,000 square miles. Additional information is available on the ERCOT Web site (www.ercot.com).

ERCOT Capacity and Demand

Figure 7: ERCOT Net Energy for Load

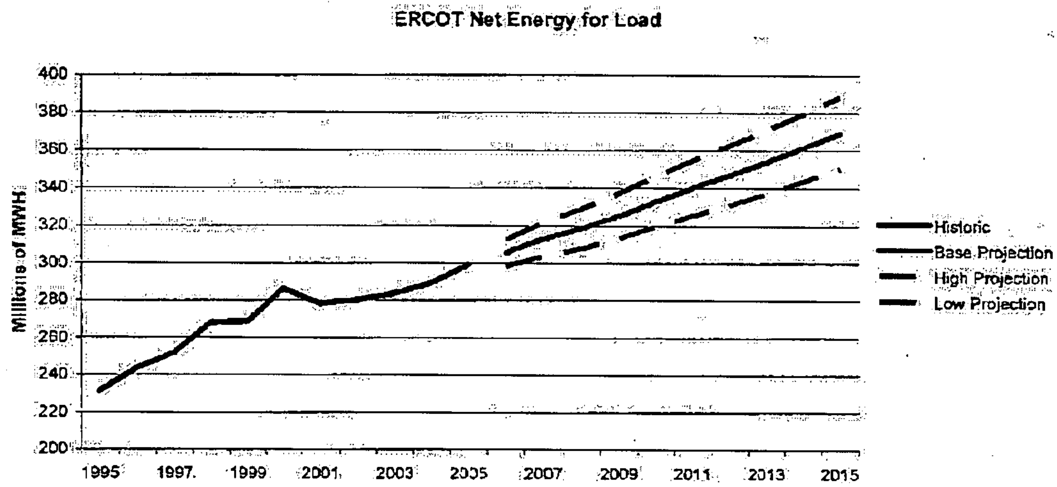


Figure 8: ERCOT Capacity Margins — Summer

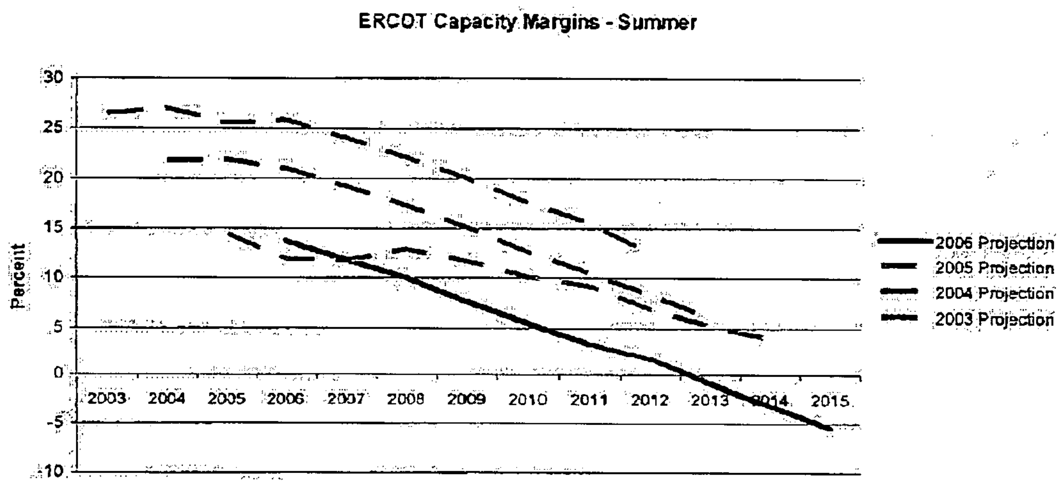


Figure 9: ERCOT Capacity Versus Demand — Summer

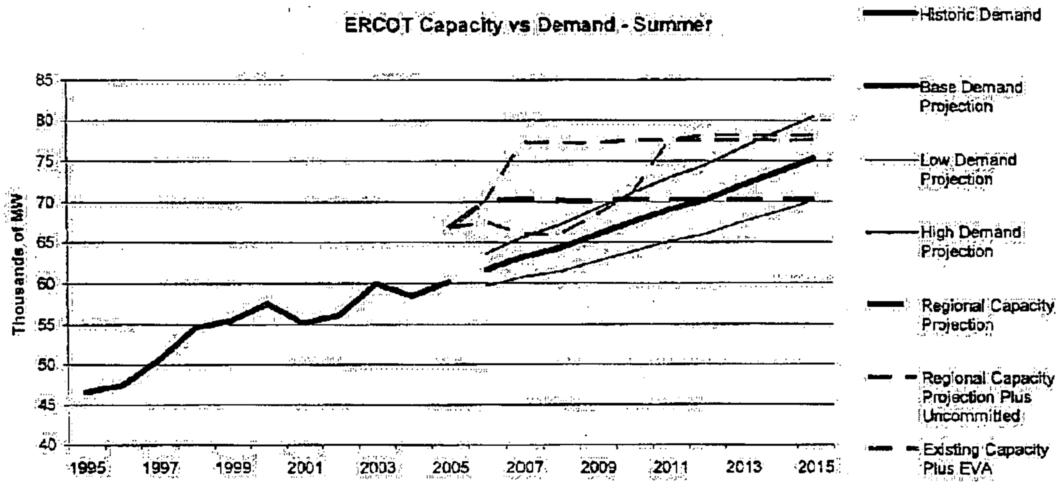
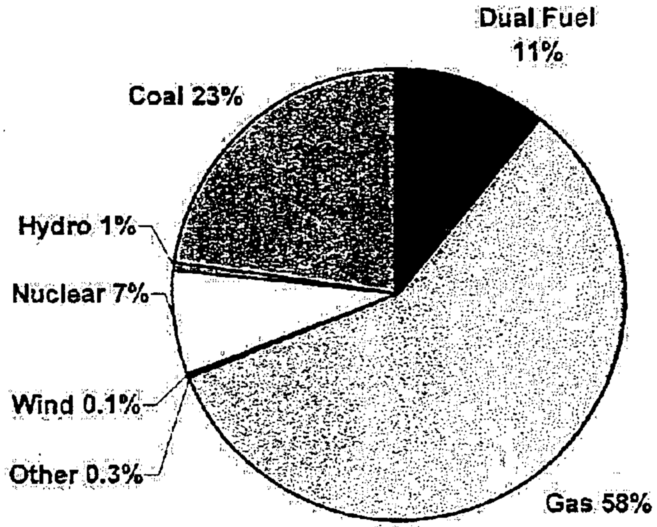
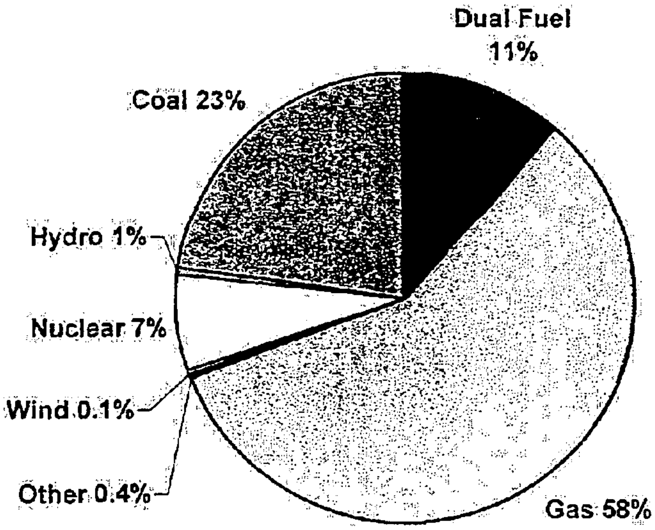


Figure 10: ERCOT Capacity Fuel Mix for 2005 and 2011

ERCOT Capacity Fuel Mix 2005



ERCOT Capacity Fuel Mix 2011



FRCC

Demand

FRCC members use historical weather databases consisting of as much as 57 years of data for the weather assumptions used in their forecasting models. Historically, FRCC has high-demand days in both the summer and winter seasons. However, because the region is geographically a subtropical area, a greater number of high-demand days normally occur in the summer. As such, this report will address the summer load values.

The 2006 ten-year demand forecasts for FRCC exhibited similar growth trends to 2005 projections. The annual net internal demands for the summer months are projected to rise at a compounded average annual growth rate of 2.4 percent from 42,761 MW in 2006 to 53 108 MW in 2015.

Individual companies within FRCC use a bandwidth analysis and/or a Monte Carlo simulation to assess the peak demand uncertainty and variability. For the bandwidth analysis, the company develops a bandwidth around the projected or most likely demand (50 percent probability). The purpose of developing bandwidths on peak demand is to quantify all uncertainties of demand. This would include weather and nonweather demand variability such as demographics, economics, and price of fuel and electricity.
Monte Carlo simulations on peak demands are performed to arrive at a probabilistic distribution as to range and likelihood of this range of outcomes of peak demand. Factors that determine the level of demand for electricity are assessed in terms of their own variability and this variability incorporated in the simulations. If the installed and planned generation is sufficient to cover a significant portion of the demand variability, then the system is deemed to be reliable at a given level of probability.

An FRCC methodology for developing bandwidths for the region forecast has not been developed; however, FRCC is assessing possible methodologies to develop region forecast bandwidths.

Energy

The 2006 ten-year energy forecast for FRCC displayed growth similar to the 2005 forecast. Yearly energy consumption is expected to rise from 226,544 GWh by 2.8 percent over the next decade, to 297,561 GWh, exactly matching last year's projected ten-year growth of 2.8 percent.

Resources

The Florida Public Service Commission (PSC) requires all Florida utilities to file an annual ten-year site plan that details how each utility will manage growth for the next decade. The data from the individual plans is aggregated into the FRCC Load and Resource Plan that is produced each year and filed with the Florida PSC. The FRCC 2006 Load and Resource Plan shows FRCC reserve margins over the winter and summer peaks for the next ten years to equal or exceed 20 percent. All years are well above the 15 percent reserve margin standard established by FRCC. The calculation of reserve margin does not include any uncommitted capacity (see Tables 3a–3d).

FRCC members are projecting a net increase (i.e., additions less removals) of 16,617 MW of new installed capacity over the next decade, compared to the 17,740 MW projected in last year's ten-year forecast. Of this increase, 10,799 MW are designated for gas-fired operation in either simple-cycle or combined-cycle configurations, and 5,524 MW are anticipated for coal-fired operation. Gas-fired generation continues to dominate a high percentage of new generation. In 2005, natural gas generation accounted for 21,974 MW of generation, which is 46 percent of FRCC's installed capacity. By 2015, it is expected that natural gas generation will account for 32,953 MW of generation, which will be 52 percent of FRCC's installed capacity.

Approximately 4,913 MW of merchant plant capability are located in FRCC, of which 3,763 MW are under firm contract. The planned construction of merchant plants has decreased significantly over prior years' projections, and the amount of merchant generation that may come on-line in the next ten years is dependent on a number of factors that are not capable of being forecasted at this time. These include the results of contractual negotiations for the sale of announced capacity, transmission interconnections and/or service requests and associated queuing issues, and federal, state and local siting requirements.

Currently, 1,552 MW are being imported into the region on a firm basis and about 839 MW are dynamically dispatched out of the Southern subregion, which together account for about 5 percent of the reserve margin. These firm imports and dynamically dispatched capacity have firm transmission service to ensure deliverability into FRCC. No firm long-term sales to other regions are anticipated.

FRCC conducted a loss of load probability (LOLP) analysis of peninsular Florida for the 2005–2014 study horizon that examined both the resource plans and load forecasts of state utilities. Factors included extreme summer and extreme winter demand scenarios; availability of SERC firm and nonfirm imports; and availability of demand-side management. The study concluded that the existing and planned resource additions over the coming decade will result in a predicted LOLP that is less than the one-day-in-ten-years criterion.

Fuel

The FRCC Regional Load and Resource Plan is developed on an annual basis and includes specification of primary and secondary fuel sources for both generating facilities and prospective units planned over the ten-year horizon. Due to the growing interdependence of generating capacity and natural gas, the FRCC has undertaken initiatives to increase coordination among natural gas suppliers and generators within the region. This coordination has provided the data necessary to perform short-term natural gas availability assessments in order to provide operators with near-term health of the gas delivery system, along with the basis for other operational recommendations up to and including regional appeals for conservation. FRCC continues to assess and coordinate responses to regional fuel supply impacts and issues, including fuel inventory and alternate supply availability, as they are identified.

During peak demand periods, operators within FRCC will use the fuel supply infrastructure to its maximum capability as most fuel delivery infrastructure is designed around projected loading. The type of infrastructure and preferred generation dispatch used would be based on economic conditions and surrounding the types of fuels, along with availability of external purchased power. Typically, during peak summer conditions, some alternate fuel unit dispatch may be used depending on system economics.

Fuel supplies continue to be adequate for the region. FRCC continues its work on a more detailed natural gas pipeline and electric interdependency study process. FRCC has begun development of a high-level, transient gas flow model to study and finitely analyze the gas pipeline system and its impact on reliability in peninsular Florida. Additional data related to natural gas use within the region has been collected, and input into the gas flow model and scenarios are being developed to perform reliability analyses.

Transmission

The results of the short-term (first five years) study for normal, single, and multiple contingency analysis of the FRCC region show that there is potential thermal and voltage violations occurring in Florida. However, these potential violations can be resolved with pre-determined operational procedures. Generation redispatch, sectionalizing, implementation of load management, planned load shedding, reactive device control, and transformer tap adjustments successfully mitigate all the reportable load and voltage violations appearing in the first five years. However, potential violations on the transmission lines between southwestern central Florida generation and the greater Orlando load area would require more extensive operational procedures. Permanent solutions are under review to resolve these deficiencies with new transmission projects. Based on the committed projects and expected generation dispatch, it is expected that these operational procedures will continue in this area until 2010. Higher than expected loads or extended generation outages could worsen the situation as well. However, additional operation strategies have been developed to address these future conditions and these strategies will continue to be evaluated to ensure system reliability.

The long-range (remaining five years) study results reveal developing problems in several areas in the FRCC region that the responsible utilities acknowledge will be studied in the near future to define needed improvements to the transmission system. These areas include northwest Florida around Tallahassee, the Avon Park area, north Florida around the site of a proposed coal-fired generation project in Taylor County, and new generation locations in central Florida. These new generation projects will have a major impact on the bulk power system in the region. Currently, these areas are being studied to determine the projects required to meet the long-range needs of the transmission system.

Interregional transmission studies are performed each year to evaluate the transfer capability between the Southern subregion of SERC and the FRCC for the upcoming summer and winter seasons. Joint studies of the Florida/Southern transmission interface have verified the current import capability of 3,600 MW into the FRCC region, and the export capability of 1,300 MW.

No scheduled transmission maintenance outages of any significance are planned over the forecast horizon, particularly during seasonal peak periods. Scheduled transmission outages are typically performed during off-seasonal peak periods to minimize any impact to the bulk power system.

Currently, individual members plan to construct 477 miles of 230-kV transmission lines during the 2006–2015 assessment to continue to meet expected load growth, integrate new generation sources into the bulk transmission system and resolve the potential reliability issues.

Operations

FRCC has a security coordinator agent (reliability coordinator) that monitors real-time system conditions and evaluates near-term operating conditions. The security coordinator uses a region-wide state estimator and contingency analysis program to evaluate current system conditions. These programs are updated with data from operating members every ten seconds. These tools enable the FRCC security coordinator to implement operational procedures such as generation redispatch, sectionalizing, planned load shedding, reactive device control, and transformer tap adjustments to successfully mitigate the line loading and voltage concerns that occur in real time and those identified in the FRCC transmission studies.

The FRCC region experienced significantly higher load levels than were forecast during the summer of 2005. This coupled with additional generation in the southwest portion of central Florida, created increased west-to-east flow levels across the central Florida metropolitan load areas.

Several transmission modifications have been accelerated and were implemented this spring to increase the operational margins and transmission configuration options for the area. If the region experiences comparable load levels to the summer of 2005, the same sensitivities to area dispatches and transmission configuration are expected as operational issues until additional transmission is constructed. Should these operational issues arise, operational procedures (operational work-arounds with pre-planning and training) will manage the impacts to the bulk power system in the area to ensure reliable operations.

Even with increased reliance on operational procedures to resolve potential transmission loading concerns through 2011, FRCC does not foresee any reliability issues for the first five years of the study period. In addition, with the proposed transmission expansion projects, FRCC does not foresee any reliability issues in the longer term.

Assessment Process

FRCC members plan for facility additions on an individual basis. However, they also provide data to FRCC to update and maintain the regional databases. These regional databases are used in the reliability assessment process to ensure the continued reliability of the bulk power system. FRCC follows a formal reliability assessment process by which it uses a committee and working group structure to annually review and assess reliability issues that either exist or have the potential to develop. This process determines which areas deserve closer scrutiny in the planning and operating studies that will be performed during the year. FRCC members use the results of these studies to ensure that the FRCC region is able to meet the reliability needs of the future.

Study results are also provided to the Florida PSC, which has the authority to require installation or repair of generating plants and transmission facilities, if it has reason to believe that inadequacies exist with respect to grid reliability.

In April 2005, FRCC adopted a very comprehensive and in-depth transmission planning process for the region. This process begins with the annual consolidation of the individual long-term transmission plans of all of the transmission owners in FRCC. A detailed analysis of the resulting regional plan will be conducted annually by the FRCC Planning Committee. The assessment will be a robust analysis and will include an examination of multiple expected system conditions and other sensitivities.

The Planning Committee will report its findings, including recommendations for changes or additions to individual transmission owner's plans, to the FRCC Board of Directors for approval. The process also provides for resolution of any identified unresolved issues. The resolution may include the use of an independent evaluator to study and provide input to FRCC. A final report will be sent to the Florida PSC.

FRCC's membership includes 28 members, which is composed of investor-owned utilities, cooperative systems, municipal utilities, power marketers, and independent power producers. Historically, the region has been divided into 11 balancing authorities.

As part of the transition to the ERO, FRCC has registered 109 entities (both members and nonmembers) performing the functions identified in the NERC Reliability Functional Model and defined in the NERC Reliability Standards glossary. The region contains a population of more than 16 million people, and has a geographic coverage of about 50,000 square miles over peninsular Florida. Additional details are available on the FRCC Web site (http://www.frcc.com).

FRCC Capacity and Demand

Figure 11: FRCC Net Energy for Load

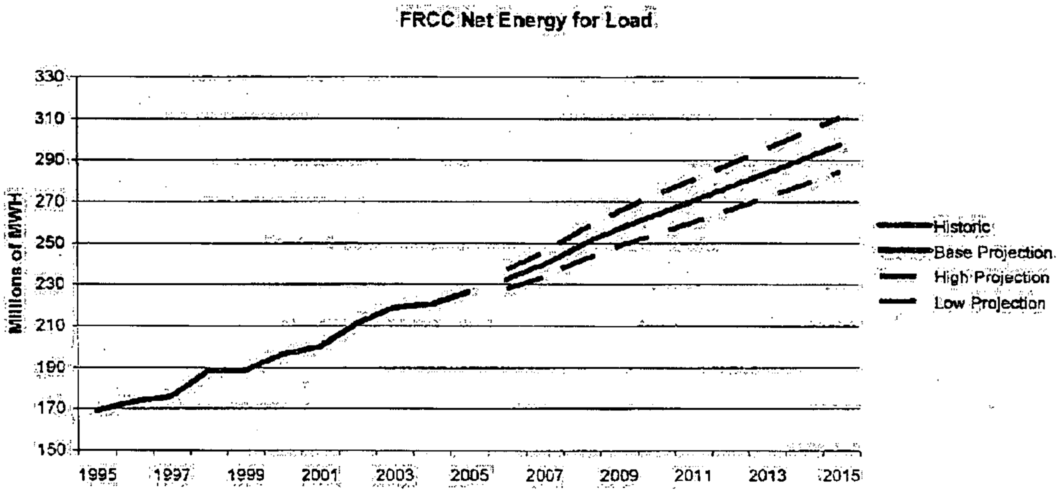


Figure 12: FRCC Capacity Margins — Summer

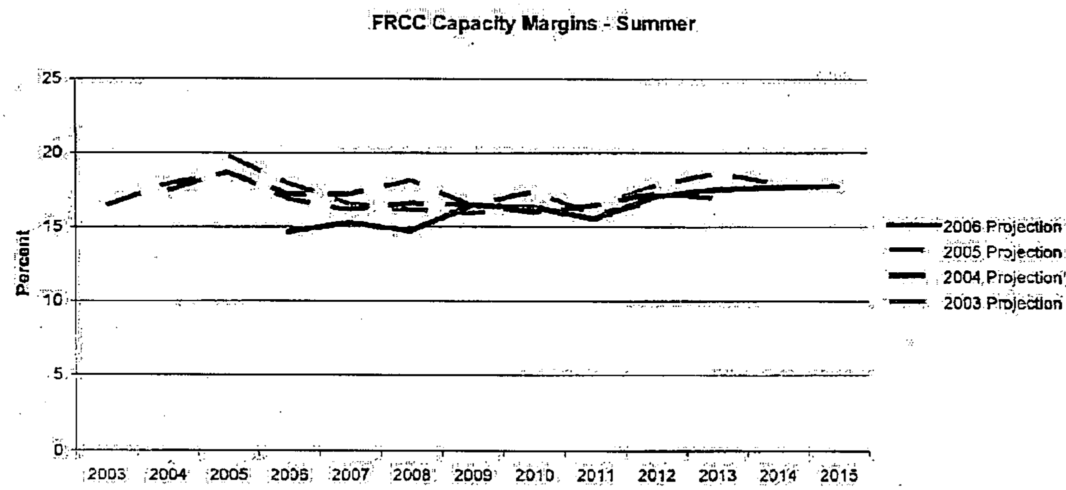


Figure 13: FRCC Capacity Versus Demand — Summer

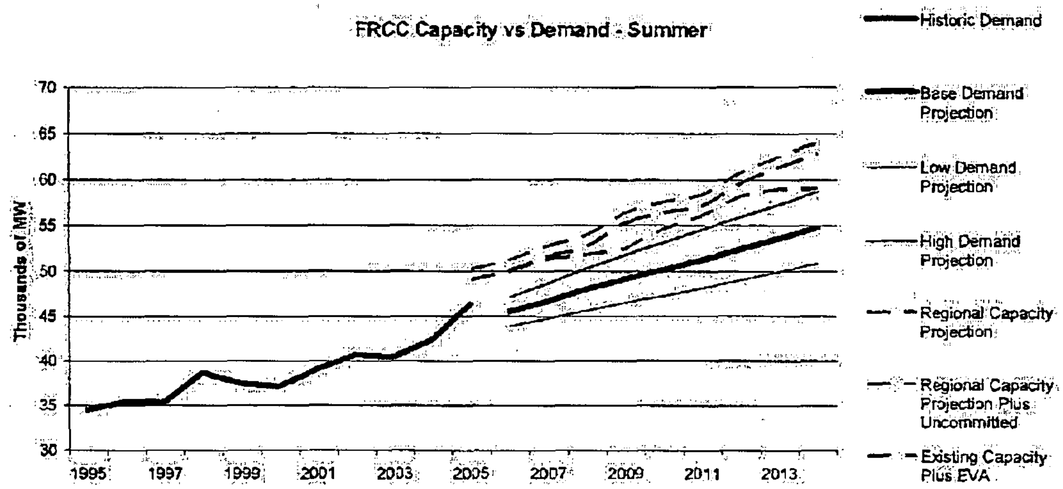
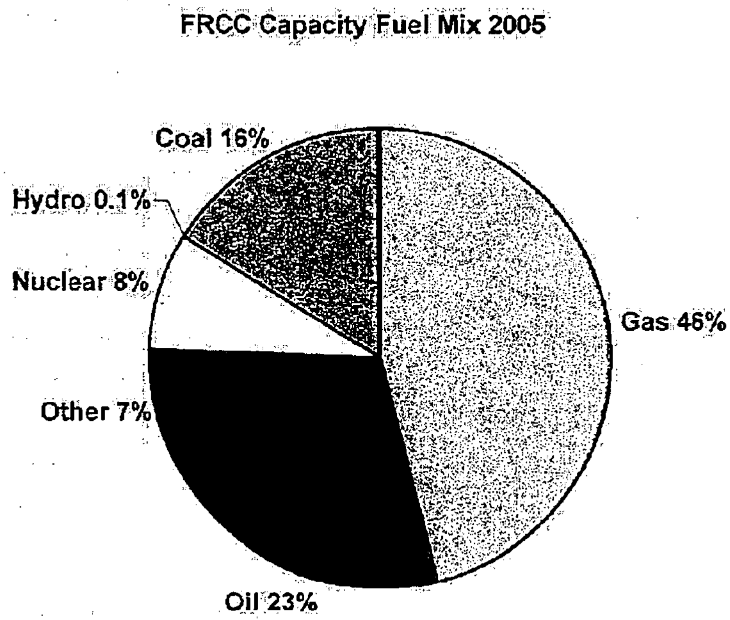
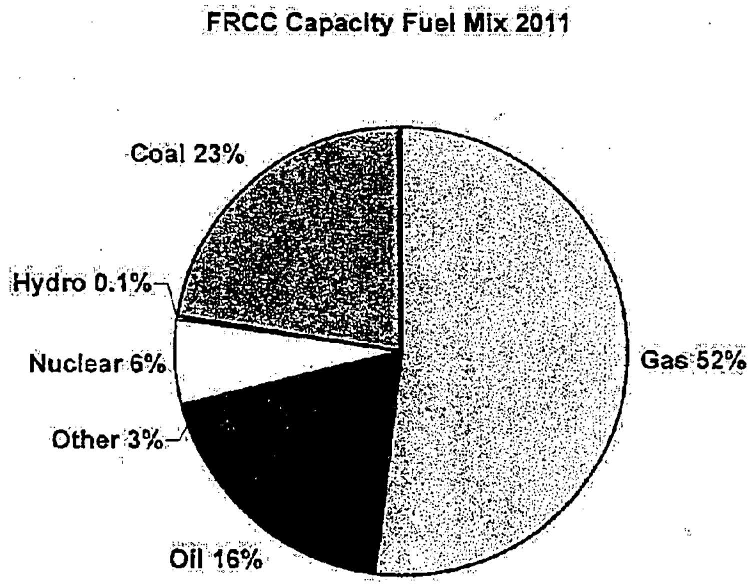


Figure 14: FRCC Capacity Fuel Mix for 2005 and 2011





MRO

The MRO replaced the Mid-Continent Area Power Pool (MAPP) as a NERC regional reliability council in January 2005. MAPP continues to exist as a regional transmission group and maintains the MAPP Generation Reserve Sharing Pool (GRSP) and the MAPP Regional Transmission Committee. As of January 2006, MRO acquired additional members from the former Mid-America Interconnected Network, Inc. (MAIN) regional reliability council. This assessment includes those new members.

Demand

The MRO-U.S. summer peak demand is expected to increase at an average rate of 1.9 percent per year during 2006–2015, as compared to 2.0 percent predicted last year for 2005–2014. The MRO-U.S. 2015 noncoincident summer peak demand is projected to be 55,518 MW. The MRO-U.S. 2015 noncoincident summer peak demand representing the MAPP membership was 37,068 MW, which represents a 4.1 percent increase compared to the 2014 projected demand level of 35,612 MW. The MRO did not make a comparison to last year's numbers for the entire footprint as data for the new members was not available for the 2005–2014 assessment.

MRO members continue to forecast load based on normal weather conditions.

The MRO-Canada summer peak demand is expected to increase at an average rate of 0.84 percent per year during 2006–2015, as compared to 1.17 percent predicted last year for 2005–2014. The MRO-Canada 2015 noncoincident summer peak demand is projected to be 6,282 MW. This projection is 1.35 percent below the 2014 noncoincident summer peak demand predicted last year (6,367 MW).

The MRO-Canada winter peak demand is expected to increase at an average rate of 0.8 percent per year during 2006–2015, as compared to 0.8 percent predicted last year for 2005–2014. The MRO-Canada 2015 noncoincident winter peak demand is projected to be 7,641 MW. This projection is 1.6 percent above the 2014 noncoincident winter peak demand predicted last year (7,521 MW).

Long-term sales to other regions where the purchasing entities are known are expected to decrease from their current level of 446 MW in 2005 to about 144 MW in 2015. Long-term purchases from other regions where the selling entities are known are expected to decrease from their current level of 2,784 MW in 2005 to about 1,600 MW in 2015. Based on information from MRO members, no purchases or sales where the buyer or seller is unknown were reported for 2006–2015.

Both the MAPP GRSP and the former MAIN MRO members utilize a load forecast uncertainty factor (LFU) within the determination of adequate generation reserve margin levels. The LFU considers both uncertainty attributable to weather conditions and economic conditions and is factored into the LOLE study used to determine adequate reserve margin levels. MRO does not conduct a review of weather impacts on an aggregate basis for the entire region.

Energy

The 2006 annual forecast energy consumption for MRO total (262,722 GWh) is 1.2 percent above the 2005 summer actual energy (259,525 GWh).

The MRO 2015 annual forecast energy is projected to be 305,891 GWh for the entire footprint. The MRO annual forecast energy is expected to increase at an average rate of 1.8 percent per year during 2006–2015. The MRO did not make a comparison to last year's numbers for the entire footprint as data for the new members was not available for the 2005–2014 assessment.

The 2006 annual forecast energy consumption for MRO-U.S. (220,006 GWh) is 1.6 percent above the 2005 annual actual energy (216,633 GWh).

The MRO-U.S. annual forecast energy is expected to increase at an average rate of 2.0 percent per year during 2006–2015. The MRO-U.S. 2015 annual forecast energy is projected to be 259,074 GWh. The 2006 annual energy consumption for MRO-Canada (42,716 GWh) is 0.4 percent below the 2005 annual actual energy (42,892 GWh).

The MRO-Canada annual forecast energy is expected to increase at an average rate of 1.1 percent per year during 2006–2015, as compared to 1.3 percent predicted last year for the 2005–2014 period. The MRO-Canada 2015 annual forecast energy is projected to be 46,817 GWh.

Resources

Adequate generating resources for MRO-Canada are forecasted over the ten-year period. Reserve levels range from 29.5 percent in the summer of 2006 to 42.5 percent during the summer of 2015. Reserve levels vary slightly during the winter seasons from 25.4 percent in winter of 2005–2006 to 26.8 percent during the winter 2014–2015.

Current planned capacity reported in the MRO-U.S. region is below MRO requirements for reserve capacity obligation during 2010–2015. For the purpose of this assessment, the MRO is utilizing the MAPP restated agreement reserve capacity obligation of 15 percent, which is the same as a 13.04 percent minimum capacity margin requirement. The summer reserve margin for MRO-U.S. is forecast to decline from a high of 21.0 percent in 2006 to 14.2 percent in 2010 and 2.4 percent in 2015. These figures include an additional 3,423 MW of new generation for the period of 2006–2015 as reported to NERC in the EIA-411 report.

The MAPP 2005 Update to the 2004 Regional Plan, however, has reported 12,439 MW of new generation for the period of 2004–2013. The capacity difference (9,016 MW) between the MAPP 2005 Update to the 2004 Regional Plan and the EIA-411 data is the uncommitted capacity that has not been sited or was not reported through the data collection process used to prepare the NERC assessment report. Therefore, for the next ten-year period, the MRO capacity margins are likely higher than those shown above. With that amount of uncommitted capacity reported in the period of 2004–2013, the MRO does not expect any capacity deficits to occur during the assessment period.

Further assurance of generation adequacy is expected through the development of an MRO Planned Resource Adequacy Requirement Standard. This standard is currently in the commenting period.

Fuel

As a region, the MRO does not specifically address fuel supply interruptions on a prospective basis in the long-term assessment. Fuel supply interruptions tend to be local in nature, that is, the failure of the supply network is due to an equipment breakdown or other problem in a specific location. These types of failures in the supply network are difficult to predict, generally short lived, and contained in a specific area. MRO members have taken actions in the past to resolve local fuel supply issues. Such actions have included alternate transportation arrangements, fuel switching, and fuel conservation. MRO members are expected to take appropriate action to resolve any short-term fuel supply interruptions into the future and secure adequate fuel supplies throughout the assessment period.

Transmission

The existing transmission system within MRO-U.S. is comprised of 7,328 miles of 230-kV, 8609 miles of 345-kV, and 343 miles of 500-kV transmission lines. The 2005 Update to the 2004 Regional Plan showed that the MRO-U.S. members planned to add 1,104 miles of 345-kV and 147 miles of 230-kV transmission lines in the 2004–2013 time frame. The MRO-Canada existing transmission system is comprised of 5,411 miles of 230-kV and 130 miles of 500-kV transmission lines. MRO-Canada is planning to add 545 miles of additional 230-kV transmissions in the 2004–2013 time frame. MRO-U.S. and MRO-Canada have a total of 2,030 miles of HVdc lines.

MRO members continue to plan for a reliable transmission system, consistent with NERC Reliability Standards. Coordination of expansion plans in the region takes place through joint model development and study by the designated subcommittees of the MAPP Regional Transmission Committee and the MISO Expansion Planning Group. These committees include transmission owning members, transmission using members, power marketers, and state regulatory bodies. Together, these planning committees assess the adequacy of the transmission system within the MRO region.

In general, the MRO transmission system is judged to be adequate to meet firm obligations of the member systems, provided that the local facility improvements identified in both transmission plans are implemented. MRO continues to monitor the limiting flowgates within the region.

System stability operating guides involving the transmission facilities connecting Minneapolis-St. Paul to the Iowa and Wisconsin areas continue to manage congestion by limiting energy transfers from northern MRO to Iowa and Wisconsin. The Arrowhead-Weston 345-kV transmission line has been identified as a significant reinforcement to improve the overall performance of this interface. This line is expected to be in service in 2008. Information on the Arrowhead-Weston project can be found at: http://www.arrowhead-weston.com/.

Operations

MRO does not anticipate any major generation outages, transmission outages, or temporary operating measures that may impact reliability for any extended periods over the next ten years.

MRO member systems jointly perform interregional and intraregional seasonal operating studies under the direction of the Transmission Operations Subcommittee to coordinate real-time operations. Subregional operating review working groups have been formed to deal with day-to-day operational issues such as unit outages and to coordinate transmission system maintenance.

The Midwest Independent Transmission System Operator (MISO) energy market commenced on April 1, 2005. The market covers transactions in portions of Reliability*First*, MRO, and SERC across 15 states. From an MRO perspective, the market-to-nonmarket seam between the MRO members in MISO and those not in MISO creates additional operational complexity. MAPP and MISO continue to discuss issues related to implementing the Seams Operating Agreement (SOA) to coordinate transmission service on reciprocally managed flowgates and congestion management including transmission loading relief (TLR) avoidance procedures.

Assessment Process

The MRO Reliability Assessment Committee (RAC) is responsible for the MRO submittal to the NERC *Long-Term Reliability Assessment*. The MAPP Transmission Reliability Assessment and Composite System Reliability Working Groups jointly prepare the MRO *Ten-Year Reliability Assessment*, which is used as input by the MRO RAC. The MAPP Reliability Studies, Design Review, and Transmission Operations Subcommittees review MRO reliability from mid- and long-term perspectives and contribute to the MRO submittal to NERC.

The MRO region includes more than 40 members supplying approximately 280 million MW hours to more than 20 million people. The MRO membership is comprised of municipal utilities, cooperatives, investor-owned utilities, a federal power marketing agency, Canadian Crown Corporations, and independent power producers. The MRO spans eight states and two Canadian provinces covering roughly one million square miles. Membership solicitation is ongoing. Additional information can be found on the MRO Web site (www.midwestreliability.org).

MRO-Canada Capacity and Demand

Figure 15: MRO-Canada Net Energy for Load

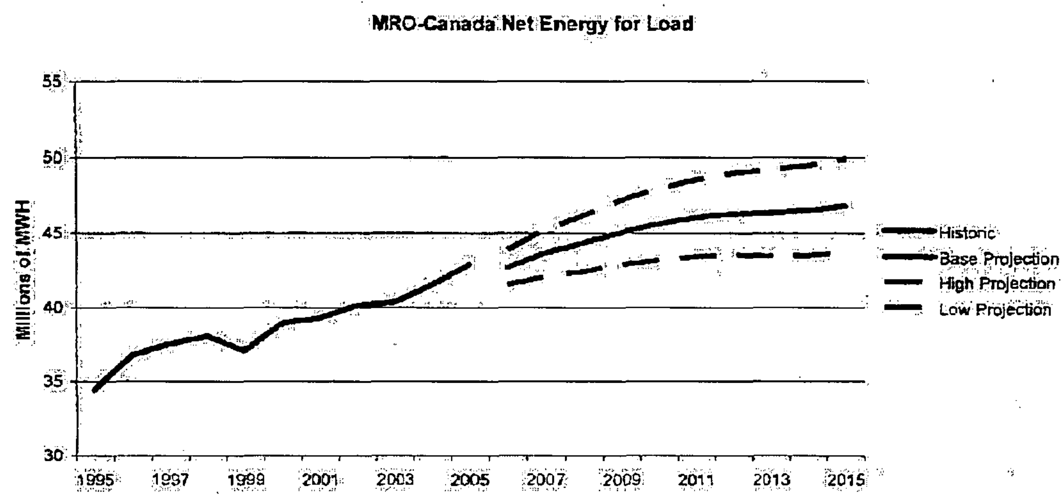


Figure 16: MRO-Canada Capacity Margins — Winter

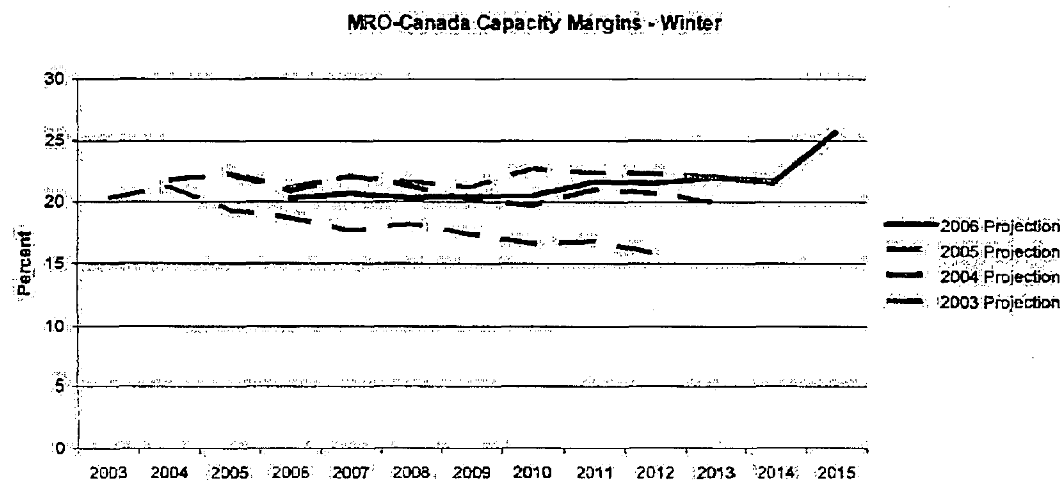
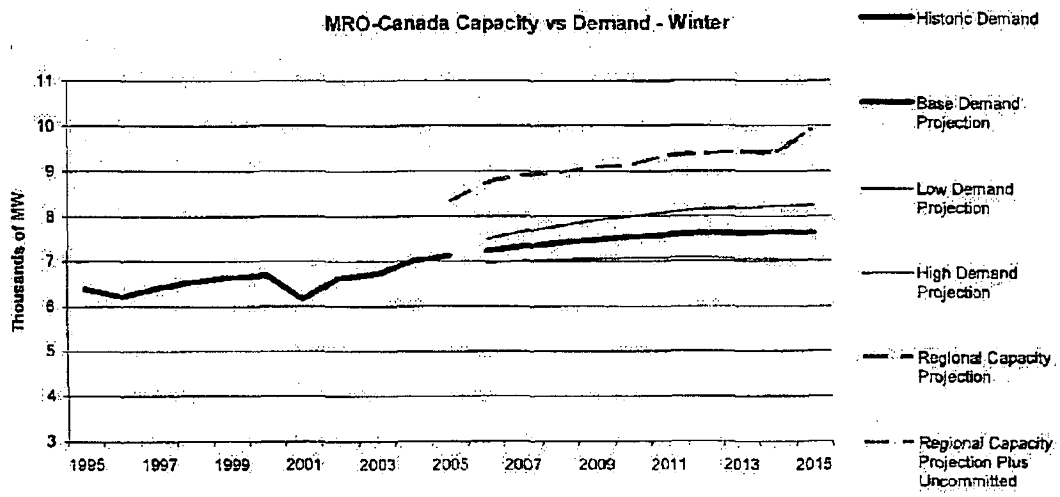


Figure 17: MRO-Canada Capacity Versus Demand — Winter



MRO-U.S. Capacity and Demand

Figure 18: MRO-U.S. Net Energy for Load

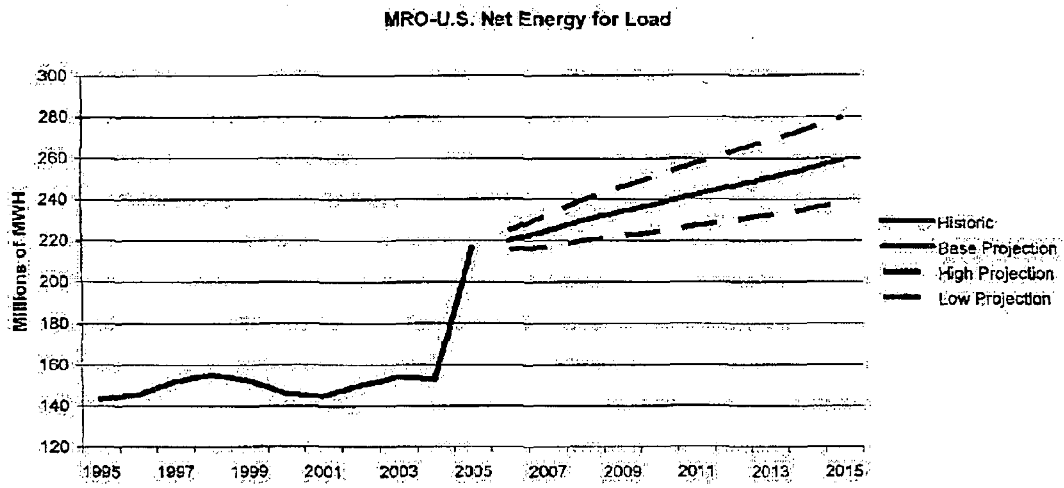


Figure 19: MRO-U.S. Capacity Margins — Summer

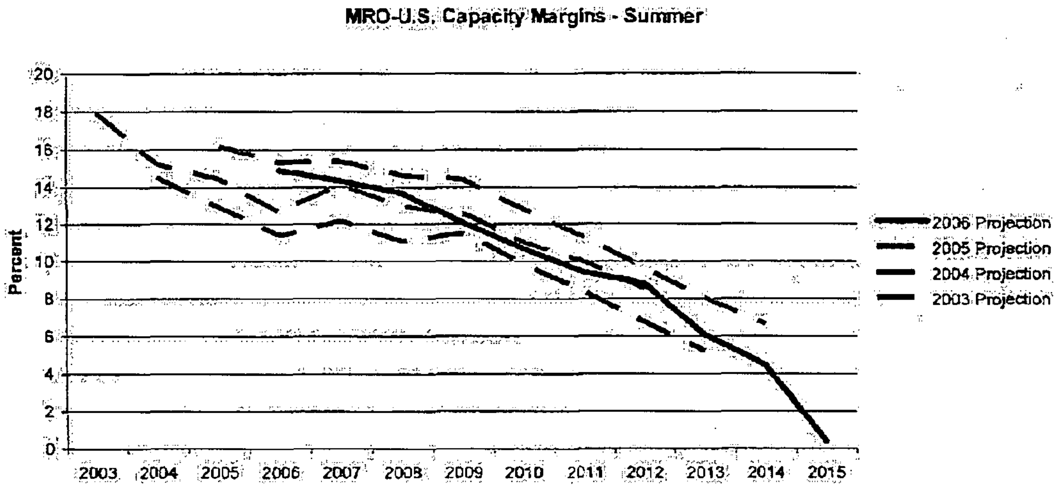


Figure 20: MRO-U.S. Capacity Versus Demand — Summer

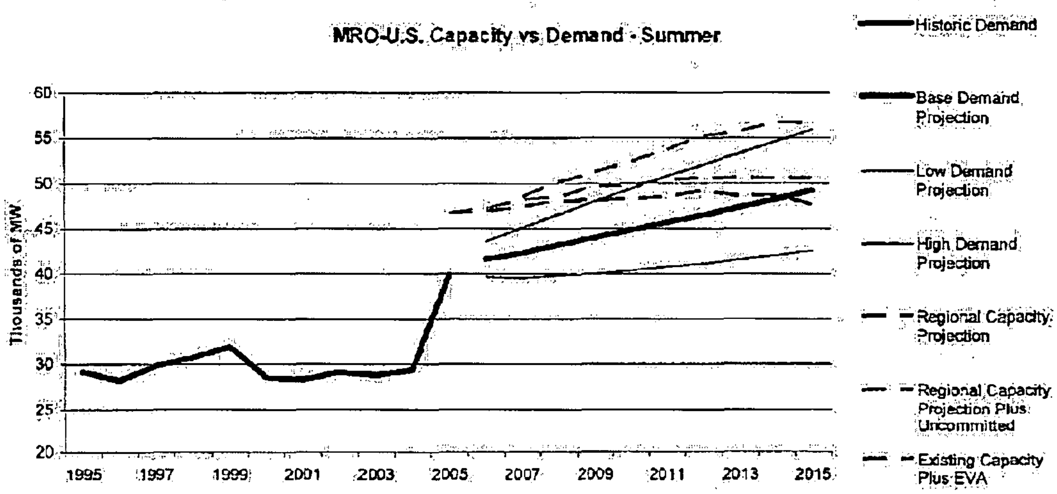


Figure 21: MRO-Canada Capacity Fuel Mix for 2005 and 2011

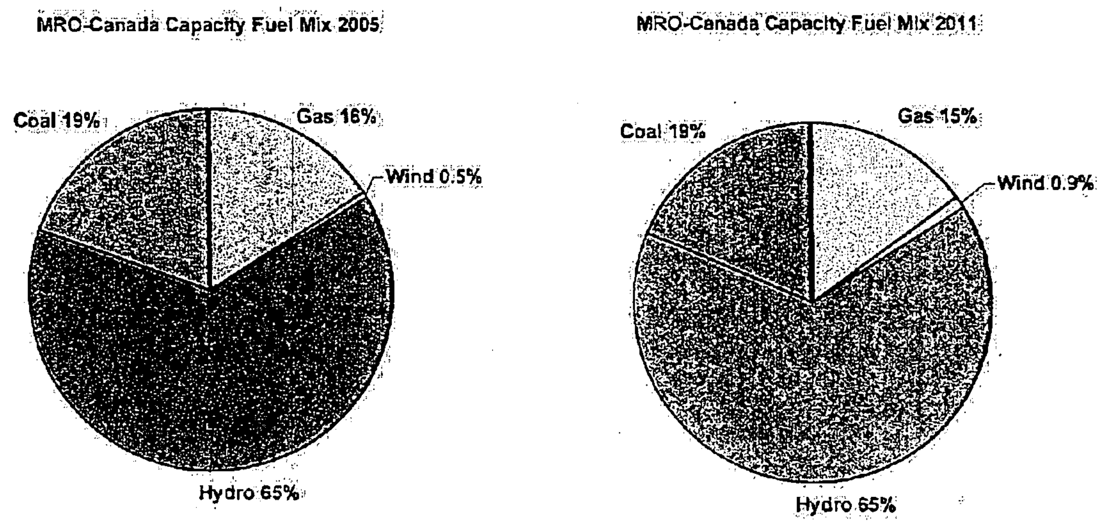
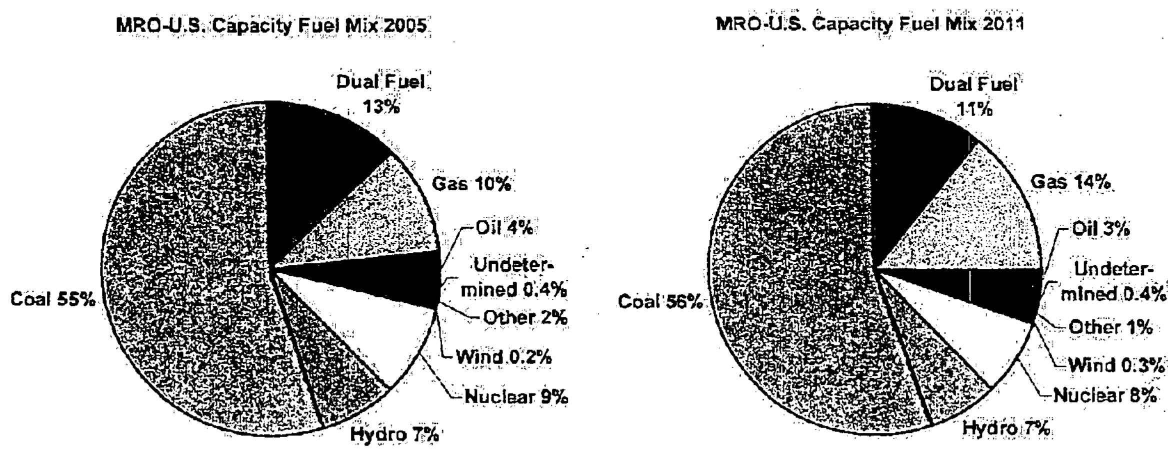


Figure 22: MRO-U.S. Capacity Fuel Mix for 2005 and 2011



NPCC

To ensure continued resource adequacy, NPCC participants must continue to realize planned merchant capacity. The near-term challenge is to ensure the timely synchronization of this expected capacity and, equally important, to fully integrate this new generation into the transmission network.

Due to their geographic and electrical diversity, the reliability of NPCC is monitored through the assessment of the five NPCC areas: the Maritimes (the New Brunswick System Operator, Nova Scotia Power Inc., the Maritime Electric Company Ltd., and the Northern Maine Independent System Administrator, Inc.), New England (the ISO New England Inc.), New York (the New York ISO), Ontario (the Independent Electricity System Operator) and Québec (Hydro-Québec TransÉnergie). Three of these areas are summer peaking in nature: New England, New York, and Ontario. The remaining two Canadian areas, the Maritimes, and Québec, are winter peaking systems.

Demand

The noncoincident peak demand for the five areas of NPCC is projected to be 142,181 MW by 2015, with an average growth of 1.4 percent. For the 2005–2014 study period, the noncoincident peak demand for the five areas of NPCC was projected to be 109,980 MW by 2014, with an average growth of 1.7 percent.

Energy

Net energy for load for the NPCC is projected to total 742,230 GWh in the calendar year 2015, with an average growth of 0.92 percent. For the 2005–2014 study period, net energy for load for the NPCC was projected to total 570,633 GWh in the year 2014, with an average growth of 1.23 percent.

Resources

NPCC has in place a comprehensive resource assessment program directed through NPCC Document B-08, *Guidelines for Area Review of Resource Adequacy* (http://www.npcc.org/publicFiles/reliability/criteriaGuidesProcedures/b-08.pdf). This document charges the NPCC Task Force on Coordination of Planning (TFCP) to conduct periodic reviews of resource adequacy for NPCC. In undertaking each review, the TFCP will ensure that the proposed resources of each NPCC area will comply with Section 3.0, *Resource Adequacy - Design Criteria*, of NPCC Document A-02, *Basic Criteria for Design and Operation of Interconnected Power Systems* (http://www.npcc.org/PublicFiles/Reliability/CriteriaGuidesProcedures/A-02.pdf). The resource adequacy criterion requires the following:

> "Each Area's probability (or risk) of disconnecting any firm load due to resource deficiencies shall be, on average, not more than once in ten years. Compliance with this criteria shall be evaluated probabilistically, such that the loss of load expectation [LOLE] of disconnecting firm load due to resource deficiencies shall be, on average, no more than 0.1 day per year. This evaluation shall make due allowance for demand uncertainty, scheduled outages and deratings, forced outages and deratings, assistance over interconnections with neighboring Areas and Regions, transmission transfer capabilities, and capacity and/or load relief from available operating procedures."

To focus on the timely installation of capacity requirements, each area must conduct an interim assessment of resource adequacy on an annual basis. A more comprehensive resource review is conducted on at least a triennial basis, and it is conducted more frequently as changing conditions may dictate. The assessment must include an evaluation of:

- the ability of the area to reliably meet projected electricity demand, assuming the most likely load forecast for the area and the proposed resource scenario;

- the ability of the area to reliably meet projected electricity demand, assuming a high growth load forecast for the area and the proposed resource scenario;
- the impact of load and resource uncertainties on projected area reliability, discussing any available mechanisms to mitigate potential reliability impacts;
- the proposed resource capacity mix and the potential for reliability impacts due to the transportation infrastructure to supply the fuel;
- the internal transmission limitations; and
- the possibility of environmental requirements.

The resource adequacy review must describe the basic load model on which the review is based together with its inherent assumptions, and variations on the model must consider load forecast uncertainty. The anticipated impact on load and energy of demand-side management programs must also be addressed. If the area load model includes pockets of demand for entities, which are not members of NPCC, the area must discuss how it incorporates the electricity demand and energy projections of such entities.

Other supporting data which must be provided include the procedures used by the area for verifying generator ratings as well as a summary of forced outages, planned outages, partial deratings, etc., which would curtail available resources.

The primary objective of NPCC resource reviews is to identify those instances in which a failure to comply with the NPCC *Basic Criteria for Design and Operation of Interconnected Power Systems* by a NPCC area could result in adverse consequences to another NPCC area or areas. If, in the course of the study, such problems of an inter-area nature are determined, NPCC informs the affected systems and areas, works with the area to develop mechanisms to mitigate potential reliability impacts, and monitors the resolution of the concern.

Fuel

Due to the diversity of fuel mix from area to area, the fuel requirements unique to each of the five NPCC areas are presented in the individual area discussions which follow.

Transmission

In a similar manner, the NPCC Task Force on System Studies (TFSS) is charged with conducting periodic reviews of the reliability of the planned bulk power transmission systems of each area of NPCC and the transmission interconnections to other areas, the conduct of which is directed through NPCC Document B-04, *Guidelines for NPCC AREA Transmission Reviews*. Each area is required to present an annual transmission review to the TFSS, assessing its transmission network four to six years in the future. Depending on the extent of the expected changes to the system, the review presented by the area may be one of three types: a comprehensive (or full) review; an intermediate (or partial) review; or an interim review.

A comprehensive review is a thorough assessment of the area's entire bulk power transmission system, and it must be conducted by each area at least every five years. The TFSS may require an area to present a comprehensive review in less than five years if changes in the area's planned facilities or forecasted system conditions warrant it.

In the years between comprehensive reviews, areas may conduct either an interim review, or an intermediate review, depending on the extent of the system changes projected for the area since its last comprehensive review. If the proposed system changes are deemed to be minor in nature, the area may conduct an interim review. In an interim review, the area provides a summary of the changes in planned facilities and forecasted system conditions since its last comprehensive review together with a discussion and assessment of the impact of those changes on the bulk power system.

If the system changes in the area since its last comprehensive review are moderate, or concentrated in a portion of the area's system, the area may conduct an intermediate review. An intermediate review covers all the elements of a comprehensive review, but the analyses may be limited to addressing only those issues considered to be of significance, considering the extent of the system changes.

Each transmission review includes a steady state assessment, a stability assessment, fault current assessments, and extreme contingency assessments. Further, special protection systems whose failure or misoperation could have a potential inter-area, or interregional impact require steady state and stability analyses of these consequences.

Actions in Response to the Power System Collapse of August 14, 2003

The NPCC assessment of the August 14, 2003 power system collapse, *NPCC August 14, 2003 Northeast Blackout Study*, was issued following approval by the NPCC Reliability Coordinating Committee (RCC) at its meeting of November 29–30, 2005. This report concluded exhaustive dynamic simulations conducted by the NPCC Working Group SS-38, replicating the August 14, 2003 sequence of events and the dynamic performance of the NPCC systems through the formation and collapse of the islands within NPCC. Upon approval of the report, the RCC proceeded to form the Blackout Recommendation Study Working Group (BRSWG) to develop a set of NPCC recommendations based on the conclusions presented in the NPCC blackout study. Linking its recommendations to the conclusions in the *NPCC August 14, 2003 Northeast Blackout Study*, specific charges were assigned to the NPCC task forces to conduct the work needed to address each recommendation. The BRSWG also completed a mapping of these recommendations against the blackout recommendations directed by the NERC Board of Trustees, the NERC Blackout Recommendation Review Task Force, and the U.S.-Canada Power System Outage Task Force to ensure no gaps or significant overlaps in the fulfillment of the recommendations. Several NPCC recommendations are similar, however, these NPCC recommendations address each item from an NPCC perspective rather than an overall industry view. Some of the key recommendations include the following:

- NPCC areas should review Type 1 and Type 2 special protection systems that rely on the indirect sensing of system conditions to reduce the possibility of their operating for conditions other than those for which they were originally designed.
- NPCC areas should complete the implementation of the incorporation of the 300 ms time delay on underfrequency load-shedding relays as recommended in the 2002 assessment of the NPCC underfrequency load-shedding program. Approved by the RCC, this project is in progress, and its completion is on schedule.
- The NPCC Task Force on System Studies should ensure that future assessments of the underfrequency load-shedding program include:
    - sensitivity studies to examine the impact of unexpected load or generation loss near the electrical center of unstable swings during island formation;
    - the continued pursuit of coordination between generating unit (generator, excitation system, and prime mover) protection systems and the underfrequency load-shedding program;
    - the simulation of island formation across area and regional boundaries, including the modeling of more extreme events;
    - an assessment of the impact of extremely low voltages on the performance of the underfrequency load-shedding program; and
    - the identification of large load areas within NPCC that are deficient in generation by more than 25 percent, that are susceptible to islanding and may accordingly require additional under frequency load shedding.

NPCC should continue to improve its modeling tools and data.

The status of the NPCC response to all recommendations generated by the blackout of August 2003 may be followed by accessing http://www.npcc.org/blackout.asp?Folder=CurrentYear.

Operations

Reliable operations within NPCC are directed through the five reliability coordinators of NPCC. Each of the NPCC areas also serves as a NERC reliability coordinator for the following geographic areas:

Entity Serving as NERC Reliability Coordinator	Reliability Coordinator Footprint
New Brunswick System Operator (NBSO)	Provinces of New Brunswick, Nova Scotia, and Prince Edward Island; the Northern Maine Independent System Administrator, Inc.
ISO New England Inc.	States of Maine, Massachusetts, Vermont, New Hampshire, Connecticut, Rhode Island
New York ISO	State of New York
Independent Electricity System Operator (IESO)	Province of Ontario
Hydro-Québec TransÉnergie	Province of Québec

Within each area, the respective reliability coordinator assumes the authority and responsibility to immediately direct the redispatch of generation, the reconfiguration of transmission, or (if necessary to return the system to a secure state) the shedding of firm load. Coordination in the daily operation of the bulk power system is assisted through enhanced communications and heightened awareness of system conditions and mutual assistance during an emergency or a potentially evolving emergency. The reliability coordinators of NPCC conduct conference calls daily and weekly to identify and assess emerging system conditions. Procedures are in place to initiate emergency conference calls whenever one or more areas anticipates a shortfall of capacity or anticipates the implementation of operating measures in response to a system emergency.

The NERC standards, together with the Regional Criteria, Guides, and Procedures, establish the fundamental principles of interconnected operations among the NPCC areas.

NPCC Document A-03, *Emergency Operation Criteria*, presents the basic factors to be considered in formulating plans and procedures to be followed in an emergency or during conditions which could lead to an emergency, in order to facilitate mutual assistance and coordination among the areas. The criterion establishes seven basic objectives in formulating plans related to emergency operating conditions, including the avoidance of interruption of service-to-firm load, minimizing the occurrence of system disturbances, containing any system disturbance and limiting its effects to the area initially impacted, minimizing the effects of any system disturbances on the customer, avoiding damage to system elements, avoiding potential hazard to the public, and ensuring area readiness to restore its system in the event of a major or partial blackout.

NPCC Document A-06, *Operating Reserve Criteria*, defines the necessary operating capacity required to: meet forecast load; accommodate load forecasting error; provide protection against equipment failure, which has a reasonably high probability of occurrence; and provide adequate regulation of frequency and tie-line power flow. The NPCC *Operating Reserve Criteria* require two components of operating reserve. The ten-minute operating reserve available to each area shall at least equal its most severe first contingency loss. The 30-minute operating reserve available to each area shall at least equal one-half its most severe second contingency loss.

Various operating guidelines and procedures complement the NPCC criteria by providing the system operator with detailed instructions to address such topics as the depletion of operating reserve, capacity shortfalls, the sharing of operating reserve, line-loading relief, declining voltage, measures to contain the spread of an emergency, light-load conditions, the rating of generating capability, the consequences of a solar magnetic disturbance, procedures for communications during an emergency, and the coordinated restoration of the systems following a partial or total blackout.

NPCC also participates in the seasonal Reliability*First* Corporation-Northeast Power Coordinating Council (RFC-NPCC) operating assessments, formerly conducted under the direction of the MAAC-ECAR-NPCC (MEN) and VACAR-ECAR-MAAC (VEM) study committees.

Assessment Process

The NPCC Reliability Assessment Program (RAP) brings together the efforts of the Council and its members in the assessment of the reliability of the bulk power system. The Reliability Coordinating Committee (RCC), as the primary technical arm of the Council, directs the RAP and monitors the compliance with all aspects of the program. The RCC is served by the five NPCC task forces, which address the major disciplines of planning, operations, protection, and communications as follows:

- Task Force on Coordination of Operation
- Task Force on Coordination of Planning
- Task Force on Infrastructure Security and Technology
- Task Force on System Protection
- Task Force on System Studies

The task forces in turn develop and administer the documents, which define reliable operation and planning within NPCC, and with which compliance is mandatory on the part of all NPCC members. The assessment of transmission reliability and resource adequacy is directed to the five NPCC areas.

Maritimes

The Maritimes area is a winter-peaking area that includes the New Brunswick System Operator (NBSO), Nova Scotia Power Inc. (NSPI), Maritime Electric Company Ltd. (MECL), and the Northern Maine Independent System Administrator, Inc. (NMISA). MECL supplies the province of Prince Edward Island. The New Brunswick Electricity Act restructured the electric utility industry in New Brunswick and created the NBSO, the reliability coordinator for the Maritimes area.

Demand — The noncoincident peak demand for the Maritimes is projected to be 6,364 MW by 2015, with an average growth of 0.8 percent. For the 2005–2014 study period, the noncoincident peak demand for the Maritimes area was projected to be 6,429 MW by 2014, with an average growth of 1.4 percent.

In the *2005 Maritimes Area Interim Review of Resource Adequacy*, compliance with the NPCC Resource Adequacy Criterion was evaluated using a load forecast uncertainty of 4.6 percent, which represents the historical standard deviation of load forecast errors based upon the four year lead time required to add new resources.

Energy — In 2005, the actual energy consumption in the Maritimes was 29,398 GWh, and this was 3.3 percent below forecast primarily due to warmer than expected temperatures in the winter months when demand is highest. Net energy for load is projected to total 33,553 GWh in the calendar year 2015, with an average growth of 1.6 percent. For the 2005–2014 study period, net energy for load was projected to total 33,908 GWh in the year 2014, with an average growth of 1.6 percent.

Resources — The NBSO and NSPI individually apply a capacity-based criterion of 20 percent in determining their required reserve, while MECL uses 15 percent. NMISA does not apply a capacity-based criterion beyond the NPCC reliability criterion. Since NBSO and NSPI comprise about 94 percent of the Maritimes area load, this effectively produces a required reserve of 20 percent for the Maritimes. This reserve requirement is to accommodate both peak demand uncertainty and generation availability uncertainty.

The planned refurbishment of the 635 MW Point Lepreau nuclear facility in New Brunswick will require an outage of 18 months, beginning in April 2008, with completion scheduled for November 2009. Due to this outage, the Maritimes area will require 20 MW of additional capacity to meet the NPCC resource adequacy criterion. Plans for replacement capacity to accommodate this refurbishment are still being evaluated by NB Power.

A sale of 200 MW of firm capacity will be sold to Québec until 2010/11. The Maritimes does not depend upon outside purchases to meet demand requirements.

There are currently no firm plans for merchant and/or uncommitted capacity over the next ten years.

Fuel — Fuel supply will be adequate to meet expected electric demand. This is accomplished with firm fuel contracts, as well as on-site storage facilities.

The Maritimes does not consider fuel-supply interruptions in the regional assessment. The Maritimes has a diversified mix of resources such that the reliance on any one type or source of fuel is reduced. In addition, fuel storage facilities located at each plant are sufficient to permit the continued operation of plants during short duration interruptions to the fuel supply. During longer-term interruptions, this fuel storage capability affords the opportunity to secure other sources of supply or, at some plants, to switch to a different fuel. No fuel delivery problems are anticipated during the projected peak demand period. Mitigation procedures include the ability of some plants to switch to a different fuel. Extremes of summer weather do not impact fuel availability since the Maritimes area is a winter-peaking system. Extreme weather conditions at other times of the year are not expected to have any impact on the Maritimes area's fuel supplies for generating facilities. Sufficient on-site fuel reserves are maintained for all fossil-fired generation. All plants which are equipped to burn Orimulsion®, for which Venezuela is the single source supplier of the fuel, can be switched to burn oil. Although the reliance of electric generation on the natural gas infrastructure is increasing, only about 8 percent of the generators in the Maritimes use natural gas.

Transmission — No transmission constraints were identified within the Maritimes area. Construction of a second 345-kV interconnection between New Brunswick and New England is scheduled to be in service by December 2007, connecting Point Lepreau, New Brunswick to Orrington, Maine. As a result of this project (including series and shunt capacitors in Maine), the maximum transfer capability between New Brunswick and New England is increased from 700 MW to 1,000 MW, and the import capability from New England to New Brunswick is expected to be raised from 100 MW to 400 MW. This second interconnection also significantly improves the reliability of the Maritimes system, since loss of either of the two interconnections to New England will no longer result in the separation of the Maritimes from the Eastern Interconnection.

The "Loss of L3001" special protection system (SPS) senses power and frequency inputs to detect conditions consistent with a system separation south of the New Brunswick-New England border. During the power system collapse of August 14, 2003, the Keswick-Orrington 345-kV interconnection between New Brunswick and New England experienced a power swing coincident with a rise in system frequency, triggering the SPS and rejecting 380 MW of generation in the Maritimes. While the SPS responded correctly for the power and frequency conditions observed, the SPS operated while the Maritimes and New England were connected to the Eastern Interconnection. Although the SPS performed according to its design, subsequent analysis by the NPCC Working Group SS-38 showed that its inadvertent operation was unnecessary. As a result of this finding, revisions will be made to the SPS associated with the second

New Brunswick-New England interconnection. The Loss of L3001 SPS will be replaced by a more robust "Maritimes Islanding SPS," which will directly sense the status of selected circuit breakers in Maine, indicating separation of the Maritimes from New England. Design details are currently under review by the appropriate NPCC task forces.

Operations — The addition of the second 345-kV tie discussed above between New Brunswick and New England will improve system reliability, stability, and efficiency in addition to expanding competition and electric energy transfers.

The outage due to the refurbishment of the 635 MW Point Lepreau nuclear generation station (April 2008 to October 2009) creates a 229 MW capacity deficiency for the Maritimes. Plans for replacement capacity to accommodate this refurbishment are still being evaluated by NB Power.

No local environmental and/or regulatory restrictions that could curtail the availability of capacity in the Maritimes area are expected. However, the Kyoto Protocol, ratified by the government of Canada, calls for a 6 percent reduction from the 1990 levels of greenhouse gas emissions to be achieved between 2008 and 2012. Initiatives to achieve this reduction may include a reduction in electric energy exports from the Maritimes area. Renewable energy targets announced by governments within the Maritimes area could result in the addition of about 1,000 MW of wind generation for the Maritimes.

New England

Demand — This year's summer peak forecast ten-year compound annual average growth rate has increased to 1.9 percent from 1.5 percent following a change in the forecasting methodology, resulting in generally higher summer peak forecasts when compared with previous long-term forecasts. (Details on the load and energy forecasting methodology used by the ISO-NE, together with data, may be found at http://www.iso-ne.com/trans/celt/fsct_detail/index.html.)

The summer peak forecast distribution is based on 30 years of weather and peak data. Using this weather and peak data, a distribution of peak loads is calculated to show the peak load forecasts associated with a probability that the forecast would be exceeded. (Further information on the load forecast may be found in the *2006–2015 Forecast Report of Capacity Energy Loads and Transmission—April, 2006*, available at http://www.iso-ne.com/trans/celt.)

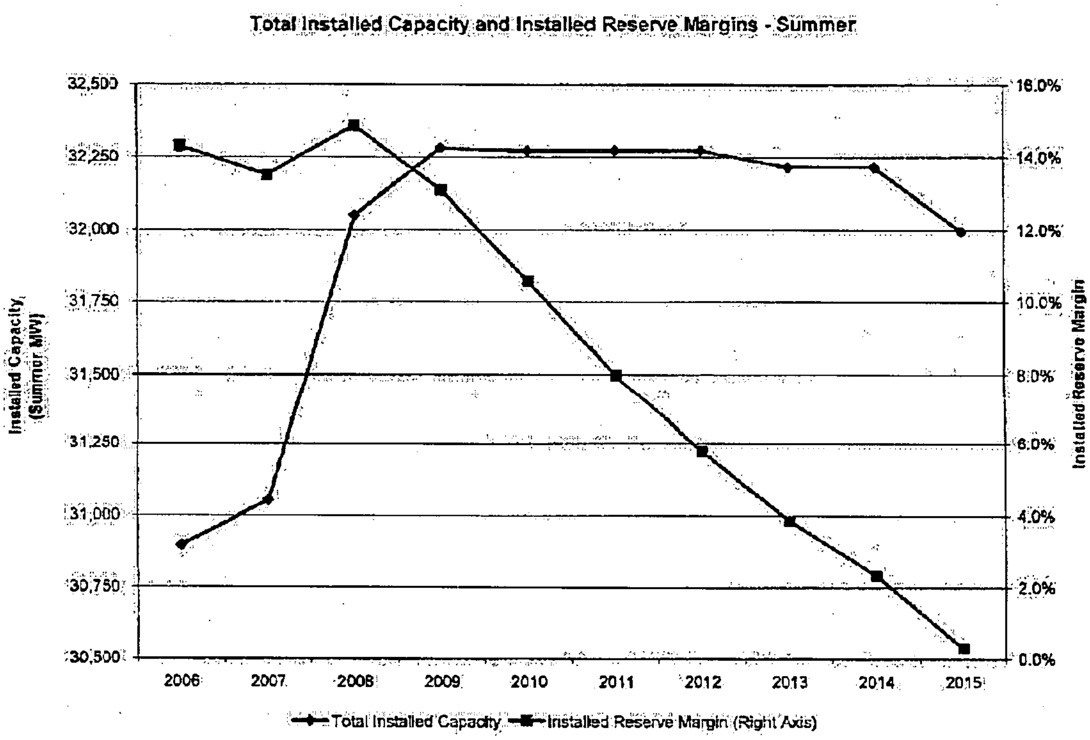
A detailed analysis of each summer's daily peaks and weather is carried out to quantify the relationship between peak and weather, and changes to that relationship. The maximum exposure under the 90/10 forecast over the ten-year study period is as follows:

Year	90/10 Load Forecast in MW
2006	28,785
2007	29,180
2008	29,775
2009	30,465
2010	31,160
2011	31,910
2012	32,580
2013	33,125
2014	33,620
2015	34,065

Energy — The projected 1.3 percent ten-year compound annual growth rate for net annual energy did not change significantly.

Resources — Figure 30 (below) illustrates the total installed capacity as well as the installed reserve margins forecasted for the study period.

Figure 23: Total Installed Capacity and Installed Reserve Margins — Summer



Installed reserve margins will be declining throughout the study period from a high of 15 percent in 2008 to almost 0 percent in 2015. The installed reserve margins reflect firm capacity purchases of approximately 400 MW per year through 2012, approximately 330 MW purchase in 2013–2014, and approximately 110 MW in 2015. Generating unit retirements are not assumed throughout the study period and new generation totaling approximately 1,390 MW (these capabilities include projects that have received proposed plan approval) is assumed to commercialize by the end of 2009.)

Last year, projected installed reserve margins were 19.4 percent in 2005 and declined through the study period to 8.5 percent in 2014. The primary factors associated with the decline from last year's forecasted reserve margins are the updated load forecast coupled with a lower installed capacity value due to deactivations/ratings of existing capacity and lower firm capacity purchases.

With respect to the regional requirement, ISO-NE anticipates that New England will meet the NPCC resource adequacy criterion of one-day-in-ten-years loss-of-load expectation through 2008 assuming forecasted loads and capacity materialize and 2,000 MW of tie reliability benefits are available. This is made up of 600 MW from New York, 1,200 MW from Hydro Québec, and 200 MW from New Brunswick. Existing transfer capability study results indicate that sufficient transfer capability is in place with surrounding areas to receive this assistance when needed. New capacity will be needed beyond that year in order to meet the reliability criterion. This assessment is based on estimated requirements calculated in the 2006 Regional System Plan.

No long-term sales to regions outside of New England were known as of January 1, 2006. When analyzing the resource adequacy situation of New England, only firm long-term capacity purchases and sales are included in the assessment. For the 2006 assessment, it is forecasted that ISO-NE will be a net importer of approximately 400 MW per year through 2012. This net import will decline to approximately 330 MW in 2013–2014, and to approximately 110 MW in 2015. These long-term capacity purchases are included as capacity when calculating the installed reserve margins for New England.

To meet NPCC criteria, and assuming 2,000 MW of tie reliability benefits are available from neighboring control areas, approximately 170 MW are needed in 2009, increasing annually and requiring a total of 4,300 MW by 2015.

Fuel — ISO-NE assesses the potential for fuel-supply interruptions and their impacts on system reliability in the annual Regional System Planning and when additional analyses are deemed necessary. It is anticipated that no constraints in fuel supply or delivery to the generators will occur during the summer peak load seasons. During extreme summer periods, no fuel supply or delivery constraints to New England generators is expected.

During extreme cold weather in the winter, when the demand for electricity and natural gas peak coincidently, the ISO-NE has special operating procedures that have been developed to mitigate possible short-term loss of operable generating capacity due to fuel unavailability. The ISO-NE is mindful of the potential for fuel constraints during peak load periods and is proactive in ensuring the reliability of the power system.

ISO-NE is encouraging the maximization and sustainability of existing dual-fuel capability as well as expand dual-fuel capability to gas only units. The study, *Dual-Fuel Generating Capacity and Environmental Constraints Analysis – Interim Report,* identified many gas-fired units had air permits to burn limited amounts of liquid fuel oil during emergency periods. However, in some cases, these air permits were ambiguous about when these units could actually burn oil. Furthermore, many of these units with air permits to burn liquids had not installed the necessary hardware (burner systems, software control, etc.) or support infrastructure (on-site storage and fuel handling) to facilitate dual-fuel operation.

ISO-NE has worked (and continues to) with regional air regulators to review existing power plant operating permits with respect to clarifying existing language and incorporating exemption clauses that will allow limited or extended oil-burning operation only during periods when the electric power system is in an abnormal state (invocation of Emergency and/or Cold Weather Operating Procedures) or when the regional natural gas and oil supply and/or delivery systems have been constrained or curtailed due to force majeure type events. ISO-NE is currently working to assess the true capability and sustainability of dual-fuel operation across the generation fleet, with emphasis on determining the exact amount and location of dual-fuel capacity required to sustain reliable winter operations.

Transmission — The 2005 Regional System Plan identifies the region's needed transmission improvements and provides a roadmap for identifying the system's needed improvements in the long term. The New England region has 272 transmission projects in various stages of planning, construction, and implementation with a total cost of about $3 billion. ISO-NE and the transmission owners collaboratively conducted the studies that support these projects. These projects are required over the next ten years to ensure local-area and system-wide reliability in accordance with NERC, NPCC, and ISO-NE planning criteria, and to facilitate the future operation of the system. These upgrades may be needed: to address electrical performance problems, such as those related to voltage or stability; to serve growing loads; or as a backstop for market solutions to system needs. The transmission improvements in load/generation pockets will reduce local-area and system-wide dependency on the generators to provide either economic operating reserves or reserves based on reliability needs and the need to commit generating resources out of merit.

Six of the 272 transmission projects are major and have significant reliability impacts on the region. These projects include the Northwest Vermont Reliability Project, the Northeast Reliability Interconnect Project, the Southwest Connecticut Reliability Project (Phase 1 and Phase 2), the Southern New England Reinforcement Project, and the NSTAR 345-kV Transmission Project. (Detailed information on the New England transmission projects can be found in the ISO New England Regional System Plan-October 20, 2005.)

A number of transmission constraints limit the efficient transportation of power across the network, and in some cases these limitations jeopardize the reliability of the local system. The significant network constraints are described below.

Maine-New Hampshire

Transmission constraints between Maine and New Hampshire limit the transfer of power from Maine into New Hampshire. This interface is impacted by stability and thermal limits. Voltage levels are often a concern in this area. These limits are also sensitive to load levels. As the load in New England increases, this restriction could further compromise New England's ability to meet its LOLE criteria as early as 2009.

A number of projects are under way to address local reliability needs that will also impact the capability of this interface. These projects are in various stages of development and approval. Most recently approved was the Y-138 Project, scheduled for 2008, which closes a normally open tie between western Maine and New Hampshire. Additional projects which are in progress are the addition of circuit breakers, scheduled for 2006 and 2008, respectively, at Deerfield and Buxton, which removes limiting stuck breaker contingencies, looping the Buxton-Scobie 345-kV line into the Deerfield Station, and the addition of new autotransformers which will provide much needed voltage support to the 115-kV lines from southern Maine into the seacoast area of New Hampshire.

Vermont

The power system serving the state of Vermont is primarily designed to serve native load, and as such it only has four bulk power system buses within the state (West Rutland 345 kV, Coolidge 345 kV, Vermont Yankee 345 kV, and Vermont Yankee 115 kV). Therefore the Vermont system is limited in its ability to move power into and within the state to serve its own load. This problem is exacerbated by the fact that the state of Vermont has only one large generation station (Vermont Yankee), and, since the plant is located at the southernmost end of the state, its capacity output loads the Vermont transmission system as if it were an import from outside the state. The most limiting contingency for Vermont has been the outage of the Highgate HVdc source. Further, the outage of any major line in Vermont could initiate localized undervoltage load shedding to alleviate voltage constraints.

The Northwest Vermont Reliability Project includes a new 345-kV line within the state, the addition of new devices to provide reactive support throughout the state, and an additional phase angle regulator to help control flows. This project is currently under construction.

Connecticut/East-West

The Connecticut system is limited in its ability to transfer power into the state to serve its own load. While it has a significant amount of internal generation, the total amount of generation is insufficient when combined with imports to reliably serve load. The most significant contingencies in the state are the outage of the Millstone unit 3 generation (~1,200 MW) or one of the three 345-kV tie lines into the state. A long-term outage of either of these compromises reliability in the state of Connecticut. The east-west interface follows approximately the Vermont border down through central Massachusetts to the Connecticut border. This interface can limit economic transfers of power from the east to load centers in the west. Under heavy load periods with generation outages in the west, this interface could affect the reliability of the western portion of New England.

A working group has been formed which will address these issues, as well as other southern New England issues. This working group has performed exhaustive testing of numerous possible system configurations and should be selecting a preferred alternative by the fall of 2006. Implementing the resulting plan will also improve the east-to-west New England transfer capability at the same time.

Southwest Connecticut
The southwest Connecticut system is served only by 115-kV and 138-kV transmission lines and internal generation which can have significant interdependencies (both thermal and short circuit) that can limit its operation. In addition to the thermal constraints which prevent the movement of power into southwest Connecticut, transmission limitations are also preventing the movement of large amounts of power within the area.

In addition to a number of smaller projects that have increased reactive support in and around southwest Connecticut, construction has already begun on two large 345-kV installations to build a 345-kV loop through the area. The first portion of this installation is expected to be in service by the end of 2006, while the second piece is expected prior to the end of 2009. These two projects should remove the generation interdependencies internal to the area, and will also increase the import capability into the area. In addition to the two 345-kV projects, a smaller 115-kV project extends new circuits from one of the new 345-kV substations to the load centers in the farthest corner of the area.

Boston
The Boston area is limited by imports into and within the area and is reliant upon internal generation. An outage of one of the major 345-kV lines feeding the area, or the outage of a significant generator could compromise the ability to reliably serve load in this area. Internal loss of source concerns are amplified by the possibility of a simultaneous loss of both Mystic units 8 and 9 (~1,600 MW), which has already occurred in real-time operations.

A number of projects are under way to relieve some of the constraints that limit Boston imports. The Ward Hill project provides significantly more transformation to the 115 kV at this location and upgrades lines which travel toward Boston. Additionally, a project is under way to add three new 345-kV cables into downtown Boston. The first stage of this project, which adds two of the three cables, is expected to be in service during the summer of 2006.

A detailed listing of all projected new facilities proposed to enhance transmission reliability in New England can be found at: http://www.iso-ne.com/trans/rsp/index.html.

Operations — The construction of new transmission projects, and any necessary outages of existing transmission or generation equipment that may be required, is closely coordinated with the ISO-NE, to avoid adverse impacts to the reliability of the system.

During the study period, it is anticipated that additional environmental requirements and regulations will be put on generators in New England. The ISO-NE is mindful of these regulations and assesses their possible impacts on system reliability. If generators in New England are required to retrofit their facilities to meet these regulations, the ISO-NE will closely coordinate the maintenance needs of these generating units to assure that system reliability is maintained at all times.

New York

Demand — The New York area is a summer-peaking system, and summer peak demands are expected to grow at an average rate of 0.9 percent, through 2015. This compares with 0.9 percent growth projected in the 2004–2015 assessment conducted by the RAS in 2005.

The forecast developed by the NYISO is based on historical weather-normalized loads provided by the transmission owners of New York State. At forecast load levels, a one-degree increase in the combined temperature humidity index, or CTHI, (an index that weights dry bulb by 60 percent and dew point by 40 percent, and includes a lag structure) above the design value of 81.31 will result in about 500 MW of additional load.

Energy — Energy consumption is forecast to grow at an average annual rate of 0.8 percent through 2015. This compares with 0.8 percent growth projected in the 2005–2014 assessment conducted by the RAS in 2005.

Resources — The New York State Reliability Council (NYSRC) has determined that an 18 percent installed reserve margin for the New York control area (NYCA) is required to meet the NPCC and more stringent NYSRC resource adequacy criterion. As a conservative assumption, the establishment of the 18 percent installed reserve margin requirement for New York does not rely on external ICAP purchases. Up to 2,000–2,400 MW of assistance through tie benefits from New York's neighboring control areas is also available.

Given current demand projections, New York would need the addition of 4,030 MW of new resources in order to meet a projected 18 percent level through 2015. This projection assumes the continuation of the current level of external purchases of approximately 2,500 MW and the continuation of special case resources (SCRs) of approximately 1,080 MW. SCRs are loads capable of being interrupted, and distributed generators rated at 100 kW or higher, that are not directly telemetered. SCRs are installed capacity (ICAP) resources that only provide energy/load curtailment when activated in accordance with the NYISO Emergency Operating Manual.

It is anticipated that the resources necessary to meet this projected requirement would be procured through the NYISO ICAP market. Currently, new capacity totaling 2,940 MW is under construction in New York. The generation currently under construction in conjunction with the approximately 2,500 MW of allowable external purchases will be sufficient for New York to meet an 18 percent reserve margin through 2015 even if no new projects are proposed.

Studies are currently in progress to assess the deliverability of this capacity within New York State and the New York City-Long Island zones.

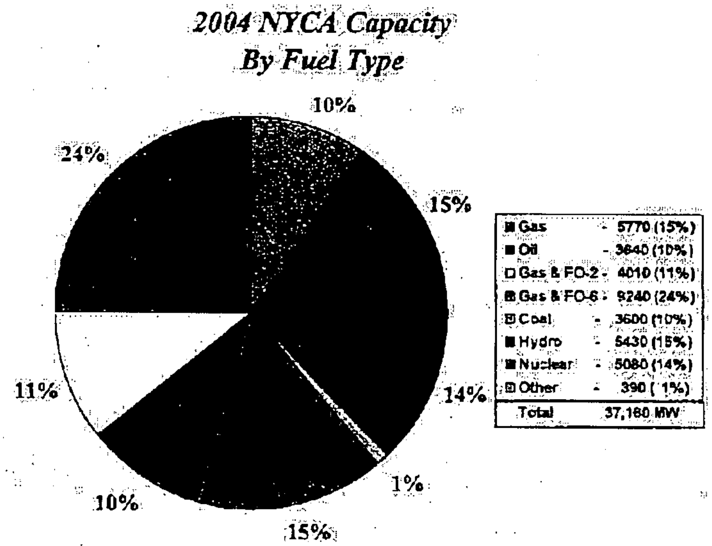
In addition to the above statewide requirement, the New York ISO imposes locational capacity requirements on load-serving entities located within New York City and Long Island due to their geography, as described in the *Locational Installed Capacity Requirements Study of March 2006*. The load-serving entities within these localities must procure a percentage of their capacity requirement from resources located within the geographic boundaries of that locality. The New York City locational capacity requirement is 80 percent of the demand level, and the locational capacity requirement is 99 percent of the demand level within Long Island.

Long Island will meet its projected demand growth with 115 MW of SCRs and the addition of the Cross Sound Controllable Line (330 MW). At the current locational requirement level, over 500 MW of additional new capacity will be needed by 2015 in order to meet projected load growth. The 660 MW Neptune dc line to New Jersey will give Long Island load-serving entities access to sufficient capacity to meet those obligations.

New York City has recently met its locational capacity requirement by the addition of a 500 MW combined-cycle plant. If the projected locational requirements stay at 80 percent, the plants currently under construction, along with SCRs, would be adequate to meet the projected load growth through the year 2015.

Fuel—Figure 31 depicts New York's resource capacity mix by fuel type for the year 2004 on an installed capacity basis.

Figure 24: 2004 NYCA Capacity by Fuel Type



Planned Resource Capacity Mix							
Month of July	Coal %	Gas and Oil %	Gas Only %	Hydro %	Nuclear %	Oil Only %	Other %
2006	9.0	46.9	5.9	14.8	12.9	9.0	1.6
2007	7.9	48.4	5.7	14.3	12.8	8.7	2.2
2008	6.9	48.2	5.9	14.7	13.1	9.0	2.2
2009	6.9	48.2	5.9	14.7	13.1	9.0	2.2
2010	7.0	48.0	5.9	14.8	13.2	9.0	2.2

The above table shows the projected installed capacity resource mix from 2006 through 2010. The "other" category includes wind power, resource recovery, wood burning, and other fuels. For the next five years, resources fueled by natural gas will meet all of the growth in projected energy consumption. Except for wind energy, no new resources employing other fuels are expected to be added in the planning period.

New York State has a potential for a natural gas shortage in the winter. This could cause natural gas-fired units to burn other fuels or curtail operations. If unit operation curtailment due to fuel unavailability occurs in load pockets, generation from other areas would need to help meet demand, causing heavier loading on the existing transmission system. Many of the dual-fired units are the larger older steam units located in load pockets and would impact reliability needs in multiple ways if retired. The real challenge on a going-forward basis will be to maintain the benefits that fuel diversity, in particular dual-fired fuel capability, provides today. This will be especially critical in New York City and Long Island, which are entirely dependent on oil- and gas-fired units many of which have interruptible gas transportation contracts. In terms of operational strategy, the NYSRC has adopted the following local reliability rule:

I-R3. Loss of Generator Gas Supply (New York City & Long Island)

"The NYS Bulk Power System shall be operated so that the loss of a single gas facility (i.e., pipeline or storage facility) does not result in the loss of electric load within the New York City and Long Island zones."

NYSIO categorizes generation capacity fuel types into three supply risks: low, moderate, and high.

The greatest risk to fuel-supply interruption occurs during the winter months when both natural gas and heating fuel oils are competing to serve electrical and heating loads. Fortunately in New York, peak electrical loads occur during the summer months when demand is nearly 7,000 MW greater than the winter peak. As such, New York can meet the winter peak of roughly 25,000 MW with sufficient generation without exposure to significant fuel risks. Even with a forced outage rate of 10 percent,sufficient generation in the low to moderate fuel risk categories is in place to meet the winter electrical peak of 25,500 MW. This would leave a margin of nearly 4,000 MW or 14 percent of the total capacity characterized by low to moderate fuel risk.

Transmission — Based on the present load forecast, planned transmission facilities, and projected generation resources, including proposed generation additions and associated transmission upgrades, the New York bulk power transmission system is judged to be adequate through 2015.

Significant transmission and generation projects currently being proposed include the following:

Major NY Transmission and Generation Projects	Status	In-Service Date
Replace Norwalk Harbor — Northport Cable	S	2008
Niagara Upgrade (325 MW hydro) (12 units completed, remaining 1 unit to be completed 12/2006	C	2006
Bethlehem Energy (Albany Steam, 400-730 MW repowering)	I/S	2005
Poletti, Astoria (500 MW)	C	2006
KeySpan, Spagnoli Road, LI (250 MW CC)	S	2008-09
Calpine Wawayanda Energy Center, Middletown (500 MW)	S	2008
Reliant Astoria Repowering — Phase 1 (367 MW)	S	2010
Mirant, Bowline Pt. 3, W. Haverstraw (750 MW)	S	2008
SCS Energy, Astoria (1000 MW CC)	C	2006-07
ANP Brookhaven Energy, LI (580 MW)	W	N/A
Glenville, Rotterdam (540 MW)	S	2008
Besicorp, Reynolds Road (660 MW)	S	2007
Reliant Astoria Repowering — Phase 2 (173 MW)	S	2011
PSEG Power Radial Line to NYC (550 MW)	S	2008
TransGas Energy, New York City (1100 MW)	S	2008-09
PG&E/ Liberty Generation Connection to New York City (400-600 MW)	S	2007
RG&E 4th Station 80 345/115 kV Transformer and Other Upgrades	S	2008
Flat Rock Wind Generation Project (240-300 MW)	S	2005-06
Mott Haven 345 kV Substation	S	2007
Sprainbrook-Sherman Creek 345 kV	S	2007
Blenheim-Gilboa Uprate (120 MW Pumped Storage) (1 unit (30 MW) each year starting Fall 2006 through Spring 2010)	S	2007

Status Key:

P – Proposed
S – Study is under way or complete
C – Under construction
I/S – In Service
O/S – Out of Service
R – Retired

Terminals		Miles	Year	Voltage	No. of Circuits
Duffy Ave Convertor Station	PJM	65.000	2007	500	1
Dunwoodie	Sherman Creek	7.8	2005	138	1
Mott Haven	Dunwoodie	9.989	2007	345	2
Mott Haven	Rainey	4.083	2007	345	2
Sprain Brook	Sherman Creek	10	2007	345	1
Newbridge Rd	East Garden City	4	2007	138	1
Newbridge Rd	Ruland Rd	9.1	2007	138	1
Duffy Ave Convertor Station	Newbridge Rd 345kv	1.7	2007	345	1
Newbridge Rd 345kv	Newbridge Rd 138kv	-	2007	-	2
Station 80	Station 82/Mortimer	3.500	2007/2008	115	1
Station 80	Station 82/Mortimer	3.500	2007/2008	115	1
Station 82	Station 67	2.400	2007/2008	115	1
Station 80	Station 67	5.900	2007/2008	115	1
Station 82	Station 48	9.500	2007/2008	115	1
Station 48	Station 7	7.500	2007/2008	115	1
Station 121	Station 230	5.700	2007/2008	115	1
Station 80	Station 80	xfrm	2007/2008	345/115	1
Sterling	Off Shore Wind Farm	10.15	2008	138	1
Hurley Ave	Saugerties	11.11	2011	115	1
Pleasant Valley	Knapps Corners	17.7	2011	115	1
Northport	Narwalk Harbor	11	2011	138	3
Saugerties	North Catskill	12.25	2012	115	1
Ramapo	Tallman	3.240	2007	138	1
Tallman	Burns	6.080	2007	138	1

Operations — No unusual operational issues have been identified for the period of 2006–2015.

Ontario

Demand — The actual summer peak demand for 2005 was 26,160 MW, which is 8.3 percent higher than the normal weather forecast of 24,147 MW in the previous report. The actual winter peak for 2005/2006 was 23,766 MW, or 2.4 percent lower than the 24,339 MW normal weather forecast in the previous report.

Ontario has historically experienced its annual peak demand in the winter. However, in recent years the system has been dual-peaking as cooling load has been growing much more quickly than heating. Going forward, this trend will continue and Ontario will be summer peaking.

The summer peak demand is expected to grow at an annual rate of 1.1 percent. The winter peak is expecting an average growth of 0.7 percent over the forecast.

The IESO uses weather scenarios to capture the variability in demand due to weather. Load forecast uncertainty (LFU), a measure of demand fluctuations due to weather variability, is a critical part of demand analysis. In conjunction with the normal weather forecast, LFU is valuable in determining a distribution of potential outcomes under various weather conditions. The IESO resource adequacy assessments use the normal weather forecast in combination with LFU to consider a full range of peak demands that can occur under various weather conditions with varying probability of occurrence. An extreme weather scenario is developed based on the most extreme weather experienced over 31 years of weather history. This scenario is valuable for studying situations where the system is under duress, especially during peak periods.

Energy — The actual Ontario energy demand for 2005 was 157.0 TWh. This was 0.9 percent higher than last year's forecast for 2005. Despite this, the new forecast calls for lower energy levels throughout the forecast period. The unusually warm summer of 2005 masked a significant loss of load due to reduced economic activity. The high Canadian dollar and high energy costs have adversely impacted a significant portion of Ontario's industrial sector. Energy demand is expected to grow by 0.9 percent per annum over the course of the forecast.

Resources — Since last summer, more than 600 MW of new supply has been added to the Ontario power system, including 515 MW at the Pickering Nuclear Generating Station and 117 MW of gas-fired co-generation. Recent capacity additions have improved Ontario's supply outlook in the short term. The IESO is anticipating a positive capacity margin of approximately 181 MW on the peak week based on forecasted weather-normal demands for the summer of 2006, as compared with a projection of 740 MW for the summer of 2005.

Under median demand growth assumptions, resources that are currently available within Ontario, together with the contracted new generation and imports, are sufficient to meet the NPCC resource adequacy criterion from 2006–2015.

Considerable steps have been taken and are planned to enable retirement of Ontario's coal-fired units (6,500 MW). In executing these changes, flexibility is essential to accommodate the large amounts of new generation required and the impact of each change on the entire system. Careful and continuous coordination and adjustment of plans is taking place to ensure successful implementation of the coal replacement program while maintaining reliability.

Provincial government directives and procurements by the Ontario Power Authority (OPA) will bring 6,300 MW into service over the ten-year period to meet demand and to implement the coal replacement program.
The IESO adequacy assessments include only those projects that are under construction or that have power supply contracts with the Ontario Power Authority. Additional demand measures and supply additions are under development and will be included as future resources once contractual arrangements are in place.

Coal units will be retired once new supply is in service.

The Ontario Power Authority (OPA) has responsibility for long-term supply, integrated power system planning, development of conservation, and demand-related measures and development of retail rate programs. This assignment of responsibilities has been implemented to provide assurance of adequate future electricity supply for Ontario. The OPA's first integrated power system plan (IPSP) is expected to be developed later this year, with Ontario Energy Board approval targeted for 2007. The IPSP will address Ontario's electricity needs for the next 20 years. Generation deliverability to load is not currently an issue in Ontario, and future requirements will be managed as part of the IPSP.

For the period 2006–2015, neither full responsibility purchases nor full responsibility sales are contracted.

Fuel — In anticipation of growing amounts of gas-fired generation in Ontario over the coming years, the IESO has joined with Union Gas, Enbridge, TransCanada Pipelines, and the Ontario Energy Board to form the Ontario Gas Electric Interface Working Group (OGEIWG). This group will establish communication protocols, cross-functional training, contingency analysis, and gas-electric day coordination in order to manage operational and reliability issues in both energy sectors. The Ontario Energy Board also has proceedings under way to review infrastructure and tariff issues.

IESO requires generator market participants in Ontario to provide specific information regarding energy or capacity impacts if fuel supply limitations are anticipated. In general, fuel delivery infrastructure redundancy for nonrenewable resources such as coal, uranium, oil, and gas is sufficient such that more explicit analysis is considered only on an ad hoc basis.

Transmission — Transmission capability into the greater Toronto area has been enhanced over the past year with the addition of the second 500/230 kV, 750 MVA auto-transformer at the Parkway TS in the fall of 2005, a 240 Mvar shunt capacitor at the Essa TS, and the planned removal of deratings on the 500/230 kV, 750 MVA autotransformer at the Trafalgar TS.

Imports from New York were limited at times by transmission constraints internal to Ontario in the summer of 2005. These limitations are being addressed by augmenting the five existing 230-kV circuits between Niagara Falls and Hamilton that form the Queenston Flow West interface with a new 230-kV double circuit line between the Allanburg TS and the Middleport TS. This expansion project, together with improved 230-kV circuit ratings in the Burlington area, will remove these internal restrictions. New York imports are expected to be limited by the ties to New York, with a net increase in import capability of about 350 MW. In addition, an existing special protection system at St. Lawrence is planned to be enhanced and be available under peak load conditions to maximize simultaneous import capability from Hydro-Québec and New York. These changes, targeted for the summer of 2006, will increase Ontario's ability to import from New York.

A number of other transmission reinforcements are being developed to permit the connection of new generation to the Ontario system. Most significant of these is the need to increase 500-kV transmission capability from the area around the Bruce nuclear plant to accommodate the return of the two nuclear units and new supply from up to 1,000 MW of wind. The final arrangements have not been decided, but they will need to be in service by 2012 to avoid delaying the restart of the nuclear units.

Interregional transmission transfer capability studies are conducted semiannually. The results are summarized below. The results have not been reviewed or accepted by IESO neighbors. Their limitations could be more restrictive in some cases.

	Winter (MW)	Summer (MW)
Ontario to Manitoba	275	263
Manitoba to Ontario	275	263
Ontario to Minnesota	140	140
Minnesota to Ontario	90	90
Ontario to Michigan	2000	1900
Minnesota to Michigan	1550	1400
Ontario to New York	1900	2100
Minnesota to New York	2000	2250
Ontario to Québec	835	750
Minnesota to Québec	1495	1400

Operations — The phase angle regulators (PARs) were in service on the Michigan-Ontario interconnections, but are being operated by the IESO at neutral tap position because an agreement to operate the PARs to control flow has not been reached. The IESO reports that high loop flows continue to be present through the Ontario system. The PARs were installed by Hydro One in Ontario to mitigate the problems caused by the loop flows affecting Ontario's most heavily used interfaces. However, this equipment cannot be used as intended until the IESO and the Midwest Independent Transmission System Operator (MISO) complete a corresponding operating agreement, which is currently awaiting negotiations between Hydro One and the International Transmission Company.

The inability to regulate flows combined with lower than expected ratings on the equipment resulted in significant congestion of imports from the Michigan direction in 2005. Until the necessary agreements are in place, the PARs will only be operated off neutral tap to prevent a 5 percent voltage reduction in Ontario or Michigan, to prevent shedding firm load, and for testing. Without agreement to control flow, the congestion experienced in 2005 can be expected to reoccur in 2006.

IESO has been working with government and stakeholders to address some of the problems that surfaced last summer when IESO relied on extensive use of emergency control actions in order to maintain reliability and avoid power interruptions. These measures, which will be implemented in the second quarter of 2006, will include:

- A day-ahead commitment process which is expected to reduce the failure of import transactions in real time and increase commitment certainty for both domestic and out-of-province generators; and
- An emergency load reduction program which will reduce consumption when required for reliability by providing incentives to loads to reduce their energy usage under stressed system conditions.

IESO has achieved significantly better blackstart preparedness after the blackout in August 2003 by procuring additional blackstart capability and requiring actual line energization tests annually in conjunction with existing generator blackstart tests.

Québec

Demand — The 2006–2007 winter peak-demand forecast, under normal weather conditions, is 36,479 MW and is expected to grow at an annual average rate of 0.61 percent, reaching 38,538 MW for the winter period of 2015–2016. This compares with the 2005 RAS *Long-Term Reliability Assessment* projection in which an annual average rate of 0.66 percent was forecast, with a peak of 37,951 MW projected for the winter of 2014–2015. In addition, Hydro-Québec Production has firm export commitments of 455 MW to neighboring networks outside Québec until October 2012. These capacity sales will decrease gradually down to 151 MW in October of 2016.

For the winter of 2005–2006, Québec had 1,235 MW of industrial interruptible load contracts. These contracts are expected to be renewed during the entire study period.

The high load scenario for the period 2005–2006 through 2009–2010 is as follows:

2005–2006	37,288 MW
2006–2007	37,509 MW
2007–2008	38,069 MW
2008–2009	38,699 MW
2009–2010	39,313 MW

The required 0.1 LOLE criterion is met in all years except for the winter of 2005–2006, when it is 0.102. External purchases will be employed if that load level is reached.

Energy — During 2006, the internal energy consumption is expected to total 192 TWh. Between 2006 and 2015, the annual consumption will grow at an average rate of 0.67 percent, reaching 204 TWh in

2015. For the winter of 2005–2006, an actual net energy for load of 183,310 GWh was recorded; an average growth rate of 1.0 percent was projected.

Resources — In the *2005 Québec Area Triennial Review of Resource Adequacy*, Québec demonstrated that the installed reserve margin requirement was about 10 percent over the annual peak load to comply with the NPCC adequacy criterion (Reference https://www.npcc.org/publicFiles/documents/adequacy/Quebec%20Triennial%202005.pdf). For the whole period, the expected installed reserve margin will be over this percentage. Even in the case of a high load scenario, Québec still meets the NPCC resource adequacy criterion (LOLE less than 0.1 day/year).

From January 2006 to January 2016, Québec capacity will increase by 4,500 MW. This increase will come from new and upgraded hydro generation plants and a new gas-fired combined-cycle plant of 547 MW (September, 2006). The overhaul of the nuclear station Gentilly 2 is planned from March 2011 to December 2012.

By 2013, the installed wind power capacity will be more than 3,500 MW. In this assessment for Québec, wind power capacity is not included. Hydro-Québec is in the process of evaluating the capacity value of wind power generation under winter peak weather conditions.

For the period 2006–2015, no full responsibility purchases have been contracted. Hydro-Québec Production has firm export commitments of 455 MW to neighboring networks outside Québec until October of 2012. These capacity sales will decrease gradually to 151 MW in October of 2016.

Fuel — Québec's energy is largely produced (93 percent) by hydro generating stations, located on different river systems geographically distributed, the major ones with multiyear storage capability. For planning and day-to-day operations, Québec can rely on those multi-year reservoirs (water reserves) and on some other nonhydroelectric resources, allowing Québec to cope with low water inflow conditions. Based on the actual water reserves and the other nonhydroelectric resources, generation shortage problems are not expected for the short and medium term.
Regarding the thermal units, each has on-site fuel storage that can be refueled by truck or by barge. The new gas-fired combined-cycle plant has a firm natural gas supply contract for the next five years.

Transmission — During the next five years, about 450 miles of new transmission lines will be added to the Hydro-Québec TransÉnergie grid. The major focus of the new transmission will be the integration of additional generation provided by wind farms and hydroelectric projects with the main grid. Moreover, the Gaspesia subsystem will be reinforced to integrate around 1,500 MW of wind generation.

Presently, the integration of a new HVdc link in the Outaouais subsystem is being studied. This HVdc link is planned to have a capability of 1,250 MW and would be connected to the Ontario grid. A scenario under study is considering a commissioning for the end of 2009.

The major focus of the new transmission will be the integration of additional generation provided by wind farms and hydroelectric projects with the main grid. Moreover, the Gaspesia subsystem will be reinforced to integrate around 1,500 MW of wind generation.

Operations — No unusual operational issues have been identified for the period 2006–2015.

NPCC is a voluntary nonprofit organization. Its 37 current members represent transmission providers and transmission customers serving the northeastern United States and central and eastern Canada. Also included are five nonvoting public interest memberships extended to regulatory agencies with jurisdiction over participants in the electricity market in northeastern North America as well as public-interest organizations expressing interest in the reliability of electric service in the region.

The geographic area covered by NPCC, approximately one million square miles, includes the state of New York, the six New England states, and the provinces of Ontario, Québec, New Brunswick, and Nova Scotia. The total population served is approximately 54 million. From an electric load perspective, 20 percent of the Eastern Interconnection load is served within NPCC. For Canadian electricity requirements, 70 percent of Canadian load is located within the NPCC region. Additional information can be found on the NPCC Web site (http://www.npcc.org/).

NPCC-Canada Capacity and Demand

Figure 25: NPCC-Canada Net Energy for Load

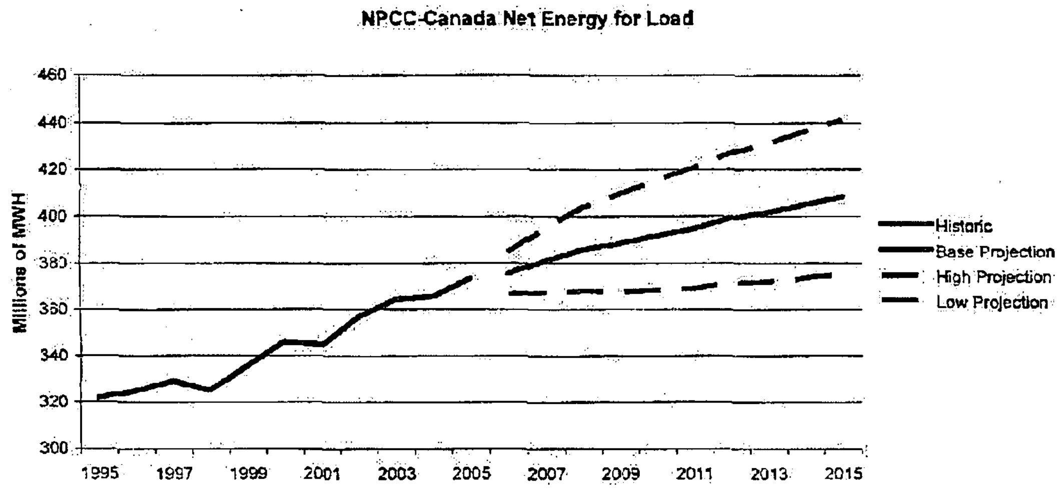


Figure 26: NPCC-Canada Capacity Margins — Winter

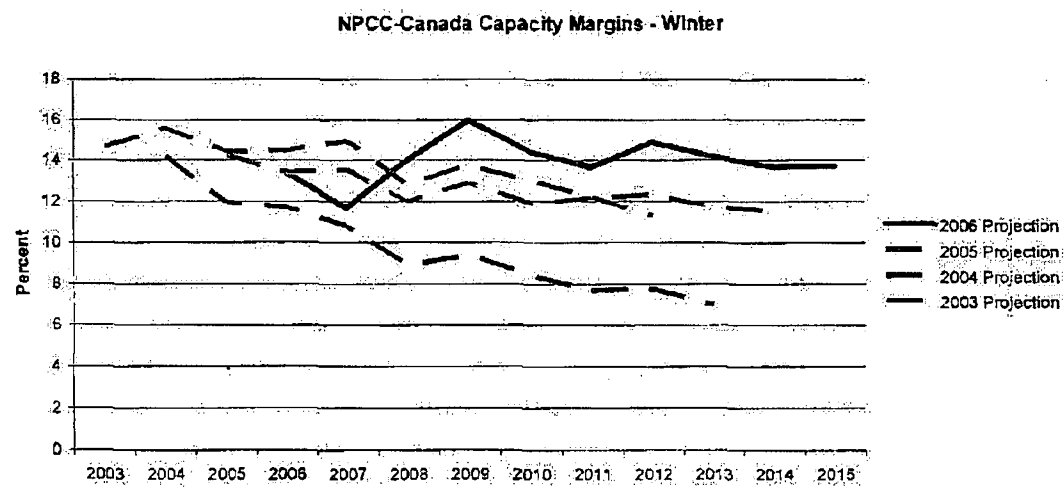
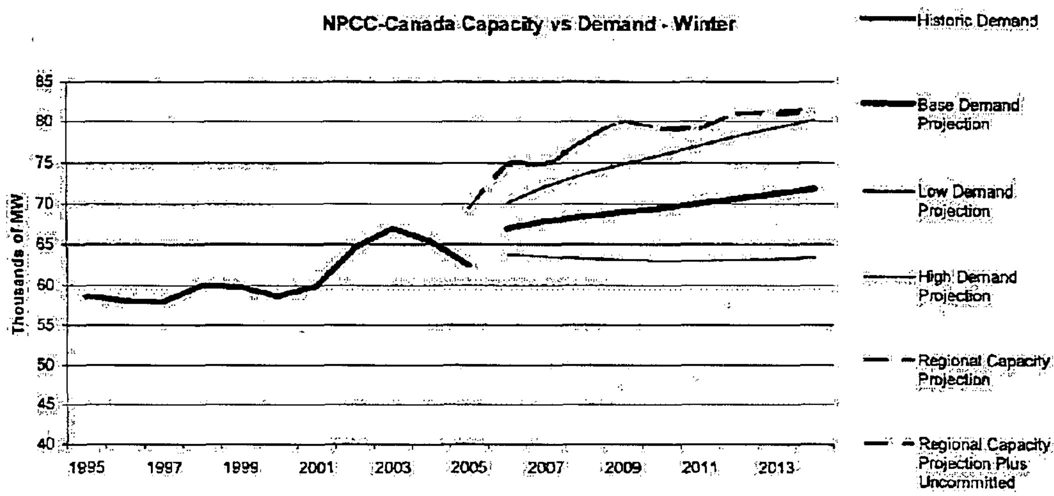


Figure 27: NPCC-Canada Versus Demand — Winter



NPCC-U.S. Capacity and Demand

Figure 28: NPCC-U.S. Net Energy for Load

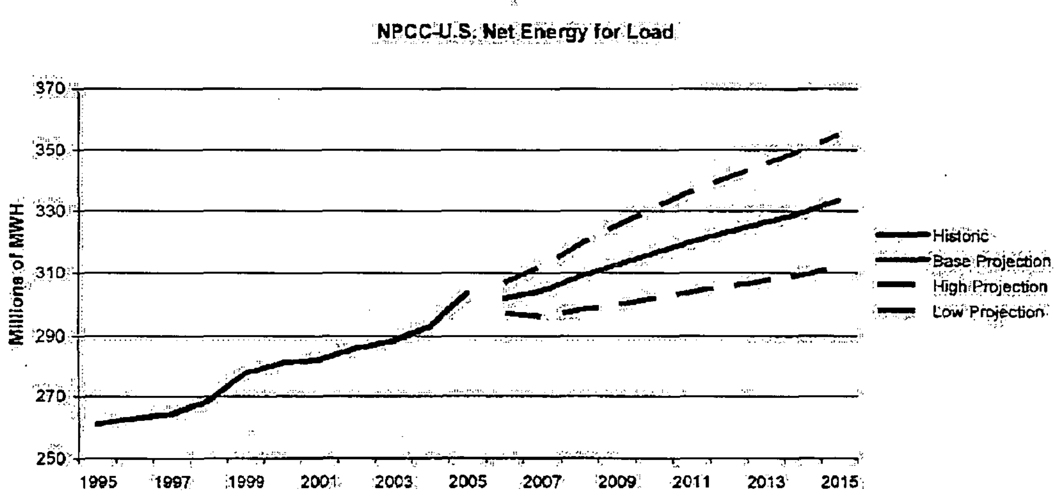


Figure 29: NPCC-U.S. Capacity Margins — Summer

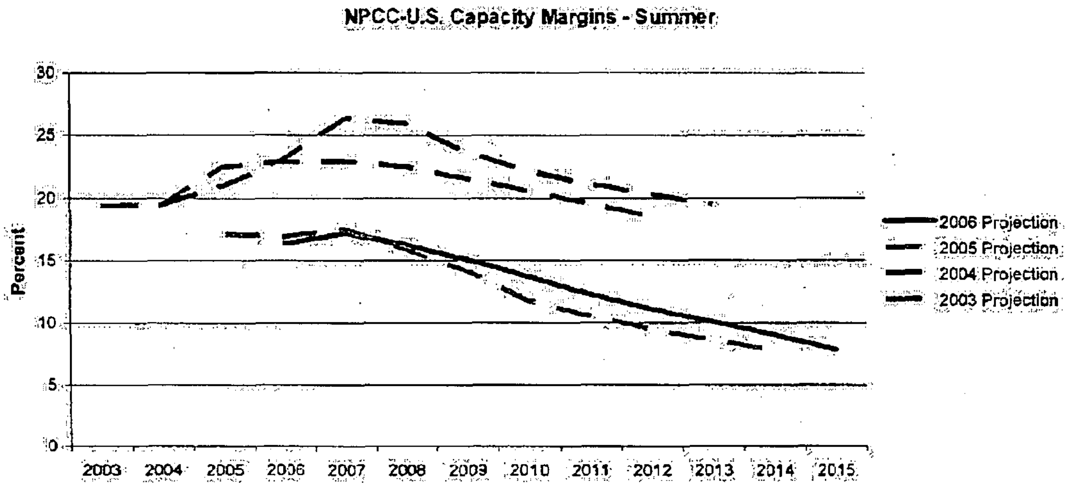


Figure 30: NPCC-U.S. Capacity Versus Demand — Summer

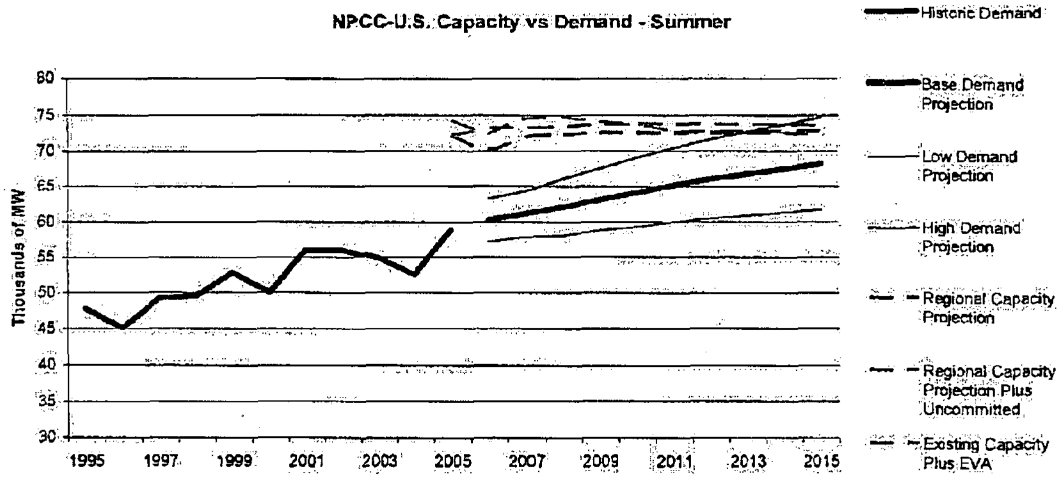
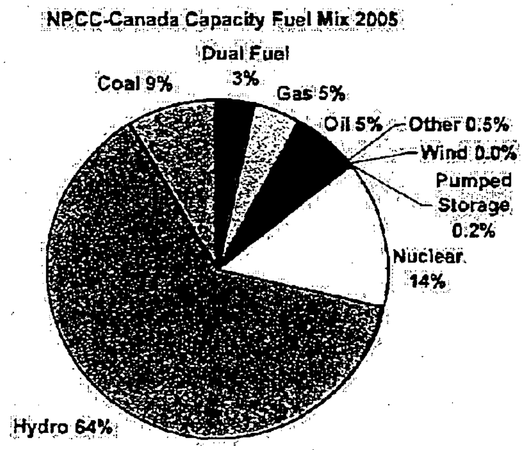


Figure 31: NPCC-Canada Capacity Fuel Mix for 2005 and 2011



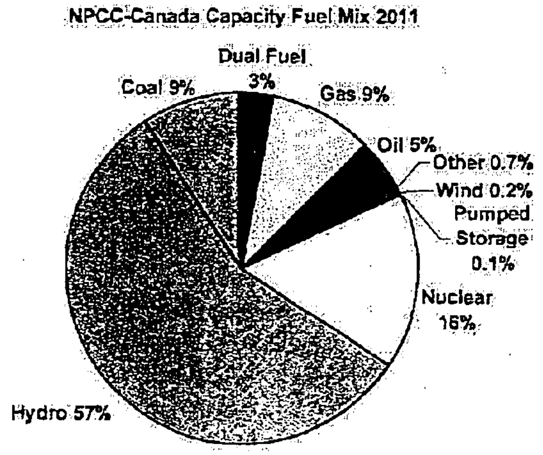
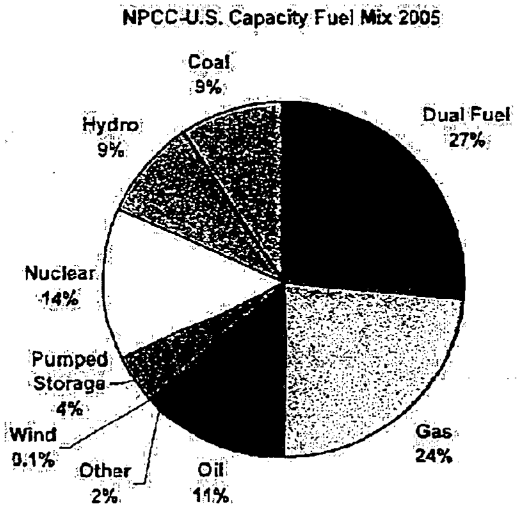
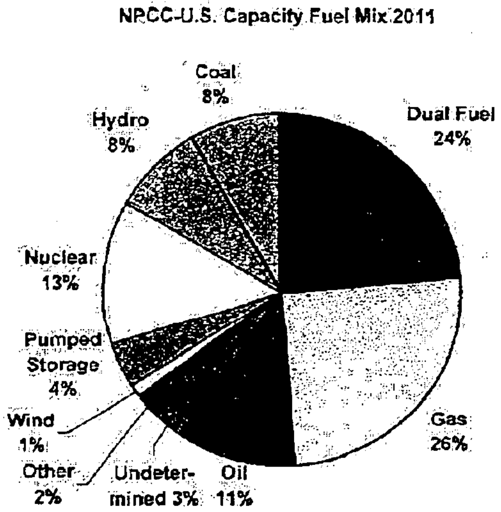


Figure 32: NPCC-U.S. Capacity Fuel Mix for 2005 and 2011





RFC

Demand

Throughout the assessment period, the annual peak in the Reliability*First* Corporation (RFC) region is expected to continue to occur during the summer. Current resource projections developed by RFC members indicate that direct-controlled and interruptible load management programs will provide up to 4,100 MW of expected load reduction at the time of the peak during the years 2006–2015. The coincident total internal demand is expected to be 191,600 MW in 2006 and 220,400 MW in 2015. With curtailment of interruptible loads and demand-side management loads, RFC's coincident net internal demand is projected to be 187,500 MW in 2006 and 216,400 MW in 2015. This is a 1.6 percent average annual load growth in net internal demand over the 2006–2015 period, which is less than the average growth rate of 1.8 percent in last year's projection. This peak demand growth is based on forecast economic factors and average summer weather conditions, and as such, actual peak demands may vary significantly from year to year.

At this time in the transition of ECAR, MAAC, and MAIN to RFC, an analysis of overall demand uncertainty and variability, and the variability in demand due to weather has not been conducted. Planning for such uncertainties is the responsibility of each individual load-serving entity. Higher than average temperature and humidity can be expected to increase the summer peak demand by as much as 11,000 MW.

Energy

RFC does not currently compare or evaluate energy forecasts since few of the RFC resources are energy limited.

Resources

RFC has adopted a regional standard for resource adequacy of LOLE of one occurrence in ten years. This standard can be reviewed at: www.rfirst.org/committees/RFC_Approved_Standards.html. This standard will be implemented by maintaining a reserve margin determined from LOLE analyses. The studies to determine the reserve margins required by regional LSE are scheduled for completion in 2007, with initial implementation in 2008. Until then, the 15 percent reserve margin of the former MAAC region is being used to assess regional resource adequacy.

The net demonstrated capability is projected to be about 241,000 MW by year end of 2006. This includes capacity from members and nonmembers alike. The total announced increase in generating capacity from 2007 through 2015 is about 15,000 MW. This does not include several thousand megawatts of "possible capacity additions" identified by some members. Approximately 3,700 MW of this potential capacity increase from 2007 through 2015 is in the form of combustion turbines and combined-cycle plants projected to operate on natural gas.

The construction status of many near-term capacity projects is not known until nearly the in-service date, and later projects are not yet under construction. This makes for uncertainty regarding the timing and amount of new capacity additions, and consequently, the expected RFC reserve margins. Additionally, a significant amount of existing capacity is not counted toward meeting the reserve requirements as this capacity is considered undeliverable, is not committed to load within the region, or is an energy only resource.

At this time in the transition of ECAR, MAAC, and MAIN to RFC, a recalculation of the 2005 reserve margins for the RFC members is not available for comparison to the reserve margins in this assessment. Based on capacity information provided by RFC members, an analysis is conducted to indicate the amount of additional capacity or power imports that would be needed to meet the required reserve margin. No purchases or sales after 2006 are included in the analysis. Summer reserve margins in RFC range from a high of 23.0 percent in 2006, declining to 11.1 percent in 2015. These reserve margins are based on forecast net internal demand and potential capacity resources.

The amount of potential capacity resources is sufficient through 2012. Starting in 2013, additional capacity resources are needed to maintain a 15 percent reserve margin. The amount of needed capacity resources ranges from 1,600 MW in 2013 to 8,400 MW in 2015. These reserve margins include over 19,800 MW of projected capacity additions and existing capacity that is currently categorized as undeliverable. If the proposed capacity projects are not completed as scheduled and the transmission system is incapable of fully delivering all existing capacity, a reduction of the entire 19,800 MW of capacity resources would reduce the reserve margin in 2015 to 1.9 percent.

Fuel

RFC does not specifically address fuel supply interruptions on a prospective basis in the long-term assessment. Fuel supply interruptions tend to be local in nature, that is, the failure of the supply network is due to an equipment breakdown or other problem in a specific location. These types of failures in the supply network are difficult to predict, generally short lived, and affect a specific area. Member companies have taken actions in the past to resolve local fuel supply issues. Such actions have included alternate transportation arrangements, fuel switching, and fuel conservation. RFC expects its members will continue to take appropriate action to resolve any short-term fuel supply interruptions into the future, and anticipates that its members will secure adequate fuel supplies throughout this assessment period.

The region is diversified with regard to the fuel supply. About 47 percent of the existing capacity uses coal for its fuel, with 94 percent delivered by rail/truck/barge and 6 percent coming from mine mouth sources. Another 14 percent of the capacity is nuclear fueled. This 61 percent of the capacity is primarily base and intermediate duty generation. Oil and natural gas fuels comprise 7 percent and 28 percent of the capacity, respectively, and 3 percent of the capacity is hydroelectric. The remaining 1 percent of capacity uses a variety of renewable and other energy supplies.

The RFC seasonal peak occurs during the summer, when the oil- and gas-fired capacity will experience the most significant day-to-day usage swings, as these are most often the units operating on the margin during the peak. A review of the gas transmission system indicates that gas transmission contingencies during the summer would not be expected to have a significant effect on generating unit operations across the region, although local problems could exist.

Extreme weather conditions can impact the fuel supply in a number of ways. An extended drought can reduce river levels such that barge transportation of fuel is reduced or curtailed. Extreme summer heat can warp rails, causing train derailments. Flooding can also cause derailments or washed out tracks. Extreme cold can cause coal to freeze together in the rail cars, and heavy snow can slow down train and truck traffic. All of these extreme weather conditions can create short-term problems in fuel supply. However, RFC does not expect weather conditions to materially affect the ability to adequately supply generation across the region during the assessment period.

Transmission

The transmission networks are expected to meet adequacy and operating criteria over a wide range of anticipated system conditions as long as established operating procedures are followed, limitations are observed, and critical facilities are placed in service when required. Local transmission overloads are possible during some generation and transmission contingencies. However, members would use operating procedures to effectively mitigate such overloads.

Current member plans in the next five years project the addition of about 592 miles of extra high-voltage (EHV) transmission lines, (230 kV and above) as well as six new substations that are expected to enhance and strengthen the bulk transmission network. Most of those additions are connections to new generators, or substations serving load centers. Depending upon specific dispatch patterns of new and existing generation, the output of all planned generation may not be fully deliverable due to transmission limitations.

The Neptune Regional Transmission System, LLC merchant transmission interconnection project consists of one HVdc connection from PJM to New York. The connection originates near the Sayreville 230-kV (a.k.a. Raritan River) substation in Sayreville, New Jersey, and will terminate at the Newbridge Road 138-kV substation on Long Island, New York. Capability will be 790 MW and the developer has requested firm transmission withdrawal rights in the amount of 685 MW and nonfirm transmission withdrawal rights in the amount of 105 MW at the HVdc terminal in PJM. Neptune is scheduled for commercial operation in July 2007.

PJM is also evaluating several additional proposals for EHV transmission to increase overall west-to-east transfer capability by at least 5,000 MW. In-service dates are expected to be within five to ten years. More details will be reported in future reliability assessments. More information is available at: www.pjm.com.

RFC actively participates in existing interregional transmission assessment efforts. Transfer capability results are included in each of the interregional reports. New interregional agreements are being negotiated between RFC and its neighboring regions.

Legacy regional activities that were initiated as a result of the August 14, 2003 blackout have continued and may be applied to all RFC members in the near future. One of these activities is a peer review process of transmission assessments to verify that owners and operators have conducted sufficient planning analyses and to complement regional assessment efforts. Since the blackout, five peer reviews of former ECAR member transmission assessments have been conducted. All assessments included both thermal and voltage analyses for a base case and several stressed case conditions with single, double, and if warranted, extreme contingencies. The results of these assessments are communicated to reliability coordinators and transmission operators. A review of all of these activities is currently being performed to determine if they will continue for all RFC members.

Operations

MISO, PJM Interconnection, and TVA are performing the reliability coordinator functions for all of the balancing authorities in the region.

Eight NERC readiness audits are being conducted in RFC in 2006. Numerous operational improvements have been implemented as a result of the recommendations from the readiness audits. The most widespread of these operational improvements dealt with improved emergency and restoration training, improved security analysis procedures and programs, and improved communications between and among reliability coordinators, balancing authorities, and transmission operators.

To mitigate congestion and other reliability concerns at the interface between PJM and MISO, a joint MISO-PJM operating agreement is in place. The agreement identifies the transmission rights and obligations of MISO in the PJM footprint and the transmission rights and obligations of PJM in the MISO footprint. Further, each RTO has the ability to request that generation be operated in the other RTO to preserve transmission rights and to relieve congestion in its footprint.

RFC is not aware of any specific operating issues that need to be addressed in this assessment.

Assessment Process

Transition to a single set of assessment processes is still in progress for all of the previous heritage regional activities. Consequently, this long-term assessment reflects an aggregation of three separate assessment activities, conducted by using the assessment processes of ECAR, MAAC, and MAIN.

Within RFC, each individual company along with its RTO performs planning analyses for facility additions. Regional reliability assessments are performed to determine the adequacy of the existing and future bulk power system to serve projected load, given the proposed changes or additions to generation capacity and transmission facilities. The operating reliability impact of interactions with neighboring regions is assessed by participation in the MEN, MET, MMS, MSW, and VEM interregional groups.

For the RFC members that were ECAR members, ECAR's assessment procedures were applied to all generation and transmission facilities within the former ECAR portion of the RFC footprint that might significantly impact bulk power system reliability. These assessments consider ECAR as a single integrated system. Generation resource assessments of the ECAR systems on a region-wide basis have been performed annually for a planning horizon of up to ten years, and semiannual assessments have been made for the upcoming summer and winter peak-demand seasons. Transmission assessments have been performed regularly for selected future years out to the planning horizon and semiannually for the summer and winter peak-demand seasons. If transmission deficiencies are discovered during this process, the member system with the deficiency will determine the actions to be taken.

For the RFC members that were MAAC members, PJM's assessment practices continue to apply. PJM's assessments cover the entire expanded PJM RTO footprint, which now includes the transmission systems in all or part of Pennsylvania, New Jersey, Maryland, Ohio, Kentucky, Delaware, Virginia, West Virginia, Illinois, North Carolina, and the District of Columbia. In addition to the former MAAC members, this PJM footprint also includes several former ECAR and MAIN members. The PJM RTO is operated and planned employing one security-constrained economic dispatch protocol using the applicable criteria of the respective region, local criteria, the PJM deliverability requirements, and PJM market rules. Through the operation and planning of the total PJM footprint reliability is ensured.

The PJM planning process has been expanded to evaluate reliability, economic, and operational performance projects. The reliability projects are designed to meet reliability criteria, while the economic projects are justified based on a cost-benefit analysis, which considers congestion costs and takes into account various financial hedging instruments. PJM performs these economic analyses for the PJM members' information only to point to areas where development of transmission or generation may be financially beneficial. Operational performance projects are intended to address events that are observed by the PJM operators, but were not predicted in the planning studies.

The PJM market rules include a capacity market and the use of a locational marginal pricing mechanism to make congestion transparent. Making congestion transparent through locational marginal pricing provides a market mechanism to allow for mitigation of congestion. A reserve requirement is presently set for a planning period two years into the future so that the market can provide sufficient capacity or for the load-serving entities to construct generation. A future reserve construct, which values the quantity, quality, and location of generation, is presently going through the stakeholder process.

The MISO market rules also include the use of a locational marginal pricing mechanism to make congestion transparent. The MISO energy market tariff requires LSEs to comply with their applicable RRO or state resource adequacy standards. Load and capability information is reported to MISO annually. To monitor compliance a planned reserve sharing group (PRSG) for the MISO LSE is currently under development. The PRSG will be designed to meet planned resource requirements of RFC.

Finally, for those RFC members that were MAIN members, the former MAIN transmission assessments included a 2009 dynamic stability-based study for a 2014 screening, and studies completed by the former MAIN Future System Study Group.

*RFC membership currently consists of 46 regular members and 19 associate members operating within 12 NERC aalancing authorities. The members serve the electrical requirements of more than 72 million people in an area covering all of the states of Delaware, Indiana, Maryland, Ohio, Pennsylvania, New Jersey, and West Virginia, plus the District of Columbia; and portions of Illinois, Kentucky, Michigan, Tennessee, Virginia, and Wisconsin. Additional details are available on the Reliability*First *Web site (http://www.rfirst.org).*

RFC Capacity and Demand

Figure 33: RFC Net Energy for Load

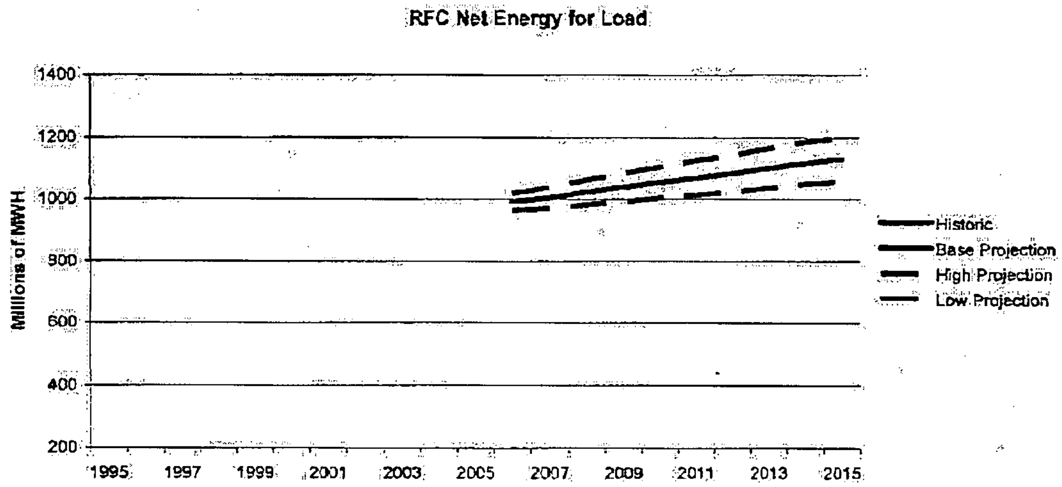


Figure 34: RFC Capacity Margins — Summer

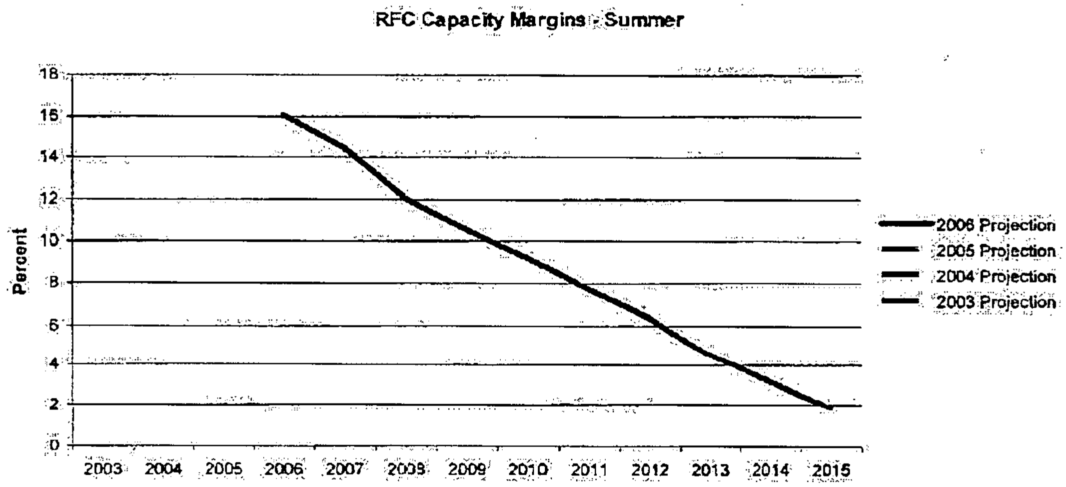


Figure 35: RFC Capacity Versus Demand — Summer

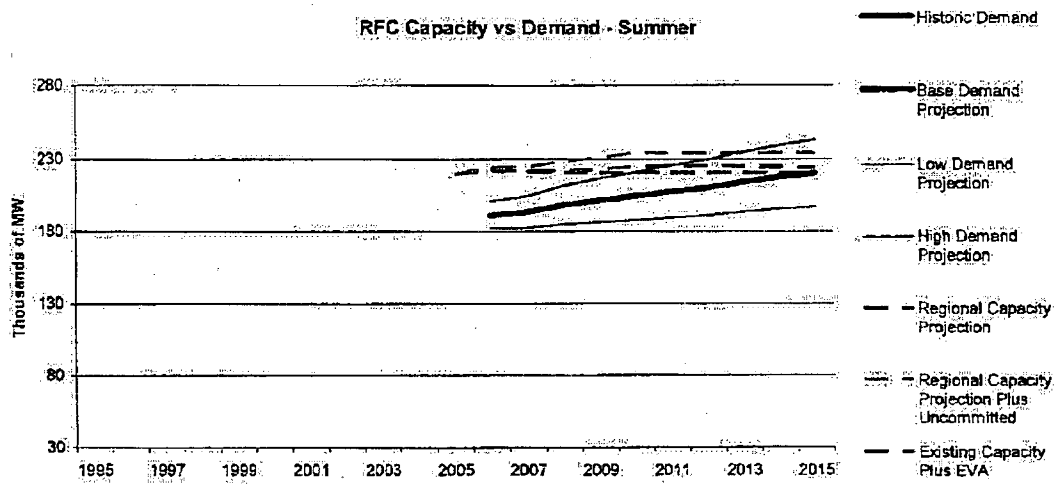
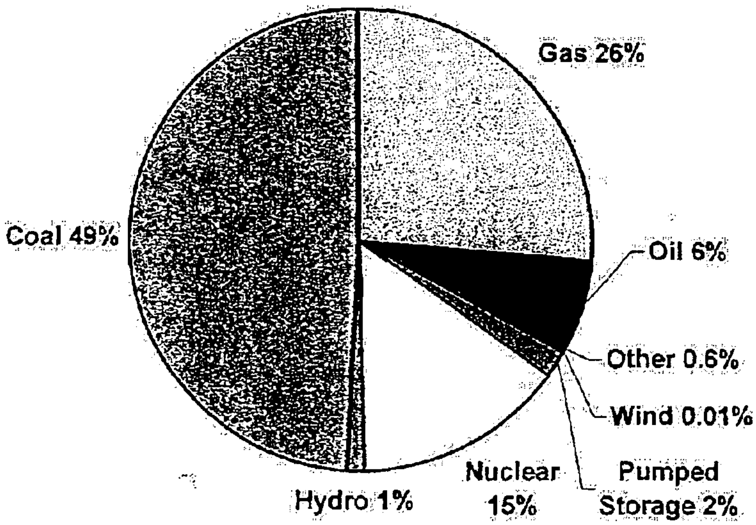
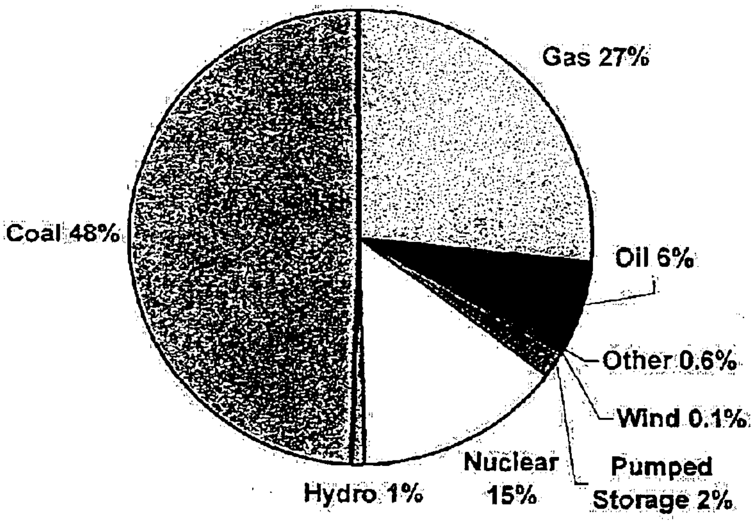


Figure 36: RFC Capacity Fuel Mix for 2005 and 2011

RFC Capacity Fuel Mix 2005



RFC Capacity Fuel Mix 2011



SERC

SERC anticipates consistent load growth in demand and energy over the next ten years.

The SERC region has extensive transmission interconnections between its subregions and its neighboring regions (FRCC, MRO, RFC, and SPP). These interconnections allow the exchange of large amounts of firm and nonfirm power and allow systems to assist one another in the event of an emergency.

Transmission capacity is expected to be adequate to supply firm customer demand and firm transmission reservations. Planned transmission additions include 1,624 miles of 230-kV lines, 270 miles of 345-kV lines, and 345 miles of 500-kV lines. SERC members invested over $1.25 billion in new transmission lines and system upgrades in 2005, and they are planning transmission capital expenditures of more than $6.75 billion over the next five years.

SERC is in a period of significant transition:

- Effective January 1, 2006, SERC membership expanded to include several members in the central part of the country, resulting in the creation of a fifth SERC subregion (Gateway subregion). The Gateway subregion is comprised of the following SERC members: Ameren, City of Columbia, Missouri, Electric Energy, Inc., Illinois Municipal Electric Agency, and Southern Illinois Power Cooperative. All but Electric Energy, Inc. are also members of the Midwest ISO.
- Also effective January 1, 2006, two new SERC members, East Kentucky Power Coop. (EKPC) and Big Rivers Electric Coop. (BREC), joined the TVA subregion.
- Development of an interregional studies agreement among the regions of the Eastern Interconnection is nearing completion and SERC has recently integrated a new framework for studies into the region's organization. Future intraregional and certain interregional study efforts will be coordinated by these SERC groups to ensure continued reliability during these times of change.
- Major changes in the electric utility industry were mandated by the Energy Policy Act of 2005. SERC is undergoing organizational and governance changes to align with the legislation.

Throughout the transition, SERC's focus remains on ensuring reliability.

Demand

The 2006 summer total internal demand forecast is 188,763 MW and the forecast for 2015 is 226,921 MW. The average annual growth rate over the next ten years is 2.1 percent. This is the same as last year's forecast growth rate. The historical growth rate over the last five years averaged 1.9 percent.

Due to the geographic size of the region, all reported demands are noncoincident. These forecasts are based on average historical weather conditions.

The SERC region has significant demand response programs. These programs allow demand to be reduced or curtailed when needed to maintain reliability. The amount of interruptible demand and load management is expected to decline slightly over the forecast period from 4,980 MW in 2006 to 4,838 MW in 2015. These amounts are comparable to last year's projections. In addition to the reported interruptible demand and load management, other significant demand-side management programs are also available to maintain reliability in the region.

Temperatures that are higher or lower than normal and the degree to which interruptible demand and demand-side management is utilized can result in actual peak demands that vary considerably from the reported forecast peak demand. Although SERC does not perform load sensitivity analyses at the region level to account for this, SERC members address these issues in a number of ways, considering all

NERC, SERC, regulatory, and other requirements. These member methodologies must be documented and are subject to audit by SERC.

While member methodologies vary to account for differences in system characteristics, many commonalities still exist.

Common considerations include:

- Use of econometric linear regression models
- Relationship of historical annual peak demands to key variables such as weather, economics, and demographics
- Variance of forecasts due to such things as high and low economic scenarios and mild and severe weather
- Development of and studies using a suite of forecasts to account for the variables mentioned above

In addition, many SERC members use sophisticated, industry-accepted software packages to evaluate load sensitivities in the development of load forecasts.

Energy

The actual annual electric energy usage in the SERC region during 2005 was 962,054 GWh. The forecast annual electric energy usage in the SERC region during 2006 is 973,215 GWh. This is an increase of 1.2 percent. The forecast annual growth rate in energy usage for the region over the next ten years is 1.7 percent, which is the same as last year's forecast growth rate. The historical SERC growth rate for the last ten years has been 2.1 percent.

Resources

SERC believes that capacity resources will be sufficient to provide adequate and reliable service for forecast demands throughout the long-term assessment period. The 2006 forecast for capacity margins show that the margin is projected to remain at or above 14 percent throughout the ten-year period. Capacity margins from last year's forecast started above 12 percent, fell below 10 percent in the near term, and remained between 6–8 percent in the longer term. This year's forecast is higher than last year's due to changes in data reporting philosophies that include more comprehensive longer-term plans, and recent acquisitions of previously uncommitted merchant generating facilities that are now committed to serving load in the region. Uncommitted capacity in the SERC region is not included in this capacity margin assessment. If a load-serving entity has a contractual arrangement with a merchant plant and therefore reported through the EIA-411 reporting process, then this capacity is included in this capacity margin assessment. Because significant uncommitted capacity exists in the region, additional generation above that which is reported in the capacity margin trend will continue to be in place. Capacity margin calculations assume the use of load management and interruptible contracts at the time of the annual peak.

Collectively, SERC members are projected to be net sellers of firm power across regional boundaries throughout the ten-year period. Firm purchases from SPP reach almost 700 MW, but are offset by sales to SPP of about 250 MW. Sales to FRCC reach 1,550 MW. Purchases from RFC reach approximately 750 MW, of which over 150 MW are to transport remote generation. Only firm transactions are included in the capacity margin calculations for the region.

Although the SERC region does not implement a regional reserve requirement, members adhere to their respective state commissions' regulations regarding maintaining adequate resources. SERC members use various methodologies to ensure adequate resources are available and deliverable to the load.

Deliverability is an important consideration in the analyses to ensure adequate resources are available at the time of peak demand. The transmission system has been planned, designed, and operated such that the region's generating resources with firm contracts to serve load are not constrained. Network customers may elect to receive energy from external resources by utilizing available transmission capacity. To the extent that firm capacity is obtained, the system is planned and operated in accordance with NERC guidelines to meet projected customer demands and provide contracted transmission services. Therefore, SERC anticipates no constraints that would reduce the availability of committed capacity resources. In addition, a significant amount of the uncommitted merchant capacity within the region has been participating in the short-term markets.

The projected 2006 capacity mix reported for SERC is approximately 38 percent coal, 16 percent nuclear, 9 percent hydro/pumped storage, 28 percent gas and/or oil, and 9 percent of purchases and miscellaneous other capacity. This capacity mix includes only committed generation. The mix has not changed significantly from last year. Steam technology (includes coal and nuclear) accounts for approximately 62 percent of the net operable capacity in 2007. This is down slightly from the 65 percent reported last year. Generation with coal and nuclear fuels continues to dominate the region's fuel mix, accounting for roughly 54 percent of net operable capacity in 2007. Units fueled by gas or with dual gas/oil capabilities account for 26 percent.

The majority of planned capacity additions are gas/oil fueled, combustion turbine or combined-cycle units. However, the ten-year planning horizon has plans for coal-fired and nuclear plant additions.

Some examples are:

- TVA subregion: Browns Ferry (nuclear) unit 1 — 1,250 MW in 2007
- VACAR subregion: Cross (coal) unit 3 — 650 MW in 2007; Cross (coal) unit 4 — 650 MW in 2009; 2,320 MW merchant nuclear plant for interconnection in 2015
- Gateway subregion: Prairie State (merchant coal) plant — 1,650 MW in 2008
- Southern subregion: 1,200 MW merchant coal plant for interconnection in 2010

Of the approximately 37,000 MW of net planned capacity additions reported for the 2006–2015 time period, 5 percent are combined-cycle, 21 percent are combustion turbine, 11 percent are steam, and 40 percent are categorized as "Other/Unknown." The "Other/Unknown" category includes projected additions that do not have finalized implementation plans. The largest change from last year is a net increase in the steam category from 0 percent to 11 percent. It appears that members are increasingly planning for future coal or nuclear base load generation instead of relying on natural gas or purchases.

Generation Development in SERC

Significant merchant generation development has occurred in SERC since 1998, especially in the Southern and Entergy subregions. Most of this merchant generation was intended for sale in the wholesale markets. However, much of this merchant generation has not been contracted to serve load within SERC and its deliverability is not assured. For these reasons, only merchant generation contracted to serve SERC load is included in the SERC reported capacity margins.

To understand the extent of generation development in the region, it is instructive to examine how much generation is connected or has requested connection to the transmission system. A summary of aggregate generation interconnection requests is shown in Table 2 below. This table includes both utility and merchant generating plants. Requests reported as "signed/filed" are assumed to have a somewhat higher probability of being built than those listed as "requested only."

Table 2: Current Status of Generation Plant Development in SERC

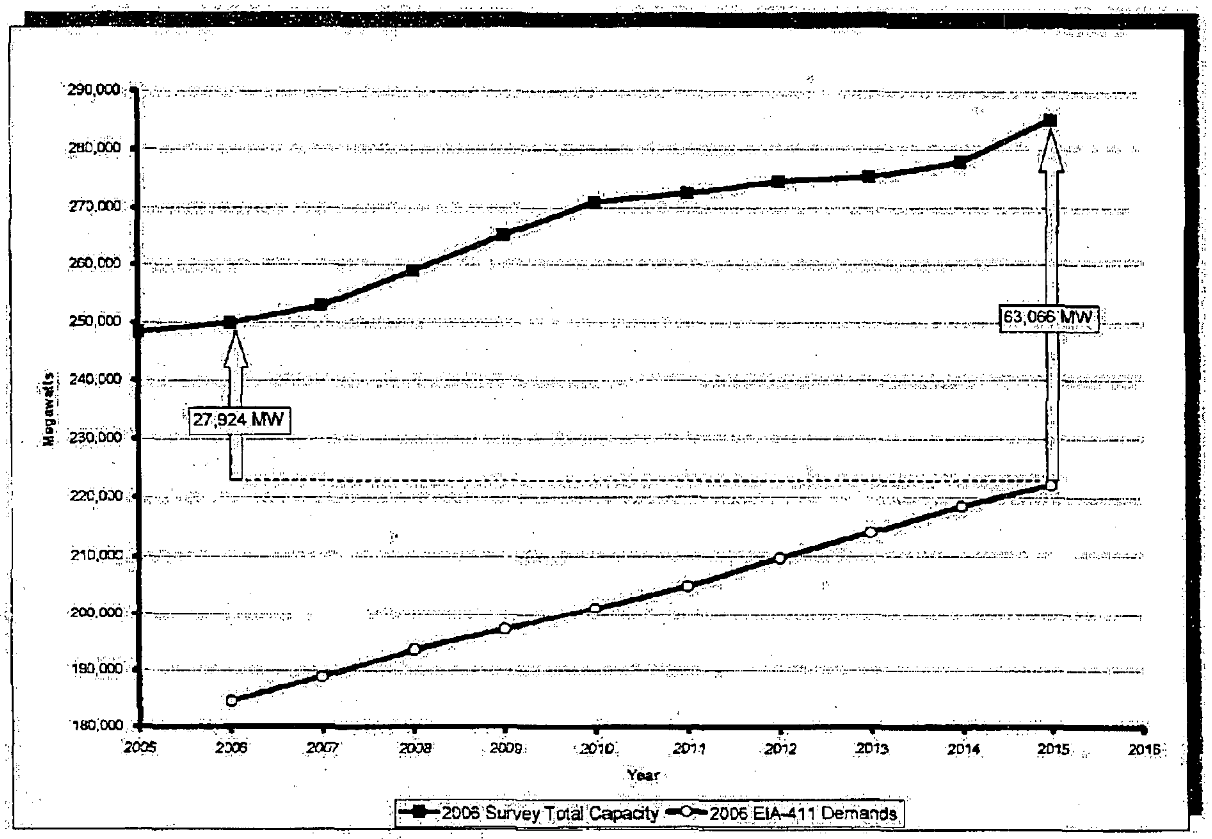
Current Status of Generation Plant Development	In-Service Year of Added Generation (MW)										
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Total
1) Interconnection Service Requested, Only	45	1437	4687	4207	1759	114	1137	784	1899	7148	23217
> Designated as Network Resource or has obtained Firm PTP Transmission service	45	713	736	2141	1684	74	1022	744	1824	4147	13130
> Uncommitted	0	724	3951	2066	75	40	115	40	75	3001	10087
2) Interconnection Agreement Signed/Filed	1579	1615	1435	1972	4157	1735	895	0	660	85	14133
> Designated as Network Resource or has obtained Firm PTP Transmission service	199	839	885	733	2182	985	895	0	660	85	7463
> Uncommitted	1380	776	550	1239	1975	750	0	0	0	0	6670
3) Unit Retirements	7	90	88	0	108	298	0	0	0	0	591
Net Projected Additions	**1617**	**2962**	**6034**	**6179**	**5808**	**1551**	**2032**	**784**	**2559**	**7233**	**36759**

*Source — SERC Reliability Review Subcommittee 2006 report to the SERC Engineering Committee

The survey indicates that an additional 1,617 MW of generation plant capacity is expected in the SERC region for the 2006 summer, the vast majority of which have signed or filed interconnection agreements by the time of the survey. In the near-term planning horizon, significant speculation exists about the amount of generation that will be added (approximately 6,000 MW for 2008 and 2009 of which over 4,000 MW fall in category 1), but the amount to actually be constructed will likely change before the next annual survey. The reported generation development decreases sharply beyond 2010 as plans for the longer term have not been finalized. The majority of generation development was reported for the first six years and totals 24,100 MW. This compares favorably to the 21,000 MW reported to be operable in the first six years of last year's survey. The amount of the reported planned capacity that will actually be built is highly dependent on factors such as market prices, fuel availability, the ability to arrange suitable interconnection and transmission access agreements, the number of other generation plants that are being constructed, the ability to permit and complete necessary transmission line additions in a reasonable amount of time, the ability of the company to obtain financial backing, and other typical business factors.

As of December 31, 2005, SERC's generation development survey indicated that the total generation connected to the transmission systems in SERC was 248,390 MW. An additional 1,617 MW of generation was planned to be connected to the transmission systems by July 1, 2006, bringing the total to just over 250,000 MW. These values differ slightly from the EIA-411 data due to inoperable capacity and mothballed units. The current total generation connected to the SERC systems exceeds projections for SERC regional load in the year 2015 by over 27,000 MW. If all of the proposed capacity described in Table 2 above is built, installed generation could exceed forecast peak demand by more than 63,000 MW in 2015. This is significantly more than the generation capability needed for reliability/adequacy in the region.

Figure 37: Proposed Generation Development in SERC



*Source — SERC Reliability Review Subcommittee 2006 Generation Development Survey

Fuel

According to assessments completed by SERC members, adequate fuel supplies are expected. Sufficient inventories (including access to salt-dome natural gas storage), fuel-switching capabilities, alternate fuel delivery routes and suppliers, and emergency fuel delivery contracts are some of the important measures used by SERC members to reduce reliability risks due to fuel supply issues. SERC entities with large amounts of gas-fired generation connected to their systems have conducted electric-gas interdependency studies. Dual-fuel units are tested to ensure their availability, and that backup fuel supplies are adequately maintained and positioned for immediate availability. Some generating units have made provisions to switch between two different natural gas pipeline systems, reducing the dependence on any single interstate pipeline system. Moreover, the diversity of generating resources serving SERC member loads further reduces the region's risk.

Current projections indicate that the fuel supply infrastructure for the near-term planning horizon is adequate, even considering possible impacts due to weather extremes. Mild winter temperatures experienced in 2005/2006 should result in a stronger gas storage position, which would reduce demand for storage injections. Additionally, new international liquefied natural gas supplies are expected to become available to the United States market during the 2006–2008 time frame.

Active hurricane seasons could periodically curtail Gulf of Mexico fuel production and delivery. Although fuel deliverability problems are possible for limited periods of time due to hurricanes or other weather extremes such as flooding, assessments indicate that this should not have a negative impact on reliability. The immediate impact will likely be economic as some production is shifted to other fuels.

Secondary impacts could involve changes in emission levels and increased deliveries from alternate fuel suppliers.

Fuel supply will always be a critical part of the power supply chain, regardless of fuel choice. SERC utilities have been able to maintain fuel diversity in their portfolios, enhancing reliability. Looking forward, SERC is following these issues to ensure reliability is maintained into the longer-term planning horizon:

- Protecting the nation's natural gas production and transportation facilities in the Gulf Coast areas
- Monitoring the development of LNG facilities in both the U.S. and in natural gas producing countries
- Monitoring the next wave of new generation additions over the next 15 years
- Ensuring that the coal delivery infrastructure keeps pace with the forecasted increase in construction of coal generation facilities
- Ensuring that fuel inventories continue to be managed appropriately to mitigate the effects of natural disasters and others causes of disruptions to fuel supplies

Transmission

The existing bulk transmission system within SERC is comprised of 17,067 miles of 161-kV, 20,028 miles of 230-kV, 2,651 miles of 345-kV, and 8,500 miles of 500-kV transmission lines. SERC member systems continue to plan for a reliable bulk power system and plan to add 387 miles of 161-kV, 1,624 miles of 230-kV, 270 miles of 345-kV, and 345 miles of 500-kV transmission lines in the 2006–2015 time period. SERC members invested over $1.25 billion in new transmission lines and system upgrades in 2005, and are planning transmission capital expenditures of more than $6.75 billion over the next five years. To allow the uncommitted generation to become committed generation, some additional transmission investment could be required.

SERC member transmission systems are directly interconnected with the transmission systems in FRCC, MRO, RFC, and SPP. Transmission studies are coordinated through joint interregional reliability study groups. The results of individual system, regional, and interregional studies are used to demonstrate that the SERC transmission systems meet NERC and SERC reliability standards. The transmission systems in SERC are expected to have adequate delivery capacity to support forecast demand and energy requirements and firm transmission service commitments during normal system conditions and NERC Reliability Standard TPL-002 type contingency conditions.

Operations

Coordinated interregional transmission reliability and transfer capability studies for the shorter-term planning horizon were conducted among all the SERC subregions and with the neighboring regions. In addition, coordinated intraregional transmission reliability and transfer capability studies for the longer-term planning horizon were conducted within SERC. These studies indicate that the bulk power systems within SERC and between adjoining regions can be expected to provide adequate and reliable service over a range of system operating conditions.

No major generating unit outages or transmission facility outages which would impact system reliability are planned for peak periods. Environmental restrictions are not anticipated to significantly impact operations.

Assessment Process

Although SERC members plan for facility (transmission and generation) additions on an individual basis, SERC performs many assessment functions at the regional level in order to provide coordination and ensure reliability.

An extensive data collection effort is required as part of the reliability assessment effort performed by SERC. Data collection is accomplished through a staff-facilitated Data Collection Task Force consisting of representatives from each reporting entity in SERC. SERC's relational database (Portal) is utilized extensively as the mechanism, via surveys and compliance and data forms, for gathering and compiling data. The collection of data for the EIA-411 has historically been a part of these reliability assessment activities as well.

In 2006 SERC consolidated a number of regional studies activities under the direction of the SERC Engineering Committee. These regional studies groups are responsible for the development of models and associated studies to ensure that planning activities in SERC are coordinated.

SERC utilizes its staff-facilitated Reliability Review Subcommittee (RRS) to perform assessments of future reliability and adequacy of the region and to prepare reports. Using information from the region's data collection efforts, the RRS makes an independent assessment of the ability of the region and subregions to serve their obligations given the demand growth projections, the amount of uncommitted or contracted capacity, etc. The RRS determines if the resource information submitted represents a reasonable and attainable plan. Also, the RRS annually performs a transmission assessment based on regional, interregional, and subregional reliability studies. The studies are reviewed and analyzed. If any additional study(ies) are required, the RRS will request the appropriate regional studies group(s) to perform the study(ies). The RRS's assessment provides a judgment on the ability of the SERC power system to operate securely under the expected range of operating conditions over the assessment period as required by the NERC Reliability Standards. The SERC *Supplement on Reliability Assessments* outlines SERC's interpretation and clarifies SERC's expectations of members with regard to the NERC Standards on Regional and Interregional Self-Assessment Reliability Reports, TPL-005 through 006. (http://www.serc1.org/Pages/ComplianceContentPage.aspx?ID=25).

Entergy

Demand — The 2006 summer net internal demand forecast for the Entergy subregion was 27,114 MW and the forecast for 2015 is 32,151 MW. The average annual growth rate over the next ten years is 1.9 percent. This is higher than last year's forecast growth rate of 1.4 percent. The historical growth rate has averaged 1.8 percent.

Energy — The 2006 annual electric energy usage forecast for the Entergy subregion was 145,013 GWh and the forecast for 2015 is 167,243 GWh. The forecast growth rate in energy usage is 1.6 percent. The historical growth rate for the last ten years is 1.2 percent.

Resources — Projected capacity margin was 21.1 percent for the 2006 summer, and declines to 5.8 percent in 2015. Capacity, in addition to that currently planned, will be needed to maintain reliability. Large amounts of uncommitted generation in the subregion could provide the needed capacity and time is adequate to build new capacity if necessary. For example, in the past year the Perryville and Attala plants were added as network resources for the Entergy operating companies with plant capacities of 718 MW and 463 MW, respectively.

Transmission — Planned transmission additions include 284 miles of 230-kV lines, 105 miles of 345-kV lines, and 30 miles of 500-kV lines.

Operations — Entergy continues to monitor load growth in the cities surrounding the areas affected by hurricanes Katrina and Rita. No reliability concerns are anticipated as a result of the load redistribution. Several substations continue to operate in a functionally and capacity limited state in the impacted zone. In addition, four substations and four transmission lines remain out of service within the same area. Entergy assessments indicate that these out-of-service facilities will not impact regional or local reliability for the coming season. These system elements will be restored as local system requirements dictate. All transmission substations and lines damaged by hurricane Rita in east Texas and southwest Louisiana have been restored.

The domestic natural gas and oil industries are still in a recovery in the aftermath of hurricanes Katrina and Rita. Most major production, processing, and transportation facilities are returning to service, but may still operate at less-than-normal capability in the near term due to limited production facilities in the Gulf of Mexico. Future weather extremes such as tropical disturbances may again affect fuel supply infrastructure or cause fuel delivery problems. However, Entergy will take steps such as managing fuel inventories to mitigate the impact of those types of events.

As a result of the recent hurricane restoration efforts, Entergy identified key success factors to minimize widespread and prolonged power outages in future storms. These include detailed advance planning for "worst case" scenarios, practice-through drills and other means, constantly improving infrastructure, and organization experience and culture. Entergy has determined that a clear command structure, assignment of decision-making at the appropriate level, and an ability to take action in a timely manner play a critical role minimizing power outage duration. High-level support and confidence in the process along with mutual assistance programs are key factors in restoration success.

Gateway

Demand — The 2006 summer net internal demand forecast for the Gateway subregion was 17,611 MW and the forecast for 2015 is 19,606 MW. The average annual growth rate over the next ten years is 1.2 percent. The historical growth rate has averaged 1.3 percent.

Energy — The 2006 annual electric energy usage forecast for the Gateway subregion was 80,220 GWh and the forecast for 2015 is 88,818 GWh. The forecast growth rate in energy usage is 1.1 percent. Energy consumption for 2006 was forecast to be 1.5 percent more than the 2005 actual consumption of 79,028.

Resources — Projected capacity margin was 31.3 percent for the 2006 summer, and remains above 31 percent over the remainder of the planning period.

Transmission — Planned transmission additions include 111 miles of 345-kV lines.

Planned reinforcements in the Jefferson City, Missouri, area are scheduled for completion in 2008 which would increase transfer capability from SERC (Gateway) to SPP.

Operations — The startup of the Midwest ISO energy market on April 1, 2005 created a marked change in dispatch across the Midwest ISO footprint. The Midwest ISO security constrained economic dispatch allows the market to prevent some TLRs prior to escalation of flows. The seams agreements that have recently been initiated with PJM and SPP should further reduce the need to call for TLR because of increased coordination. This and the new auction in the fall of 2006 to supply Illinois retail electric load customers in 2007 are new items for Gateway members and the Midwest ISO to manage.

Southern

Demand — The 2006 summer net internal demand forecast for the Southern subregion was 47,718 MW and the forecast for 2015 is 59,614 MW. The average annual growth rate over the next ten years is 2.5 percent. This is the same as last year's forecast growth rate. The historical growth rate has averaged 2.4 percent.

Energy — The 2006 annual electric energy usage forecast for the Southern subregion was 243,713 GWh and the forecast for 2015 is 299,072 GWh. The forecast growth rate in energy usage is 2.3 percent. The historical growth rate for the last ten years is 2.8 percent.

Resources — Projected capacity margin was 14.7 percent for the 2006 summer, and ranges from 11.4 percent to 14.6 percent over the remainder of the planning period.

Transmission — Planned transmission additions include 693 miles of 230-kV lines and 170 miles of 500-kV lines.

Operations — Southern subregion companies are currently assessing and making adjustments to hurricane restoration manuals from lessons learned during the 2005 hurricane season, particularly regarding the Katrina restoration.

Transmission system stability studies, which have been posted on OASIS, have found four potential stability challenged areas within the Southern subregion. Two of these areas were found during interconnection studies for which the generators requesting interconnection ultimately were not built. Therefore, stability is not currently an issue in these two areas for the amount of generation located in the area now, and for the amount proposed in the foreseeable future. A third area has enough generation still being considered for interconnection that, along with the generation already in service, could create a potential stability concern that must be carefully studied. It may become an operating issue in the future. The fourth area, the southwest quadrant, has substantial generation on the ground which requires that the area must be carefully monitored for stability, especially at lighter system load levels. Management of this stability challenged area is accomplished in real-time operations by monitoring a stability proxy flowgate. System operators monitor flows on the transmission lines which form the boundary of the quadrant. A table of limits for the proxy flowgate, considering specific lines out of service and/or units with PSS out of service, is used to cover all scenarios. Southern Company has also recently implemented online stability tools for system operations.

TVA

Demand — The 2006 summer net internal demand forecast for the TVA subregion was 32,677 MW and the forecast for 2015 is 39,888 MW. The average annual growth rate over the next ten years is 2.2 percent. This is slightly lower than last year's forecast growth rate of 2.3 percent. The historical growth rate has averaged 1.7 percent (excluding new members).

Energy — The 2006 annual electric energy usage forecast for the TVA subregion was 193,392 GWh and the forecast for 2015 is 216,410 GWh. The forecast growth rate in energy usage is 1.3 percent. The historical growth rate for the last ten years is 2.9 percent, which is higher than forecast due to the inclusion of two new members into the subregion in the past year.

Resources — Projected capacity margin was 11.4 percent for the 2006 summer, and ranges from 10.8 percent–12.5 percent over the remainder of the planning period.

Transmission — Planned transmission additions include 54 miles of 345-kV lines and 40 miles of 500-kV lines.

During periods of significant north-south transfers, certain facilities in the subregion experience high loading. Transmission system additions are scheduled for completion by the summer of 2007 that will greatly reduce the loading on the limiting facilities.

Operations — The TVA power system has experienced large and volatile flows in recent years and these flows may continue to occur. The 500-kV corridor in upper east Tennessee continues to experience congestion due to west-to-east and south-to-north transfer patterns. Additionally, the 500-kV corridor from western Kentucky to middle Tennessee can experience congestion during high west-to-east and north-to-south transfers. Operating guides have been developed to address these constraints.

VACAR

Demand — The 2006 summer net internal demand forecast for the VACAR subregion was 59,447 MW and the forecast for 2015 is 70,824 MW. The average annual growth rate over the next ten years is 2.0 percent. This is the same as last year's forecast growth rate. The historical growth rate has averaged 2.5 percent.

Energy — The 2006 annual electric energy usage forecast for the VACAR subregion was 310,877 GWh and the forecast for 2015 is 362,667 GWh. The forecast growth rate in energy usage is 1.7 percent. The historical growth rate for the last ten years is 1.9 percent.

Resources — Projected capacity margin was 13.1 percent for the 2006 summer, and ranges from 11.9 percent–13.0 percent over the remainder of the planning period.

Transmission — Planned transmission additions include 647 miles of 230-kV lines and 105 miles of 500-kV lines.

Completion of American Electric Power's (AEP) Wyoming to Jacksons Ferry 765-kV line during the summer of 2006 which will relieve congestion between RFC and VACAR.

Operations — Heavy loading internal to the VACAR subregion could be experienced on several facilities. Studies have shown that generation internal to VACAR can be redispatched to relieve the loading on these internal lines, if necessary.

Also, several improvements to VACAR facilities have been completed or are planned. Transmission improvements intended to reinforce delivery of power are expected to be completed in the fall of 2006. Projects have been completed to provide stronger networking of the 115-kV system in Dominion Virginia Power's northwest area.

The SERC region includes portions of 16 states (Alabama, Georgia, Mississippi, Missouri, North Carolina, South Carolina, Tennessee, Arkansas, Louisiana, Florida, Oklahoma, Illinois, Texas, Iowa, Virginia, and Kentucky) in the southeastern and central United States, covers an area of approximately 560,000 square miles, and serves almost 40 million customers. SERC is divided geographically into five diverse subregions that are identified as Entergy, Gateway, Southern, TVA, and VACAR. SERC and its five subregions are all summer peaking. Currently totaling in excess of 50, SERC membership is comprised of investor-owned, municipal, cooperative, state and federal systems, RTOs/ISOs, merchant electricity generators, and power marketers. Additional information can be found on the SERC Web site (www.serc1.org).

SERC Capacity and Demand

Figure 38: SERC Net Energy for Load

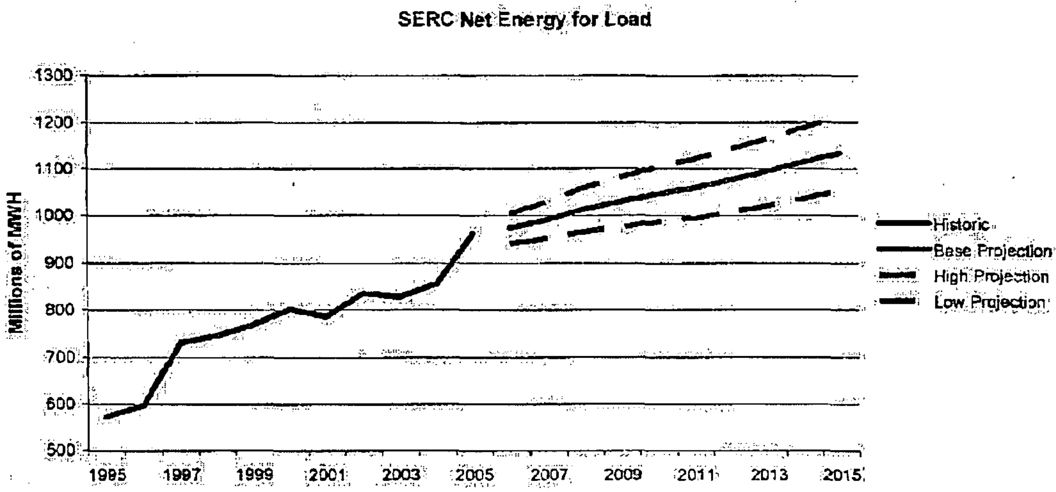


Figure 39: SERC Capacity Margins — Summer

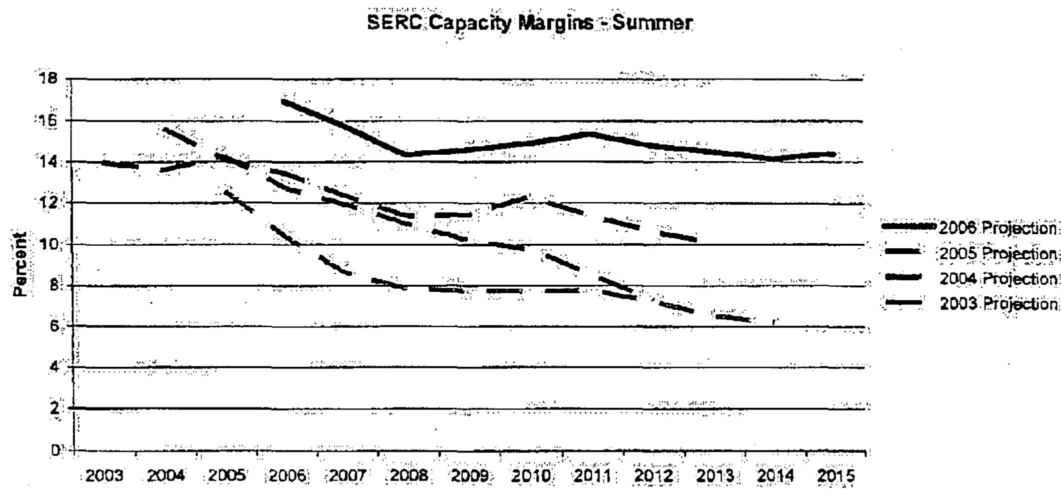


Figure 40: SERC Capacity Versus Demand — Summer

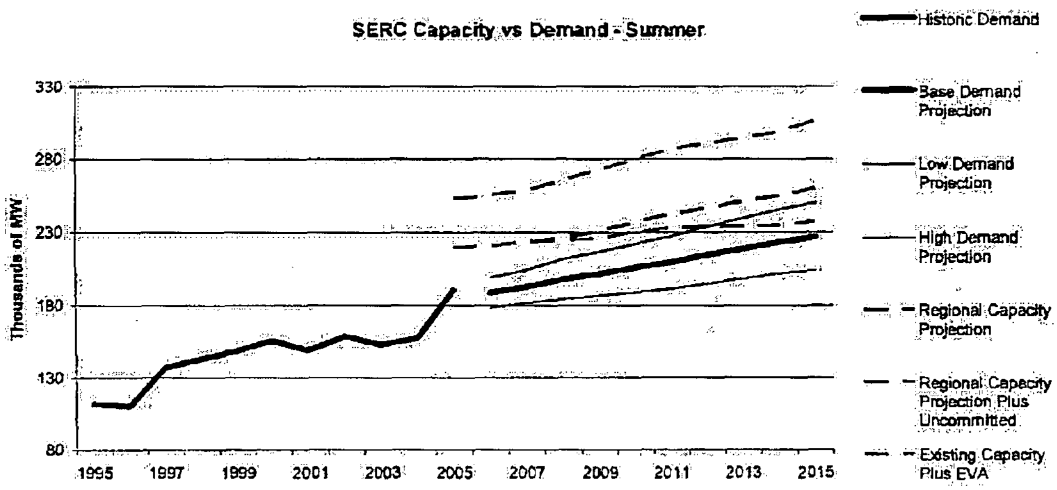
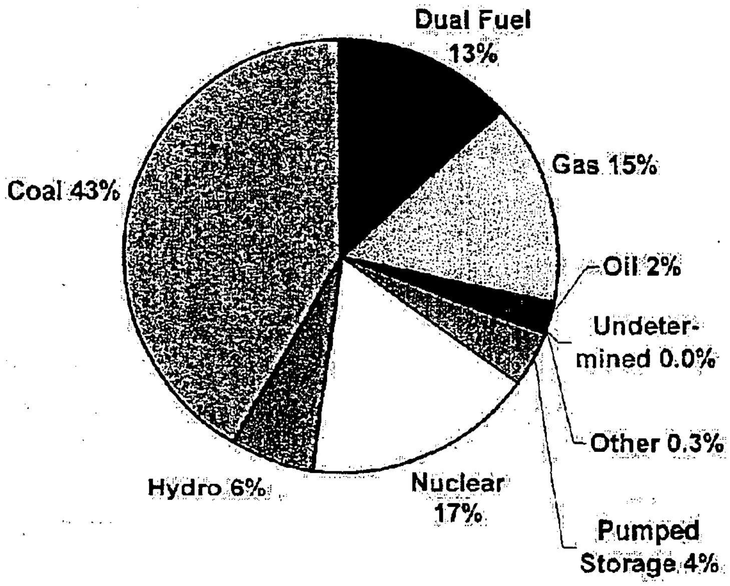
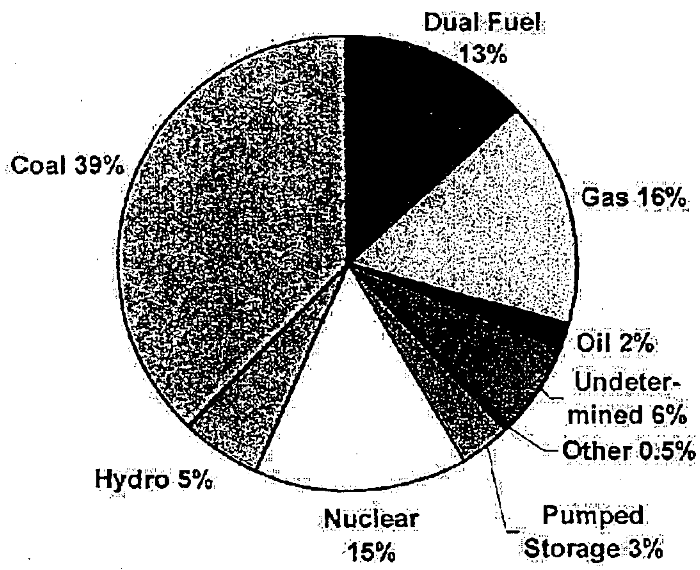


Figure 41: SERC Capacity Fuel Mix for 2005 and 2011

SERC Capacity Fuel Mix 2005



SERC Capacity Fuel Mix 2011



SPP

Demand

SPP is a summer-peaking region with a projected annual peak demand growth rate of 1.3 percent over the 2006–2015 period. This compares to last year's ten-year forecast of 1.3 percent for the 2005–2014 time frame. The forecasted growth rate is comparable to actual experience based on recent history. Although actual demand is very dependent upon weather conditions and typically includes interruptible loads, forecasted net internal demands are based on normal weather conditions and do not include interruptible loads.

Each SPP member annually provides a ten-year forecast of peak demand and net energy requirements. The forecasts are developed in accordance with generally recognized methodologies and also in accordance with the following principles:

- Each member selects its own demand forecasting methodology and establishes its own forecast.
- Each member forecasts demand based on expected weather conditions.
- Methods used, factors considered, and assumptions made are submitted along with the annual forecast to SPP.
- Economic, technological, sociological, demographic, and any other significant factors are considered when producing the forecast.

The resultant SPP forecast is the total of the member forecasts. High- and low-growth rates and unusual weather scenario bands are then produced for the SPP regional and subregional demand and energy forecasts. Peak demand would be increased by 2.9 percent in the case of extreme weather. To ensure against negative impacts due to forecast error, SPP requires a 12 percent capacity margin.

Energy

The projected annual energy growth rates is 1.3 percent per year for the 2006–2015 period. This compares to last year's ten-year forecast of 1.5 percent for the 2005–2014 time frame.

Resources

The net aggregate capacity reported by SPP members is 47,236 MW for the summer of 2007 with a mix of 38 percent coal, 36 percent gas, 8 percent dual fuel, 7 percent hydro, 4 percent nuclear, 2 percent oil, and 5 percent other.

SPP criteria requires that members maintain a 12 percent capacity margin. Expected capacity margins reflected in EIA-411 data are 16.9 percent in 2007, 17.0 percent in 2008, and 15.1 percent in 2009. The capacity margin ten-year forecast is 15.2 percent. This compares to last year's ten-year forecast of 13.6 percent. The capacity margins remain above 12 percent until 2015 when it drops to 11.1 percent. These numbers correspond closely with the ten-year average capacity margins reported last year.

Based on SPP's transactions database that may consist of firm and nonfirm data, a total of 1,550 MW of long-term sales to other regions is planned for the next ten years. This breaks down into 60 MW to ERCOT, 400 MW to WECC, 1,000 MW to SERC, and 100 MW to RFC.

A very small portion of the capacity margin depends on the purchases from other regions. A total of 1,630 MW of total purchases from other regions is planned for the next ten years. This breaks down into 220 MW from ERCOT, 1,160 MW from SERC, and 250 MW from MRO.

The capacity reported for SPP based on the EIA-411 information does not reflect 7,652 MW of merchant plants that are located in the SPP footprint. It is important to note that some of these uncommitted resources may not be deliverable to reliably serve customer demand. Additionally, SPP expects around 10,000 MW of nameplate capacity from new merchant generation over the next ten years. The majority of these future additions are wind farms that can only be expected to contribute between zero and 20 percent of nameplate rating during summer peak load conditions.

Fuel

Fuel supply for SPP generating units is expected to be adequate. The SPP region is blanketed with major gas pipelines, which should provide adequate supply for gas-fired plants. Coal-fired plants are expected to have an adequate fuel supply in compliance with SPP criteria requiring sufficient quantities of standby fuel. SPP hydro reservoirs are anticipated to be abundant, although the energy output from hydro is not projected to have regional impact given that only 7 percent of SPP capacity is hydro based.

Transmission

SPP held its 2006 Regional Transmission Expansion Planning Summit in Kansas City, Missouri, on May 18th with over 120 participants. SPP's planning process was recently shortened to a 12-month cycle with an initial reliability assessment to be followed with a commercial/economic based assessment. SPP staff presented the results of an analysis that identified locations where the SPP system will require reinforcements for years 2011–2016. SPP solicited feedback and recommendations from all stakeholders.

Key areas of system improvement focus include the north Arkansas, Missouri area where transmission improvements are needed as a result of rapid load growth such as in the northwest Arkansas/Fayetteville area. West Oklahoma and north Texas is another focus area of unexpected load growth due to recent increase in the gas and oil prices.

Currently, SPP members are investing approximately $250 million in transmission expansion projects, which will be completed in 2006–2007. Several significant EHV transmission expansion projects are expected in SPP in the near future. In addition to reliability projects, SPP members are sponsoring system upgrades to mitigate congestion and improve economic efficiencies. The most recent nonreliability-based system upgrades to the SPP network include:

- LaCygne-West Gardner 345-kV line — reconductored April, 2006
- Redbud-Arcadia 345-kV lines — replaced three 345-kV circuit breakers and ten 345-kV switches at the Arcadia substation in May, 2006

Planned transmission upgrades of regional significance addressing system load growth and capacity needs include the following:

- McDowell 230/115-kV transformer, fall 2006
- Tulsa area 345-kV and 138-kV expansion projects, summer 2007
- Seven Rivers-Pecos-Potash Junction 230-kV line and Pecos 230/115-kV transformer, spring 2008
- Paola 345/161-kV transformer, summer 2008
- Lubbock South 230/115-kV transformer, summer 2009
- Nichols 230/115-kV transformer, winter 2010
- Northwest Arkansas 345-kV and 161-kV expansion in 2007 and 2010
- East Centerton 345/161-kV transformer, summer 2011
- Auburn 230/115-kV transformer, summer 2012

A comprehensive reliability assessment for the 2006 SPP RTO expansion plan is well under way. The 2006 SPP Expansion Planning Summit was an important step to get the stakeholders involved in the expansion planning process. The next step is for SPP to analyze plans submitted by stakeholders and SPP staff to determine the recommended reinforcements for the SPP expansion plan. Once the feedback has been incorporated, the report will be sent to the SPP Board of Directors for approval.

Several other special studies are being conducted, including:

- Ozark Study (N.W. Arkansas, SW Missouri)
- Kansas Security Constrained Unit Commitment Study
- Texas/Oklahoma Study (Panhandle area)
- NE Texas/N.W. Louisiana Study
- SPP/ERCOT (W. Texas)
- Acadiana Study (S. Louisiana)
- Entergy Louisiana Study

SPP continues to assess the general reliability of the transmission network for the 1–5 year time frames in accordance with applicable NERC planning standards. SPP members will identify transmission plan to address their reliability needs out to the five-year study horizon.

Operations

SPP has operated a reliability coordination center since 1997. The reliability coordination center provides the exchange of near real-time operating information and around-the-clock reliability coordination. Currently, no major generator unit or transmission outages affecting reliability in an adverse manner are anticipated over the next ten years for SPP.

Even though no operational issues are anticipated, SPP is reviewing regional operating practices and the influence they might have on long-term regional system reliability improvements. Additionally, SPP recently completed a scheduled five-year review of the underfrequency load shed program anticipating a renewal of its defined load shed response as regional criteria.

SPP has experienced TLR curtailments on its transmission facilities in recent years and expects that this will continue in the future. Although SPP has adequate transmission to reliably serve native load, it expects heavy use of the transmission system for economy transactions to continue into the future.

SPP operates an automatic reserve sharing program as a sub-function of the regional operating reserve criteria. Requirements in which regional participation ensures necessary capacity reserves are available on a daily basis for unexpected loss of generation. The automatic reserve sharing program meets NERC operating policy.

SPP continues to work with neighboring entities to implement effective seams agreements to facilitate coordinated operations and planning.

No known environmental and/or regulatory restrictions are expected to impede reliability during the summer months.

Assessment Process

The SPP engineering group prepares SPP's submittal to the *NERC Long-Term Reliability Assessment*. The Transmission Working Group (TWG), a committee that is represented by SPP members and other stakeholders is responsible for publication of seasonal and future reliability assessment studies on the transmission system of the SPP region. TWG also provides oversight of coordinated planning efforts and transmission contingency evaluations. The long-range planning models used for the *NERC Long-Term Reliability Assessment* are developed by SPP's Model Development Working Group (MDWG) which is also represented by SPP members.

SPP, a reliability coordinator in the southwest quadrant of the Eastern Interconnection system, currently consists of 46 members, serves more than 4 million customers, and covers a geographic area of 400,000 square miles containing a population of over 18 million people. In covering a wide political, philosophical, and operational spectrum, SPP's current membership consists of 13 investor-owned utilities, seven municipal systems, nine generation and transmission cooperatives, two state authorities and one federal government agency, three independent power producers, and 12 power marketers. SPP is comprised of more than 350 electric industry employees on various organizational groups that bring together industry-wide expertise to deal with tough reliability and equity issues. An administrative and technical staff of approximately 220 facilitates the organization's activities and services. Additional information can be found on the SPP Web site (www.spp.org).

SPP Capacity and Demand

Figure 42: SPP Net Energy for Load

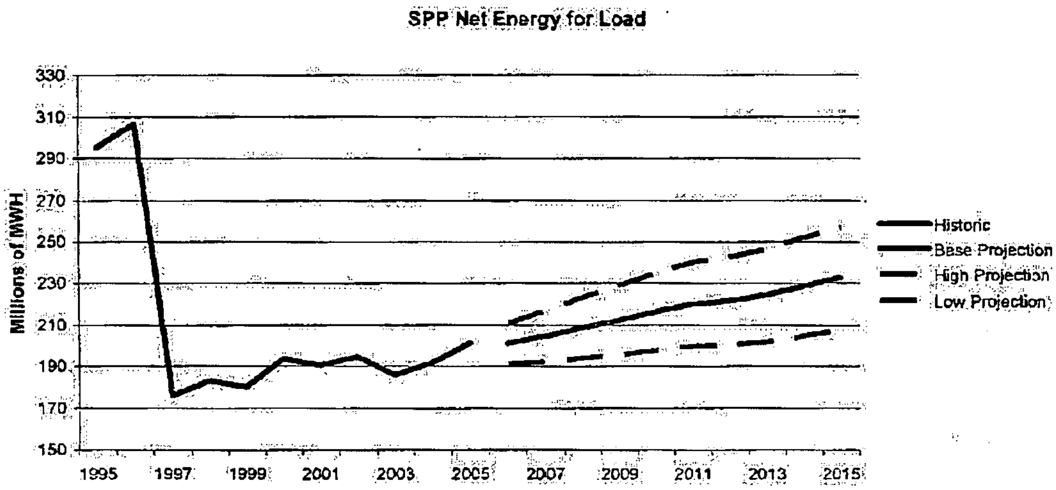


Figure 43: SPP Capacity Margins — Summer

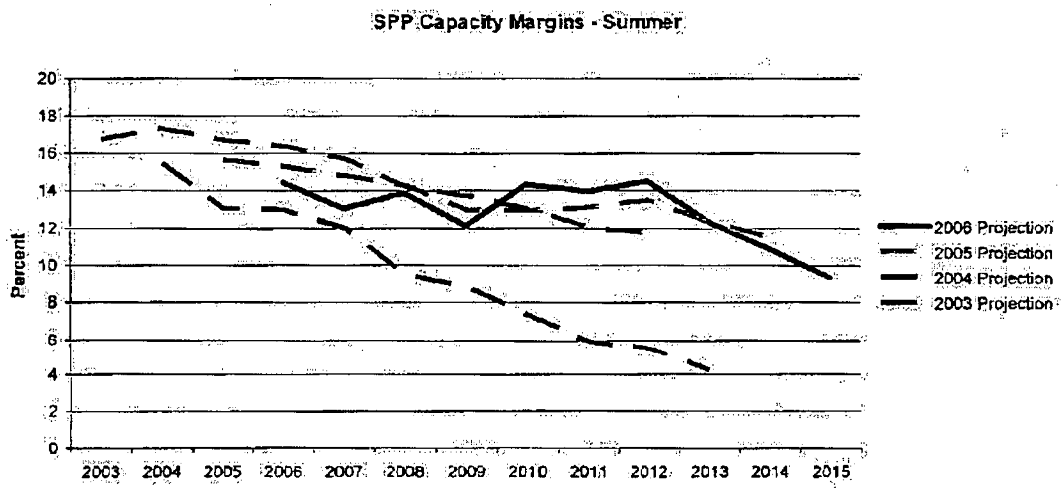


Figure 44: SPP Capacity Versus Demand — Summer

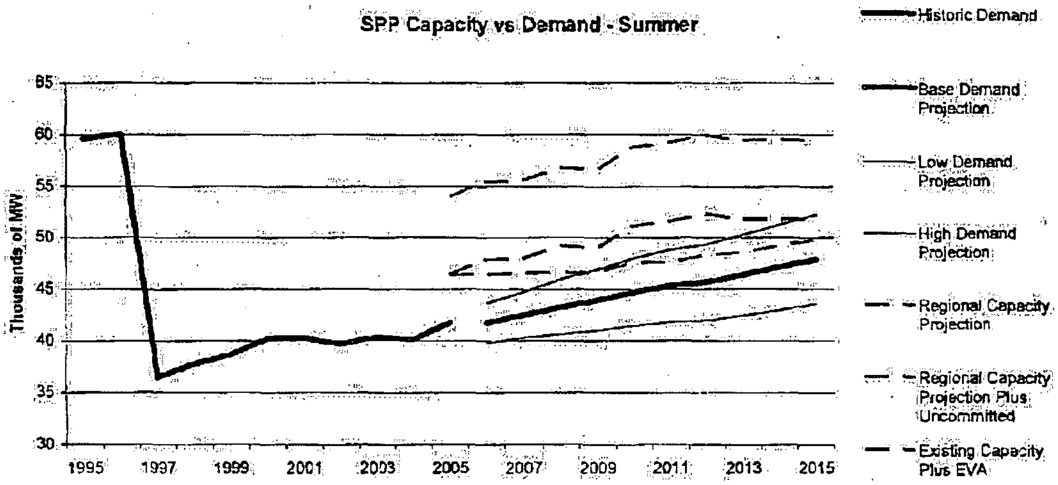
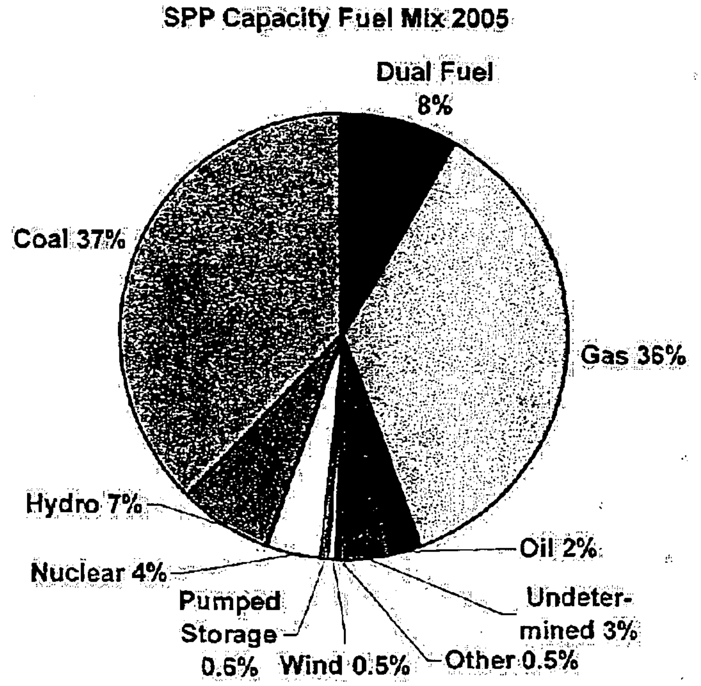
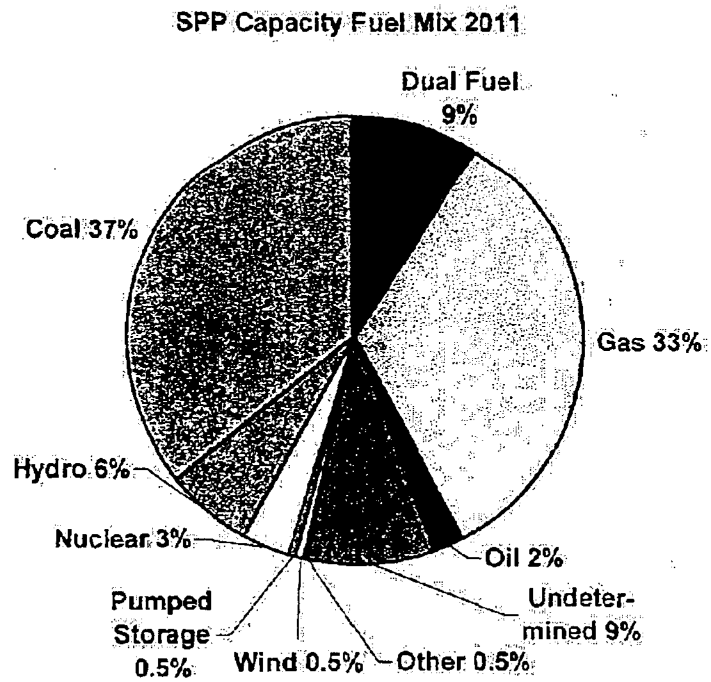


Figure 45: SPP Capacity Fuel Mix for 2005 and 2011





WECC

Demand

Total internal demand increased by 5.7 percent from 2004 to 2005. Since the 2005 summer temperatures were warmer than normal, projected 2006 summer total internal demand is expected to increase by only 0.7 percent from 149,147 MW in 2005 to 150,177 MW in 2006. Thereafter, summer total internal demand is expected to increase by about 2.2 percent per year compared to 2.4 percent projected last year for 2005–2014.

Demand response and interruptible loads are about 3,070 MW, with about 2,060 MW of the 3,070 MW in California. It should be noted that capacity margins are measured against net internal demand, not total internal demand.

WECC's *2006 Power Supply Assessment Report* (PSA) indicates that summer peak demands may increase region-wide by about an additional 2,100 MW above the forecasted peak and about 2,530 MW above the forecasted 2015 peak, should the region experience a hot spell, similar to that experienced on July 9, 1985. For the winter period, a region-wide increase of almost an additional 2,570 MW in 2006–2007 to about an additional 3,030 MW in 2015–2016 may occur should the region experience a cold spell similar to that experienced on December 22, 1998. The above peak demand weather sensitivities are equivalent to roughly one year or less of normal expected demand growth.

WECC has not established an interconnection-wide process for addressing the issue of planning for peak demand uncertainty and variability in demand due to weather and other conditions. Individual entities within the interconnection, however, have addressed multiple uncertainties and variability issues as a part of either their integrated resources plan procedures or other similar processes. Those various independent processes generally report that maintaining a reserve margin in the mid-teens would provide sufficient cushion relative to multiple uncertainties.

Energy

Annual energy usage increased by 1.9 percent from 816,079 GWh in 2004 to 831,570 GWh in 2005. The 2005 energy usage was 1.2 percent lower than the forecast in last year's assessment. Annual energy usage for the ten-year period from 2005 through 2015 was forecasted to increase by 2.0 percent compared to the historic annual energy usage increase of 1.9 percent from 1995 through 2005. Annual energy usage for the nine-year period from 2006 through 2015 is forecast to increase by 2.2 percent.

Resources

WECC has not established an interconnection-wide process for assessing resource adequacy. Individual entities within the interconnection, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process. Entities within the interconnection have not reported changes in generation/resource planning brought about by the Eastern Interconnection blackout.

The WECC resource data is reduced to reflect nonmetered self-generation and expected wind and adverse hydro limitations. The uncommitted resources reflect reported resource additions that are not under construction or are under construction with reported in-service dates after July 2007 (or July 2008 if coal fired).

Other announced generic resource additions and, generally, projects without identified locations and/or in-service dates, are excluded from the committed and uncommitted resource data. The resource data for the individual WECC-U.S. systems subregions include a potential utilization of seasonal demand diversity between the winter-peaking northwest and the summer-peaking southwest. To avoid double counting of resources, the WECC-U.S. systems net capacity resource totals do not include the diversity utilization. Utilization of the seasonal demand diversity may be limited due to factors such as internal transmission constraints.

WECC's PSA reports that by 2009 summer transfer capability limitations between the northern and southern portions of the Western Interconnection result in a 1,000 MW resource shortfall. The southern portion resource needs increase to roughly 20,000 MW by 2015, even though the northern portion is capacity surplus throughout the period. Although the transmission limitations represented in the PSA analysis are conservative, they are not unreasonable and the report establishes that WECC has insufficient transmission to fully utilize seasonal capacity/demand diversity within the Western Interconnection. A 1,600 MW undersea dc cable has been proposed to interconnect a substation near Portland, Oregon, and the San Francisco Bay area. Completion of the 650-mile interconnection would allow additional California imports of low-cost and renewable electricity from the northwest.

The net resource addition of 20,720 MW used in this report is composed of 6,599 MW of plants under construction and 15,938 MW of plants identified but not presently under construction. The regulatory and financial status of these projects is not known at this time. If the 1,817 MW of planned retirements and other derates occur as scheduled and if no plants are built beyond those already under construction, the WECC capacity margin would drop from 19.4 percent in the summer of 2007 to 11.3 percent by the summer of 2011.

In the near term, WECC entities report firm purchases from Eastern Interconnection entities of about 500 MW, partially offset by firm sales of about 200 MW. By the summer of 2015, purchases decline to about 300 MW and sales decline to about 200 MW.

Fuel

WECC has not implemented a formal fuel supply interruption analysis methodology and does not consider such conditions in any formal assessment process. Historically, coal-fired plants have been built at or near their fuel source and generally have long-term fuel contracts with the mine operators, or actually own the mines. Gas-fired plants were historically located near major load centers and relied on relatively abundant western gas supplies. While a few of the older gas-fired generators in the region have backup fuel capability and normally carry an inventory of backup fuel, most of the newer generators are strictly gas-fired plants, increasing the region's exposure to interruptions to that fuel source. This is particularly true for California, which is highly reliant on gas-fired generation and has only three plants that maintain dual-fuel capability.

The natural gas supply system within WECC is fairly robust and the region is not highly dependent on external natural gas supplies. However, the western gas transmission system is interconnected with external transmission systems so gas deliveries can be redirected to other regions. Many individual entities have fuel supply interruption mitigation procedures in place, including on-site coal storage facilities. However, on-site natural gas storage is generally impractical so gas-fired plants rely on the general robustness of the pipeline delivery system and firm supply contracts. WECC does not impose fuel supply requirements on its members.

Transmission

Transmission facilities are planned in accordance with NERC and WECC planning standards. Those standards establish performance levels intended to limit the adverse effects of each transmission system's operation on others and recommend that each system provide sufficient transmission capability to serve its customers, to accommodate planned interarea power transfers, and to meet its transmission obligation to others.

The standards do not require construction of transmission to address intraregional transfer capability constraints. WECC, in conjunction with MRO and SPP, studies intra-area power transfer capabilities. During the study period, entities within WECC plan to add 5,951 miles of transmission lines.

Operations

Under WECC's regional reliability plan, three reliability centers have been established for the region in California, Colorado, and Washington. The reliability coordinators are charged with actively monitoring, on a real-time basis, the interconnected system conditions on a wide-area basis to anticipate and mitigate potential reliability problems and to coordinate system restoration should an outage occur.

The blackout in the Eastern Interconnection has increased awareness regarding ongoing tree trimming programs, and several entities within WECC have reported increased long-range transmission right-of-way clearance work.

WECC operations personnel are progressing on implementing an interconnected system operating condition model.

Significant amounts of thermal generation within WECC are subject to air emission limitations. The limitations may adversely affect operating costs and flexibility but are not expected to reduce margins.

No extended major unit outages or temporary operating measures have been reported that may impact reliability for extended periods over the next ten years. Operational issues are expected to center around issues such as transmission congestion management, hydroelectric energy generation limitations, and integration of renewable resources.

Assessment Process

Each year WECC prepares a transmission study report that provides an ongoing reliability-security assessment of the WECC interconnected system in its existing state and for system configurations planned through the next ten years. The disturbance simulation study results are examined relative to NERC and WECC planning standards. If study results do not meet expected performance levels established in the criteria, the responsible organizations are obligated to provide a written response that specifies how and when they expect to achieve compliance with the criteria. Other measures that have been implemented to reduce the likelihood of widespread system disturbances include: an islanding scheme for loss of the AC Pacific Intertie that separates the Western Interconnection into two islands and drops load in the generation-deficit southern island; a coordinated off-nominal frequency load shedding and restoration plan; measures to maintain voltage stability; a comprehensive generator testing program; enhancements to the processes for conducting system studies; and a reliability management system.

- Operating Transfer Capability Policy Committee Process

  Operating studies are reviewed to ensure that simultaneous transfer limitations of critical transmission paths are identified and managed through nomograms and operating procedures. Four subregional study groups prepare seasonal transfer capability studies for all major paths in a coordinated subregional approach for submission to WECC's Operating Transfer Capability Policy Committee.

On the basis of these ongoing activities, transmission system reliability within the Western Interconnection is expected to meet NERC and WECC standards throughout the ten-year period.

Northwest Power Pool Area

Demand — The Northwest Power Pool (NWPP) area is comprised of all or major portions of the states of Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming; a small portion of northern California; and the Canadian provinces of British Columbia and Alberta. For the period from 2006 through 2015, winter total internal demands are projected to grow at annual compound rates of 1.6 percent and 1.9 percent in the United States and Canadian areas, respectively.

WECC's 2006 PSA indicates that summer peak demands may increase by about an additional 490 MW in 2006 to about 565 MW in 2015 should the region experience a hot spell similar to that experienced on July 9, 1985. For the winter period, an increase of almost an additional 1,940 MW in 2006–2007 to about an additional 2,230 MW in 2015–2016 may occur should the region experience a cold spell similar to that experienced on December 22, 1998.

Energy — Annual energy usage increased by 3.9 percent from 347,313 GWh in 2004 to 360,889 GWh in 2005. The 2005 energy usage was 1.9 percent greater than the forecast in last year's assessment. Annual energy usage for the ten-year period from 2005 through 2015 is forecast to increase by 1.9 percent compared to the historic annual energy usage increase of 1.3 percent from 1995 through 2005. Annual energy requirements are projected to grow at annual compound rates of 1.9 percent and 2.1 percent in the U.S. and Canada areas, respectively.

Resources — The data for the United States portion of the NWPP present winter 2007/2008 capacity margins of 28.4 percent without uncommitted resources and 30.0 percent with uncommitted resources. By winter 2011/2012, those margins change to 23.7 percent and 30.3 percent, respectively. For the Canadian portion of the NWPP, the winter 2007/2008 capacity margins are 7.6 percent without uncommitted resources and 9.4 percent with uncommitted resources. By winter 2011/2012, those margins decline to -1.1 percent without uncommitted resources and 5.1 percent with uncommitted resources. The Canadian entities are aware of the resource adequacy issue for their areas and have instituted very active resource acquisition and transmission reinforcement processes.

NWPP planning is conducted by sub-area. Idaho, northern Nevada, Wyoming, Utah, British Columbia, and Alberta individually optimize their resources to their demand. The coordinated system (Oregon, Washington, and western Montana) coordinates the operation of its hydro resources to serve its demand. In 2001, the northwest experienced its second lowest Coordinated Columbia River System volume runoff since record keeping began, with reservoirs refilling to just 71 percent of capacity, the lowest levels in almost a decade. Since 2001, the reservoir refill has ranged between 87 percent and 92 percent of capacity.

The reservoirs are managed to address all of the competing requirements including but not limited to: current electric power generation, future (winter) electric power generation; flood control; fish and wildlife requirements; special river operations for recreation; irrigation; navigation; and refilling of the reservoirs. In addition to managing the competing requirements, other available generating resources, market conditions, and load requirements are considered and incorporated into the decision for refilling the reservoirs. Any time precipitation levels are below normal, balancing these interests becomes even more difficult. A ten-year agreement was reached in 2000 among parties involved in operation of the Columbia River Basin concerning river operations. However this agreement is subject to three-, five-, and eight-year performance checks and reopening by the parties. The net impact of the agreement is a reduction in generating capability as a result of hydro generation spill policies designed to favor fish migration. The capability reduction, which varies depending on water flows and other factors, is reflected in the margin calculations presented in this report. The agreement includes a provision for negotiating changes in the plan under emergency conditions as occurred in 2001.

Generation in the province of Alberta, Canada, operates in a fully deregulated market and thus resource additions are market driven. Generation additions and load growth are expected to result in some transmission constraints in a number of areas over the course of the review period if identified system reinforcements are not completed on time. The impact of most of these constraints is anticipated to be local in nature and will not impact the transmission systems outside of Alberta.

The subregion has not established a process for assessing resource adequacy. Individual entities within the subregion, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process. Entities within the subregion have not reported changes in generation/resource planning brought about by the Eastern Interconnection blackout.

Fuel — A significant portion of the electric power generated in the Pacific Northwest is derived from hydroelectric generation. Hence, wide variations in annual precipitation, water storage and flow limitations, and other factors significantly affect energy generation from other resources and complicate the fuel planning processes. Coal-fired generation in the area is also very significant. Much of the coal-fired generation has near-fuel sources and is often operated in a base-load mode. Consequently, the area is not highly reliant on gas-fired plants relative to annual energy generation and many of those plants are more often operated as seasonal peaking units. Wind-powered generation is increasing rapidly in the area. Since the wind resources exhibit wide fluctuations in output, areas with relatively large amounts of wind-powered generation are investigating potential interconnection limitations as necessary to minimize adverse consequences that may occur.

Transmission — In view of the longer time required for transmission permitting and construction, it is recognized that network planning should focus on establishing a flexible grid infrastructure. This is being done with the goals of allowing anticipated transfers among NWPP systems, addressing several areas of constraint within Washington, Oregon, Montana, and other areas within the region, and integrating new generation. Projects at various stages of planning and implementation include approximately 986 miles of 500-kV transmission lines.

Maintaining the capability to import power into the Pacific Northwest during infrequent extreme cold weather periods continues to be an important component of transmission grid operation. In order to support maximum import transfer capabilities under double-circuit simultaneous outage conditions, the northwest depends on an automatic underfrequency load shedding scheme.

Approvals for two major system developments have been received from the Alberta provincial regulatory authority. The first of these is for the development of approximately 105 kilometers (65 miles) of 240-kV transmission line to accommodate several new wind generation developments in southwest Alberta. This development has an in-service date of 2007.

The second approval is for the construction of a 500-kV line, approximately 330 kilometers (200 miles) in length, to strengthen the main north-south transmission grid. This development has a proposed in-service date of 2009. In conjunction with this project, approval to install 520 Mvar of capacitor banks in the Calgary area has also been received. The capacitor banks were placed in service at the end of 2005.

A Calgary area transmission must run (TMR) procedure has been updated to address the 240-kV transmission grid-loading issues and to ensure that voltage stability margins are maintained. The TMR service is an ancillary service contract with generators that is required to address contingencies in areas of inadequate transmission to help provide voltage support to the transmission system in southern Alberta, near Calgary, and assist in maintaining overall system security.

Increased local area load has reduced the export capability of the Alberta-Saskatchewan dc tie. A planning study is currently under way to analyze the Empress area and the Alberta-Saskatchewan dc tie.

export capability. The study and recommendations are expected to be completed by December 2006. Applications for additional transmission developments will be filed as required.

The Canadian province of British Columbia relies on hydroelectric generation for 90 percent of its resources. British Columbia Hydro and Power Authority is addressing constraints between remote hydro plants and lower mainland and Vancouver Island load centers. The definition phase of a new 500-kV line between Nicola and Meridian substations and a 230-kV underwater cable between Arnott substation and Vancouver Island terminal is under way.

The new 500-kV line will increase the total transfer capability of the interior to lower mainland area grid and the new 230-kV cable will increase the transfer capability from the lower mainland area to Vancouver Island. These projects have proposed in-service dates of 2013 and 2008, respectively.

Proposed NWPP Projects > 50 Miles	Status	Date
Cordell, AB to Metiskow, AB 240-kV line	Completed	November 2005
Ellensburg, WA to Sunnyside WA 500-kV line	Completed	December 2005
Goose Lake to N. Lethbridge, AB 240-kV line	Permitting	2007
Benewah, ID to Shawnee, WA 230-kV line	Planning	2007
Montana-Alberta 230-kV merchant line	Permitting	2007
American Falls, ID to Hunt, ID 230-kV line	Under way	2007
Vancouver Island-Arnott 230-kV line	Planning	2008
Keephills-Genesee-Ellerslie, AB 500-kV line	Permitting	2009
Genessee, AB to Langdon, AB 500-kV line	Permitting	2009
Cranbrook, BC to Invermere, BC 230-kV line	Planning	2011
Mona, UT to Salt Lake, UT 345-kV line	Planning	2007/2011
Nicola, BC to Meridian, BC 500-kV	Planning	2013
Southwest Intertie project (ID-NV 260 mile tie)	Planning	2013

Operations — Under normal weather conditions, the NWPP does not anticipate dependence on imports from external areas during summer peak demand periods. In the event of either extreme weather or much lower than normal precipitation, the NWPP could increase imports, which would reduce reservoir drafts and aid reservoir filling. Off-peak energy transfers allow southwest generators to increase thermal plant loading during normally light load hours to offset to some extent the effects of any adverse hydro conditions.

WECC's 2006 PSA report notes that transmission constraints exist between the United States and Canadian portions of the NWPP and that by 2015 over 3,000 MW of additional capacity (generation or transmission for imports) will be needed in Canada. Both provinces are addressing the capacity issue. For example, British Columbia recently announced the awarding of a few dozen contracts representing over 1,500 MW of capacity.

Rocky Mountain Power Area

Demand — The Rocky Mountain Power Area (RMPA) consists of Colorado, eastern Wyoming, and portions of western Nebraska and South Dakota. The RMPA may experience its annual peak demand in either the summer or winter season due to variations in weather. For the period from 2006 through 2015, summer total internal demands and annual energy requirements are projected to grow at annual compound rates of 2.4 percent and 2.2 percent, respectively.

WECC's 2006 PSA report indicates that summer peak demands may not increase should the region experience a hot spell similar to that experienced on July 9, 1985. For the winter period, an increase of almost an additional 50 MW in 2006–2007 to about an additional 60 MW in 2015–2016 may occur should the region experience a cold spell similar to that experienced on December 22, 1998.

Energy — Annual energy usage increased by 3.4 percent from 57,214 GWh in 2004 to 59,190 GWh in 2005. The 2005 energy usage was 4.3 percent less than the forecast in last year's assessment. Annual energy usage for the ten-year period from 2005 through 2015 is forecast to increase by 2.1 percent compared to the historic annual energy usage increase of 3.1 percent from 1995 through 2005. Annual energy usage for the nine-year period from 2006 through 2015 is forecast to increase by 2.2 percent.

Resources — The data for the Rocky Mountain Power Area (RMPA) present the summer 2007 capacity margins of 9.8 percent without uncommitted resources and 13.2 percent with uncommitted resources. By the summer of 2011, those margins become -0.8 percent and 15.5 percent, respectively. A significant portion of the expected uncommitted resources has received state utility commission approval and is under active development.

Due to extended drought, hydro generation is at low levels along the North Platte River. The low flows have impacted cooling water availability at a major coal-fired plant, requiring acquisition of groundwater rights as a supplemental water source. Water levels in Lake Powell, which is the reservoir for Glen Canyon dam generation, are expected to end the 2006 water year 70 feet below full. This results in a capacity reduction of about 170 MW (14 percent) due to a lower hydraulic head at the plant.

Tri-State Generation and Transmission Association announced plans in late 2005 to construct two 600 MW coal-fired units at the Holcomb generator site near Garden City, Kansas. Plant in-service dates are slated for a 2012–2013 time frame. Basin Electric Power Cooperative is developing the Dryfork 385 MW coal plant near Gillette, Wyoming, with a 2011 in-service date. Public Service Company of Colorado (PSC) is in the process of a request for proposals (RFP) for new resources to meet its needs through 2010. PSC already has 300 MW of wind generation integrated into its system as of 2006. PSC has received approval to construct a 750 MW coal-fired plant at the existing Comanche station in 2010, and plans on adding 1,600 MW of other resources over the next five years. The RMPA margins referred to above do not include the possible 1,600 MW resource additions.

The subregion has not established a process for assessing resource adequacy. Individual entities within the subregion, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process.

Fuel — Coal, hydro, and gas-fired plants are the dominant electricity sources in the area. Much of the coal is provided by relatively nearby mines and is often procured through long-term contracts. Hydroelectric plants, however, may experience operational limitations due to variations in precipitation. As in the northwest, gas-fired plants are most often operated in a peaking mode. Abundant natural gas supplies exist within the area but delivery constraints may occur at some plants during unexpected severe cold weather conditions.

Transmission — The Western Area Power Administration (WAPA) plans to upgrade several 115-kV transmission lines to 230 kV over the next ten years to increase transfer capabilities and to help maintain the operating transfer capability between southeastern Wyoming and northeastern Colorado. In addition to those conversions, the table below describes additional transmission projects.

Proposed RMPA Projects ≥ 50 Miles	Status	In-service Date
Carr Draw-Hartzog-Teckla, WY 230-kV lines	Completed	November 2005
Walsenburg, CO to Gladstone, NM 230-kV line	Under way	Late 2007
Hughes, WY to Sheridan, WY 230-kV line	Planned	2008
San Luis Valley-Walsenburg, CO 230-kV line	Planned	2009
Upgrades to Path 36 (TOT3) between southeast Wyoming and northeast Colorado	Under way	2009
Comanche-Daniels Park #1 & #2 345-kV lines	Planned	May 2009
Beaver Creek-Erie #2 230 kV	Under way	2010
Holcomb, KS to Front Range, CO 500 kV	Planned	2011

Operations — Transmission upgrades in the area have alleviated some transfer capability limitations, but some system constraints remain. Operator flexibility will be limited by the transmission constraints and operating conditions must be closely monitored, especially during periods of high demand. In some cases, special protection schemes are utilized to preserve system adequacy should multiple outage contingencies occur.

Arizona-New Mexico-Southern Nevada Power Area

Demand — The Arizona-New Mexico-Southern Nevada (AZ-NM-SNV) power area consists of Arizona, most of New Mexico, southern Nevada, the westernmost part of Texas, and a portion of southeastern California. For the period from 2006 through 2015, summer total internal demands and annual energy requirements are projected to grow at annual compound rates of 2.9 percent.

WECC's 2006 PSA report indicates that summer peak demands may increase by about an additional 45 MW in 2006 to about 55 MW in 2015 should the region experience a hot spell similar to that experienced on July 9, 1985. For the winter period, an increase of almost an additional 50 MW in 2006–2007 to about an additional 65 MW in 2015–2016 may occur should the region experience a cold spell similar to that experienced on December 22, 1998.

Energy — Annual energy usage increased by 2.9 percent from 122,940 GWh in 2004 to 126,540 GWh in 2005. The 2005 energy usage was 1.0 percent greater than the forecast in last year's assessment. Annual energy usage for the ten-year period from 2005 through 2015 was forecasted to increase by 2.8 percent compared to the historic annual energy usage increase of 3.7 percent from 1995 through 2005. Annual energy usage from 2006 through 2015 is forecast to increase by 2.9 percent.

Resources — The data for this sub-area present the summer 2007 capacity margins of 19.6 percent without uncommitted resources and 19.8 percent with uncommitted resources. By the summer of 2011, those margins become 8.4 percent and 13.7 percent, respectively. As in the RMPA, a significant portion of the uncommitted resources has received state utility commission approval and is under active development.

As with other areas within WECC, the future adequacy of the generation supply over the next ten years in this area will depend on how much new capacity is actually constructed. Generally, the proposed plants have relatively short construction times once the decision is made to proceed, although an expansion of the Springerville coal-fired plant is under way with one unit under construction and an additional unit scheduled to be in commercial operation by late 2009. Frequently, resource acquisitions are subject to a request for proposal process that may increase the uncertainty regarding plant type, location, etc. These factors combine to make generation adequacy forecasting problematic for an extended period of time.

The subregion has not established a process for assessing resource adequacy. Individual entities within the subregion, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process.

Fuel — Coal, hydro, and nuclear plants are the dominant electricity sources in the area. As in the northwest, gas-fired plants are most often operated in a peaking mode. Much of the coal is provided by relatively nearby mines and is often procured through long-term contracts. Major hydroelectric plants are located at dams with significant storage capability so short-term variations in precipitation are not a significant factor in fuel planning.

Transmission — Transmission providers from the AZ-NM-SNV Power area are actively engaged in the Southwest Transmission Expansion Planning (STEP) group along with stakeholders from southern California. The goal of this group is to participate in the planning, coordination, and implementation of a robust transmission system between the Arizona, southern Nevada, Mexico, and southern California areas that is capable of supporting a competitive, efficient, and seamless west-wide wholesale electricity market while meeting established reliability standards. Three projects have resulted from the study efforts to upgrade the transmission path from Arizona to southern California and southern Nevada. The three projects will increase the transmission path capability by about 3,000 MW. The first set of upgrades will increase the transfer capacity by 505 MW and will be completed in 2006. The second set of upgrades will increase the transfer capacity by 1,245 MW and is scheduled to be completed in 2008. The last set of upgrades is the Palo Verde to Devers #2 500-kV transmission line reported in the California-Mexico power area table.

Proposed AZ/NM/SNV Projects > 50 Miles	Status	In-service Date
Harry Allen, NV to Mead 500-kV line	Under way	2007
Stirling Mt-Northwest-Vista, NV 230-kV line	Planned	2007
Palo Verde-TS5 500-kV line	Permitted	2009
Palo Verde to Southeast Valley (Phoenix area)	3 Parts	2011
A. Hassayampa to Pinal West 500-kV line	Under way	2008
B. Pinal West to Santa Rosa 500-kV line	Under way	2008
C. Santa Rosa to Browning 500-kV line	Permitted	2011
Centennial II (Las Vegas, NV area) 500-kV line	Planning	2011
TS5-Raceway 500-kV line	Planning	2012
Pinal West-Tortolita, AZ 500-kV line	Planning	2012
Palo Verde-North Gila 500-kV line	Planning	2012
Shiprock, NM to Marketplace, NV 500-kV line	Permitted	2010/2013
Northern to central New Mexico 345-kV generation outlet lines	Planning	2013
Greenlee-Springerville, AZ #2 345-kV line	Planning	2014
Tucson, AZ area 345-kV reinforcements	Planning	2014
Nogales, AZ to Sahuarita, AZ 345-kV lines	Planned	2014

Operations — Special protection schemes play an important role in maintaining system adequacy should multiple system outages occur. These schemes include generator tripping in response to specific transmission line outages. In addition, operators rely on procedures such as operating nomograms so that the system can respond adequately to planned and unplanned transmission and/or generation outages.

California-Mexico Power Area

Demand — The California-Mexico power area encompasses most of California and the northern portion of Baja California, Mexico. Summer total internal demands are currently projected to grow at annual compound rates of 1.9 percent and 4.5 percent in the United States and Mexican areas, respectively, from

2006 through 2015. Annual energy requirements are projected to grow at annual compound rates of 1.9 percent and 5.1 percent in the U.S. and Mexican areas, respectively.

WECC's 2006 PSA report indicates that summer peak demands may increase by about an additional 1,565 MW in 2006 to about 1,910 MW in 2015 should the region experience a hot spell similar to that experienced on July 9, 1985. For the winter period, an increase of almost an additional 530 MW in 2006–2007 to about an additional 675 MW in 2015–2016 may occur should the region experience a cold spell similar to that experienced on December 22, 1998.

Energy — Annual energy usage decreased by 1.3 percent from 288,612 GWh in 2004 to 284,951 GWh in 2005. The 2005 energy usage was 5.2 percent less than the forecast in last year's assessment, due to generally mild weather conditions throughout much of the year. Annual energy usage for the ten-year period from 2005 through 2015 was forecasted to increase by 1.8 percent compared to the historic annual energy usage increase of 1.7 percent from 1995 through 2005. Annual energy usage for the nine-year period from 2006 through 2015 is forecast to increase by 2.1 percent.

Resources — The data for the United States portion of the California-Mexico sub-area present summer 2007 capacity margins of 13.5 percent without uncommitted resources and 13.7 percent with uncommitted resources. By summer 2011, those margins become 10.8 percent and 12.6 percent, respectively. For the Mexican portion of the subregion, the summer of 2007 capacity margins are 12.3 percent without uncommitted resources and 15.4 percent with uncommitted resources. By summer 2011, those margins become -4.8 percent and 22.3 percent,respectively. The Mexican uncommitted resources include plans for a 228 MW combined-cycle plant at San Luis Rio, Colorado, with a 2008 expected in-service date.

The summer of 2007 data for the United States portion of the California-Mexico subarea includes 2,534 MW of possible diversity utilization, of total net imports from 7,517 MW, which is below historic summer import levels. By 2011, however, the possible diversity utilization resource component is increased to 5,648 MW with total net imports at 10,445 MW. Beyond about 2011, the possible diversity utilization becomes problematic due to possible resource inadequacies in other subregions and due to possible transmission constraints.

Uncertainty surrounding responsibility to acquire resources in California has raised questions regarding future projections of generating capacity, energy production by generators, and effects of customer energy efficiency and other demand-side management programs. For example, four years ago over 45,000 MW of planned resource additions were reported for the area for the 2002–2011 ten-year period. This year's assessment reports a continued decrease to 3,160 MW for the 2006–2015 period compared to 6,783 MW reported last year for the 2005–2014 period.

The *California Energy Commission's Energy Action Plan II*, dated September 21, 2005, notes that cost effective energy efficiency is the resource of first choice for meeting California's energy needs and presents a key action item that all cost-effective energy efficiency be integrated into utilities' resource plans on an equal basis with supply-side resource options. Should this happen, loads supplied through the bulk power system will not grow as fast as projected in this report.

The state is implementing a mandatory minimum reserves requirement to achieve resource adequacy and is looking to new customer electricity metering equipment as a key component to achieving demand response goals. State entities are working together and with other entities in the Western Interconnection to address transmission planning issues.

The subregion has not established a process for assessing resource adequacy. Individual entities within the subregion, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process.

Fuel — California is highly reliant on gas-fired generation and has very little alternate fuel capability for these plants. California is also highly reliant on natural gas imports so gas supply is of concern to area energy planners, including the California Energy Commission. The Commission's September 21, 2005 *Energy Action Plan II Implementation Roadmap For Energy Policies* identifies eight key actions to address natural gas supply, demand, and infrastructure. The report is available at: http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

Transmission — Since the addition of several generating plants in Arizona, southern Nevada, and Mexico, the bulk power system into southern California has become increasingly congested due to the desire to increase imports from the surrounding areas. Special protection schemes have been implemented for generation connected to the Imperial Valley substation in order to relieve some of the congestion and an operating nomogram is used to limit the simultaneous operation of generating plants connected to the Imperial Valley substation and imports from CFE and Arizona. The CISO anticipates that the 500-kV interconnection between Arizona and California that connects to the Imperial Valley substation will be constrained most of the time due to increased imports from new southwest generation.

Proposed CA/MX Projects > 50 Miles	Status	Date
La Jovita Project, MX 230-kV lines	Planning	2009
Palo Verde-Devers #2 500-kV line	Permitting	2009
Imperial Valley-San Diego 500-kV line	Planning	2010
Indian Hills-Upland 500-kV line	Planning	2010
New Vincent-Mira Loma 500-kV line	Planning	2011
Tehachapi Area Transmission — 500 kV	Permitting	2010–2011

Operations — The California ISO (CAISO) is moving forward on a Market Redesign and Technology Upgrade (MRTU) program of changes to ISO market and grid operations. The CAISO has set a November 2007 launch date for the MRTU program, which includes upgrades to the CAISO's computer technology to a scalable system that can grow and adapt to future system requirements. Transmission upgrades in the area have alleviated some transfer capability limitations, but numerous system constraints remain. Operator flexibility is limited by the transmission constraints and is further impacted by forest and brush fires that often occur during high-demand periods. The CAISO and other entities within the subregion are interacting in developing an integrated transmission plan for the state to address significant constraint issues.

WECC's 180 members represent the entire spectrum of organizations with an interest in the bulk power system. Serving an area of nearly 1.8 million square miles and 71 million people, it is the largest and most diverse of the eight NERC regional reliability councils. The WECC region is spread over a wide geographic area with significant distances between load and generation areas. In addition, the northern portion of the region is winter peaking while the southern portion of the region is summer peaking. Consequently, transmission constraints are a significant factor affecting economic grid operation in the region. However, reliability in WECC is best examined at a subregional level. The capacity margins discussed in the subregional assessments assume the planned construction of 20,720 MW of net new generation, which is significantly less than the net planned capacity additions of 25,155 MW reported last year for the 2005–2014 time period. Generation decreased by about 1,150 MW in 2005. Additional information can be found on the WECC Web site (www.wecc.biz).

WECC-Canada Capacity and Demand

Figure 46: WECC-Canada Net Energy for Load

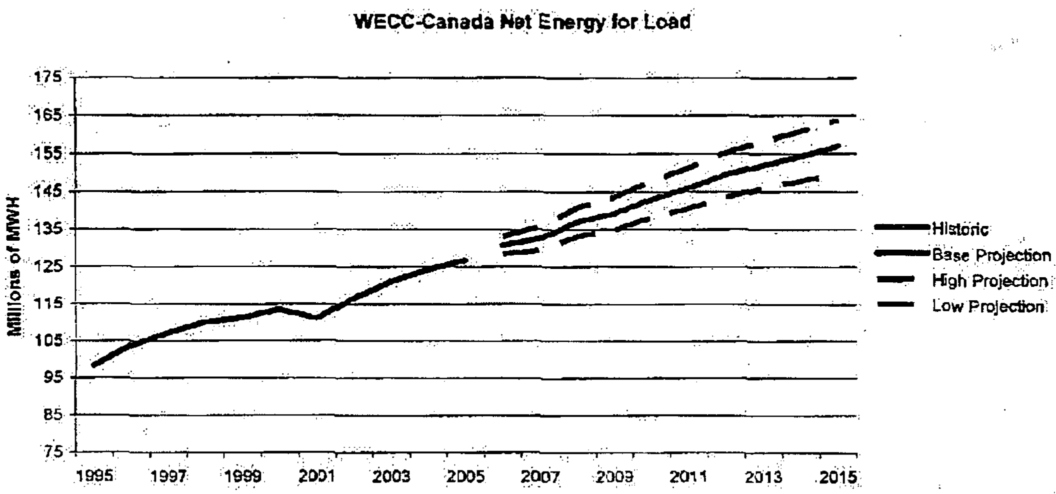


Figure 47: WECC-Canada Capacity Margins — Winter

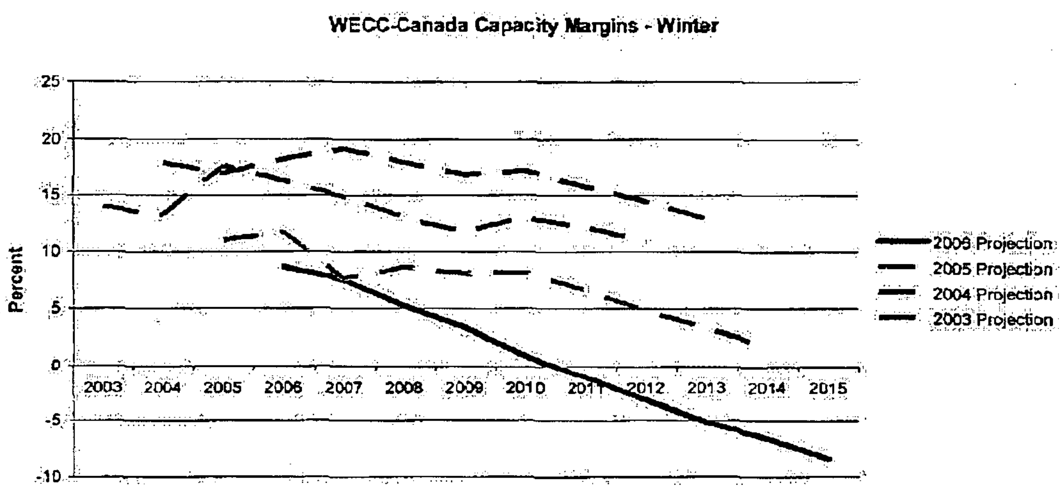
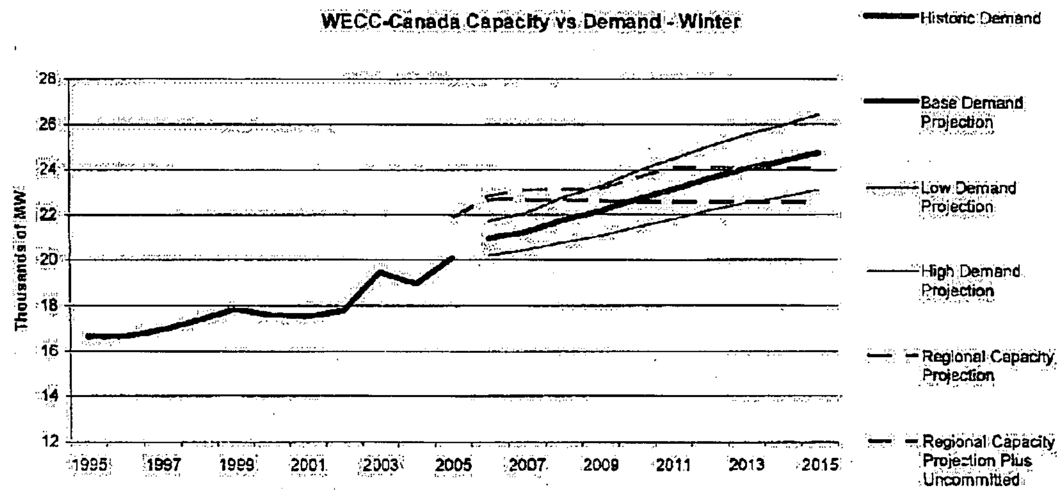


Figure 48: WECC-Canada Capacity Versus Demand — Winter



WECC-U.S. Capacity and Demand

Figure 49: WECC-U.S. Net Energy for Load

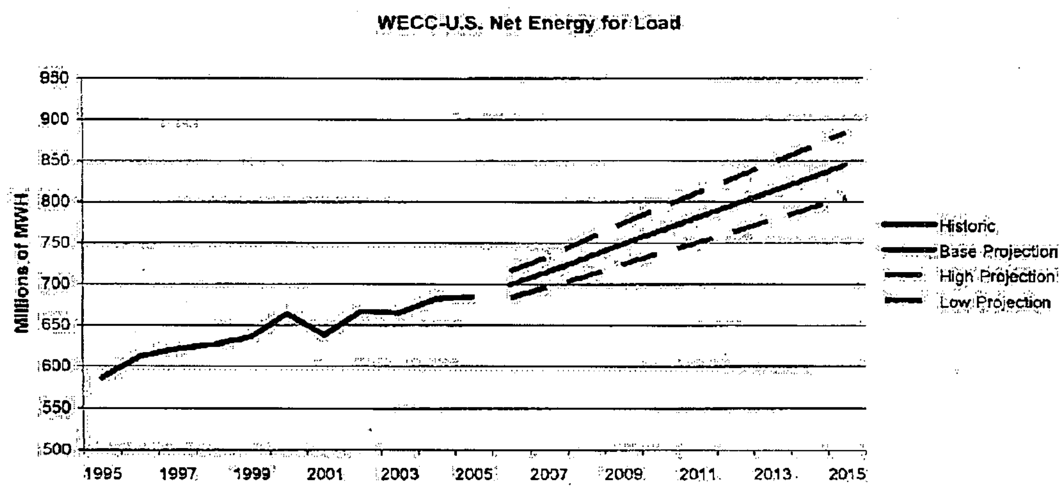


Figure 50: WECC-U.S. Capacity Margins — Summer

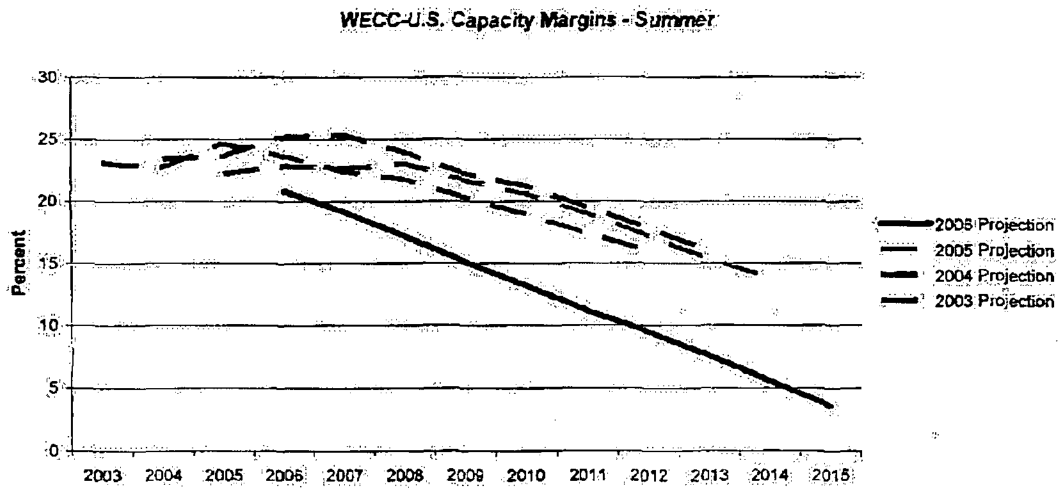


Figure 51: WECC-U.S. Capacity Versus Demand — Summer

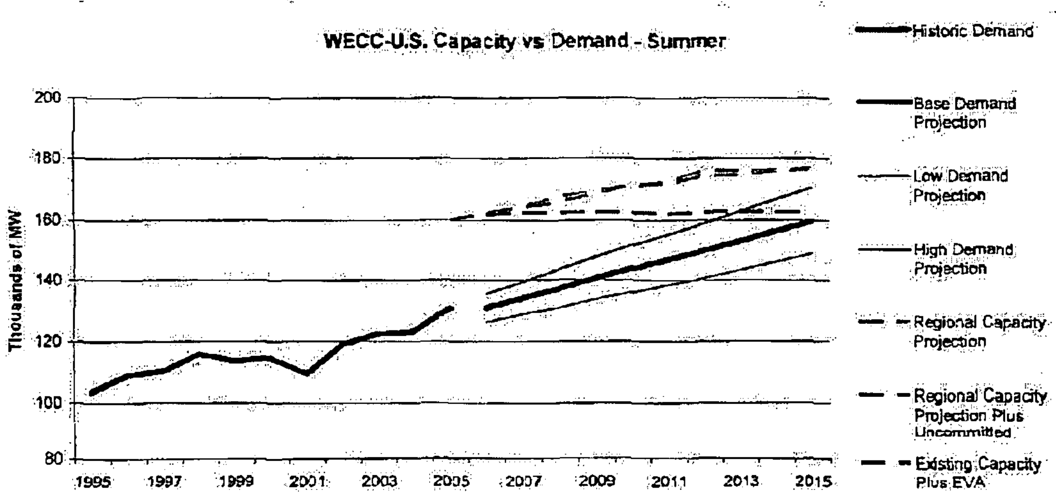


Figure 52: WECC-Canada Capacity Fuel Mix for 2005 and 2011

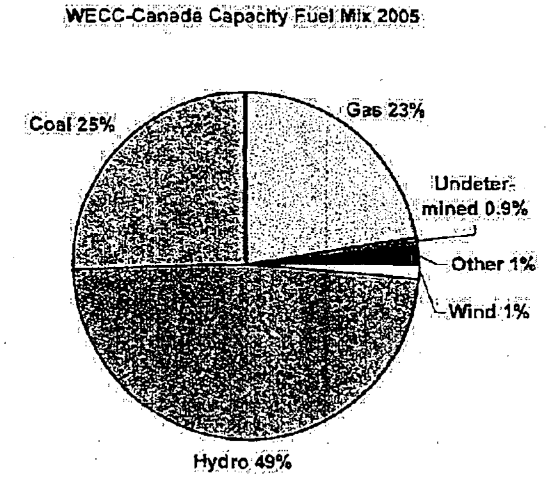
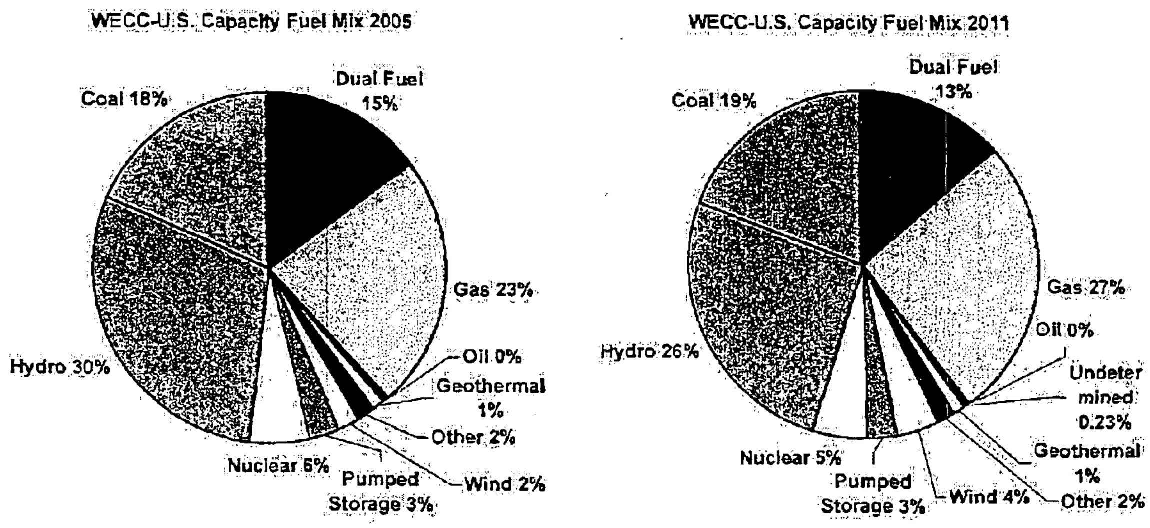


Figure 53: WECC-U.S. Capacity Fuel Mix for 2005 and 2011



Demand, Resource, and Transmission Projections

Table 3a: Estimated 2007 Summer Resources and Demands (MW) and Margins (%)

	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted/ Energy-only/ Transmission-limited Resources (MW)	Available Capacity Margin W/O Uncommitted (%)	Potential Capacity Margin With Uncommitted (%)
United States					
ERCOT	62,072	70,384	6,836	11.8	19.6
FRCC	43,778	51,680	1,150	15.3	17.1
MRO	40,630	47,440	1,045	14.4	16.2
NPCC	59,582	71,950	2,635	17.2	20.1
New England	27,041	31,053	2,635	12.9	19.7
New York	32,541	40,897	0	20.4	20.4
RFC	189,900	221,980	9,422	14.5	17.9
SERC	187,982	223,103	35,000	15.7	27.2
Entergy	27,673	33,183	16,602	16.6	44.4
Gateway	17,839	25,924	2,576	31.2	37.4
Southern	49,131	56,394	6,947	12.9	22.4
TVA	33,578	38,023	4,131	11.7	20.3
VACAR	60,611	69,579	4,744	12.9	18.4
SPP	41,694	47,960	7,652	13.1	25.0
WECC	131,418	162,566	1,585	19.2	19.9
AZ-NM-SNV	28,753	35,778	95	19.6	19.8
CA-MX-US	56,079	64,830	173	13.5	13.7
NWPP-US	35,836	52,650	783	31.9	32.9
RMPA	11,506	12,752	534	9.8	13.4
Total-U.S.	757,056	897,063	65,325	15.6	21.3
Canada					
MRO	5,702	7,918	0	28.0	28.0
NPCC	51,395	67,362	52	23.7	23.8
Maritimes	3,117	6,250	52	50.1	50.5
Ontario	25,423	28,727	0	11.5	11.5
Québec	22,855	32,385	0	29.4	29.4
WECC	17,312	22,131	452	21.8	23.3
Total-Canada	74,409	97,411	504	23.6	24.0
Mexico					
WECC	2,065	2,355	86	12.3	15.4
Total-NERC	833,530	996,829	65,915	16.4	21.6

Table 3b: Estimated 2007/2008 Winter Resources and Demands (MW) and Margins (%)

	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted/ Energy-only/ Transmission-limited Resources (MW)	Available Capacity Margin W/O Uncommitted (%)	Potential Capacity Margin With Uncommitted (%)
United States					
ERCOT	44,184	72,642	7,720	39.2	45.0
FRCC	45,905	56,021	1,190	18.1	19.8
MRO	33,717	45,078	1,045	25.2	26.9
NPCC	49,363	77,304	1,971	36.1	37.7
New England	22,580	34,254	1,971	34.1	37.7
New York	26,783	43,050	0	37.8	37.8
RFC	155,100	231,216	9,865	32.9	35.7
SERC	167,660	228,036	35,000	26.5	36.3
Entergy	22,772	35,654	16,602	36.1	56.4
Gateway	13,796	26,390	2,576	47.7	52.4
Southern	41,626	54,863	6,947	24.1	32.7
TVA	33,647	39,058	4,131	13.9	22.1
VACAR	55,820	72,163	4,744	22.6	27.4
SPP	29,973	48,421	8,062	38.1	46.9
WECC	107,500	155,499	2,191	30.9	31.8
AZ-NM-SNV	18,374	33,804	149	45.6	45.9
CA-MX-US	40,559	52,178	217	22.3	22.6
NWPP-US	39,995	55,872	1,266	28.4	30.0
RMPA	9,840	12,906	622	23.8	27.3
Total-U.S.	633,402	914,217	67,044	30.7	35.5
Canada					
MRO	7,073	8,918	0	20.7	20.7
NPCC	66,076	74,811	52	11.7	11.7
Maritimes	5,137	6,580	52	21.9	22.5
Ontario	25,370	28,634	0	11.4	11.4
Québec	35,569	39,597	0	10.2	10.2
WECC	20,970	22,686	454	7.6	9.4
Total-Canada	94,119	106,415	506	11.6	12.0
Mexico					
WECC	1,525	1,968	86	22.5	25.8
Total-NERC	729,046	1,022,600	67,636	28.7	33.1

Table 3c: Estimated 2011 Summer Resources and Demands (MW) and Margins (%)

	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted/ Energy-only/ Transmission-limited Resources (MW)	Available Capacity Margin W/O Uncommitted (%)	Potential Capacity Margin With Uncommitted (%)
United States					
ERCOT	67,884	70,330	7,202	3.5	12.4
FRCC	48,318	57,222	1,150	15.6	17.2
MRO	44,000	48,572	5,045	9.4	17.9
NPCC	63,629	72,622	1,248	12.4	13.9
New England	29,571	32,273	1,248	8.4	11.8
New York	34,058	40,349	0	15.6	15.6
RFC	203,800	220,841	19,874	7.7	15.3
SERC	204,992	242,176	44,217	15.4	28.4
Entergy	29,776	34,084	18,102	12.6	42.9
Gateway	18,723	28,227	3,991	33.7	41.9
Southern	54,144	62,902	8,697	13.9	24.4
TVA	36,686	41,698	4,131	12.0	20.0
VACAR	65,663	75,265	9,296	12.8	22.3
SPP	44,410	51,615	7,652	14.0	25.1
WECC	144,065	162,207	9,366	11.2	16.0
AZ-NM-SNV	32,622	35,609	2,190	8.4	13.7
CA-MX-US	60,535	67,878	1,360	10.8	12.6
NWPP-US	39,197	52,625	3,423	25.5	30.1
RMPA	12,513	12,411	2,393	-0.8	15.5
Total-U.S.	821,098	925,585	95,754	11.3	19.6
Canada					
MRO	5,984	8,213	0	27.1	27.1
NPCC	54,328	72,036	121	24.6	24.7
Maritimes	3,308	6,364	121	48.0	49.0
Ontario	27,490	32,192	0	14.6	14.6
Québec	23,530	33,480	0	29.7	29.7
WECC	18,964	22,023	1,502	13.9	19.4
Total-Canada	79,276	102,272	1,623	22.5	23.7
Mexico					
WECC	2,467	2,355	822	-4.8	22.3
Total-NERC	902,841	1,030,212	98,199	12.4	20.0

Table 3d: Estimated 2011/2012 Winter Resources and Demands (MW) and Margins (%)

	Net Internal Demand (MW)	Net Capacity Resources (MW)	Uncommitted/ Energy-only/ Transmission-limited Resources (MW)	Available Capacity Margin W/O Uncommitted (%)	Potential Capacity Margin With Uncommitted (%)
United States					
ERCOT	48,115	72,785	7,880	33.9	40.4
FRCC	50,288	61,823	1,190	18.7	20.2
MRO	36,437	46,952	5,045	22.4	29.9
NPCC	51,929	77,746	713	33.2	33.8
New England	24,170	35,095	713	31.1	32.5
New York	27,759	42,651	0	34.9	34.9
RFC	165,200	230,017	19,083	28.2	33.7
SERC	179,682	244,461	44,217	26.5	37.8
Entergy	24,403	37,722	18,102	35.3	56.3
Gateway	14,621	28,703	3,991	49.1	55.3
Southern	45,699	60,752	8,697	24.8	34.2
TVA	35,277	40,306	4,131	12.5	20.6
VACAR	59,682	77,071	9,296	22.6	30.9
SPP	32,325	51,955	8,062	37.8	46.1
WECC	116,728	154,790	10,185	24.6	29.2
AZ-NM-SNV	20,577	34,147	2,192	39.7	43.4
CA-MX-US	43,734	51,061	1,368	14.3	16.6
NWPP-US	42,824	56,134	5,315	23.7	30.3
RMPA	10,646	12,783	2,635	16.7	31.0
Total-U.S.	680,704	940,529	96,375	27.6	34.4
Canada					
MRO	7,333	9,358	0	21.6	21.6
NPCC	68,263	79,068	150	13.7	13.8
Maritimes	5,394	6,700	150	19.5	21.3
Ontario	26,420	32,256	0	18.1	18.1
Québec	36,449	40,112	0	9.1	9.1
WECC	22,850	22,596	1,484	-1.1	5.1
Total-Canada	98,446	111,022	1,634	11.3	12.6
Mexico					
WECC	1,861	1,697	822	-9.7	26.1
Total-NERC	781,011	1,053,248	98,831	25.8	32.2

Definitions and Notes for Tables 3a, 3b, 3c, and 3d

Net Internal Demand — Projected total internal demand less interruptible demand and direct control demand-side management. The regions are not expected to reach their peak demand simultaneously. Demand served under liquidated damages contracts is included.

Net Capacity Resources — Net generating capacity resources (existing, under construction, or planned) considered available (net operable), deliverable, and committed to serve demand, plus the net of capacity purchases and sales.

Uncommitted Resources — Generating resources (existing, under construction, or planned) that are not counted towards capacity margin calculations.

Uncommitted resources may include one or more of the following:

- Generating resources that have not been contracted nor have legal or regulatory obligation to deliver at time of peak.
- Generating resources that do not have or do not plan to have firm transmission service reserved (or its equivalent) or capacity injection rights to deliver the expected output to load within the region.
- Generating resources that have not had a transmission study conducted to determine the level of deliverability.
- Generating resources that are designated as energy-only resources or have elected to be classified as energy-only resources.
- Transmission-constrained generating resources that have known physical deliverability limitations to load within the region.

Available Capacity Margin — The difference between net capacity resources (available committed resources) and net internal demand, expressed as a percentage of net capacity resources.

Potential Capacity Margin — The difference between total potential resources (the sum of net capacity resources and uncommitted resources) and net internal demand, expressed as a percentage of total potential resources. This is the capacity that could be available to cover random factors such as forced outages of generating equipment, demand forecast errors, weather extremes, and capacity service schedule slippage.

Note 1: The ERCOT capacity margin without uncommitted capacity is less than the minimum reliability target of 11 percent. Inclusion of some uncommitted capacity and publicly announced new generation that does not currently have an interconnection agreement could bring capacity margins up to or above the minimum target level by 2011.

Note 2: It is not always possible to obtain SERC region totals by simply summing the subregions. Due to the diversity caused by geographic size and other factors, peaks do not occur simultaneously. This accounts for noncoincident demands and differences in reported resources, especially purchases and sales, across the subregions and the region.

Note 3: The sum of WECC-U.S. systems, Canada, and Mexico peak hour demands or planned capacity resources do not necessarily equal the coincident Western Interconnection total because of subregional and country peak demand diversity. Also, the WECC-U.S. area subregional net capacity resources numbers include utilization of seasonal demand diversity between the winter peaking northwest and the summer peaking southwest. To avoid double counting of resources, the WECC-U.S. net capacity resource totals do not include the diversity utilization.

Note 4: The WECC-U.S. systems uncommitted resources are not necessarily the sum of the U.S. subregion numbers. Subregion committed and uncommitted resources are for the month of maximum seasonal peak demand, which may differ from the month of maximum seasonal peak demand for the WECC-U.S. area. For the winter peak period, the NWPP-U.S. and AZ-NM-SNV subregions peak in

January, while the WECC-U.S. area and the remaining U.S. subregions peak in December. For the summer peak period, the CA-MX-U.S. subregion peaks in August, while the WECC-U.S. area and the remaining U.S. subregions peak in July. Hence, committed and uncommitted additions reported with August and January in-service dates might be reported for some subregions for a given year but not in the WECC-U.S. area until the following year.

Transmission Additions

More than 9,179 miles of new transmission (230 kV and above) are proposed for construction through 2010, with a total of 12,873 miles added over the 2006–2015 time frame. This represents a 6.1 percent increase in the total amount of installed transmission in North America over the assessment period. Table 4 provides a projection of planned increases in transmission circuit miles for 230 kV and above.

Table 4: Planned Transmission Circuit Miles – 230 kV and Above

	2005 Existing	2006-2010 Additions	2011-2015 Additions	2015 Total Installed
United States				
ERCOT	8,311	648	-	8,959
FRCC	6,998	350	127	7,475
MRO	15,912	1,382	272	17,566
NPCC	6,426	364	16	6,806
New England	2,493	273	16	2,782
New York	3,933	91	-	4,024
RFC	26,258	592	-	26,850
SERC	31,179	1,292	947	33,418
Entergy	5,037	151	268	5,456
Gateway	1,897	111	-	2,008
Southern	9,405	350	513	10,268
TVA	2,666	94	-	2,760
VACAR	12,174	586	166	12,926
SPP	9,955	14	21	9,990
WECC	58,751	3,063	1,821	63,635
AZ-NM-SNV	10,271	835	1,471	12,577
CA-MX-US	17,676	790	-	18,466
NWPP-US	24,883	704	350	25,937
RMPA	5,921	734	-	6,655
Total-U.S.	163,790	7,705	3,204	174,699
Canada				
MRO	6,730	303	65	7,098
NPCC	28,998	603	-	29,601
Maritimes	2,196	60	-	2,256
Ontario	11,137	95	-	11,232
Québec	15,665	448	-	16,113
WECC	10,979	416	233	11,628
Total-Canada	46,707	1,322	298	48,327
Mexico				
WECC	638	152	192	982
Total-NERC	211,135	9,179	3,694	224,008

DEFINITIONS, PEER REVIEW PROCESS, AND ABBREVIATIONS

How NERC Defines Bulk Power System Reliability

NERC defines the reliability of the interconnected bulk power system in terms of two basic and functional aspects:

- Resource Adequacy — The ability of the bulk power system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
- Operating Reliability — The ability of the bulk power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Under the heading of Adequacy, system operators can and should take "controlled" actions or procedures to maintain a continual balance between supply and demand within a balancing area (formerly control area). These actions include:

- Public appeals.
- Voltage reductions (sometimes referred to as "brownouts" because incandescent lights will dim as voltage is lowered, sometimes as much as 5 percent).
- Interruptible demand — customer demand that, in accordance with contractual arrangements, can be interrupted by direct control of the system operator or by action of the customer at the direct request of the system operator.
- Rotating blackouts — the term "rotating" is used because each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, in effect rotating the outages among many sets of feeders.

Under the heading of Operating Reliability, are all other system disturbances that result in the unplanned and/or uncontrolled interruption of customer demand, regardless of cause. When these interruptions are contained within a localized area, they are considered unplanned interruptions or disturbances. When they spread over a wide area of the grid, they are referred to as "cascading blackouts" — the uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.

What occurred in 1965 and again in 2003 in the northeast were uncontrolled cascading blackouts. What happened in the summer of 2000 in California, when supply was insufficient to meet all the demand, was a "rotating blackout" or controlled interruption of customer demand to maintain a balance with available supplies while maintaining the overall reliability of the interconnected system.

Peer Review Process

The RAS uses a three-phase approach in its peer reviews process during the preparation of reliability assessments. First, prior to the subcommittee meeting(s), each regional self-assessment is individually assigned to a subcommittee member (from another region) for an in depth, comprehensive review of the self-assessment. The results of that analysis are reviewed with the writer(s) of the respective self-assessment, and refinements/adjustments are made as necessary prior to the subcommittee meeting. Second, during the subcommittee meeting(s), each regional self-assessment is subjected to a group scrutiny and review by the entire subcommittee. Finally, at each meeting a region is selected on a rotating basis to present a review of the assessment process used in their region following a broad set of questions aimed towards providing the subcommittee with a thorough understanding of that region's assessment procedures and practices.

About the Data Used in This Report

Detailed background data used in the preparation of this report is available in NERC's Electricity Supply & Demand (ES&D) database, 2005 edition (http://www.nerc.com/~esd/).

Most new generation additions over the next few years will be constructed by the merchant generation industry. NERC has contracted with Energy Ventures Analysis, Inc. (EVA) (http://www.evainc.com) to monitor and track the status of proposed new power plant projects as well as plant cancellations, delays, and retirements. In some cases, data available from EVA are used in this report to supplement data submitted by the NERC regions.

Abbreviations Used In This Report

AZ-NM-SNV	Arizona-New Mexico-Southern Nevada (Subregion of WECC)
CA-MX-US	California-Mexico (Subregion of WECC)
dc	Direct Current
DOE	U.S. Department of Energy
ECAR	East Central Area Reliability Coordination Agreement
EECP	Emergency Electric Curtailment Plan
ERCOT	Electric Reliability Council of Texas
FERC	U.S. Federal Energy Regulatory Commission
FRCC	Florida Reliability Coordinating Council
GHG	Greenhouse Gas
GRSP	Generation Reserve Sharing Pool
GTA	Greater Toronto Area
GWh	Gigawatthours
ICAP	Installed Capacity
IESO	Independent Electric System Operator (in Ontario)
IPSI	Integrated Power System Plan
ISO	Independent System Operator
ISO-NE	New England Independent System Operator
kV	kilovolts (thousands of volts)
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LSE	Load-serving Entities
LTRA	Long-Term Reliability Assessment
MAAC	Mid-Atlantic Area Council
MAIN	Mid-America Interconnected Network, Inc.
MAPP	Mid-Continent Area Power Pool
MEN	MAAC-ECAR-NPCC
MISO	Midwest Independent Transmission System Operator

MRO	Midwest Reliability Organization
MVA	Megavoltamperes
Mvar	Megavars
MW	Megawatts (millions of watts)
NERC	North American Electric Reliability Council
NIETC	National Interest Electric Transmission Corridor
NPCC	Northeast Power Coordinating Council
NWPP	Northwest Power Pool Area (subregion of WECC)
NYISO	New York Independent System Operator
OVEC	Ohio Valley Electric Corporation
PAR	Phase Angle Regulators
PJM	PJM Interconnection
PRB	Powder River Basin
PRSG	Planned Reserve Sharing Group
RAS	Reliability Assessment Subcommittee
RCC	Reliability Coordinating Committee
RFC	ReliabilityFirst Corporation
RFP	Request For Proposal
RMPA	Rocky Mountain Power Area (subregion of WECC)
RMR	Reliability Must Run
RRS	Reliability Review Subcommittee
RTO	Regional Transmission Organization
SCR	Special Case Resources
SERC	Southeastern Electric Reliability Council
SPP	Southwest Power Pool
SPS	Special Protection System
THI	Temperature Humidity Index
TLR	Transmission Loading Relief
TVA	Tennessee Valley Authority
VACAR	Virginia and Carolinas (subregion of SERC)
WECC	Western Electricity Coordinating Council

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Section 8.1 Ref 4

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 87-223-E - ORDER NO. 98-502

JULY 2, 1998

#2

IN RE: Least-Cost Planning Procedures for Electric Utilities Under the Jurisdiction of the Public Service Commission.	)))	ORDER MODIFYING REPORTING REQUIREMENTS

This matter comes before the Public Service Commission of South Carolina (the Commission) on the February 3, 1998 Petition filed by Duke Energy Corporation (Duke) which requested modification of this Commission's Integrated Resource Planning (IRP) Order by replacing Order No. 91-1002 and the Appendix A attached thereto with modified reporting requirements. Carolina Power & Light (CP&L) and South Carolina Electric & Gas Company (SCE&G) filed documents supporting Duke's proposal. Comments from the parties were then solicited.

On April 16, 1998, the South Carolina State Energy Office released a report performed by Slater & Associates regarding the adequacy of the Commission's existing IRP rules. Basically, the Slater Report recommends that the Commission's existing rules be amended to require electric utilities to file additional information, provide additional demand-side management programs, and require the Commission to formally approve a utility's triennial integrated resource plan. The Commission then requested comments from the parties in this Docket on the Slater Report. Some of the comments received fully supported the recommendations in the report, while others urged this Commission to reject the recommendations. The issue of confidentiality of certain materials comprising the reporting requirements was also raised.

We have examined the original Petition by Duke, the supporting Petitions, the Slater Report itself, and the comments of all the parties in this Docket, and have reached a number of conclusions, which we hold are applicable to all investor owned electric utilities. First, with regard to the confidentiality requirements question, we hold that electric utilities may request that information deemed confidential or proprietary be held in confidentiality by this Commission. The Commission may then make a decision on whether or not to grant a request for confidentiality, however, such a decision regarding confidentiality is subject to challenge by the utilities and interested parties through established legal channels.

We have also determined, after studying the materials in this Docket, that we do believe that IRP filings should be modified from the present requirements. IRP filings shall contain the following information, and the Commission shall provide further information to interested parties, which the Commission deems, after notice and opportunity to respond, necessary for interested parties to reasonably understand the following information:

1. The demand and energy forecast for at least a 15-year period.

2. The supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner, including both demand-side and supply-side options.

3. A brief description and summary of cost-benefit analysis, if available, of each option, which was considered, including those not selected.

4. The supplier's and producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and a description of the external, environmental and economic consequences of the plan to the extent practicable.

The IRP filing shall also contain any other information as determined appropriate from time to time by the Commission.

We believe that this required information is a good balance between the present IRP requirements and the information recommended by the Slater Report in today's regulatory environment, and will furnish helpful information, while minimizing the reporting burden on the investor owned electric utilities.

This Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

Philip T. Bradley
Chairman

ATTEST:

Gary E. Walsh
Acting Executive Director

(SEAL)

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2001-420-E - ORDER NO. 2002-19

JANUARY 11, 2002

IN RE:	Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity for Jasper County Generating Facility	)))))	ORDER GRANTING CERTIFICATE

SCEG-633

I. INTRODUCTION

This matter comes before the Public Service Commission of South Carolina (Commission) on the Application of South Carolina Electric & Gas Company (SCE&G; Company) for a Certificate of Environmental Compatibility and Public Convenience and Necessity to construct and operate an 875 MW combined-cycle electrical generating plant on a site located in Jasper County near Hardeeville, South Carolina. The Application was filed pursuant to the provisions of S.C. Code Ann. Section 58-33-10 et seq. (1976 & Cum. Supp. 2000).

The Application contains a Statement of Need for the project. According to that Statement, the Company currently has a net generating capacity of 4563 megawatts from units on its system, consisting of 644 megawatts at V.C. Summer Nuclear Plant, 2,745 megawatts at 8 coal and steam generating plants, 804 megawatts at six hydro plants, and 370 megawatts of peaking combustion turbine capacity at various locations throughout its system. Including power available under long-term purchase agreements with other utilities and non-utility generators, the Company has a total available capability of 4,588 megawatts.

Further, according to the Statement of Need, the Company's peak demands are forecasted to increase by 857 megawatts during the next ten years. According to the Company, without the additional capacity of the proposed plant, SCE&G will not be able to meet the increasing need for power and assure system reliability. In order to provide the necessary generating capacity and to assure reliable electric service to its customers, the Company proposes to construct the combined-cycle generating plant in Jasper County, which will consist of three General Electric 7FA combustion turbine generators, three heat recovery steam generators (HRSGs), and one steam turbine generator. The combustion turbines will be equipped with inlet chilling to maximize the output of the plant during hot weather, and the plant will have the capability to generate additional "peaking" output of up to 120 megawatts using supplementary firing. The peak output from the plant will be approximately 900 megawatts during the winter and 875 megawatts during the summer.

With regard to notice, a copy of the application was served on the Chief Executive Officer of each municipality and the head of each State and local government agency charged with the duty of protecting the environment or planning land use in the area in the county in which any portion of the facility is to be located. Further, notice was given to persons residing in the municipalities entitled to receive such notice pursuant to S.C. Code Ann. Section 58-33-120(3)(1976) by publication of a summary of the application and the date on which it was or was about to be filed in newspapers of general circulation. The Company furnished affidavits of publication to show publication of the Notice. A Petition to Intervene was received from the Consumer Advocate for the State of South Carolina.

Accordingly, a hearing was held on December 3, 2001, at 10:30 a.m. in the offices of the Commission, with Hon. William Saunders, Chairman, presiding. The Company was represented by Catherine D. Taylor and Francis P. Mood. The Company presented the testimony of Neville O. Lorick, Joseph M. Lynch (Direct and Rebuttal), Stephen M. Cunningham (Direct and Rebuttal), and John W. Preston, Jr. The Consumer Advocate was represented by Hana Williamson and presented the testimony (Direct and Surrebuttal) of Peter J. Lanzalotta. The Commission Staff was represented by F. David Butler.

In addition to the witnesses referenced above, the Commission heard from seven public witnesses regarding this project. Duane Swygert spoke in opposition to the project expressing concerns about noise, traffic, environmental impact and the possibility of an alternate site. He also submitted a petition requesting a night hearing. This petition and a letter from one Rodney Cannon were entered into the record as exhibits. However, Mr. Swygert subsequently withdrew his testimony, exhibits, and request. The other six public witnesses spoke in favor of the project. They were: Thomas McClary, a Jasper County Councilman; Dericee Steele, a local business owner and member of Hardeeville City Council; Gladys Jones, a Jasper County Councilwoman; Chris Bickley of the Lowcountry Regional Council of Governments; Hal Stone, Director of National Business Development for the S.C. Department of Commerce; and Clementa Pinckney, S.C. State

Senator, Senate District 45. The testimony of the various witnesses confirmed the support of the project by Jasper County Council, Hardeeville City Council, Lowcountry Regional Council of Governments, and the S.C. Department of Commerce, as well as the individual support of each witness. Witnesses McClary, Jones, and Pinckney stated that there was widespread knowledge of the project in Jasper County and a broad base of local support for it.

II. SUMMARY OF TESTIMONY

Neville Lorick, President and Chief Operating Officer of SCE&G, presented in his testimony an overview of the Company's planning for the Jasper County Generation Project. He explained how SCE&G arrived at the decision to request certification of the Commission to build the Project.

Mr. Lorick testified that the decision to build a combined cycle plant arose from SCE&G's annual load and resource forecast and related planning. The Company projects that its system will require 254 megawatts of additional capacity by 2004, and 480 megawatts by 2006 due to growth in its peak demand. SCE&G considered various options to meet this need, including the addition of two combustion turbines of 150 megawatts in 2004 and a third CT in 2006. However, Mr. Lorick stated that it was more economical to add the two CTs in a combined-cycle configuration. The combined cycle turbines would add 459 megawatts to the system in 2004 and would produce electricity more efficiently than a simple cycle configuration. SCE&G further determined that increasing the scale of the combined-cycle facility to include three CTs and supplementary duct-firing would result in the cost of incremental capacity being approximately sixty percent less than the cost of base capacity. The three CTs facility would provide 875 megawatts to SCE&G's system. Therefore, SCE&G determined that this option was a prudent solution to meet its customers' needs for economical and reliable energy. Mr. Lorick further explained that the Company arranged for a long term sale of 250 megawatts for nine years, beginning in 2004, to carry the cost of the incremental capacity until the capacity is needed by its South Carolina customers. Therefore, additional power will be available to SCE&G's system in the future when it is needed; Mr. Lorick states that SCE&G's customers will realize economy of scale benefits due to the construction of the larger plant's construction.

Mr. Lorick further detailed that another important aspect of the selection of the Jasper site relates to the availability and volume of natural gas necessary for the operation of the proposed project. The CTs will utilize natural gas as a primary fuel, and will consume approximately 155,000 dekatherms (DT) per day at 100% load factor. Mr. Lorick explained that the Company plans to contract with SCANA Energy Marketing, Inc., for 120,000 DT for firm natural gas supply, and it will purchase the balance on an interruptible basis. The project site itself is located near the point where SCG Pipeline, Inc., will connect. The gas primarily will flow to the plant through SCG from a liquefied natural gas facility near Savannah, Georgia. The contractual arrangements contemplated will allow the generation units to be available and utilized when SCE&G's electric generation economic dispatch model dictates the need. If natural gas is not utilized due to interruption of supply, the generation units will fire on distillate oil. The Company will have oil storage tanks of 3.6 million gallons of capacity to supply the CTs.

In response to examination by the Commission, Mr. Lorick assured the Commission that all reasonable alternatives were considered in the decision to site this generation facility. He believes that the decision to build this plant is an optimal solution in light of all of the factors and circumstances.

Dr. Joseph M. Lynch, Manager of Resource Planning for SCE&G, presented the Company's load and resource forecast and its reserve margin requirements in order to demonstrate the need for additional capacity and that the proposed project is the most cost effective option for meeting these requirements. Dr. Lynch discussed the Company's growth in peak demand and the rate at which it expects such demand to continue. The Company's average annual change in peak demand for the eleven year period 1990 to 2001 was 88 megawatts per year; the average change for the next nine years, 2002 to 2010, is forecasted to be 88 megawatts per year. The Company's firm peak demand is the difference between its gross peak and its demand side management capacity. Its supply requirement is the sum of the Company's firm peak demand and its reserve margin range of 12% to 18% (for calculation purposes, Dr. Lynch used 15%). Included in the Company's existing capacity are 350 megawatts related to the Urquhart Re-Powering Project, approved by this Commission in Order 2000-544 (June 28, 2000) which is scheduled to come on line during 2002. Dr. Lynch projects a supply shortfall of 254 megawatts by 2004 and 480 megawatts by 2006. Without additions to system generation, the supply shortfall will reach 870 megawatts by 2010.

Dr. Lynch also explained the analyses and assumptions leading to the Company's conclusion that the proposed project is the best option for meeting capacity requirements.

He specifically discussed the economies of scale to be achieved by building an 875 megawatt plant, although all of this capacity will not be needed immediately in 2004. To avoid unreasonably imposing costs on the Company's native load customers prior to the time capacity is needed, the Company has entered into a nine-year contract to provide 250 megawatts of firm capacity to another supplier. The contract provides, however, that this capacity is recallable by the Company during these nine years, if it is needed by the Company to serve its native load. In its decision-making process, the Company considered purchased power as an option, but decided not to pursue this alternative.

The Company is familiar with the electric power markets and, in fact, went through an extensive consideration of this alternative in connection with its Urquhart Project, referenced above. The Company decided to pursue self-owned capacity in the present case, because according to Dr. Lynch, (1) it provides significantly more flexibility in scheduling and does not put the Company at risk for penalties; (2) it is more reliable since the Company will maintain the plant and the availability of capacity will not be subject to the time required and uncertainty inherent in enforcing purchased power agreements when its customers' energy needs are immediate; (3) it should be more economical in the long run, since purchased power costs tend to rise with inflation, while the cost of carrying a self-owned plant will decrease over time as a result of depreciation; and (4) there are economic benefits to the community when generation is built.

Stephen M. Cunningham, manager for the proposed project, presented a general description of the project. SCE&G is negotiating a fixed price contract for the engineering, procurement and construction of the combined cycle generating plant to be located on a rural site in Jasper County. The project will consist of three General Electric 7FA combustion turbine generators, three heat recovery steam generators and one steam turbine generator. The combustion turbines will be equipped with inlet chilling to maximize the output of the plant during hot weather. The plant will generate approximately 775 net megawatts during the winter and 750 net megawatts during the summer. The plant will have the capability to generate additional "peaking" output of up to 120 megawatts using supplementary firing. The peak output from the plant will be approximately 900 megawatts during the winter and 875 megawatts during the summer. Natural gas will be the primary fuel for the plant, with distillate (No. 2) fuel oil as a back-up. Natural gas will be supplied to the site through a connection to interstate pipelines. The facility will comply with all applicable federal, State and local laws, specifically including all applicable environmental laws and regulations. The plant's water requirements (supply and discharge) will be supplied by Beaufort-Jasper Water and Sewer Authority utilizing a new water treating facility to be located adjacent to the plant. The electrical output of the facility will be delivered through the 230 kV transmission grid. The substation connecting the plant to the transmission lines is included in the project cost of approximately $450 million. Transmission siting requirements will be addressed in a later filing with this Commission.

John W. Preston, Jr. SCE&G's final witness was John W. Preston, Jr. Mr. Preston is Senior Engineer in the Corporate Environmental Services Department of SCANA Services, Inc., and provides direct support for SCE&G's generation group. In his testimony, Mr. Preston discussed the environmental matters related to the Jasper

Generating project. He described SCE&G's effort to minimize the environmental impacts of the project, the permitting process, and the status of the acquisition of required environmental permits. According to Mr. Preston, the Jasper project will have minimal environmental impacts due to a variety of reasons. Since clean-burning natural gas will be the primary fuel utilized to fire the generation, sulfur and ash emissions will be very minimal. State of the art control technology for nitrous oxide emissions will be utilized, and therefore the concentration of these emissions will be extremely low. Combustion controls will also minimize the carbon monoxide and volatile organic compound emissions. Mr. Preston further stated that use of water and the discharge of water at the Jasper project will have minimal environmental impacts. No direct discharge of process wastewater to the waters of the United States will be necessary. SCE&G will purchase water from the Beaufort Jasper Water Authority (BJWA). The project usage will be 5530 gallons per minute during normal usage. Sanitary wastes and other smaller waste streams will be discharged to the BJWA. SCE&G has conducted a wetland delineation at the Jasper site, and all construction and operation activities will avoid wetlands, thus having no impact on those ecosystems. Mr. Preston went on to say that an Endangered Species Assessment was performed, and no State or federally listed threatened or endangered species were observed in the project area.

In regards to permitting, Mr. Preston testified that the Company has made application to receive approval from all regulatory agencies at the federal, State, and local levels. SCE&G has submitted a complete application for its air permits to the Department of Health and Environmental Control's (DHEC) Bureau of Air Quality. The

United States Environmental Protection Agency will also conduct a review of this application. The Company expects approval of the air permit in May 2002. In regards to permitting for waters usage and discharge, no National Pollutant Discharge Elimination System (NPDES) permit will be required, except for a general permit for stormwater discharges during construction and operation. The stormwater permits are expected to be issued in February 2002.

Mr. Peter J. Lanzalotta testified on behalf of the Consumer Advocate. Although he concluded that SCE&G's need for additional generation is "apparent" (pp. 2-3), he criticized the way in which the Company addressed impacts on the electric transmission system, natural gas supplies and water-related systems. He also asserted that the Company should have solicited competitive proposals for purchased power from wholesale suppliers as a part of its economic analysis.

Based on Mr. Lanzalotta's testimony, at the close of the proceedings, counsel for the Consumer Advocate filed a motion requesting that, if the Commission issues a Certificate of Environmental Compatibility and Public Convenience and Necessity to the Company, it should include a condition that the Company evaluate the purchased power option before requesting any future rate relief.

III. FINDINGS OF FACT

1. The Commission finds that the Company meets the requirements of Section 58-33-120 regarding the submittal of the application. Further, the Company provided, as a late filed exhibit, a summary of alternative generating sites and the economic and engineering justification for siting the facility at the proposed Jasper

County site. This late filed exhibit was critical to the decision of the Commission, and a similar exhibit should be considered a required component of all future siting applications before this Commission. Consistent with Section 58-33-160, the Commission also finds the following:

2. The Company clearly demonstrated the need for the facility consistent with the Company's 2001 Integrated Resource Plan (IRP). Lynch Prefiled Testimony pp. 2-8; Lanzalotta Prefiled Testimony pp. 2-3. The SC General Assembly has not instituted any form of electric deregulation, and the facility is needed to meet the requirements of the Company to reliably serve native load. Further, an 875 MW facility allows for economies of scale resulting in incremental capacity costs of approximately 60% of the cost of base capacity. Lynch Prefiled Testimony, p. 8.

3. An 875 MW facility is within the demand forecast error bounds of the 2001 IRP, and promotes increased reliability within the Company's territory and the Company's required VACAR reserve margin. Lynch Prefiled Testimony, *supra*.

4. Due to the remote location of the facility, the probable environmental impact is justified. No evidence of adverse environmental impact was presented which would preclude this Commission from granting this certificate application. Preston Prefiled Testimony pp. 2-6. However, to insure that the Company meets the required environmental permits (both State and Federal) and the environmental compatibility requirements of the Siting Act, the Company shall provide a copy of all such permits, once issued, to the Commission to become a part of the docket in this case.

5. Considering the state of available energy and environmental technology and the nature of the economics of various alternatives, the proposed combined cycle natural gas facility provides a clean and efficient alternative to meeting the Company's obligation to serve. Further, the addition of a gas fired facility adds additional fuel diversity to the Company's generation portfolio which is currently heavily dependent on coal. Lynch Prefiled Testimony, *supra*; Lynch Prefiled Rebuttal Testimony pp. 1-5.

6. Due to the location of this facility and the proximity of electric transmission and natural gas pipelines, and the efficiency of the proposed facility, the Commission finds that the facility serves system economy. Given the future consideration of regional transmission organizations (RTOs), the facility will also promote the development of transmission within this area of the State to minimize loop flows and other transmission concerns between the VACAR and Southern systems. Cunningham Prefiled Testimony pp. 2-5; Lynch Prefiled Testimony and Prefiled Rebuttal Testimony, *supra*.

7. Further, the Company provided, as a late filed exhibit, the transmission interconnection study on the transmission impacts of the proposed facility. This late filed exhibit was critical to the decision of the Commission, and a similar exhibit should be considered a required component of all future siting applications before this Commission.

8. Further, we find and conclude that the Company's decision-making process which considered, but rejected purchased power, was adequate and prudent. The Company's knowledge of electric markets and recent experience with its Urquhart Re-

Powering Project made unnecessary an elaborate RFP process in reaching its final decision. Lynch Prefiled Testimony and Prefiled Rebuttal Testimony, *supra.*

IV. CONCLUSIONS

1. The Company has complied with all requirements of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. Section 58-33-10 et seq. (1976, Supp. 2000).

2. The Application of the Company is granted as filed.

3. A Certificate of Environmental Compatibility and Public Convenience and Necessity is hereby granted for the project.

4. SCE&G has established a basis for the need for the facility. The Company has established that a shortfall in the ability of the Company to generate adequate supplies of electricity may well result in the future without the construction of the project. *See* Finding of Fact No. 2, above.

5. The nature of any environmental impact resulting from the project is minimal. *See* Finding of Fact Nos. 5 and 6, above.

6. The impact of the facility upon the environment is justified, considering the state of available technology, the economics of various alternatives, and other pertinent considerations. *See* Findings of Fact Nos. 5 and 6, above.

7. The facility will serve the interests of system reliability and economy. *See* Findings of Fact Nos. 2, 3, 5, 6 and 7, above. Clearly, the project is needed to assure system reliability for needed capacity. Moreover, we concur in the Company's decision to provide this capacity with owned generation. The uncertainty of supply and attendant

costs presently associated with purchased power coupled with the economic benefits of owned generation make the Company's decision to build generation a prudent one.

8. With regard to applicable State and local laws and regulations, the evidence presented indicated concerted compliance commitments and efforts by the Company.

9. Public convenience and necessity require the construction of the proposed facility. We conclude, based on the testimony of the witnesses and the evidence in this case as a whole that the construction of this facility is necessary in order to generate needed amounts of electricity, overcome the forecasted shortfall, and maintain a proper reserve margin. We believe that without the facility, SCE&G may well face an inability to generate needed amounts of electricity and will not be able to meet the growth in peak demand in the future, much less maintain a proper reserve margin. The project is needed to properly serve the public.

10. The Consumer Advocate filed a Motion which asserts that if the Commission issues the certificate in this matter, it should include a condition that SCE&G evaluate the power purchase option before it requests rate relief. This Motion is made by the Consumer Advocate based on the belief that SCE&G did not compare the estimated cost of the proposed facility with the cost to purchase generating capacity from other wholesale suppliers. SCE&G in response to the Motion asserts that it did, in fact, make a comparison of the option to purchase generating capacity from other wholesale suppliers; it simply did not make the evaluation using a Request For Proposal.

In further response to the Consumer Advocate's motion, in calendar year 2001, the Commission has issued certificates to three different exempt wholesale generating companies. The certified capacity of these facilities totals 2,040 MW. Should the Company need to purchase power from the wholesale market, capacity exists in excess of the combined need of all VACAR in South and North Carolina to meet both their total firm obligation and required SERC reserve margins. Therefore, the Motion of the Consumer Advocate is denied. We would note that should SCE&G file a rate application including this plant in rate base, the Consumer Advocate will have an opportunity to address this issue during that rate proceeding.

This Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

Chairman

ATTEST:

Executive Director

(SEAL)

Section 8.1 Ref 5

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2001-420-E - ORDER NO. 2002-19

JANUARY 11, 2002

IN RE: Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity for Jasper County Generating Facility	)))))	ORDER GRANTING CERTIFICATE

SCEG-633

I. INTRODUCTION

This matter comes before the Public Service Commission of South Carolina (Commission) on the Application of South Carolina Electric & Gas Company (SCE&G; Company) for a Certificate of Environmental Compatibility and Public Convenience and Necessity to construct and operate an 875 MW combined-cycle electrical generating plant on a site located in Jasper County near Hardeeville, South Carolina. The Application was filed pursuant to the provisions of S.C. Code Ann. Section 58-33-10 et seq. (1976 & Cum. Supp. 2000).

The Application contains a Statement of Need for the project. According to that Statement, the Company currently has a net generating capacity of 4563 megawatts from units on its system, consisting of 644 megawatts at V.C. Summer Nuclear Plant, 2,745 megawatts at 8 coal and steam generating plants, 804 megawatts at six hydro plants, and 370 megawatts of peaking combustion turbine capacity at various locations throughout its system. Including power available under long-term purchase agreements with other utilities and non-utility generators, the Company has a total available capability of 4,588 megawatts.

Further, according to the Statement of Need, the Company's peak demands are forecasted to increase by 857 megawatts during the next ten years. According to the Company, without the additional capacity of the proposed plant, SCE&G will not be able to meet the increasing need for power and assure system reliability. In order to provide the necessary generating capacity and to assure reliable electric service to its customers, the Company proposes to construct the combined-cycle generating plant in Jasper County, which will consist of three General Electric 7FA combustion turbine generators, three heat recovery steam generators (HRSGs), and one steam turbine generator. The combustion turbines will be equipped with inlet chilling to maximize the output of the plant during hot weather, and the plant will have the capability to generate additional "peaking" output of up to 120 megawatts using supplementary firing. The peak output from the plant will be approximately 900 megawatts during the winter and 875 megawatts during the summer.

With regard to notice, a copy of the application was served on the Chief Executive Officer of each municipality and the head of each State and local government agency charged with the duty of protecting the environment or planning land use in the area in the county in which any portion of the facility is to be located. Further, notice was given to persons residing in the municipalities entitled to receive such notice pursuant to S.C. Code Ann. Section 58-33-120(3)(1976) by publication of a summary of the application and the date on which it was or was about to be filed in newspapers of general circulation. The Company furnished affidavits of publication to show publication of the Notice. A Petition to Intervene was received from the Consumer Advocate for the State of South Carolina.

Accordingly, a hearing was held on December 3, 2001, at 10:30 a.m. in the offices of the Commission, with Hon. William Saunders, Chairman, presiding. The Company was represented by Catherine D. Taylor and Francis P. Mood. The Company presented the testimony of Neville O. Lorick, Joseph M. Lynch (Direct and Rebuttal), Stephen M. Cunningham (Direct and Rebuttal), and John W. Preston, Jr. The Consumer Advocate was represented by Hana Williamson and presented the testimony (Direct and Surrebuttal) of Peter J. Lanzalotta. The Commission Staff was represented by F. David Butler.

In addition to the witnesses referenced above, the Commission heard from seven public witnesses regarding this project. Duane Swygert spoke in opposition to the project expressing concerns about noise, traffic, environmental impact and the possibility of an alternate site. He also submitted a petition requesting a night hearing. This petition and a letter from one Rodney Cannon were entered into the record as exhibits. However, Mr. Swygert subsequently withdrew his testimony, exhibits, and request. The other six public witnesses spoke in favor of the project. They were: Thomas McClary, a Jasper County Councilman; Dericee Steele, a local business owner and member of Hardeeville City Council; Gladys Jones, a Jasper County Councilwoman; Chris Bickley of the Lowcountry Regional Council of Governments; Hal Stone, Director of National Business Development for the S.C. Department of Commerce; and Clementa Pinckney, S.C. State

Senator, Senate District 45. The testimony of the various witnesses confirmed the support of the project by Jasper County Council, Hardeeville City Council, Lowcountry Regional Council of Governments, and the S.C. Department of Commerce, as well as the individual support of each witness. Witnesses McClary, Jones, and Pinckney stated that there was widespread knowledge of the project in Jasper County and a broad base of local support for it.

II. SUMMARY OF TESTIMONY

Neville Lorick, President and Chief Operating Officer of SCE&G, presented in his testimony an overview of the Company's planning for the Jasper County Generation Project. He explained how SCE&G arrived at the decision to request certification of the Commission to build the Project.

Mr. Lorick testified that the decision to build a combined cycle plant arose from SCE&G's annual load and resource forecast and related planning. The Company projects that its system will require 254 megawatts of additional capacity by 2004, and 480 megawatts by 2006 due to growth in its peak demand. SCE&G considered various options to meet this need, including the addition of two combustion turbines of 150 megawatts in 2004 and a third CT in 2006. However, Mr. Lorick stated that it was more economical to add the two CTs in a combined-cycle configuration. The combined cycle turbines would add 459 megawatts to the system in 2004 and would produce electricity more efficiently than a simple cycle configuration. SCE&G further determined that increasing the scale of the combined-cycle facility to include three CTs and supplementary duct-firing would result in the cost of incremental capacity being approximately sixty percent less than the cost of base capacity. The three CTs facility would provide 875 megawatts to SCE&G's system. Therefore, SCE&G determined that this option was a prudent solution to meet its customers' needs for economical and reliable energy. Mr. Lorick further explained that the Company arranged for a long term sale of 250 megawatts for nine years, beginning in 2004, to carry the cost of the incremental capacity until the capacity is needed by its South Carolina customers. Therefore, additional power will be available to SCE&G's system in the future when it is needed; Mr. Lorick states that SCE&G's customers will realize economy of scale benefits due to the construction of the larger plant's construction.

Mr. Lorick further detailed that another important aspect of the selection of the Jasper site relates to the availability and volume of natural gas necessary for the operation of the proposed project. The CTs will utilize natural gas as a primary fuel, and will consume approximately 155,000 dekatherms (DT) per day at 100% load factor. Mr. Lorick explained that the Company plans to contract with SCANA Energy Marketing, Inc., for 120,000 DT for firm natural gas supply, and it will purchase the balance on an interruptible basis. The project site itself is located near the point where SCG Pipeline, Inc., will connect. The gas primarily will flow to the plant through SCG from a liquefied natural gas facility near Savannah, Georgia. The contractual arrangements contemplated will allow the generation units to be available and utilized when SCE&G's electric generation economic dispatch model dictates the need. If natural gas is not utilized due to interruption of supply, the generation units will fire on distillate oil. The Company will have oil storage tanks of 3.6 million gallons of capacity to supply the CTs.

In response to examination by the Commission, Mr. Lorick assured the Commission that all reasonable alternatives were considered in the decision to site this generation facility. He believes that the decision to build this plant is an optimal solution in light of all of the factors and circumstances.

Dr. Joseph M. Lynch, Manager of Resource Planning for SCE&G, presented the Company's load and resource forecast and its reserve margin requirements in order to demonstrate the need for additional capacity and that the proposed project is the most cost effective option for meeting these requirements. Dr. Lynch discussed the Company's growth in peak demand and the rate at which it expects such demand to continue. The Company's average annual change in peak demand for the eleven year period 1990 to 2001 was 88 megawatts per year; the average change for the next nine years, 2002 to 2010, is forecasted to be 88 megawatts per year. The Company's firm peak demand is the difference between its gross peak and its demand side management capacity. Its supply requirement is the sum of the Company's firm peak demand and its reserve margin range of 12% to 18% (for calculation purposes, Dr. Lynch used 15%). Included in the Company's existing capacity are 350 megawatts related to the Urquhart Re-Powering Project, approved by this Commission in Order 2000-544 (June 28, 2000) which is scheduled to come on line during 2002. Dr. Lynch projects a supply shortfall of 254 megawatts by 2004 and 480 megawatts by 2006. Without additions to system generation, the supply shortfall will reach 870 megawatts by 2010.

Dr. Lynch also explained the analyses and assumptions leading to the Company's conclusion that the proposed project is the best option for meeting capacity requirements.

He specifically discussed the economies of scale to be achieved by building an 875 megawatt plant, although all of this capacity will not be needed immediately in 2004. To avoid unreasonably imposing costs on the Company's native load customers prior to the time capacity is needed, the Company has entered into a nine-year contract to provide 250 megawatts of firm capacity to another supplier. The contract provides, however, that this capacity is recallable by the Company during these nine years, if it is needed by the Company to serve its native load. In its decision-making process, the Company considered purchased power as an option, but decided not to pursue this alternative.

The Company is familiar with the electric power markets and, in fact, went through an extensive consideration of this alternative in connection with its Urquhart Project, referenced above. The Company decided to pursue self-owned capacity in the present case, because according to Dr. Lynch, (1) it provides significantly more flexibility in scheduling and does not put the Company at risk for penalties; (2) it is more reliable since the Company will maintain the plant and the availability of capacity will not be subject to the time required and uncertainty inherent in enforcing purchased power agreements when its customers' energy needs are immediate; (3) it should be more economical in the long run, since purchased power costs tend to rise with inflation, while the cost of carrying a self-owned plant will decrease over time as a result of depreciation; and (4) there are economic benefits to the community when generation is built.

Stephen M. Cunningham, manager for the proposed project, presented a general description of the project. SCE&G is negotiating a fixed price contract for the engineering, procurement and construction of the combined cycle generating plant to be located on a rural site in Jasper County. The project will consist of three General Electric 7FA combustion turbine generators, three heat recovery steam generators and one steam turbine generator. The combustion turbines will be equipped with inlet chilling to maximize the output of the plant during hot weather. The plant will generate approximately 775 net megawatts during the winter and 750 net megawatts during the summer. The plant will have the capability to generate additional "peaking" output of up to 120 megawatts using supplementary firing. The peak output from the plant will be approximately 900 megawatts during the winter and 875 megawatts during the summer. Natural gas will be the primary fuel for the plant, with distillate (No. 2) fuel oil as a back-up. Natural gas will be supplied to the site through a connection to interstate pipelines. The facility will comply with all applicable federal, State and local laws, specifically including all applicable environmental laws and regulations. The plant's water requirements (supply and discharge) will be supplied by Beaufort-Jasper Water and Sewer Authority utilizing a new water treating facility to be located adjacent to the plant. The electrical output of the facility will be delivered through the 230 kV transmission grid. The substation connecting the plant to the transmission lines is included in the project cost of approximately $450 million. Transmission siting requirements will be addressed in a later filing with this Commission.

John W. Preston, Jr. SCE&G's final witness was John W. Preston, Jr. Mr. Preston is Senior Engineer in the Corporate Environmental Services Department of SCANA Services, Inc., and provides direct support for SCE&G's generation group. In his testimony, Mr. Preston discussed the environmental matters related to the Jasper

Generating project. He described SCE&G's effort to minimize the environmental impacts of the project, the permitting process, and the status of the acquisition of required environmental permits. According to Mr. Preston, the Jasper project will have minimal environmental impacts due to a variety of reasons. Since clean-burning natural gas will be the primary fuel utilized to fire the generation, sulfur and ash emissions will be very minimal. State of the art control technology for nitrous oxide emissions will be utilized, and therefore the concentration of these emissions will be extremely low. Combustion controls will also minimize the carbon monoxide and volatile organic compound emissions. Mr. Preston further stated that use of water and the discharge of water at the Jasper project will have minimal environmental impacts. No direct discharge of process wastewater to the waters of the United States will be necessary. SCE&G will purchase water from the Beaufort Jasper Water Authority (BJWA). The project usage will be 5530 gallons per minute during normal usage. Sanitary wastes and other smaller waste streams will be discharged to the BJWA. SCE&G has conducted a wetland delineation at the Jasper site, and all construction and operation activities will avoid wetlands, thus having no impact on those ecosystems. Mr. Preston went on to say that an Endangered Species Assessment was performed, and no State or federally listed threatened or endangered species were observed in the project area.

In regards to permitting, Mr. Preston testified that the Company has made application to receive approval from all regulatory agencies at the federal, State, and local levels. SCE&G has submitted a complete application for its air permits to the Department of Health and Environmental Control's (DHEC) Bureau of Air Quality. The

United States Environmental Protection Agency will also conduct a review of this application. The Company expects approval of the air permit in May 2002. In regards to permitting for waters usage and discharge, no National Pollutant Discharge Elimination System (NPDES) permit will be required, except for a general permit for stormwater discharges during construction and operation. The stormwater permits are expected to be issued in February 2002.

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Based on Mr. Lanzalotta's testimony, at the close of the proceedings, counsel for the Consumer Advocate filed a motion requesting that, if the Commission issues a Certificate of Environmental Compatibility and Public Convenience and Necessity to the Company, it should include a condition that the Company evaluate the purchased power option before requesting any future rate relief.

III. FINDINGS OF FACT

1. The Commission finds that the Company meets the requirements of Section 58-33-120 regarding the submittal of the application. Further, the Company provided, as a late filed exhibit, a summary of alternative generating sites and the economic and engineering justification for siting the facility at the proposed Jasper

County site. This late filed exhibit was critical to the decision of the Commission, and a similar exhibit should be considered a required component of all future siting applications before this Commission. Consistent with Section 58-33-160, the Commission also finds the following:

2. The Company clearly demonstrated the need for the facility consistent with the Company's 2001 Integrated Resource Plan (IRP). Lynch Prefiled Testimony pp. 2-8; Lanzalotta Prefiled Testimony pp. 2-3. The SC General Assembly has not instituted any form of electric deregulation, and the facility is needed to meet the requirements of the Company to reliably serve native load. Further, an 875 MW facility allows for economies of scale resulting in incremental capacity costs of approximately 60% of the cost of base capacity. Lynch Prefiled Testimony, p. 8.

3. An 875 MW facility is within the demand forecast error bounds of the 2001 IRP, and promotes increased reliability within the Company's territory and the Company's required VACAR reserve margin. Lynch Prefiled Testimony, *supra*.

4. Due to the remote location of the facility, the probable environmental impact is justified. No evidence of adverse environmental impact was presented which would preclude this Commission from granting this certificate application. Preston Prefiled Testimony pp. 2-6. However, to insure that the Company meets the required environmental permits (both State and Federal) and the environmental compatibility requirements of the Siting Act, the Company shall provide a copy of all such permits, once issued, to the Commission to become a part of the docket in this case.

5. Considering the state of available energy and environmental technology and the nature of the economics of various alternatives, the proposed combined cycle natural gas facility provides a clean and efficient alternative to meeting the Company's obligation to serve. Further, the addition of a gas fired facility adds additional fuel diversity to the Company's generation portfolio which is currently heavily dependent on coal. Lynch Prefiled Testimony, *supra*; Lynch Prefiled Rebuttal Testimony pp. 1-5.

6. Due to the location of this facility and the proximity of electric transmission and natural gas pipelines, and the efficiency of the proposed facility, the Commission finds that the facility serves system economy. Given the future consideration of regional transmission organizations (RTOs), the facility will also promote the development of transmission within this area of the State to minimize loop flows and other transmission concerns between the VACAR and Southern systems. Cunningham Prefiled Testimony pp. 2-5; Lynch Prefiled Testimony and Prefiled Rebuttal Testimony, *supra*.

7. Further, the Company provided, as a late filed exhibit, the transmission interconnection study on the transmission impacts of the proposed facility. This late filed exhibit was critical to the decision of the Commission, and a similar exhibit should be considered a required component of all future siting applications before this Commission.

8. Further, we find and conclude that the Company's decision-making process which considered, but rejected purchased power, was adequate and prudent. The Company's knowledge of electric markets and recent experience with its Urquhart Re-

Powering Project made unnecessary an elaborate RFP process in reaching its final decision. Lynch Prefiled Testimony and Prefiled Rebuttal Testimony, *supra*.

IV. CONCLUSIONS

1. The Company has complied with all requirements of the Utility Facility Siting and Environmental Protection Act, S.C. Code Ann. Section 58-33-10 et seq. (1976, Supp. 2000).

2. The Application of the Company is granted as filed.

3. A Certificate of Environmental Compatibility and Public Convenience and Necessity is hereby granted for the project.

4. SCE&G has established a basis for the need for the facility. The Company has established that a shortfall in the ability of the Company to generate adequate supplies of electricity may well result in the future without the construction of the project. *See* Finding of Fact No. 2, above.

5. The nature of any environmental impact resulting from the project is minimal. *See* Finding of Fact Nos. 5 and 6, above.

6. The impact of the facility upon the environment is justified, considering the state of available technology, the economics of various alternatives, and other pertinent considerations. *See* Findings of Fact Nos. 5 and 6, above.

7. The facility will serve the interests of system reliability and economy. *See* Findings of Fact Nos. 2, 3, 5, 6 and 7, above. Clearly, the project is needed to assure system reliability for needed capacity. Moreover, we concur in the Company's decision to provide this capacity with owned generation. The uncertainty of supply and attendant

costs presently associated with purchased power coupled with the economic benefits of owned generation make the Company's decision to build generation a prudent one.

8. With regard to applicable State and local laws and regulations, the evidence presented indicated concerted compliance commitments and efforts by the Company.

9. Public convenience and necessity require the construction of the proposed facility. We conclude, based on the testimony of the witnesses and the evidence in this case as a whole that the construction of this facility is necessary in order to generate needed amounts of electricity, overcome the forecasted shortfall, and maintain a proper reserve margin. We believe that without the facility, SCE&G may well face an inability to generate needed amounts of electricity and will not be able to meet the growth in peak demand in the future, much less maintain a proper reserve margin. The project is needed to properly serve the public.

10. The Consumer Advocate filed a Motion which asserts that if the Commission issues the certificate in this matter, it should include a condition that SCE&G evaluate the power purchase option before it requests rate relief. This Motion is made by the Consumer Advocate based on the belief that SCE&G did not compare the estimated cost of the proposed facility with the cost to purchase generating capacity from other wholesale suppliers. SCE&G in response to the Motion asserts that it did, in fact, make a comparison of the option to purchase generating capacity from other wholesale suppliers; it simply did not make the evaluation using a Request For Proposal.

In further response to the Consumer Advocate's motion, in calendar year 2001, the Commission has issued certificates to three different exempt wholesale generating companies. The certified capacity of these facilities totals 2,040 MW. Should the Company need to purchase power from the wholesale market, capacity exists in excess of the combined need of all VACAR in South and North Carolina to meet both their total firm obligation and required SERC reserve margins. Therefore, the Motion of the Consumer Advocate is denied. We would note that should SCE&G file a rate application including this plant in rate base, the Consumer Advocate will have an opportunity to address this issue during that rate proceeding.

This Order shall remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

Chairman

ATTEST:

Executive Director

(SEAL)

Santee Cooper.

One Riverwood Drive
Moncks Corner, SC 29461-2901
(843) 761-8000
P.O. Box 2946101
Moncks Corner, SC 29461-6101

December 8, 2005

Mr. Mitchell Perkins
Director
South Carolina Energy Office
1201 Main Street, Suite 1010
Columbia, South Carolina 29201

Re: Integrated Resource Plan (2004) from the South Carolina Public Service Authority

Dear Mr. Perkins:

Enclosed is the 2004 Integrated Resource Plan (IRP) from the South Carolina Public Service Authority ("Santee Cooper") as required by SC Code Section 58-37-10, -30 and -40. The plan contains the demand and energy forecast for a fifteen-year period, as well as a program for meeting the requirements shown in the forecast. A description of demand-side management programs is also included.

If you have any questions, please call me at (843) 761-4123.

Sincerely,

Sylleste H. Davis
Manager, Wholesale Markets

South Carolina Public Service Authority

Integrated Resource Plan 2004

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Introduction

The South Carolina Public Service Authority ("Santee Cooper") is a body corporate and politic of the State of South Carolina. Santee Cooper operates an integrated electric utility system, including facilities for generation, transmission, and distribution of electric power and energy at retail and wholesale levels.

The source of power for more than 1.8 million South Carolinians, Santee Cooper provides direct service to almost 138,000 residential and commercial customers in Berkeley, Georgetown and Horry counties. Santee Cooper is the primary source of power distributed by the state's 20 electric cooperatives to over 625,000 customers located in all of the state's 46 counties. Santee Cooper also supplies power to 31 large industrial facilities, the cities of Bamberg and Georgetown, and the Charleston Air Force Base. Santee Cooper is the nation's fourth largest publicly owned electric utility of its type based on generation and megawatt-hour sales to ultimate customers.

On a regular basis, Santee Cooper analyzes the existing and future energy needs of its customers in order to ensure it has a plan that will serve its customers in an economical and reliable manner. The process of developing a comprehensive plan to effectively serve the needs of the diverse customer classes involves several various steps. In deciding what future resources are necessary to meet the customers' needs, it is necessary to first forecast the long-term load for each group. The load forecast is then compared to Santee Cooper's existing capacity and planned reserve margins to determine how much generation is needed in the future. A generation plan is developed, and the adequacy of the transmission and distribution system is evaluated. Additionally, options to manage the customer's demand needs are evaluated.

This Integrated Resource Plan ("IRP") contains the demand and energy forecast for a fifteen-year period, as well as a program for meeting the requirements shown in the forecast. This report also includes a description of demand-side management programs as required by SC Code Section 58-37-10, -30 and – 40.

I. Load Forecast

Overview

On an annual basis, Santee Cooper staff in conjunction with its consultant, GDS Associates, Inc., develops a forecast which contains projections of monthly energy and peak demand requirements over a twenty-year period. This load forecast is based on an analysis of historical events and on assumptions regarding the future. These assumptions relate to key factors known to influence energy consumption and peak demand (e.g., economic activity, weather conditions, and local area demographics).

For energy, the weather-sensitive portion of the forecast (residential and commercial classifications) is developed using econometric models. The non-weather sensitive industrial energy forecast is developed based on historical trends and information provided by individual industrial customers.

For demand, an econometric model is developed to project long-term peak demand based on temperatures on historical peak days. In addition to the peak demand base case forecast, high and low-range scenarios are developed to address uncertainties regarding the future.

The forecast referenced within this version of the IRP is Santee Cooper 2004 Load Forecast (LF0401) for Calendar Years 2004 – 2023.

Process

1) Data Collection

The load forecast database is updated each year to include the most recent historical data, including: electric system data (number of customers, kWh sales, and revenues by customer class), economic data, and weather data.

2) Economic Outlook

An economic outlook is prepared each year to address recent trends in economic activity and to develop growth trends for key economic and demographic factors, including: population, employment, personal income, retail sales, and inflation. Economic outlooks are prepared for three areas: the Santee Cooper service area (Horry and Georgetown counties), the Central Electric Cooperative ("Central") service area (primarily the state of South Carolina excluding counties in the northwest area), and the Saluda River Electric Cooperative ("Saluda") service area (northwest counties of the state). Historical values are based on data provided by the U.S. Census Bureau, the Department of Labor, and the Bureau of Economic Analysis. Projected values are based on information obtained from Woods & Poole Economics, Economy.com, the University of South Carolina (Division of Research, Moore School of Business), and the Center for Economic Forecasting at Charleston Southern University.

3) Forecasting Development

The Santee Cooper load forecast represents a territorial load covering portions throughout the state of South Carolina and is comprised of three independent electric systems: Santee Cooper, Central, and Saluda. Forecasts are prepared for each entity and aggregated to produce the Santee Cooper territorial load forecast.

4) Santee Cooper Requirements

Santee Cooper requirements include energy sales, peak demand, and associated distribution losses for the residential, commercial, municipal, and industrial customer classifications. Econometric models are used to project the number of customers and average energy use per customer for both the residential and commercial classifications.

The models quantify the impacts of population, employment, personal income, retail sales, and weather conditions relative to customer growth and energy sales. Retail energy sales are computed as the product of number of customers and average energy use per customer. Projections of municipal energy sales are based on historical trends. Projections of industrial energy sales are developed for each customer and are based on historical trends and information regarding future plans collected from the individual industrial customers.

Projections of peak demand are developed at the aggregate residential and commercial level for the summer and winter seasons. An econometric model is developed to project long-term peak demand based on temperatures on historical peak days.

5) Central Requirements

Central requirements include energy sales, peak demand, and associated distribution losses for the residential, commercial, and industrial customer classifications. The commercial class includes all commercial accounts not on special contracts and all public buildings customers. Econometric models are used to project the number of customers and average energy use per customer for both the residential and commercial classification. The models quantify the impacts of population, employment, personal income, retail sales, and weather conditions relative to customer growth and energy sales. Energy sales are computed as the product of number of customers and average energy use per customer.

Projections of peak demand are developed at the total Central level for the summer and winter seasons and are based on equations that incorporate total energy requirements and the development of an econometric model to project long-term peak demand.

6) Saluda Requirements

Saluda requirements include energy sales, peak demand, and associated distribution losses for the residential, commercial, and industrial customer classifications. The commercial class includes all commercial accounts not on special contracts and all public buildings customers. Econometric models are used to project the number of customers and average energy use per customer for both the residential and commercial classifications. The models quantify the impacts of population, employment, personal income, retail sales, and weather conditions relative to customer growth and energy sales. Energy sales are computed as the product of number of customers and average energy use per customer.

Projections of peak demand are developed at the total Saluda River level for the summer and winter seasons and based on equations that incorporate total energy requirements and the development of an econometric model to project long-term peak demand.

7) Total Territorial Requirements

Total territorial requirements include the combined energy and peak demand requirements for Santee Cooper, Central, and Saluda. The peak demand projections represent the highest simultaneous 60-minute load for the three combined entities.

Future uncertainties are addressed in the forecasting process through model simulations. Simulation software is used to analyze peak demand and to develop a peak demand probability distribution. Historical weather data is used to develop a probability distribution of temperatures at the time of the territorial peak. The temperature distribution serves as input for the peak demand simulation. Results of the simulation analysis provide peak demand estimates for given temperatures and the probabilities that peak demand will rise or fall to specific levels around the base case forecast. The simulation process addresses both peak demand and energy requirements.

Below is a table with the 2004 Load Forecast for energy and demand, and a table with historical energy and demand.

Projected Energy & Summer/Winter Peak Demands

	Summer Peak (MW)	Winter Peak (MW)	Energy Sales (GWH)
2004	4,893	5,181	26,986
2005	5,095	5,440	28,140
2006	5,215	5,584	28,745
2007	5,325	5,718	29,302
2008	5,435	5,849	29,852
2009	5,552	5,981	30,445
2010	5,663	6,121	31,008
2011	5,777	6,257	31,576
2012	5,892	6,395	32,153
2013	6,009	6,536	32,739
2014	6,128	6,677	33,331
2015	6,247	6,820	33,930
2016	6,369	6,966	34,537
2017	6,493	7,113	35,154
2018	6,618	7,263	35,781

*Source is 2004 Load Forecast

Historical Sales and System Peak Loads

Year	Sales (GWH)	System Peak Load (1) (MW)
2004	24,451	5,088
2003	24,060	5,373
2002	24,121	4,795
2001	22,400	4,803
2000	22,139	3,876
1999	20,286	3,729
1998	19,466	3,523
1997	18,437	3,336
1996	17,548	3,441
1995	16,022	3,102

(1) Excludes firm off-system sales to other utilities

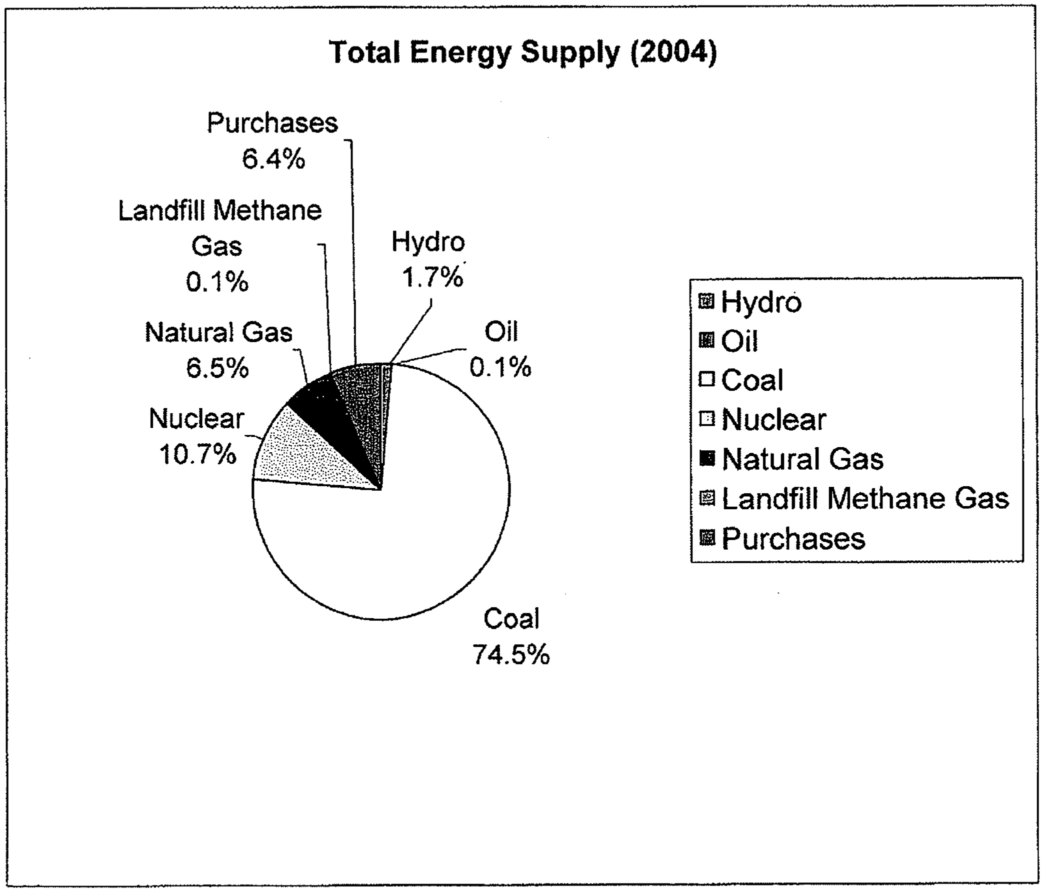
II. Existing Capacity

The following table lists Santee Cooper's existing generating facilities:

Generating Facility	Units	Location	Summer Capacity	Winter Capacity	Fuel	Began Commercial Operation
Jefferies Hydroelectric	1, 2, 3, 4, 6	Moncks Corner	128	128	Hydro	1942
Wilson Dam		Lake Marion	2	2	Hydro	1950
Jefferies	1 and 2	Moncks Corner	92	92	Oil	1954
	3 and 4		306	306	Coal	1970
Grainger	1 and 2	Conway	170	170	Coal	1966
Myrtle Beach Combustion Turbines	1 and 2	Myrtle Beach	20	22	Oil/Gas	1962
	3 and 4		40	50	Oil	1972
	5		30	35	Oil	1976
Hilton Head Combustion Turbines	1	Hilton Head Island	20	25	Oil	1973
	2		20	25	Oil	1974
	3		57	70	Oil	1979
Winyah Station	1	Georgetown	295	295	Coal	1975
	2		295	295	Coal	1977
	3		295	295	Coal	1980
	4		270	270	Coal	1981
V.C. Summer Nuclear Station*		Jenkinsville	318	318	Nuclear	1983
Cross Station	1	Cross	620	620	Coal	1995
	2		540	540	Coal	1983
Horry County Landfill Gas Station		Conway	3	3	Landfill methane gas	2001
Lee County Landfill Gas Station		Bishopville	5	5	Landfill methane gas	2005
Rainey Station	Combined Cycle	Starr	447	508	Gas	2002
	CT 2A		146	168	Gas	2002
	CT 2B		146	168	Gas	2002
	CT 3		74	85	Gas	2004
	CT 4		74	85	Gas	2004
	CT 5		74	85	Gas	2004
Diesel Units		Various	17	17	Oil	Purchased in 2003
Total Capacity			**4,504**	**4,682**		

* Santee Cooper's one-third ownership share. The operating license was extended to August 6, 2042 on April 23, 2004.

Santee Cooper's current total summer peak generating capacity is 4,504 MWs. In addition, Santee Cooper presently receives 84 MW of firm supply from the U.S. Army Corps of Engineers ("Corps") and 327 MW of firm hydroelectric power from the Southeaster Power Administration ("SEPA"). Santee Cooper has entered into a contract to purchase 175 MW of firm power from Progress Ventures, Inc. through December 31, 2006. This additional capacity supplied under contract by the Corps, SEPA, and Progress Ventures brings the total existing summer power supply peak capability to 5,090 MW.



III. Projections of Load, Capacity, and Reserves

In order to ensure Santee Cooper has sufficient generation capacity to cover uncertainties in serving the needs of our customers, it operates using planning reserve targets of 10% and 13% for the winter and summer months, respectively. Uncertainties in meeting customers' load requirements can arise from unit outages, adverse weather conditions, unexpected demand, or an unplanned loss in the transmission system. The planning reserves of 10% for the winter and 13% for the summer have been deemed to be sufficient to mitigate the risks that the various uncertainties pose.

Deciding the optimal reserve margin level requires Santee Cooper to use the most recent long term load forecast. In planning for the future reserve needs, the load forecast's firm load requirements, less any requirements that are served by reserved resources such as SEPA, are used. The load forecast is based on normal weather temperatures in order to determine a base line forecast. The load forecast, as well as reserve margin and capacity information, is contained in the table that follows:

Seasonal Projections of Load, Capacity, and Reserves

W= WINTER, S=SUMMER	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S
	04/05	2005	05/06	2006	06/07	2007	07/08	2008	08/09	2009	09/10	2010	10/11	2011	11/12	2012	12/13	2013	13/14	2014	14/15	2015
Forecast Requirements																						
1 Santee Cooper System Peak	5,404	5,059	5,549	5,179	5,682	5,290	5,814	5,400	5,945	5,517	6,086	5,628	6,222	5,742	6,360	5,857	6,500	5,974	6,642	6,092	6,785	6,212
2 Interruptible Load	(345)	(345)	(345)	(345)	(345)	(345)	(345)	(345)	(345)	(345)	(345)	(345)	(345)	(345)	(345)	(345)	(345)	(345)	(345)	(345)	(345)	(345)
3 Firm Sales	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
4 Total Required Reserved Load	5,085	4,740	5,230	4,860	5,363	4,971	5,495	5,081	5,626	5,198	5,767	5,309	5,903	5,423	6,041	5,538	6,181	5,655	6,323	5,773	6,466	5,893
5 Load Not Requiring Reserve	(619)	(619)	(619)	(619)	(619)	(619)	(619)	(619)	(619)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)
6 Total Load Requiring Reserve	4,466	4,121	4,611	4,241	4,744	4,352	4,876	4,462	5,007	4,787	5,356	4,898	5,492	5,012	5,630	5,127	5,770	5,244	5,912	5,362	6,055	5,482
Cumulative System Capacity																						
7 Available Generating Capacity	4,717	4,539	4,717	4,539	4,717	4,539	4,717	4,539	4,717	4,539	4,717	4,539	4,717	4,539	4,717	4,539	4,717	4,539	4,717	4,539	4,717	4,539
8 Catawba Entitlement	208	208	208	208	208	208	208	208	208													
9 Projected Resource Additions	0	5	17	20	613	619	622	623	1,205	1,210	1,214	1,214	1,214	1,214	1,382	1,360	1,550	1,506	1,550	1,506	1,718	1,652
10 Available Generating Capacity	4,925	4,752	4,942	4,767	5,538	5,366	5,547	5,370	6,130	5,749	5,931	5,753	5,931	5,753	6,099	5,899	6,267	6,045	6,267	6,045	6,435	6,191
Cumulative Purchase Contracts																						
11 Long Term	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411
12 Mid Term Contract	175	175	175	175	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13 Proj Short Term Contract	25		165	65			30						115		95		85		240	20	240	
14 Cumulative Production Capacity	5,536	5,338	5,693	5,418	5,949	5,777	5,988	5,781	6,541	6,160	6,342	6,164	6,457	6,164	6,605	6,310	6,763	6,456	6,918	6,476	7,086	6,602
Reserves																						
15 Generating Reserves	451	598	463	558	586	806	493	700	915	962	575	855	554	741	564	772	582	801	595	703	620	709
16 % Reserve Margin	10%	15%	10%	13%	12%	19%	10%	16%	18%	20%	11%	17%	10%	15%	10%	15%	10%	15%	10%	13%	10%	13%

*based on 2004 Load Forecast

IV. Generation Expansion Plan

Santee Cooper's overall power supply objective is to continue to satisfy the electric power and energy needs of its customers with economical and reliable service. Santee Cooper reviews, from time to time, its power resources and requirements and considers the possible addition of new power resources, which may include nuclear, natural gas, oil and coal fired units, as well as long-term power purchase agreements. Current and future Demand Side Management programs are evaluated on an individual, case-by-case basis.

The 2001 Generation Resource Plan ("2001 Plan") assessed the need for additional generating resources to meet future customer demands and developed a least-cost plan to provide the resources for Santee Cooper to meet these demands. The 2001 Plan evaluated potential purchased power options against Santee Cooper's self-build generation options.

For the planning period of 2001 through 2008, the 2001 Plan recommended the following:

- Short-term firm power purchases,
- Completion of the construction of the Rainey Station Units as planned, including one (1) 500 MW-class combined cycle unit and two (2) simple cycle combustion turbine units,
- Installation of (2) additional simple cycle turbines by January 2004, and
- Construction of a new 600 MW coal-fueled unit at the Cross Generating Station.

As recommended by the 2001 Plan, a 508 MW combined-cycle unit began operation in January 2002. One 168 MW simple cycle unit began commercial operation in March 2002 and a second 168 MW simple cycle unit began operation in May 2002. In January, 2004, additional simple cycle turbines began operation at the Rainey Station, for a total of over 1000 MWs at that site. The construction of a third coal-fueled unit at the Cross Generating Station was approved and is planned for commercial operation January 1, 2007.

The 2001 Plan was updated in 2003. All assumptions, including fuel prices, load forecast, new capacity options and cost, and economic parameters, were updated. No retirements were assumed to occur during the study period. A study period of 2003 through 2015 was used. Current and future Demand Side Management programs were not evaluated in the plan, but are separately evaluated on an individual, case-by-case basis.

Sensitivity analysis was performed on load growth, fuel costs, construction costs, and interest rates. Also, scenarios were run to determine the cost effects of varying levels of contract purchases.

The results of the 2003 Generation Plan ("2003 Plan") recommended the purchase of short term contracts as needed prior to the construction of an additional 600 MW coal unit to begin operation in January, 2009. The short term purchases and construction of the fourth unit at Cross were approved by the Santee Cooper Board of Directors in March, 2004.

The construction of the third and fourth coal-fired units at Cross is in progress and on schedule.

V. Transmission System Adequacy

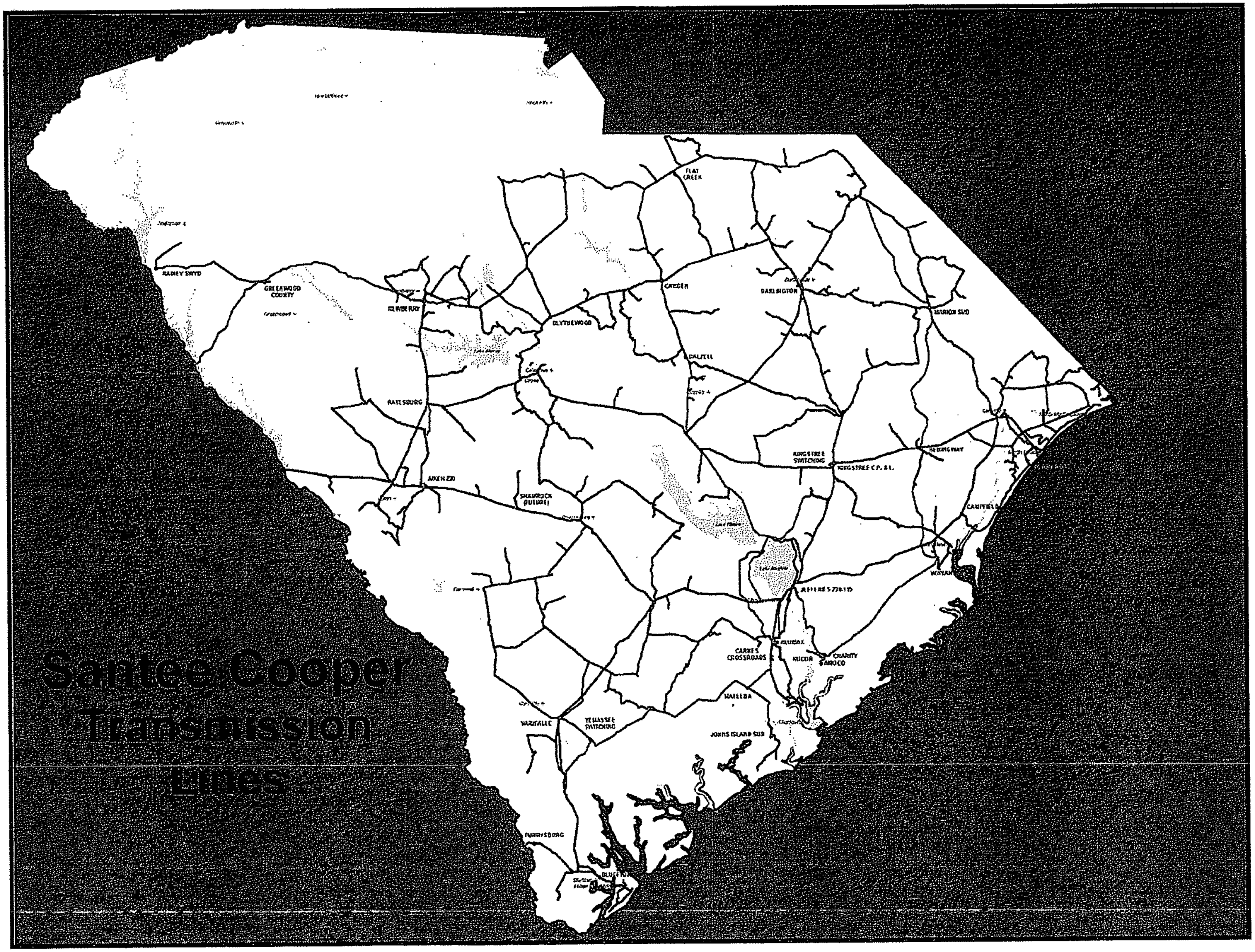
Santee Cooper's transmission and distribution lines, as well as substations, deliver from the generating stations the reliable, low-cost power expected by customers. Santee Cooper operates an integrated transmission system which includes lines owned and leased by Santee Cooper as well as those owned by Central. The transmission system includes approximately 4,400 miles of transmission lines (see map below). Santee Cooper operates 82 transmission substations and switching stations serving 75 distribution substations and 335 Central Cooperative delivery points. Communications sites at 97 locations are in place to support the monitoring and controlling of integrated power system operations. Santee Cooper plans the transmission system to operate during normal and single contingency conditions and to maintain system voltages that are consistent with good utility practice.

Santee Cooper's transmission system is interconnected with other major electric utilities in the region. It is directly interconnected with SCE&G at eight locations; with Progress Energy Carolinas ("Progress Energy") at five locations; with Southern Company Services, Inc. ("Southern Company") at one location; and with Duke Power, a subsidiary of Duke Energy Corporation ("Duke"), at two locations. Santee Cooper is also interconnected with SCE&G, Duke, Southern Company and SEPA through a five-way interconnection at SEPA's J. Strom Thurmond Hydroelectric Project, and with Southern Company and SEPA through a three-way interconnection at SEPA's R. B. Russell Hydroelectric Project. Through these interconnections, Santee Cooper's transmission system is integrated into the regional transmission system serving the southeastern areas of the United States and the Eastern Interconnection. Santee Cooper has separate interchange agreements with each of the companies with which it is interconnected which provide for mutual exchanges of power. Santee Cooper is currently developing two additional ties with Progress Energy.

Santee Cooper is party to the Virginia-Carolinas Reliability Agreement ("VACAR") which exists for the purpose of safeguarding the reliability of the electric service of the parties thereto. Other parties to the VACAR agreement are SCE&G, Progress Energy, Duke, SEPA, APGI-Yadkin Division., Dominion Virginia Power, North Carolina Electric Membership Corporation, North Carolina Eastern Municipal Power Agency, North Carolina Municipal Power Agency #1 and Public Works Commission of the City of Fayetteville.

As a party to VACAR, Santee Cooper is also a member of the Southeastern Electric Reliability Council, which is one of 10 regions of the North American Electric Reliability Council.

Santee Cooper Transmission Lines



VI. Demand Side Management (DSM) Activities

1. Good Cents New and Improved Home Program

The Good Cents Program was developed to provide residential customers an incentive to build new homes to higher levels of energy efficiency and improve existing homes by upgrading heating and air conditioning equipment and the thermal envelope to high energy efficiency standards. All homes are evaluated to determine if they meet the standards set for the program. Inspections are completed during construction for new homes and at the completion of construction for new and improved homes.

Program participation in 2004 resulted in an estimated demand savings of 13,803 kW and estimated energy savings of 19,719,000 kWh. Total expenditures for the Good Cents Program incurred through Santee Cooper in 2004 were $5,804,116. (Demand savings are based on summer peak demand reduction of 1.05 kW).

2. H_2O Advantage Water Heating Program

H_2O Advantage is a storage water heating program designed to shift the demand related to water heating off-peak. This is accomplished with the installation of an electronic timer or radio controlled switch on an 80 gallon water heater. This program began in 1990 and was offered for the last time in 2000. The contract spans 10 years so this program will no longer be impacting the system after 2010.

Program participation in 2004 resulted in an estimated demand savings of 1,390 kW. Total expenditures for the H_2O Advantage Program incurred through Santee Cooper in 2004 for existing participants were $2,090,130.

3. Commercial Good Cents

Commercial Good Cents is offered to commercial customers building new facilities that improve the efficiency in the building thermal envelope, heating and cooling equipment, and lighting. Commercial customers that meet program standards are given an up-front rebate to encourage participation in the program.

Program participation in 2004 resulted in an estimated demand savings of 177 kW and estimated energy savings of 284,858 kWh. Total expenditures for the Commercial Good Cents Program incurred through Santee Cooper in 2004 were $52,758.

4. Thermal Storage Cooling Program

The Thermal Storage Cooling Program shifts energy used by commercial customers for air conditioning from peak to off-peak hours by utilizing thermal energy stored in a medium such as ice or water. Rebates are offered to customers who install this type of equipment. There is currently only one active participant in this program.

VII. Other Information

Environmental

Santee Cooper is ever mindful of balancing the stringent expectations of being an environmental steward with reliable, low-cost power. Protecting the state's environment plays an important role in the company's planning for new facilities. Santee Cooper is proud to operate some of the cleanest coal-fired generating stations in the country. In fact, 88 percent of Santee Cooper's coal-fired generating units will have state of the art emission control equipment by 2009. Since 1999, Santee Cooper has decreased its system emissions rates by 16 percent for nitrogen oxide and by 21 percent for sulfur dioxide, in part due to new emission control equipment. Of the Southeast's seven scrubbed units, five are owned and operated by Santee Cooper. Scrubbers work to remove sulfur dioxide from power plants so that emissions are not released into the atmosphere. The two new units at Cross Generating Station are being built with no net increase of nitrogen oxide or sulfur dioxide emissions at the facility.

Other examples of Santee Cooper's environmental stewardship are the Give Oil For Energy Recovery ("GOFER") program and Green Power. The GOFER program, in place since 1990, provides do-it-yourself oil changers a place to safely dispose of used motor oil. In 2004, Santee Cooper collected 900,000 gallons of used oil from more than 560 sites and used the oil to generate electricity.

The utility's Green Power program continues to be successful. Santee Cooper took a potent greenhouse gas, methane gas, and turned it into a fuel source. Santee Cooper currently generates over 8 MWs of Green Power with plans for additional methane-gas-to-electricity generating units in Anderson and Richland counties. More than 2600 industries, businesses and homeowners all across the state have joined the effort to protect the environment by purchasing green power.

Interruptible / Economy Power Pricing Rates

Santee Cooper has developed and offers time-of-use, non-firm, and off-peak rates to its direct-served commercial and industrial customers to encourage them to reduce their peak demand.

An "economy power" rate is available to industrial customers, which is based on an hourly incremental energy rate. This is a real time pricing rate; the price for energy changes each hour. Customers must schedule their usage each hour. Service under this Rider is curtailable in emergency situations by Santee Cooper. Pricing alternatives are available under this rate where the energy price is fixed during certain hours.

There are also supplemental curtailable and interruptible rates available to industrial customers which allow for curtailment under certain circumstances.

Conclusion

Santee Cooper continues to evaluate and adjust the load forecast and resource plans as needed to meet future customer demand in a reliable and cost effective manner. Demand-side management programs are evaluated on a regular basis for their effect on energy and demand. Santee Cooper offers these DSM programs where cost effective, and has completed generation resource planning necessary to ensure a reliable generation plan to meet customer demands through 2010. Additionally, Santee Cooper has developed rates that have encouraged over 400 MWs of peak load control by industrial customers.

Section 8.1
Ref 7

Santee Cooper.

One Riverwood Drive
Moncks Corner, SC 29461-2901
(843) 761-8000
P.O. Box 2946101
Moncks Corner, SC 29461-6101

November 17, 2006

Mr. Mitchell Perkins
Director
South Carolina Energy Office
1201 Main Street, Suite 1010
Columbia, South Carolina 29201

Re: Annual Update to Integrated Resource Plan (2004) from the South Carolina Public Service Authority

Dear Mr. Perkins:

Enclosed is the annual update (dated November 2006) to Santee Cooper's Integrated Resource Plan (IRP). This update provides a status of DMS Programs and the Generation Resource Plan as required by the South Carolina Code, Section 58-37-40.

If you have any questions, please call me at (843) 761-4123.

Sincerely,

Sylleste H. Davis

Sylleste H. Davis
Manager, Wholesale Markets

2004 INTEGRATED RESOURCE PLAN
ANNUAL UPDATE

South Carolina Public Service Authority

Originally submitted: December 2005

Updated: November 2006

TABLE OF CONTENTS

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2004 Integrated Resource Plan Annual Update

As required by South Carolina Code, Section 58-37-40, this report provides an annual update to the South Carolina Public Service Authority ("Santee Cooper") 2004 Integrated Resource Plan submitted December 8, 2005.

I. Update to: Load Forecast

Load Forecast LF0501 was completed and published in October 2005, and provides an update to the 2004 Load Forecast.

Projected Energy & Summer/Winter Peak Demands

	Summer Peak (MW)	Winter Peak (MW)	Energy Sales (GWH)
2005	5,189	5,252	27,672
2006	5,305	5,393	28,258
2007	5,421	5,534	28,848
2008	5,538	5,676	29,448
2009	5,659	5,821	30,069
2010	5,772	5,960	30,646
2011	5,886	6,098	31,235
2012	6,003	6,240	31,833
2013	6,122	6,385	32,441
2014	6,243	6,532	33,059
2015	6,364	6,679	33,678
2016	6,486	6,827	34,301
2017	6,610	6,977	34,934
2018	6,736	7,129	35,577
2019	6,864	7,284	36,229

*Source is 2005 Load Forecast

Historical Sales and System Peak Loads

Year	Sales (GWH)	System Peak Load [1] (MW)
2005	25,064	5,371
2004	24,451	5,088
2003	24,060	5,373
2002	24,121	4,795
2001	22,400	4,803
2000	22,139	3,876
1999	20,286	3,729
1998	19,466	3,523
1997	18,437	3,336
1996	17,548	3,441
1995	16,022	3,102

(1) Excludes firm off-system sales to other utilities

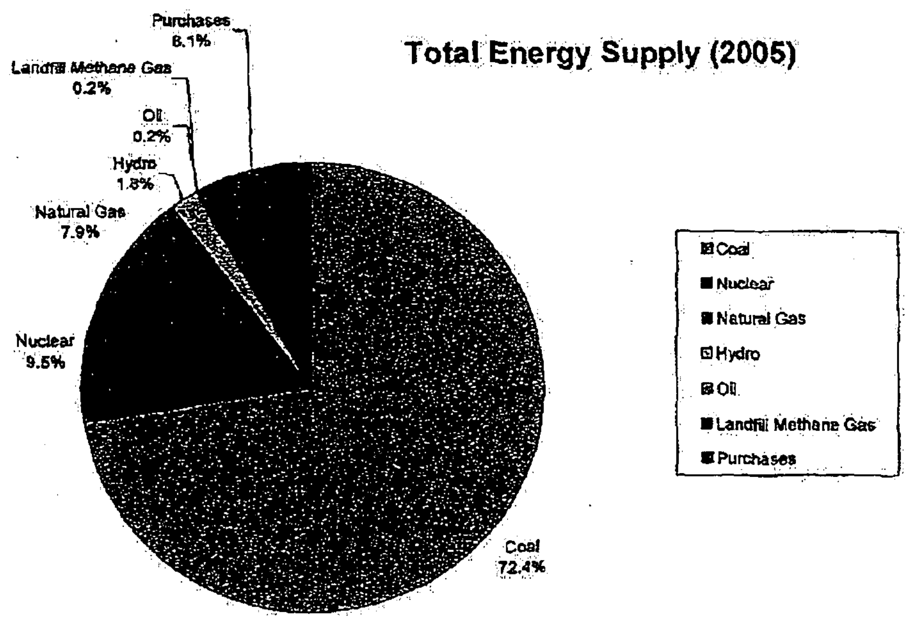
II. Update to: Existing Capacity

The Authority's generating facilities consist of the following facilities:

Generating Facilities	Location	Initial Date in Service	Winter Peak Capability (MW)	Summer Peak Capability (MW)	Energy Source
Jefferies Hydroelectric Generating Station	Moncks Corner	1942	128	128	Hydro
Wilson Dam Generating Station	Lake Marion	1950	2	2	Hydro
Jefferies Generating Station	Moncks Corner				
Nos. 1 and 2		1954	92	92	Oil
Nos. 3 and 4		1970	306	306	Coal
Grainger Generating Station Nos. 1 and 2	Conway	1966	170	170	Coal
Combustion Turbines Nos. 1 and 2	Myrtle Beach	1962	22	20	Oil/Gas
Combustion Turbines Nos. 3 and 4	Myrtle Beach	1972	50	40	Oil
Combustion Turbine No. 5	Myrtle Beach	1976	35	30	Oil
Combustion Turbine No. 1	Hilton Head Island	1973	25	20	Oil
Combustion Turbine No. 2	Hilton Head Island	1974	25	20	Oil
Combustion Turbine No. 3	Hilton Head Island	1979	70	57	Oil
Winyah Generating Station	Georgetown				
No. 1		1975	295	295	Coal
No. 2		1977	295	295	Coal
No. 3		1980	295	295	Coal
No. 4		1981	270	270	Coal
Summer Nuclear Station(1)	Jenkinsville	1983	318(2)	318(2)	Nuclear
Cross Generating Station	Cross				
Unit 1		1995	620	620	Coal
Unit 2		1983	540	540	Coal
Horry Landfill Gas Station	Conway	2001	3	3	LMG(3)
Lee County Landfill Gas Station	Bishopville	2005	5	5	LMG
Richland County Landfill Gas Station	Elgin	2006	5	5	LMG
Rainey Generating Station	Starr				
Unit 1		2002	508	447	Gas
Unit 2A		2002	168	146	Gas
Unit 2B		2002	168	146	Gas
Unit 3		2004	85	74	Gas
Unit 4		2004	85	74	Gas
Unit 5		2004	85	74	Gas
Diesel Generating Units		2003(4)	17	17	Oil
Total Capability			4,687	4,509	

(1) Virgil C. Summer Nuclear Station ("Summer Nuclear Station").
(2) Represents the Authority's one-third ownership interest.
(3) Landfill Methane Gas ("LMG")
(4) Year Purchased by the Authority.

In 2005, Santee Cooper met its energy requirements using the following resources:



III. Update to: Projections of Load, Capacity, and Reserves

Santee Cooper continues to operate using planning reserve targets of 10% and 13% for the winter and summer months, respectively. The load forecast, as well as reserve margin and capacity information, is contained in the table that follows:

Seasonal Projections of Load, Capacity, and Reserves

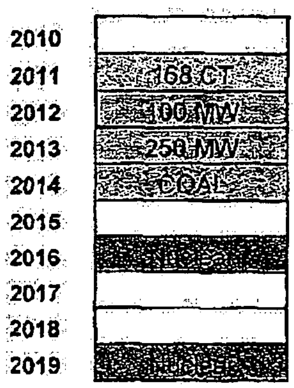
W=Winter, S=Summer	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S	W	S
	05/06	2006	06/07	2007	07/08	2008	08/09	2009	09/10	2010	10/11	2011	11/12	2012	12/13	2013	13/14	2014	14/15	2015
Forecast Requirements																				
1 *Santee Cooper System Peak*	5,394	5,307	5,534	5,423	5,675	5,538	5,822	5,659	5,960	5,773	6,100	5,887	6,241	6,003	6,385	6,123	6,532	6,244	6,679	6,366
2 Interruptible Load	(298)	(299)	(298)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)	(299)
3 Firm Sales	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
4 Total Reserved Load	5,122	5,034	5,262	5,150	5,402	5,265	5,549	5,386	5,687	5,500	5,827	5,614	5,968	5,730	6,112	5,850	6,259	5,971	6,406	6,093
5 *Load Not Requiring Reserve*	(619)	(619)	(619)	(619)	(619)	(619)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)	(411)
6 Total Load Requiring Reserve	4,503	4,415	4,643	4,531	4,783	4,646	5,138	4,975	5,276	5,089	5,416	5,203	5,557	5,319	5,701	5,439	5,848	5,560	5,995	5,682
Cumulative ***System Capacity***																				
7 Available Generating Capacity	4,722	4,544	4,722	4,544	4,722	4,544	4,722	4,544	4,722	4,544	4,722	4,544	4,722	4,544	4,722	4,544	4,722	4,544	4,722	4,544
8 Catawba Entitlement	208	208	208	208	208	208														
9 Projected Resource Additions	0	10	592	592	600	607	1,196	1,196	1,202	1,204	1,204	1,204	1,804	1,804	1,804	1,804	1,804	1,804	1,804	1,804
10 Available *Generating Capacity*	4,930	4,762	5,522	5,344	5,530	5,359	5,918	5,740	5,924	5,748	5,926	5,748	6,526	6,348	6,526	6,348	6,526	6,348	6,526	6,348
Cumulative Purchase Contracts																				
11 *Long Term*	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411	411
12 Mid Term Contract	175	175																		
13 Proj Short Term Contract	60	265				105				5	35	135							70	75
14 Cumulative Production Capacity	5,576	5,613	5,933	5,755	5,941	5,875	6,329	6,151	6,335	6,164	6,372	6,294	6,937	6,759	6,937	6,759	6,937	6,759	7,007	6,834
Reserves																				
15 Generating Reserves	454	579	671	606	539	610	760	766	648	664	645	680	969	1,029	825	909	678	788	601	741
16 % Reserve Margin	10%	13%	14%	13%	11%	13%	15%	15%	12%	13%	10%	13%	17%	19%	14%	17%	12%	14%	10%	13%

*based on 2005 Load Forecast

IV. Update to: Generation Expansion Plan

As noted in the 2004 Integrated Resource Plan, a 600 MW coal-fired unit (Cross 3) is scheduled for commercial operation in January 2007, with another 600 MW coal-fired unit (Cross 4) scheduled for January 2009. The construction of these units is well underway and projected COD dates are expected to be met.

In 2005, the Generation Resource Plan was updated and recommended the following, in addition to the Cross 3 and 4 units, for the 2010-2019 time period:



- (1) 168 MW simple cycle combustion turbine to be operational in 2011,
- Purchased power amounts of 100 MW and 250 MW for 2012 and 2013 respectively,
- (1) 600 MW class supercritical pulverized coal unit to be built and operational no later than January 2014, and,
- A 45% ownership share of two (2) 1100 MW class Westinghouse Nuclear units located at the V.C. Summer Nuclear site to be built and operational no later than January 2016 and January 2019, respectively.

In March 2006, the Santee Cooper Board of Directors (i) approved the 2005/2006 Generation Plan, (ii) authorized management to take actions necessary or appropriate to construct and install a 600 MW coal unit to begin operations as soon as possible but not later than January 2014, and (iii) authorized management to take actions necessary or appropriate to obtain a construction and operating permit for ownership shares of (2) 1100 MW nuclear units. In May 2006, the Board authorized management to take actions necessary to accelerate the construction schedule for the 2014 coal unit to as early as January 2012. Shortfalls in capacity and reserves requirements will be met using purchases as necessary.

V. Update to: Demand Side Management (DSM) Activities

1. Good Cents New and Improved Home Program

The Good Cents Program was developed to provide residential customers an incentive to build new homes to higher levels of energy efficiency and improve existing homes by upgrading heating and air conditioning equipment and the thermal envelope to high energy efficiency standards. All homes are evaluated to determine if they meet the standards set for the program. Inspections are completed during construction for new homes and at the completion of construction for new and improved homes.

Program participation in 2005 resulted in an estimated demand savings of 15,470 kW and estimated energy savings of 22,101,000 kWh. Total expenditures for the Good Cents Program incurred through Santee Cooper in 2005 were $202,559.21. (Demand savings are based on summer peak demand reduction of 1.05 kW).

2. H_2O Advantage Water Heating Program

H_2O Advantage is a storage water heating program designed to shift the demand related to water heating off-peak. This is accomplished with the installation of an electronic timer or radio controlled switch on an 80 gallon water heater. This program began in 1990 and was offered for the last time in 2000. The contract spans 10 years so this program will no longer be impacting the system after 2010.

Program participation in 2005 resulted in an estimated demand savings of 853 kW. Total expenditures for the H_2O Advantage Program incurred through Santee Cooper in 2005 for existing participants were $167,294.85.

3. Commercial Good Cents

Commercial Good Cents is offered to commercial customers building new facilities that improve the efficiency in the building thermal envelope, heating and cooling equipment, and lighting. Commercial customers that meet program standards are given an up-front rebate to encourage participation in the program.

Program participation in 2005 resulted in an estimated demand savings of 119 kW and estimated energy savings of 182,884 kWh. Total expenditures for the Commercial Good Cents Program incurred through Santee Cooper in 2005 were $24,620.

4. Thermal Storage Cooling Program

The Thermal Storage Cooling Program shifts energy used by commercial customers for air conditioning from peak to off-peak hours by utilizing thermal energy stored in a medium such as ice or water. Rebates are offered to customers who install this type of equipment. There is currently one active participant in this program.

As part of Santee Cooper's demand control program, currently there are approximately 500 MW of load taking service under interruptible and economy power schedules. This load is excluded from the peak demand calculations for generation planning and reserves resource planning.

VI. Update to: Environmental

1. Green Power

Santee Cooper entered the arena of Green Power in 2001, being the first electric utility in South Carolina to offer electricity generated from renewable resources. In March 2006, the Richland County Generating Station was dedicated as Santee Cooper's third "Green Power" generating facility. A similar Green Power station at the Anderson Regional Landfill is currently under construction. Approval was given in September 2006 for the development of a new environmental program to offer to everyone in South Carolina, for the first time, the ability to purchase local renewable energy through a Green Tag program. This program allows all citizens and businesses in the state to do something positive to improve their environment, no matter their electric provider.

2. Renewables

In 2005, Santee Cooper announced a five-year, statewide and multi-tiered plan that would add solar projects at state universities and in various South Carolina regions, potential wind demonstration projects, and the continuation of landfills across South Carolina to the mix of renewables. In October 2006, Santee Cooper and Coastal Carolina University officially dedicated South Carolina's first solar Green Power site, a historic solar pavilion demonstration project that delivers on Santee Cooper's commitment to reinvest Green Power funds into future renewable energy projects in the state. Santee Cooper has also partnered with Clemson University to implement solar energy technology there.

3. Other

Santee Cooper's coal-fired power plants at Cross and Winyah generate a synthetic gypsum byproduct as a result of using scrubbing technology to reduce sulfur dioxide emissions. American Gypsum is currently constructing a new wallboard plant adjacent to Santee Cooper's Winyah Generating Station. By utilizing Santee Cooper's synthetic gypsum and excess steam in its gypsum wallboard production, the partners are converting waste that would otherwise be landfilled into a valuable building product.

Section 8.1 Ref 8

Santee Cooper

INNOVATION IN ACTION

2006 ANNUAL REPORT

Santee Cooper's Mission

The mission of Santee Cooper is to be the state's leading resource for improving the quality of life for the people of South Carolina.

To fulfill this mission, Santee Cooper is committed to:

- being the lowest-cost producer and distributor of reliable energy, water, and other essential services;
- providing excellent customer service;
- maintaining a quality workforce through effective employee involvement and training;
- operating according to the highest ethical standards;
- protecting our environment; and
- being a leader in economic development.

Innovation in Action

Innovation played a key role in our successes. We see innovation throughout all that we do. In 2006, our employees implemented breakthrough strategies to meet the growing demand for energy, use fuel more efficiently and reliably, save money, conserve energy, boost economic development and protect our environment while overcoming significant challenges related to the growth of South Carolina.

INNOVATION
EXECUTIVE REPORT

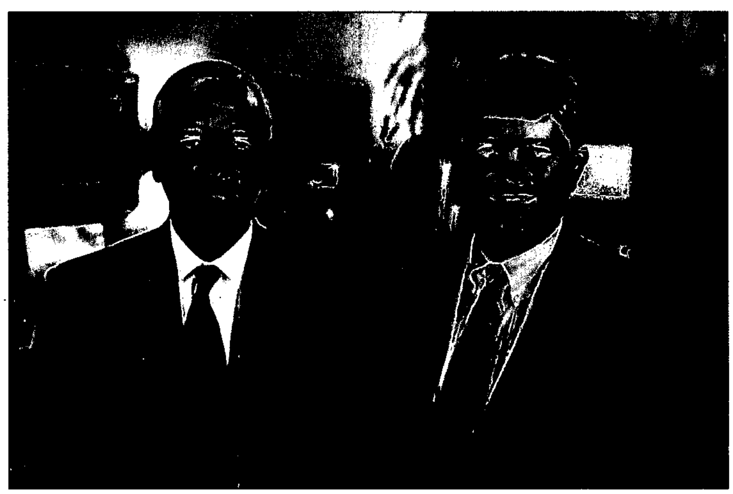
Executive Report

Santee Cooper's performance was strong in 2006.

Innovation played a key role in our successes. We see innovation throughout all that we do. In 2006, our employees implemented breakthrough strategies to meet the growing demand for energy, use fuel more efficiently and reliably, save money, conserve energy, boost economic development and protect our environment while overcoming significant challenges related to the growth of South Carolina.

2006 MILESTONES

The increased emphasis on renewable energy, the beginning of a new building era in the company's history and new conservation measures only begin to highlight the ways in which Santee Cooper added value to the state in 2006.



In April, the board approved Santee Cooper's new generation plan to meet future load growth, which involves constructing a new 600-megawatt (MW) supercritical coal-fired facility in Florence County on our Pee Dee site by 2012 and exploring additional nuclear energy. We are proceeding with the necessary steps before we make a final decision on more nuclear power.

We were efficient in 2006 completing one half of the largest capital expenditure in our history. Our Cross Unit 3 became commercially operational on Jan. 1, 2007. On time and on budget, employees and more than 1,700 contractors weathered tight deadlines and other substantial hurdles to deliver a state-of-the-art and environmentally cutting-edge facility. Cross Unit 3 will significantly reduce the amount of purchased power and natural gas we need, thereby helping customers save money.

Our reliability rates continue to be the envy of the energy industry. We achieved a generation availability rate of 93.59 percent, transmission rate of 99.9976 percent and distribution rate of 99.9962 percent. Our overall average customer satisfaction rating remained high at 99 percent.

We maintained some of the highest municipal electric utility financial ratings in the nation. Those include an AA rating from both Fitch Ratings and Moody's Investors Services and an AA- rating from Standard & Poor's. As part of a $599,880,000 bond offering in January, we were very successful in targeting the retail segment of the market and selling over $52 million to retail investors in South Carolina. In October, the board approved the sale of $9.9 million worth of tax-free mini-bonds to help fund capital improvement projects. A refunding bond sale also in November resulted in the sale of $114,755,000 of the 2006 Series C bonds. The net present-value savings were $8.1 million, which equated to a 7.08 percent savings. Our debt to equity ratio of 69/31 remains stable.

We unveiled our next phase of Green Power with the opening of the state's first solar Green Power site at Coastal Carolina University in October.

Our economic development activities flourished. As examples, 2006 saw the groundbreaking of American Gypsum's $125 million wallboard facility on our Winyah Station site and the announcement of Builders FirstSource's $5 million expansion project in the Loris Commerce Center. It was also the first full year of the implementation of our economic development initiatives, in which we dedicated funds for our site certification, strategic economic development planning and professional development opportunities. The electric cooperatives have been supportive and helpful with these efforts.

Since 1988, when Santee Cooper joined with the South Carolina Electric Cooperatives to create the Palmetto Economic Development Corporation, the South Carolina Power Team has been involved in more than 400 new industrial locations and expansions, representing $6.6 billion in capital investment and more than 37,000 new jobs. In 2006, 1,864 new jobs, $196.4 million in new capital investments and 18,250 new kilowatts of needed capacity came about due to our efforts and those of our partners.

CHALLENGES AWAIT

The issues surrounding growth and increased energy consumption dominated our thinking and planning process in 2006, and will continue for the next several years.

Our single biggest challenge is meeting the load growth. Electricity demand is expected to rise more than 30 percent during the next 15 years in the Southeast, one of the fastest-growing regions in the United States. The U.S. Census Bureau reports that nearly 40 percent of the nation's population will live in the South by the year 2030.

Santee Cooper's growth rate in its direct serve area has averaged 3.5 percent over the past five years. Santee Cooper serves one of the state's fastest growing areas, Myrtle Beach, directly. And Santee Cooper generates and transmits power to the vast majority of the state's growing rural areas through the state's 20 electric cooperatives.

As further evidence of the growth, this year Santee Cooper experienced a record number of new retail customers, 7,474, which far surpassed our previous record of 6,303 in 1997.

This growth phenomenon presents challenges for Santee Cooper.

We are up for these challenges and are working to implement our long-term generation plan to meet this load growth. We must manage the process in a way that protects the environment, keeps power costs low and reliable and maintains the quality of life we enjoy.

We were the only public power utility in 2006 to announce it is exploring the viability of additional nuclear power. We do not take this quest lightly and fully comprehend the ramifications and magnitude our future decision will have on our company's history and direction.

Conservation and the use of renewables are critical, and our role is to encourage and give the proper economic signals. However, it will take a combination of conserving and building to meet our growing number of customers' energy demands.

We must remain vigilant, as we will be expending significant amounts of capital to build our next generation of power plants and transmission and distribution facilities. Santee Cooper is well respected in the financial markets and will continue to work hard to retain our strong financial position.

The issue of climate change continues to gain momentum in the public arena. The solutions to reducing carbon emissions include greater energy conservation, increased use of renewables, additional nuclear power facilities and advances in research and technologies. We will continue to fully participate in this important discussion and gauge the impact to our customers, our environment and our nation's economy.

BUILDING ON THE FUTURE

Santee Cooper's future is bright. We have ambitious construction schedules for Cross Unit 4 and Pee Dee Unit 1 and we are on an accelerated schedule to evaluate additional nuclear energy.

Our employees drive innovation. It is this spirit and passion for improvements that allow us to take calculated risks and do what perhaps others have not done.

We are dedicated to finding creative solutions to keep power costs low, provide excellent customer service, enhance employee productivity and be a valued corporate citizen.

We have a responsibility to keep the lights on, and we take it seriously. The choices we are making today will ensure future generations can enjoy the extraordinary standard of living we have in South Carolina.

Being the state's leading resource for improving the quality of life for the people of South Carolina requires nothing less, and we are confident we'll continue to fulfill our mission in 2007 and beyond.

O.L. Thompson III
Chairman, Board of Directors

Lonnie N. Carter
President and Chief Executive Officer

Low Cost Power

Retail Bond Offerings

In January 2006, Santee Cooper expended additional efforts to market bonds to South Carolina retail investors in advance of a major bond issue by holding our first retail pre-order period. We feel it is important, when experiencing such growth, to reemphasize the importance of people knowing Santee Cooper and investing in us.

And when people own our debt, the money stays in our state, further adding value and positive economic impact to South Carolina.

Employees like Nan Cline, a financial analyst in our Treasury department, helped develop a strategy to expand our offerings to retail investors in South Carolina. It was the success with the past mini-bond sales that encouraged Santee Cooper to further our efforts in the retail market.

The Santee Cooper Board of Directors approved the sale of $599,880,000 revenue obligation bonds, of which $52,375,000 was sold to retail investors, 2006 Series A and B, with maturities ranging from 2007 through 2039. The all in-true interest cost was calculated at 4.64 percent.

"We view this response as a vote of confidence in the financial strength of Santee Cooper by our owners, the people of South Carolina. It says people support Santee Cooper as a good investment for the state," said Cline.

We plan to continue retail marketing to South Carolinians as an integral part of future bond sales.

Meeting Growth

How does a utility plan to meet the future power needs in one of the fastest growing regions of the country? Through strategic planning, thinking differently, and using both expertise and foresight to operate in a new world.

Santee Cooper needs to add much more base load electrical generation within the next several years to keep up with growing customer demand. While in the midst of building Cross Units 3 and 4, we ramped up our New Generation Plan, and considered all cost-effective options.

Folks like John Dills, manager of station construction, and Jay Hudson our manager of environmental management, are working to safely and effectively design, permit and construct our new Pee Dee Generating Station, a 600-megawatt coal-fired facility in Florence County.

"We aim to make the Pee Dee Station one of the cleanest power plants in the country. We're doing it by incorporating high efficiency systems and the best available control technology from the beginning, so it protects the environment and is cost-effective," said Dills.

Even with the Pee Dee Station, additional generation is needed. America needs to kick its oil addiction in a way that does not harm the environment and with a price tag we can afford. The answer may be nuclear energy.

We are contemplating something many thought would never happen in their lifetimes...working to restart the nuclear industry. We are one of the national industry leaders moving forward with steps necessary to determine nuclear power expansion. Nuclear power is safe, clean, reliable and can help reduce the country's dependence on foreign fuel sources.

While the physical results of these decisions won't be visible for a few years, the benefits of the strategic thinking and smart planning are already coming to light.

Cross 3

Cross Generating Station Unit 3 began commercial operation on Jan. 1, 2007, delivering on our promise to generate this new power on time and under budget.

The unit is a 600-megawatt pulverized coal-fired facility and joins Units 1 and 2 at the power plant in Cross, S.C. Unit 3 cost $675 million to construct, and combined with the $755 million Cross Unit 4 also under construction, make it a $1.4 billion project, the largest capital expenditure in Santee Cooper's history.

"Our construction team began this effort in April 2004, and in 33 months they have built and started a major coal unit, amid steel and worker shortages, delays in permits, and other construction hurdles. I don't know of any other utility who has achieved such a feat," said Bill McCall, executive vice president and chief operating officer. "Our employees worked long hours and through many tough situations to achieve this historic success. They weathered the bumps well, which is a testament to their expertise and perseverance."

Employees like Jack Holder, manager of station construction, worked to navigate our way through the many challenges. "Serving as our own general contractor allows us to assume the risk and better manage our schedule and costs. Once again, this strategy has paid off for our customers, who benefit with reliable and low cost power now and in the future," he said.

Cross Unit 3 will reduce the amount of high-priced natural gas and purchased power Santee Cooper needs to use and instead allows the company to burn lower-priced and plentiful coal, which helps keep power costs level for customers.

We are not resting on our laurels. Construction work continues on Cross 4, a companion 600-megawatt unit. That unit is on track and is scheduled to come on line Jan. 1, 2009. When complete, it will bring the total output generated at Cross to 2,400 MW, making it the largest coal-fired generating station in both North and South Carolina and increasing Santee Cooper's total generating capacity to more than 5,600 MW.

Cross Generating Station Units 3 and 4

$1.4 Billion... cost to build Units 3 and 4

33... months it took to build Unit 3 at a cost of $675 million

2,400 megawatts... will be largest coal-fired power plant in the Carolinas when complete

809,000 homes... how many homes it will power daily when complete

1,810... workers at height of construction, more than entire Santee Cooper workforce

2... train loads of coal the facility will burn every day

20,000... truckloads of concrete used in the two units. This equates to more than 200,000 cubic yards of concrete, and most of it is manufactured at an onsite batch plant

300,000... cubic yards of soil that will be excavated, hauled, compacted and graded

20,000... concrete pilings that will be installed

40,000... tons of steel used to construct two units

10,500... tons of structural steel used for the turbine building, coal silo bay and boiler. They are fastened together with more than 150,000 bolts

65... acres of laydown area being used to stage and store parts and material

Customer Service

Energy Conservation

Santee Cooper partnered with its largest customer, The Electric Cooperatives of South Carolina, in a groundbreaking program in 2006 to promote energy conservation by distributing thousands of energy efficient light bulbs across the state.

Under the theme, "Together, we have the power to make a difference," the two organizations did something that they've never done before: distributed 60,000 compact fluorescent lights (CFL) to the cooperative member-owners at each of their annual meetings, to Santee Cooper employees at safety meetings, and at various community and business functions.

Santee Cooper expanded the CFL idea by giving one away to all its new direct serve customers and any customers who purchased Green Power, our renewable energy program. It's just another way of encouraging customers to think differently about their energy habits.

Employees like Mike Goff and Sherry Coleman, marketing representatives in the Horry-Georgetown office, saw the need to encourage smarter energy use habits, and customers have responded well to the different-looking bulbs.

"They look different, because they are. CFLs are just one way we can make a simple change, yet they make a big difference financially and environmentally. Compact fluorescent lighting uses 75 percent less energy and lasts up to 10 times longer," said Coleman.

Energy conservation is a powerful tool that allows us to become more energy independent, save money and protect the environment for future generations.

Reliability award

In April, Santee Cooper joined the ranks with 63 other national public power utilities in winning the inaugural Reliable Public Power Provider (RP3) award. This prestigious recognition from the American Public Power Association is awarded to public power utilities that provide consumers with the highest degree of reliable and safe electric service.

RP3 recognizes utilities that demonstrate proficiency in four key areas: reliability, safety, training and system improvement. Criteria within each category is based on sound business practices and represent a utility-wide commitment to safe and reliable delivery of electricity.

Employees like Jimmy Greene, a crew supervisor in Garden City, and Kyle Powell, a line technician in North Myrtle Beach, helped make this award a reality. They, along with fellow teammates, achieved a 99.9962 percent distribution reliability rate in 2006. They did it by focusing on the high correlation between work safety and high reliability.

Examples of safe work practices at Santee Cooper include participating in regular safety meetings, having management participate in utility safety programs, having a safety-specific corporate goal with financial incentives, providing annual training of CPR techniques, and being able to use automatic electric defibrillators.

"We're extremely pleased to be recognized with this award, especially at a time of rapid customer growth and increased demands," Greene said. Added Powell, "It takes an entire Santee Cooper team to keep the lights on for our growing number of customers."

Value to the State

Solar energy

Santee Cooper built the state's first Green Power solar site in 2006, heralding a new era in renewable energy progress for South Carolina.

We partnered with Coastal Carolina University on this $385,000 renewable project, making it the first solar photovoltaic project at a public university in South Carolina.

Employees like Liz Kress, principal engineer, helped chart new paths by engineering the solar panels that sit atop four new multi-purpose pavilions along a major CCU campus thoroughfare.

This historic solar pavilion demonstration project, which produces 16 kilowatts, delivers on Santee Cooper's commitment to promote renewable energy and to reinvest Green Power funds into future renewable energy projects in the state.

"The solar pavilions are intended to encourage the design of buildings with photovoltaic solar applications in mind, educate the public and inspire tomorrow's inventors to seek future solutions in renewable energy," said Kress.

Last year, we announced a five-year, statewide and multi-tiered plan that would add solar, wind and small-landfill energy to the company's mix of renewables. The solar pavilions deliver on that promise, and more is to come.

Fly ash

Dirt roads, as we know them, with muddy ruts and water-filled potholes, may be a thing of the past thanks to a creative solution by Santee Cooper employees.

Employees like Tommy Edens, administrator of combustion products utilization, worked with consultants to incorporate Santee Cooper's fly ash to enhance road strength and pave dirt roads in a way that used a valuable resource in an environmentally-friendly and cost-effective manner.

Fly ash is a combustion byproduct from burning coal and we produce approximately 700,000 tons of it yearly from our coal-burning power plants. We've been selling it since 1999 to companies who make useful building materials with it, such as concrete blocks and tile. It even went into the Cooper River Bridge in Charleston.

Tommy and the consultants thought fly ash may be a great material for paving dirt roads too because its minute particle shape is round and would naturally bind together with sand's irregular shape. They were right. The result is a road that is as hard as an asphalt road, but much cheaper.

"By using this material today, counties can build a road for about $125,000 a mile, instead of $600,000 a mile for regular asphalt treatment," says Edens.

Following on the heels of a successful patch test on a road near St. Stephens in Berkeley County in 2004, Santee Cooper began initial work in 2006 in order to prepare to test a dirt road on McKnight Forest Road, near Moncks Corner. A one-mile section of road is planned to be paved using 400 tons of fly ash trucked to the site from our Cross Station.

If successful, it could mean the eventual end of the traditional sand and gravel roads used for generations, a new market for Santee Cooper's fly ash and lower maintenance cost for counties in the road business.

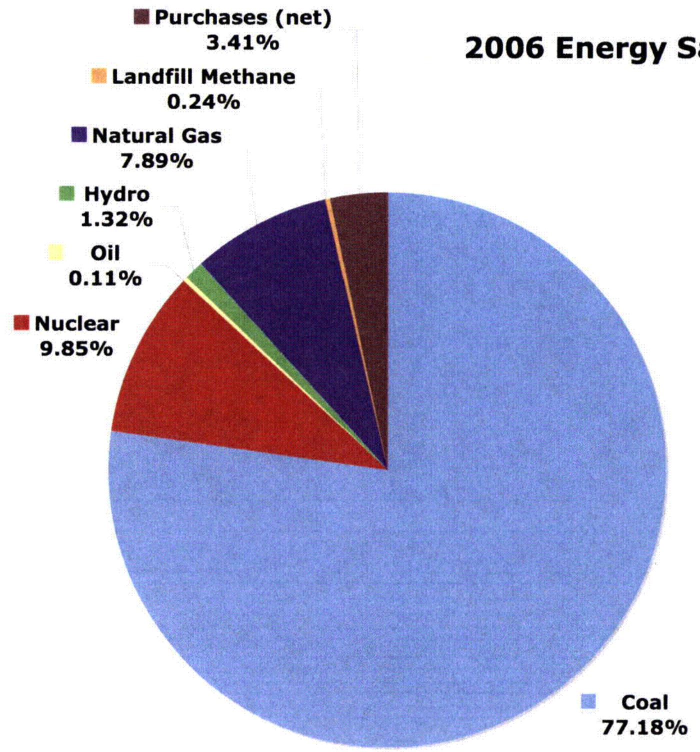
2006 Corporate Statistics

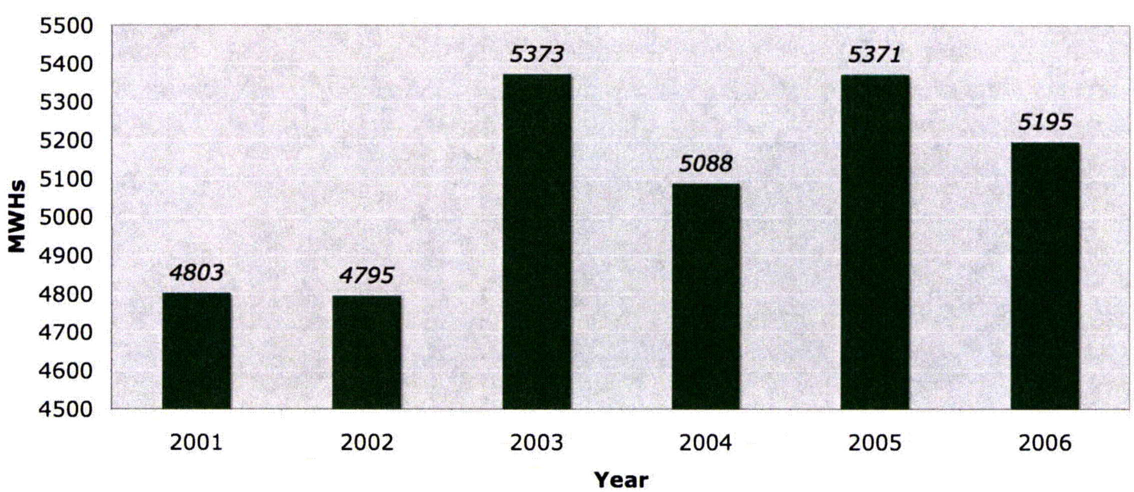
System Data 2006

Miles of transmission lines	4,560
Miles of distribution lines	2,541
Number of transmission/switching station	83
Number of distribution/switching stations	75
Number of Central delivery points	346
Municipal Customers	2

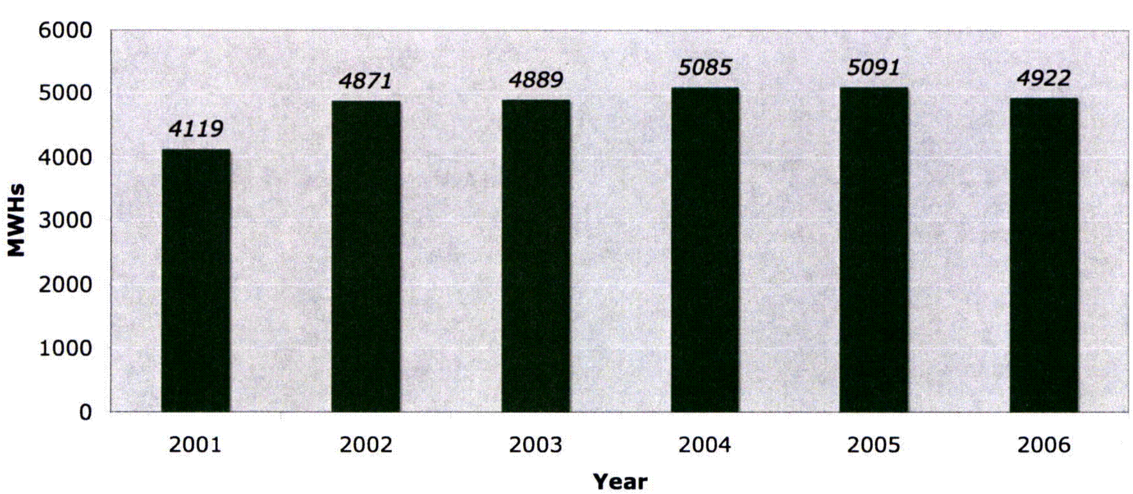
Corporate Statistics	**2006**	2005	2004	2003	2002
FINANCIAL (Thousands):					
Total Revenues & Income	**$ 1,457,376**	$ 1,382,395	$ 1,166,030	$ 1,057,591	$ 1,056,551
Total Expenses & Interest Charges	**$ 1,359,494**	$ 1,268,956	$ 1,073,529	$ 973,326	$ 944,651
Other	**$ 4,885**	$ 34,374	$ 10,373	$ (15,411)	$ (29,935)
Reinvested Earnings	**$ 102,767**	$ 147,813	$ 102,874	$ 68,854	$ 81,965
OTHER FINANCIAL:					
Debt Service Coverage	**1.79**	2.01	1.81	1.86	1.79
Debt / Equity Ratio	**69/31**	67/33	71/29	68/32	70/30
STATISTICAL:					
Number of Customers (at Year-End)					
Retail Customers	**156,462**	148,988	143,081	137,823	134,299
Military and Large Industrial	**33**	32	32	32	33
Wholesale	**4**	4	4	4	4
Total Customers	**156,499**	149,024	143,117	137,859	134,336
Generation:					
Coal	**19,621**	19,033	19,160	19,010	18,628
Nuclear	**2,503**	2,485	2,745	2,445	2,455
Hydro	**335**	482	432	670	253
Natural Gas	**2,007**	2,067	1,674	1,191	2,256
Oil	**29**	55	31	26	35
Landfill Gas	**61**	44	23	22	15
Total Generation (GWh)	**24,556**	24,166	24,065	23,364	23,642
Purchases, Net Interchanges, etc. (GWh)	**1,733**	1,957	1,417	1,738	1,367
Wheeling, Interdepartmental, and Losses	**(867)**	(1,059)	(1,031)	(1,042)	(888)
Total Energy Sales (GWh)	**25,422**	25,064	24,451	24,060	24,121
Summer Peak Generating Capability (net MW)	**4,511**	4,505	4,499	4,277	4,259
Territorial Peak Demand (MW)	**5,195**	5,371	5,088	5,373	4,795

2006 Energy Sales





Capability



INNOVATION

FINANCIALS

FINANCE-AUDIT COMMITTEE CHAIRMAN'S LETTER

The Finance-Audit Committee of the Board of Directors is comprised of five independent directors: Paul G. Campbell Jr., Chairman, G. Dial DuBose, William A. Finn, David Springs and Barry Wynn.

The committee meets regularly with members of management and Internal Audit to review and discuss their activities and responsibilities.

The Finance-Audit Committee oversees Santee Cooper's financial reporting and internal auditing processes on behalf of the board of directors.

Periodic financial statements and reports from management and the internal auditors pertaining to operations and representations were received. In fulfilling its responsibilities, the committee also reviewed the overall scope and specific plans for the respective audits by the internal auditors and the independent public accountants. The committee discussed the company's financial statements and the adequacy of its system of internal controls. The committee met with the independent public accountants and with the General Auditor to discuss the results of the audit, the evaluation of Santee Cooper's internal controls, and the overall quality of Santee Cooper's financial reporting.

Paul G. Campbell, Jr.

Paul G. Campbell, Jr.
Chairman
Finance-Audit Committee

MANAGEMENT'S DISCUSSION AND ANALYSIS

Overview of the Financial Statements

In June 1999 the Governmental Accounting Standards Board issued Statement No. 34, "Basic Financial Statements – Management's Discussion and Analysis - for State and Local Governments" (GASB 34). The objective of this Statement is to enhance the understandability and usefulness of the general-purpose external financial reports of state and local governments to the citizenry, legislative and oversight bodies, and investors and creditors. This Statement was effective for the Authority beginning in fiscal year 2001.

By definition within this Statement, the Authority is deemed a proprietary or enterprise fund, in which a government entity operates like a business. GASB 34 requires the following components in a governmental entity's annual report.

Management's Discussion and Analysis
The purpose is to provide an objective and easily readable analysis of the Authority's financial activities based on currently known facts, decisions, or conditions.

Statement of Net Assets
Assets and liabilities of proprietary funds should be presented to distinguish between current and long-term assets and liabilities.

Statement of Revenues, Expenses and Changes in Net Assets
This statement provides the operating results of the Authority broken into the various categories of operating revenues and expenses, non-operating revenues and expenses, as well as revenues from capital contributions.

Statement of Cash Flows
Sources and uses of cash are classified using the direct method as resulting from operating, non-capital financing, capital and related financing or investing activities.

Notes to the Financial Statements
The notes are used to explain some of the information in the financial statements and provide more detailed data.

Financial Condition Overview

The Authority's Balance Sheets as of December 31, 2006, 2005 and 2004 are summarized as follows:

	2006	2005	2004
		(Thousands)	
ASSETS			
Plant – net	**$ 3,876,291**	$ 3,528,628	$ 3,165,259
Current assets	**742,585**	678,948	577,034
Other noncurrent assets	**592,220**	456,062	661,601
Deferred debits	**329,397**	319,564	282,238
Total assets	**$ 5,540,493**	$ 4,983,202	$ 4,686,132
LIABILITIES & NET ASSETS			
Long-term debt - net	**$ 3,090,030**	$ 2,518,991	$ 2,600,744
Current liabilities	**638,352**	694,944	540,576
Other noncurrent liabilities	**387,725**	432,697	343,633
Net assets	**1,424,386**	1,336,570	1,201,179
Total liabilities and net assets	**$ 5,540,493**	$ 4,983,202	$ 4,686,132

2006 Compared to 2005

Assets

- Net plant increased by $347.7 million. Additions less retirements to Utility plant were $260.6 million in 2006. The change in Accumulated depreciation was an increase of $142.3 million and was consistent with prior years. The increase in Construction work in progress was $229.4 million and included major construction related to Cross 3, Cross 4, Pee Dee 1 and environmental compliance.

- Current assets increased $63.6 million due to increases in Accounts receivable and Inventories.

- Other noncurrent assets increased $136.2 million primarily due to an increase in restricted cash and investments.

- Deferred debits increased $9.8 million due to increases in the Costs to be recovered from future revenue and Unamortized debt expenses.

Liabilities

- Long-term debt increased $571.0 million due to the net affect of bond refinancing and new money issues, and principal repayments.

- Current liabilities decreased $56.6 million due to decreases in Commercial paper notes outstanding and Other current liabilities. These were partially offset by increases in Accounts payable, Current portion of long-term debt and Accrued interest.

- Other noncurrent liabilities decreased $45.0 million primarily due to a decrease in the Asset retirement obligation liability.

- Net assets increased $87.8 million due to the increases in Unrestricted assets, Restricted for debt service and Restricted for capital projects. These were partially offset by a decrease in Invested in capital assets.

2005 Compared to 2004

Assets

- Net plant increased by $363.4 million. Additions less retirements to Utility plant were only $75.2 million in 2005 with no single plant asset driving the activity. This figure was significantly lower than in recent years. The change in Accumulated depreciation (including ARO) of $132.2 million was considered normal. The increase in Construction work in progress was $420.2 million related primarily to Cross 3 and Cross 4 construction.

- Current assets increased $101.9 million due to increases in Current cash and investments, Accounts receivable, Inventories, and Prepaid and Other assets.

- Other non-current assets decreased $205.5 million primarily due to an decrease in Restricted cash and investments.

- Deferred debits increased $37.3 million due to an increase in the Costs to be recovered from future revenue asset resulting from a decrease in the principal and an increase in the depreciation components.

Liabilities

- Long-term debt decreased $81.8 million due to the net affect of bond refinancing, principal repayments and new money issues.

- Current liabilities increased $154.4 million due to increases in Commercial paper notes outstanding, Accounts payables, and Other current liabilities. These were partially offset by decreases in the Current portion of long-term debt and Accrued interest.

- Other non-current liabilities increased $89.1 million due to increases in the Construction fund and Asset retirement obligation liabilities.

- Net assets increased $135.4 million primarily due to the increase in Investment in capital assets net of related debt.

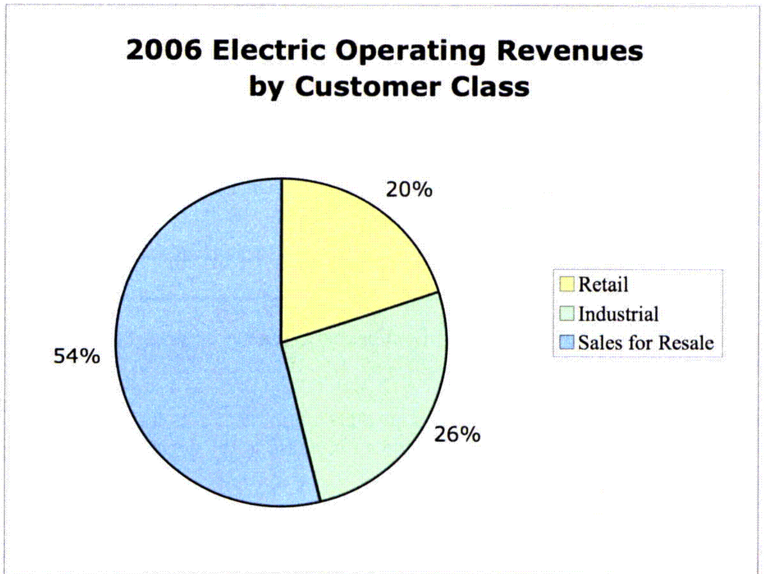
Results of Operations

		2006		2005		2004
				(Thousands)		
Operating revenues	**$**	**1,413,343**	$	1,350,080	$	1,151,009
Operating expenses		**1,173,989**		1,102,360		909,665
Operating income	**$**	**239,354**	$	247,720	$	241,344
Interest charges		**(185,505)**		(166,596)		(163,864)
Costs to be recovered from future revenue		**4,885**		34,374		10,373
Other income		**44,033**		32,315		15,021
Transfers out		**(14,951)**		(12,422)		(24,175)
Change in net assets	**$**	**87,816**	$	135,391	$	78,699
Ending net assets	**$**	**1,424,386**	$	1,336,570	$	1,201,179

2006 Compared to 2005

Operating Revenues

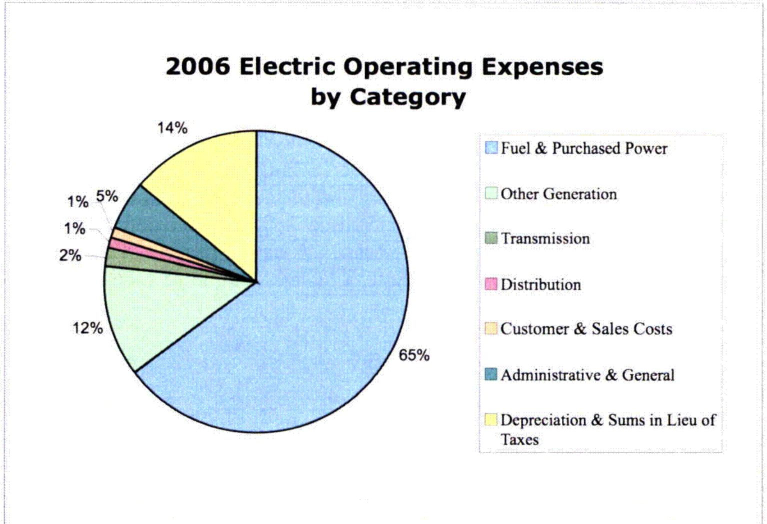
Operating revenues for 2006 increased $63.3 million or 5% over the prior year. A rise in fuel and demand related revenues were the major factors. Energy sales exceeded 25 million megawatts for the second consecutive year. There was a 2% increase in both the industrial and sales for resale customer classes.



Electric Operating Revenues		2006		2005		2004
				(Thousands)		
Retail	**$**	**280,374**	$	268,893	$	235,679
Industrial		**362,527**		360,510		294,945
Sales for Resale		**753,041**		705,352		605,162
Totals	**$**	**1,395,942**	$	1,334,755	$	1,135,786

Operating Expenses

Operating expenses for 2006 reflected a net increase of $71.6 million or 6% compared to 2005. Throughout the industry, market fuel prices (coal, natural gas and oil) again increased over the prior year. In a continued effort to lower fuel costs, the Authority uses a combination of long-term and short-term contracts, an expanding fuel related risk hedging program and a mix of solid fuels (petcoke, coal, and synfuel). Fuel and purchased power accounted for the majority of this expense variance, rising by $49.6 million or 7% when compared to 2005. During 2006, the Authority again used synfuel (a processed coal that is cheaper) which resulted in an estimated savings to our customers of approximately $12.7 million. Savings from synfuel are reflected in the fuel expense and revenue reported. Other generation operating and maintenance costs increased by approximately $10.0 million in 2006 due to additional costs of operating environmental equipment and station outages. Depreciation expense showed an increase over last year of $9.4 million.



Electric Operating Expenses		2006		2005		2004
				(Thousands)		
Fuel & Purchased Power	**$**	**759,040**	$	709,422	$	531,061
Other Generation		**139,435**		129,420		122,792
Transmission		**21,952**		21,055		19,600
Distribution		**12,751**		11,369		10,254
Customer & Sales Costs		**12,654**		11,385		11,377
Administrative & General		**64,167**		66,015		66,568
Depreciation & Sums in Lieu of Taxes		**161,148**		151,077		145,608
Totals	**$**	**1,171,147**	$	1,099,743	$	907,260

Below-The-Line Items

Interest Charges - Interest charges for 2006 were $18.9 million or 11% higher than 2005 as a result of the 2005 and 2006 bond transactions.

Costs to be Recovered From Future Revenue - Costs to be recovered from future revenue increased expenses by $29.5 million when compared to last year due to higher principal payments and a decrease in the depreciation component.

Other Income - Other income increased $11.7 million or 36%. Interest income and the change in Fair market value of investments increased by $18.4 million. This was offset primarily by a reduction of $7.5 million in the surplus land sales for the reimbursement of the 2004 non-recurring special contribution to the State.

Transfers out - Transfers out represents the dollars paid by the Authority to the State of South Carolina. There was an increase of $2.5 million or 20% over 2005 which resulted from an increase in projected revenues from the prior year.

2005 Compared to 2004

Operating Revenues

Operating revenues for 2005 increased $199.1 million or 17% over the prior year. The rise in fuel related revenue was a key contributing factor due to higher market prices industry wide. Energy sales for the Authority were over 25 million megawatt-hours for the year. This was an increase of 3% which represents higher sales in all customer categories. For the second consecutive year, the retail class experienced a 4% customer growth. The revenue continues to maintain a stable distribution across its customer base as follows: Retail 20%, Industrial 27%, and Sales for Resale 53%.

Operating Expenses

Operating expenses for 2005 reflected a net increase of $192.7 million or 21% compared to 2004. Coal, natural gas and oil prices have risen dramatically over the past two years. The Authority strives to mitigate these costs with a combination of long-term and short-term contracts, a gas risk hedging program and burning a variety of solid fuels (petcoke, coal, and synfuel). Fuel and purchased power accounted for the majority of this expense variance, rising by $178.4 million or 34% when compared to 2004. The Authority continues to burn synfuel, a processed coal that results in savings to our customers. In 2005, this provided an estimated savings to our customers of approximately $20.0 million which was reflected in the fuel expense and revenue reported. Other generation operating and maintenance costs also increased by approximately $6.6 million in 2005 due to additional costs of operating environmental equipment and the station outages. Depreciation expense showed an increase over last year of $4.9 million due primarily to a reclassification of certain assets between depreciation groups and re-calculation of prior depreciation.

Below-The-Line Items

Interest Charges - Interest charges for 2005 were $2.7 million or 2% higher than 2004 as a result of the 2004 and 2005 bond transactions and additional expense due to increased commercial paper activity and higher interest rates offset by higher debt related expenses.

Costs to be recovered from future revenue - Costs to be recovered from future revenue reduced expenses by $24.0 million when compared to last year due to lower principal payments and an increase in the depreciation component.

Other Income - Other income increased $17.3 million or 115%. In 2004 certain lands were declared surplus property so they could be sold to reimburse the Authority for the non-recurring special contribution to the State. These land sales in 2005 totaled $10.7 million. Interest income and the change in fair value increased by $5.9 million due to higher interest rates and favorable market conditions for the types of investments held by the Authority.

Transfers out - Transfers out represents the dollars paid by the Authority to the State of South Carolina. The expense for 2004 was $11.8 million higher than 2005 due to the non-recurring special contribution in the amount of $13.0 million which was paid in 2004 by authorization of the Authority's Board of Directors.

Capital Improvement Program

The purpose of the capital improvement program is to continue to meet the energy and water needs of the Authority's customers with economical and reliable service. The Authority's capital improvement program for years 2007 through 2009 is estimated to be $1.9 billion expended as follows:

	2006 Budget 2007-09	2005 Budget 2006-08	2004 Budget 2005-07
Capital Improvement Expenditures		(Thousands)	
Cross 3 & Cross 4 Generating Units	**$ 465,000**	$ 724,000	$ 879,000
Environmental Compliance	**49,000**	157,000	151,000
General Improvements to the System	**647,000**	510,000	386,000
Pee Dee 1 Unit	**534,000**	0	0
Future Nuclear Units	**190,000**	0	0
Totals	**$ 1,885,000**	$ 1,391,000	$ 1,416,000

The cost of the capital improvement program will be provided from internally generated funds, additional revenue obligations, commercial paper notes and other short-term obligations, as determined by the Authority.

Currently under construction are Cross Unit 3 and Cross Unit 4 which are scheduled to be commercial in January 2007 and 2009, respectively. Each of these units will be a 600 MW (net) pulverized coal-fired unit which will be located at the existing Cross Generating Station. The capital improvement program also includes funds for Pee Dee Unit 1, two future nuclear units, and general improvements to the Authority's system.

One new landfill generating unit was added in 2006 at the Richland County site, increasing the total landfill generating sites for the Authority to three. The Authority also dedicated a 16KW solar demonstration facility at Coastal Carolina University. Energy from these Green Power sources further diversifies the Authority's fuel mix and reinforces the commitment to the environment for the State of South Carolina.

The Authority's estimated three-year capital improvement program for the years ended December 31, 2005 and 2004 was $1.4 billion for each of the periods.

Debt Service Coverage

The Authority's debt service coverage (not including commercial paper) at December 31, 2006, 2005, and 2004 was 1.79, 2.01 and 1.81, respectively.

Bond Ratings

Bond ratings assigned by the various agencies for years 2006, 2005, and 2004 were as follows:

Agency / Lien Level	2006	2005	2004
Fitch Ratings			
Priority Bonds	Not Applicable	AAA	AAA
Revenue Bonds	AA	AA	AA
Revenue Obligations	AA	AA	AA
Commercial Paper	F1+	F1+	F1+
Moody's Investors Service, Inc.			
Priority Bonds	Not Applicable	Aa2	Aa2
Revenue Bonds	AA	Aa2	Aa2
Revenue Obligations	AA	Aa2	Aa2
Commercial Paper	P-1	P-1	P-1
Standard & Poor's Rating Services			
Priority Bonds	Not Applicable	AAA	AAA
Revenue Bonds	AA-	AA-	AA-
Revenue Obligations	AA-	AA-	AA-
Commercial Paper	A1+	A1+	A1+

Bond Market Transactions for Years 2006, 2005 and 2004

Par Amount	Type	Date Closed	Purpose	Comments
Year 2006				
$470,765,000	Revenue Obligations: 2006 Series A	02/01/2006	To finance a portion of the tax-exempt construction for Cross Unit No. 3, Cross Unit No. 4, SIP Call and New Source Review environmental requirements, and ongoing transmission system construction and improvements	Tax-exempt bonds. All-in true interest cost of 4.58 percent.
$129,115,000	Revenue Obligations: 2006 Series B	02/01/2006	To finance a portion of the taxable construction for Cross Unit No. 3, Cross Unit No. 4, SIP Call and New Source Review environmental requirements, and ongoing transmission system construction and improvements	Taxable bonds. All-in true interest cost of 5.18 percent.
$7,268,000	Revenue Obligations: 2006 Series M-Current Interest Bearing Bonds (CIBS)	11/15/2006	To finance a portion of the Authority's capital improvements	Tax-exempt mini-bonds.
$2,632,600	Revenue Obligations: 2006 Series M-Capital Appreciation Bonds (CABS)	11/15/2006	To finance a portion of the Authority's capital improvements	Tax-exempt mini-bonds.
$114,755,000	Revenue Obligations: 2006 Refunding Series C	11/16/2006	Refund the following: 1999 Series A (partial) 2002 Series B (partial)	Gross savings of $11.2 million over the life of the bonds.
Year 2005				
$125,295,000	Revenue Obligations: 2005 Refunding Series A	10/4/2005	Refund the following: 1995 Refunding Series A (partial) 1995 Refunding Series B (partial) 1996 Refunding Series A (partial)	Gross savings of $20.1 million over the life of the bonds.
$278,005,000	Revenue Obligations: 2005 Refunding Series B	10/4/2005	Refund the following: 1995 Refunding Series A 1995 Refunding Series B 1996 Refunding Series A 1996 Refunding Series B	Gross savings of $58.3 million over the life of the bonds.
$78,150,000	Revenue Obligations: 2005 Refunding Series C	02/24/2005	Refund 1993 Refunding Series C Bonds	Gross savings of $14.6 million over the life of the bonds.
$10,924,500	Revenue Obligations: 2005 Series M-Current Interest Bearing Bonds (CIBS)	11/16/2005	To finance a portion of the Authority's ongoing transmission system construction and improvements	Tax-exempt mini-bonds.
$4,442,000	Revenue Obligations: 2005 Series M-Capital Appreciation Bonds (CABS)	11/16/2005	To finance a portion of the Authority's ongoing transmission system construction and improvements.	Tax-exempt mini-bonds.
Year 2004				
$434,870,000	Revenue Obligations: 2004 Series A	04/21/2004	To finance a portion of the tax-exempt construction for Cross Unit No. 3, Cross Unit No. 4, SIP Call environmental requirements, Rainey 2002 Combined Cycle and two Simple Cycle Units, and Rainey Transmission projects.	Tax-exempt bonds. All-in true interest cost of 4.46 percent.
$17,635,000	Revenue Obligations: 2004 Series B	04/21/2004	To finance a portion of the taxable construction for Cross Unit No. 4.	Taxable bonds. All-in true interest cost of 4.41 percent.
$19,806,000	Revenue Obligations: 2004 Series M-Current Interest Bearing Bonds (CIBS)	08/24/2004	To finance a portion of the taxable construction for Cross Unit No. 4.	Tax-exempt mini-bonds.
$8,147,600	Revenue Obligations: 2004 Series M-Capital Appreciation Bonds (CABS)	08/24/2004	To finance a portion of the taxable construction for Cross Unit No. 4.	Tax-exempt mini-bonds.

(Note: There are no 2007 bond market transactions to date.)

CHERRY BEKAERT & HOLLAND

CERTIFIED PUBLIC ACCOUNTANTS & CONSULTANTS

Report of Independent Auditors

The Advisory Board and Board of Directors
The South Carolina Public Service Authority
Moncks Corner, South Carolina

We have audited the accompanying combined balance sheet of the South Carolina Public Service Authority (a component unit of the state of South Carolina) as of December 31, 2006, and the related combined statement of revenues, and expenses and changes in net assets, and cash flows for the year then ended. These financial statements are the responsibility of the Authority's management. Our responsibility is to express an opinion on these financial statements based on our audit. The financial statements of the Authority as of December 31, 2005, were audited by other auditors whose report dated March 22, 2006, expressed an unqualified opinion on those statements.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Authority's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the South Carolina Public Service Authority as of December 31, 2006, and the changes in its net assets and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

The Management's Discussion and Analysis section listed in the table of contents is not a required part of the financial statements but is supplementary information required by the Governmental Accounting Standards Board. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the required supplementary information. However, we did not audit this information and express no opinion thereon.

Our audit was conducted for the purpose of forming an opinion on the basic financial statements taken as a whole. The other information included in the annual report is presented for purposes of additional analysis and is not a required part of the basic financial statements. Such information has not been subjected to the auditing procedures applied in our audit of the basic financial statements and, accordingly, we express no opinion on it.

Cherry, Bekaert & Holland LLP

Raleigh, North Carolina
March 2, 2007

Combined Balance Sheets

South Carolina Public Service Authority
As of December 31, 2006 and 2005

	2006	2005
	(Thousands)	
ASSETS		
Current assets		
Unrestricted cash and cash equivalents	**$ 106,179**	$ 90,614
Unrestricted investments	**18,326**	90,980
Restricted cash and cash equivalents	**76,995**	124,555
Restricted investments	**109,666**	12,352
Receivables, net of allowance for doubtful accounts of $674 and $713 at December 31, 2006 and 2005, respectively	**167,798**	157,722
Materials inventory	**67,309**	56,892
Fuel inventory		
Fossils fuels	**142,061**	67,080
Nuclear fuel - net	**22,111**	15,987
Interest receivable	**4,437**	1,807
Prepaid expenses and other current assets	**27,703**	60,959
Total current assets	**742,585**	678,948
Noncurrent assets		
Unrestricted cash and cash equivalents	**1,674**	62
Unrestricted investments	**78,084**	75,527
Restricted cash and cash equivalents	**53,510**	37,901
Restricted investments	**284,664**	182,905
Capital assets		
Utility plant	**4,657,520**	4,336,788
Long lived assets - asset retirement cost	**33,078**	93,240
Accumulated depreciation	**(2,103,066)**	(1,960,802)
Total utility plant - net	**2,587,532**	2,469,226
Construction work in progress	**1,286,639**	1,057,193
Other physical property - net	**2,120**	2,209
Investment in associated companies	**7,672**	6,567
Regulatory asset - asset retirement obligation	**164,192**	153,090
Regulatory assets - derivative and hedging instruments	**2,424**	10
Deferred debits and other noncurrent assets		
Unamortized debt expenses	**31,943**	27,071
Costs to be recovered from future revenue	**251,134**	246,249
Other	**46,320**	46,244
Total noncurrent assets	**4,797,908**	4,304,254
Total assets	**$ 5,540,493**	$ 4,983,202

The accompanying notes are an integral part of these combined financial statements.

Combined Balance Sheets (continued)

South Carolina Public Service Authority
As of December 31, 2006 and 2005

	2006	2005
	(Thousands)	
LIABILITIES		
Current liabilities		
Current portion of long-term debt	$ **79,136**	$ 69,674
Accrued interest on long-term debt	**79,742**	63,718
Commercial paper	**195,072**	285,449
Accounts payable	**217,512**	183,488
Other current liabilities	**66,890**	92,615
Total current liabilities	**638,352**	694,944
Noncurrent liabilities		
Construction fund liabilities	**63,582**	48,380
Asset retirement obligation liability	**277,920**	322,358
Total long-term debt (net of current portion)	**3,190,690**	2,657,160
Unamortized refunding and other costs	**(100,660)**	(138,169)
Long-term debt - net	**3,090,030**	2,518,991
Other deferred credits and noncurrent liabilities	**46,223**	61,959
Total noncurrent liabilities	**3,477,755**	2,951,688
Total liabilities	**4,116,107**	3,646,632
NET ASSETS		
Invested in capital assets, net of related debt	**787,362**	814,282
Restricted for debt service	**84,804**	70,263
Restricted for capital projects	**20,854**	3,079
Restricted for other	**164,677**	165,427
Unrestricted	**366,689**	283,519
Total net assets	**1,424,386**	1,336,570
Total liabilities and net assets	$ **5,540,493**	$ 4,983,202

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Combined Statements of Revenues, Expenses and Changes in Net Assets

South Carolina Public Service Authority

Years ended December 31, 2006 and 2005

	2006	2005
	(Thousands)	
Operating revenues		
Sale of electricity	$ **1,395,942**	$ 1,334,754
Sale of water	**4,917**	4,728
Other operating revenue	**12,484**	10,598
Total operating revenues	**1,413,343**	1,350,080
Operating expenses		
Electric operating expenses		
Production	**70,235**	65,614
Fuel	**654,760**	591,903
Purchased and interchanged power	**104,280**	117,519
Transmission	**14,375**	14,192
Distribution	**8,938**	8,041
Customer accounts	**9,287**	8,388
Sales	**3,367**	2,997
Administrative and general	**60,148**	62,223
Electric maintenance expense	**84,609**	77,789
Water operation expense	**1,614**	1,354
Water maintenance expense	**335**	372
Total operation and maintenance expenses	**1,011,948**	950,392
Depreciation and amortization	**157,832**	148,412
Sums in lieu of taxes	**4,209**	3,556
Total operating expenses	**1,173,989**	1,102,360
Operating income	$ **239,354**	$ 247,720
Nonoperating revenues (expenses)		
Interest and investment revenue	$ **25,800**	$ 12,952
Net increase in the fair value of investments	**9,666**	4,126
Interest expense on long-term debt	**(163,208)**	(143,562)
Other interest expense	**(22,297)**	(23,034)
Costs to be recovered from future revenue	**4,885**	34,374
Other - net	**8,567**	15,237
Total nonoperating revenues (expenses)	**(136,587)**	(99,907)
Income before transfers	**102,767**	147,813
Transfers out		
Distribution to the State	**(14,951)**	(12,422)
Total transfers out	**(14,951)**	(12,422)
Change in net assets	**87,816**	135,391
Total net assets - beginning	**1,336,570**	1,201,179
Total net assets - ending	$ **1,424,386**	$ 1,336,570

The accompanying notes are an integral part of these combined financial statements.

Combined Statements of Cash Flows

South Carolina Public Service Authority
Years ended December 31, 2006 and 2005

	2006	2005
	(Thousands)	
Cash flows from operating activities		
Receipts from customers	$ 1,403,306	$ 1,333,354
Payments to non-fuel suppliers	(370,537)	(260,791)
Payments for fuel	(645,495)	(586,692)
Purchased power	(101,785)	(117,098)
Payments to employees	(122,032)	(116,951)
Other receipts-net	169,466	100,278
Net cash provided by operating activities	332,923	352,100
Cash flows from non-capital related financing activities		
Distribution to the State of South Carolina	(14,951)	(12,422)
Net cash used in non-capital related financing activities	(14,951)	(12,422)
Cash flows from capital-related financing activities		
Proceeds from sale of bonds	724,535	496,816
Net commercial paper (repayments) issuance	(90,486)	92,298
Repayment and refunding of bonds	(180,106)	(612,849)
Interest paid on borrowings	(150,712)	(156,665)
Construction and betterments of utility plant	(559,355)	(440,739)
Debt premium	18,414	11,130
Other - net	(2,036)	(2,994)
Net cash used in capital-related financing activities	(239,746)	(613,003)
Cash flows from investing activities		
Net (increase) decrease in investments	(119,310)	247,333
Interest on investments	23,144	13,173
Gain on sale of surplus property	3,166	10,952
Net cash (used by) provided by investing activities	(93,000)	271,458
Net (decrease) in cash and cash equivalents	(14,774)	(1,867)
Cash and cash equivalents-beginning	253,132	254,999
Cash and cash equivalents-ending	$ 238,358	$ 253,132

The accompanying notes are an integral part of these combined financial statements.

Combined Statements of Cash Flows (continued)
South Carolina Public Service Authority
Years ended December 31, 2006 and 2005

	2006	2005
	(Thousands)	
Reconciliation of operating income to net cash provided by operating activities		
Operating income	$ **239,354**	$ 247,720
Adjustments to reconcile operating income to net cash provided by operating activities		
Depreciation and amortization	**167,329**	153,602
Net power gains involving associated companies	**(31,577)**	(45,359)
Distributions from associated companies	**27,420**	44,164
Advances to associated companies	**10**	(97)
Other income	**1,599**	207
Changes in assets and liabilities		
Accounts receivable - net	**(10,076)**	(16,608)
Inventories	**(85,398)**	(40,024)
Prepaid expenses	**30,274**	(38,702)
Other deferred debits	**(830)**	(5,337)
Accounts payable	**36,518**	44,058
Other current liabilities	**(25,795)**	29,369
Other noncurrent liabilities	**(15,905)**	(20,893)
Net cash provided by operating activities	$ **332,923**	$ 352,100
Composition of cash and cash equivalents		
Current		
Unrestricted cash and cash equivalents	$ **106,179**	$ 79,068
Restricted cash and cash equivalents	**76,995**	136,101
Noncurrent		
Unrestricted cash and cash equivalents	**1,674**	62
Restricted cash and cash equivalents	**53,510**	37,901
Cash and cash equivalents at the end of the year	$ **238,358**	$ 253,132

NOTES

Note 1 - Summary of Significant Accounting Policies:

A - Reporting Entity - The South Carolina Public Service Authority (the "Authority" or "Santee Cooper"), a component unit of the State of South Carolina, was created in 1934 by the State legislature. The Santee Cooper Board of Directors (Board) is appointed by the Governor of South Carolina with the advice and consent of the Senate. The purpose of the Authority is to provide electric power and wholesale water to the people of South Carolina. Capital projects are funded by commercial paper in addition to bonds and internally generated funds. As authorized by State law, the Board of Directors sets rates charged to customers to pay debt service and operating expenses and to provide funds required under bond covenants.

B - System of Accounts - The accounting records of the Authority are maintained on an accrual basis in accordance with accounting principles generally accepted in the United States (GAAP) issued by the Governmental Accounting Standards Board (GASB) applicable to governmental entities that use proprietary fund accounting and the Financial Accounting Standards Board (FASB) that do not conflict with rules issued by the GASB. The Authority's combined financial statements include the accounts of the Lake Moultrie Regional Water System after elimination of inter-company accounts and transactions. The accounts are maintained substantially in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) for the electric system and the National Association of Regulatory Utility Commissioners (NARUC) for the water system. The Authority also complies with policies and practices prescribed by its Board of Directors and to practices common in both industries. As the Board of Directors is authorized to set rates, the Authority has historically followed FASB Statement No. 71, "Accounting for the Effects of Certain Types of Regulation" (FASB 71). This statement provides for the reporting of assets and liabilities consistent with the economic effect of the rate structure. The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from those estimates.

C - Reclassifications - Certain amounts in the prior year's financial statements have been reclassified to conform to current year presentation.

D - Cash and Cash Equivalents - For purposes of the Combined Statements of Cash Flows, the Authority considers highly liquid investments with original maturities of ninety days or less and cash on deposit with financial institutions as cash and cash equivalents. In 2001, the Authority adopted GASB Statement No. 34, "Basic Financial Statements - Management's Discussion and Analysis - for State and Local Governments" (GASB 34) which requires cash and cash equivalents to be shown as either restricted or unrestricted. "Restricted" refers to those funds limited by law, regulations or Board action as to their allowable disbursement. "Unrestricted" refers to all other funds not meeting the requirements of restricted.

E - Inventory - Material inventory and fuel inventory are carried at weighted average costs. At the time of issuance or consumption, an expense is recorded at the weighted average cost. Fuel expense for all customers are billed utilizing rates and contracts, the majority of which include fuel adjustment provisions based on either the actual costs for the previous month or the actual weighted average costs for the previous three-month period.

F - Utility Plant - Utility plant is recorded at cost, which includes materials, labor, overhead, and interest capitalized during construction. Interest is only capitalized when interest payments are funded through borrowings. There was no interest capitalized in 2006 or 2005. Other interest expense is recovered currently through rates. The costs of maintenance, repairs and minor replacements are charged to appropriate operation and maintenance expense accounts. The costs of renewals and betterments are capitalized. The original cost of utility plant retired and the cost of removal, less salvage, are charged to accumulated depreciation.

G - Depreciation - Depreciation is computed using composite rates on a straight-line basis over the estimated useful lives of the various classes of the plant. Composite rates are applied to the net carrying basis of various classes of plant which includes appropriate adjustments for cost of removal and salvage. The Authority periodically has depreciation studies performed by independent parties to assist management and the Board in establishing appropriate composite depreciation rates. Annual depreciation provisions, expressed as a percentage of average depreciable utility plant in service, were approximately 3.6 percent for each of the periods ended December 31, 2006 and 2005, respectively. Amortization of capitalized leases is also included in depreciation expense.

H - Investment in Associated Companies - The Authority is a member of The Energy Authority (TEA) along with City Utilities of Springfield (Missouri), Gainesville Regional Utilities (Florida), JEA (Florida), MEAG Power (Georgia), and Nebraska Public Power District (NPPD). The Authority is also a member of Colectric Partners (Colectric). In addition to the Authority, Colectric's member participants are: Florida Municipal Power Agency, Gainesville Regional Utilities, JEA, Lansing Board of Water & Light, MEAG Power, Nebraska Public Power District and Orlando Utilities Commission.

TEA markets wholesale power and coordinates the operation of the generation assets of its members to maximize the efficient use of electrical energy resources, reduce operating costs and increase operating revenues of the members. TEA is expected to accomplish the foregoing without impacting the safety and reliability of the electric system of each member. TEA does not engage in the construction or ownership of generation or transmission assets. In addition, TEA assists members with fuel hedging activities and acts as an agent in the execution of forward gas transactions. The Authority accounts for its investment in TEA under the equity method of accounting.

All of TEA's revenues and costs are allocated to the members. The following table summarizes the transactions applicable to the Authority:

TEA Investment	**2006**	2005
	(Thousands)	
Opening balance	**$ 6,395**	$ 6,741
Reduction to power costs and increases in electric revenues	**31,021**	44,952
Less: Distributions from TEA	**27,420**	44,164
Less: Other (includes equity losses)	**2,486**	1,134
Ending balance	**$ 7,510**	$ 6,395

At December 31, 2006, the Authority had a payable to TEA of $9.7 million for power and gas purchases. In addition, at December 31, 2006, the Authority had a receivable due from TEA of approximately $4.2 million for power sales and sales of excess gas capacity.

The Authority's exposure relating to TEA is limited to the Authority's capital investment, any accounts receivable and trade guarantees provided by the Authority. These guarantees are within the scope of FASB Financial Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, including Indirect Guarantees of Indebtedness of Others" (FIN 45). Upon the Authority making any payments under its electric guarantee, it has certain contribution rights with the other members of TEA in order that payments made under the TEA member guarantees would be equalized ratably, based upon each member's equity ownership interest in TEA. After such contributions have been effected, the Authority would only have recourse against TEA to recover amounts paid under the guarantee. The term of this guarantee is generally indefinite, but the Authority has the ability to terminate its guarantee obligations by causing to be provided advance notice to the beneficiaries thereof. Such termination of its guarantee obligations only applies to TEA transactions not yet entered into at the time the termination takes effect. The Authority's support of TEA's trading activities is limited based on the formula derived from the forward value of TEA's trading positions at a point in time. The formula was approved by the Authority's Board and at December 31, 2006, the trade guarantees are an amount not to exceed approximately $96.0 million.

Colectric provides public power utilities with key project and business management resources. Colectric also specializes in the development, project management, operations and maintenance of public power utilities' electric generation and gas infrastructure facilities. The members may elect to participate in various Colectric initiatives based on individual utility needs.

Currently, the Authority participates in two of Colectric's initiatives. The first involves managing the major gas turbine overhauls thereby promoting the sharing of spare parts and technical expertise. The second initiative is a supply chain management initiative intended to achieve major cost savings through volume purchasing leverage.

The Authority's exposure relating to Colectric is limited to its capital investment in Colectric, any accounts receivable from Colectric and any indemnifications related to agreements between Colectric and the Authority. These indemnifications are within the scope of FIN 45. The Authority's initial investment in Colectric was $413,000. The balance in the Authority's Member Equity account at December 31, 2006 was approximately $162,000.

I - Bond Issuance Costs and Refunding Activity - Unamortized debt discount, premium, and expense are amortized to income over the terms of the related debt issues. Gains or losses on refunded debt are amortized to income over the shorter of the remaining life of the refunded debt or the life of the new debt.

J - Revenue Recognition and Fuel Costs - Substantially all wholesale and industrial revenues are billed and recorded at the end of each month. Revenues for electricity delivered to retail customers that have not been billed are accrued. Accrued revenue for retail customers totaled $10.7 million in 2006 and $10.1 million in 2005.

Fuel costs are reflected in operating expenses as fuel is consumed.

K - Payment to the State - The Authority is operated for the benefit of the people of South Carolina (the "State") and was created by Act No. 887 of the Acts of the State of South Carolina for 1934 and acts supplemental thereto and amendatory thereof (Code of Laws of South Carolina 1976, as amended – Sections 58-31-10 through 58-31-50) (the "Act"). Nothing in the Act prohibits the Authority from paying to the State each year up to one percent of its projected operating revenues, as such revenues would be determined on an accrual basis from the combined electric and water systems. The Authority recognizes the distributions (shown as "Transfers out" on the Combined Statements of Revenues, Expense and Changes in Net Assets) as a reduction to net assets when paid.

Payments made to the State totaled $15.0 million in 2006 and $12.4 million in 2005.

L - Accounting for Derivative Instruments - The Authority follows the requirements of FASB No. 133, "Accounting for Derivative Instruments and Hedging Activities" (FASB 133) as amended by FASB No. 149. The majority of the Authority's derivative instruments have been determined to meet the normal purchases and normal sales exception provided by FASB 133.

Natural gas, a core business commodity input for the Authority, has historically been hedged in an effort to mitigate gas cost risk by reducing cost volatility and improving cost effectiveness. In 2006, due to the increased market volatility of crude oil and its impact on the Authority's total fuel cost, the Authority began hedging crude oil.

Unrealized gains and losses related to such activity are deferred in a regulatory account and recognized in earnings as gas or transportation costs are incurred in the production cycle. At December 31, 2006, the Authority recorded $6.1 million in net unrealized losses from natural gas and crude oil transactions using mark-to-market accounting as outlined FASB 133. During 2006, the Authority recognized $2.0 million in net gains associated with hedging transactions.

M - Retirement of Long-Lived Assets - Statement of Financial Accounting Standards No. 143 "Accounting for Asset Retirement Obligations" (SFAS 143) addresses financial accounting and reporting for legal obligations associated with the retirement of long-lived assets and the related retirement costs. The standard applies to legal obligations associated with the retirement of long-lived assets that result from acquisition, construction and/or normal use of the asset. The Authority has a one-third undivided interest in the V.C. Summer Nuclear Station ("Summer") and is therefore subject to the requirements of SFAS 143 due to legal and regulatory requirements related to nuclear decommissioning. Summer was placed in service in 1983 and in 2004, the Nuclear Regulatory Commission (NRC) extended the operating license to August 6, 2042.

SFAS 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The fair value of a liability is added to the carrying amount of the associated asset. This carrying amount, called the Asset Retirement Cost (ARC) is then depreciated over the life of the asset. The asset retirement obligation liability increases due to the passage of time based on the time value of money until the retirement obligation is settled.

SFAS 143 was effective for fiscal years beginning after June 15, 2002, and was adopted by the Authority on January 1, 2003. At December 31, 2006 and 2005, the Authority recorded an asset retirement obligation (ARO) on its one-third share of Summer of approximately $226.0 million and $273.1 million, respectively. Approximately $22.7 million was recorded on the accompanying balance sheet as an associated ARC within "Capital assets." The ARC was recorded commencing on the in-service date of the nuclear facility.

In March 2005, FASB issued Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations" (FIN 47). FIN 47 clarifies the accounting for conditional asset retirement obligations as used in SFAS 143. It requires that an entity recognize a liability for the fair value of a conditional asset retirement obligation when incurred if the fair value of the liability can be reasonably estimated. Uncertainty about the timing or method of settlement of a conditional asset retirement obligation is factored into the measurement of the liability when sufficient information exists.

FIN 47, together with SFAS 143, provides guidance for recording and disclosing liabilities related to future legally enforceable obligations to retire assets (ARO). At December 31, 2006 and 2005, the Authority recorded an ARO on the closing of its ash ponds of approximately $51.9 million and $49.3 million, respectively. Approximately $10.4 million was recorded as an associated ARC within "Capital assets" on the accompanying balance sheet.

The asset retirement obligation is adjusted each period for any liabilities incurred or settled during the period, accretion expense and any revisions made to the estimated cash flows. The $49.3 million listed as "Adoption of FIN47," was a first year only calculation for 2005. The additional $2.6 million Ash Pond ARO liability for 2006 is included in "Accretion Expense." The following table summarizes the Authority's transactions:

Reconciliation of Asset Retirement Obligation Liability

Years Ended December 31,	**2006**	2005
	(Millions)	
Balance as of January 1,	**$ 322.4**	$ 260.6
Accretion Expense	**15.7**	12.5
Revision in Estimated Cash Flows	**(60.2)**	0.0
Adoption of FIN 47	**0.0**	49.3
Balance as of December 31,	**$ 277.9**	$ 322.4

N - Review of New Accounting Standards - In April 2004, GASB issued statement No. 43, "Financial Reporting for Postemployment Benefit Plans Other than Pension Plans" (GASB 43) and in June, 2004 issued No. 45, "Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions" (GASB 45). The purpose of these two statements is to set new accounting standards for state and local government employers that offer retiree health benefits and other non-pension postemployment benefits. In particular, these statements require the accrual of liabilities and expenses of other postemployment benefits (OPEB) over the working career of plan members.

The effective start date of GASB 43 applies for periods beginning after December 15, 2005 for companies with total annual revenues of $100.0 million or more. GASB 45 regulations come into effect one year after implementation of GASB 43. The Authority believes that it does not fall under the requirements of GASB 43 since the South Carolina Retirement System provides certain health, dental, and life insurance benefits for retired employees of the Authority. The requirements of both GASB 43 and GASB 45 are still under review by the Authority and the State of South Carolina. The implementation of GASB 43 and GASB 45 is not expected to have a material effect on the Authority's financial position or results of operations.

In May 2004, GASB issued Statement No. 44, "Economic Condition Reporting: The Statistical Section" (GASB 44). GASB 44 enhances and updates the statistical section that accompanies a state or local government's basic financial statements to reflect the significant changes that have taken place in government finance, including the more comprehensive government-wide financial information required by GASB Statement 34. The statistical section comprises schedules presenting trend information about revenues and expenses, outstanding debt, economics and demographics, and other subjects. These schedules are intended to provide financial statement users with contextual information they need to assess a government's financial health. After review and discussion with the State of South Carolina Comptroller General Office, it was determined that GASB 44 would not apply to the Authority since the Authority does not elect to provide a statistical section as defined under GASB 44. The Authority is a discrete component unit of the State and is reported within the State's Comprehensive Annual Financial Report.

In December 2004, GASB issued Statement No. 46, "Net Assets Restricted by Enabling Legislation - an amendment of GASB Statement 34" (GASB 46). This Statement clarifies that a legally enforceable enabling legislation restriction is one that a party external to a government such as citizens, public interest groups, or the judiciary can compel a government to honor. GASB 46 states that the legal enforceability of an enabling legislation restriction should be re-evaluated if any of the resources raised by the enabling legislation are used for a purpose not specified by the enabling legislation or if a government has other cause for reconsideration. The only enabling legislation affecting the Authority is that legislation (SC Code of Laws Section 58-31-10 et seq.) by which it was created. There has been no enabling legislation since inception that imposes limits on the use of new capital. Therefore, the Authority believes it does not fall under the requirements of GASB 46.

In June 2005, GASB issued Statement No. 47, "Accounting for Termination Benefits" (GASB 47). This statement establishes accounting standards for termination benefits. The Authority, a member of the South Carolina Retirement System, has established that general recognition and measurement requirements should be reported under the requirements of GASB Statement No. 27, "Accounting for Pensions by State and Local Government Employers" (GASB 27) or GASB 45. For these reasons, the Authority believes it does not fall under the requirements of GASB 47 which was effective for periods beginning after June 15, 2005.

O - Issued But Not Yet Effective Pronouncements - In September 2006, GASB issued Statement No. 48, "Sales and Pledges of Receivables and Future Revenues and Intra-Entity Transfers of Assets and Future Revenues" (GASB 48). Governments sometimes exchange an interest in their expected cash flows from collecting specific receivables or future revenues for immediate cash payments—generally, a single lump sum. This Statement establishes criteria that governments will use to ascertain whether the proceeds received should be reported as revenue or as a liability. GASB 48 is effective for periods beginning after December 15, 2006 and is not expected to have a material effect on the Authority's financial position or results of operations.

In November 2006, GASB issued Statement No. 49, "Accounting and Financial Reporting for Pollution Remediation Obligations" (GASB 49). GASB 49 addresses accounting and financial reporting standards for pollution (including contamination) remediation obligations, which are obligations to address the current or potential detrimental effects of existing pollution by participating in pollution remediation activities such as site assessments and cleanups. The scope of the document excludes pollution prevention or control obligations with respect to current operations, and future pollution remediation activities that are required upon retirement of an asset, such as landfill closure and post closure care and nuclear power plant decommissioning. GASB 49 is effective for periods beginning after December 15, 2007 and is currently under review for any impact on the Authority's financial position or results of operations. The Authority currently follows the requirements of AICPA Statement of Position (SOP) 96-1, Environmental Remediation Liabilities, which became effective in fiscal year 1997. SOP 96-1 provides guidance on specific circumstances of recognizing, measuring, accruing and disclosing environmental remediation liabilities.

Note 2 – Costs to Be Recovered from Future Revenue:

The Authority's electric rates are established based upon debt service and operating fund requirements. Depreciation is not considered in the cost of service calculation used to design rates. In accordance with FASB 71, the differences between debt principal maturities (adjusted for the effects of premiums, discounts, expenses and amortization of deferred gains and losses) and depreciation on debt financed assets are recognized as costs to be recovered from future revenue. The recovery of outstanding amounts recorded as costs to be recovered from future revenue will coincide with the repayment of the applicable outstanding debt of the Authority.

Note 3 – Cash and Investments Held by Trustee:

Cash and investments as of December 31, 2006 are classified in the accompanying financial statements as follows:

Combined Balance Sheet:		
		(Thousands)
Current assets		
Unrestricted cash and cash equivalents	$	106,179
Unrestricted investments		18,326
Restricted cash and cash equivalents		76,995
Restricted investments		109,666
Noncurrent assets		
Unrestricted cash and cash equivalents		1,674
Unrestricted investments		78,084
Restricted cash and cash equivalents		53,510
Restricted investments		284,664
Total cash and investments	$	729,098

Cash and investments as of December 31, 2006 consist of the following:

Cash/Deposits	$	14,411
Investments		714,687
Total cash and investments	$	729,098

Unexpended funds from the sale of bonds, debt service funds, other special funds, and cash and investments are held and maintained by trustees, and their use is designated in accordance with applicable provisions of various bond resolutions, lease agreements, and the Enabling Act included in the South Carolina Code of Laws.

The Authority's investments are authorized by the Enabling Act included in the South Carolina Code of Laws, the Authority's investment policy, and various debt resolutions. Authorized investment types include Federal Agency Securities, State of South Carolina General Obligation Bonds, and U.S. Treasury Obligations, all of which are limited to a ten year maximum maturity. Certificate of Deposits and Repurchase Agreements are also authorized with a maximum maturity of one year.

In 1998, the Authority adopted the provisions of GASB Statement No. 31, "Accounting and Financial Reporting for Certain Investments and for External Investment Pools" (GASB 31). GASB 31 establishes standards of accounting and financial reporting for certain investments in securities and requires that all equity and debt securities be recorded at their fair value with gains and losses in fair value reflected as a component of non-operating income in the Combined Statements of Revenues, Expenses and Changes in Net Assets. As of December 31, 2006 and 2005, the Authority had investments totaling approximately $714.7 million and $586.3 million, respectively.

As of December 31, 2006, the Authority's cash and investments carried at fair market value included nuclear decommissioning funds of $128.6 million including unrealized holding gains of $9.8 million. As of December 31, 2005, decommissioning funds totaled approximately $123.1 million including unrealized holding gains of $12.6 million. In accordance with the provisions of FASB 71, earnings, both realized and unrealized, on the decommissioning fund assets are credited to the Regulatory asset - asset retirement obligation and not as a separate component of non-operating income in the Combined Statements of Revenues, Expenses and Changes in Net Assets.

All of the Authority's investments, with the exception of decommissioning funds, are limited to a maturity of 10 years or less. For the year ended December 31, 2006, the Authority made total investment purchases and sales at cost of approximately $35.4 billion and $35.3 billion, respectively. Of these amounts, the Authority's investment purchases and sales at cost for its decommissioning funds were $229.2 million and $225.5 million, respectively. Compared to the year ended December 31, 2005, the Authority's total investment purchases and sales at cost were approximately $30.4

billion and $30.6 billion, respectively. Of these amounts, investment purchases and sales at cost for the decommissioning funds were $49.9 million and $46.7 million, respectively.

With adoption of GASB Statement No. 40, "Deposit and Investment Risk Disclosures" (GASB 40), reporting requirements for GASB Statement No. 3, "Deposits with Financial Institutions, Investments (including Repurchase Agreements), and Reverse Repurchase Agreements" (GASB 3) were modified.

Under disclosure requirements for GASB 3, the Authority's repurchase agreements at December 31, 2006 totaled approximately $130.3 million. The Authority requires that securities underlying repurchase agreements have a market value of at least 102 percent of the cost of the repurchase agreement. Securities underlying repurchase agreements are delivered by broker/dealers to the Authority's trust agents. Prior disclosure requirements concerning credit and market risk are now included in GASB 40 disclosures.

GASB 40 addresses modifications of disclosure requirements for common deposit and investment risks related to credit risk, custodial credit risk, concentration of credit risk, interest rate risk, and foreign currency risk. The Authority's requirements for disclosure are as follows:

Credit Risk - Generally, credit risk is the risk that an issuer of an investment will not fulfill its obligation to the holder of the investments. This is measured by the assignment of rating by a nationally recognized statistical rating organization. State law and restrictions established by bond indenture and resolution limit investments in debt securities to those securities issued by the U.S. government and agencies or instrumentalities of the United States created pursuant to an Act of Congress. Examples of these agencies' securities are Federal Home Loan Bank and Federal National Mortgage Association. As of December 31, 2006, all of the agency's securities held by the Authority were rated AAA by Fitch and Aaa by Moody's Investors.

Custodial Credit Risk - Custodial credit risk for deposits is the risk that, in the event of the failure of a depository financial institution, an entity will not be able to recover its deposits or will not be able to recover collateral securities that are in the possession of an outside party. The custodial credit risk for investments is the risk that, in the event of the failure of the counterparty to a transaction, an entity will not be able to recover the value of its investment or collateral securities that are in the possession of another party. As of December 31, 2006, all of the Authority's investment securities are held by the Trustee or Agent of the Authority and therefore have no custodial risk.

At December 31, 2006, the Authority had deposits exposed to custodial credit risk as follows:

Depository Account Type	Bank Balance
	(Thousands)
Uninsured and collateral held by Bank's agent not in Authority's name	$ 11,462

Concentration of Credit Risk - The investment policy of the Authority contains no limitations on the amount that can be invested in any one issuer. Investments in any one issuer (other than U.S. Treasury securities) that represent 5 percent or more of total Authority investments are as follows:

Issuer	Investment Type	Fair Value
		(Thousands)
Federal Home Loan Bank	Federal agency securities	$ 217,844
Federal National Mortgage Association	Federal agency securities	$ 198,525
Federal Home Loan Mortgage Corp	Federal agency securities	$ 66,476

Interest Rate Risk - Interest rate risk is the risk that changes in market interest rates will adversely affect the fair value of an investment. Generally, the longer the maturity of an investment, the greater the sensitivity of its fair value to changes in market interest rates. The Authority manages its exposure to interest rate risk by investing in securities that mature as necessary to provide the cash flow and liquidity needed for operations.

The following table shows the distribution of the Authority's investments by maturity:

Investment Type	Fair Value	Weighted Average Maturity
	(Thousands)	(Years)
Certificates of Deposits	$ 2,100	0.24
Federal Agency Discount Notes	178,794	0.02
Federal Agency Securities	337,272	3.91
Repurchase Agreements	130,337	0.01
U.S. Treasury Obligations	66,183	3.39
Total	$ 714,686	
Portfolio Weighted Average Maturity		2.15

The Authority holds zero coupon bonds which are highly sensitive to interest rate fluctuations in both the Nuclear Decommissioning Trust and Nuclear Decommissioning Fund. Together these accounts hold $48.6 million in U.S. Treasury Strips ranging in maturity from February 15, 2008 to May 15, 2019. They also hold $59.7 million in government agency zero coupon securities (i.e. Resolution Corp, FNMA, FICO and REFCORP Securities) in the two portfolios ranging in maturity from October 15, 2007 to November 15, 2026. Zero coupon bonds or U.S. Treasury Strips are subject to wider swings in their market value than coupon bonds. These portfolios are structured to hold these securities to maturity or early redemption. The Authority has a buy and hold strategy for these portfolios. Based on the Authority's current decommissioning assumptions, it is anticipated that no funds will be needed any earlier than 2043. The Authority has no other investments that are highly sensitive to interest rate fluctuations.

Foreign Currency Risk - Foreign currency risk exists when there is a possibility that changes in exchange rates could adversely affect investment or deposit fair market value. The Authority is not authorized to invest in foreign currency and therefore has no exposure.

Note 4 – Long-Term Debt Outstanding:

The Authority's long-term debt at December 31, 2006 and 2005 consisted of the following:

	2006	2005	Interest Rate(s) (1)	Call Price (1)
	(Thousands)		(%)	(%)
Electric Revenue Bonds - Priority Obligations: (final maturity 7/1/06)	**$ 0**	$ 4,420	N/A	N/A
Capitalized Lease Obligations (Net): (mature through 2014)	**9,896**	11,937	2.00-5.00	N/A
Revenue Bonds: (mature through 2032)				
1997 Tax-exempt Refunding Series A	**204,885**	204,885	4.875-5.125	101
1998 Tax-exempt Refunding Series B	**22,485**	23,200	4.50-5.25	101
Total Revenue Bonds	**227,370**	228,085		
Revenue Obligations: (mature through 2039)				
1999 Tax-exempt Improvement Series A	**69,960**	181,300	4.80-5.625	101
1999 Taxable Improvement Series B	**63,680**	68,135	7.12-7.42	Non-callable
2001 Tax-exempt Improvement Series A	**42,180**	44,265	4.00-5.25	101
2001 Tax-exempt Refunding Series A	**0**	3,100	N/A	N/A
2002 Tax-exempt Refunding Series A	**100,615**	104,320	5.00-5.50	101
2002 Tax-exempt Improvement Series B	**271,140**	281,140	5.00-5.375	100
2002 Taxable Improvement Series C	**51,835**	68,765	5.27-5.51	P&I Plus Make-Whole Premium
2002 Tax-exempt Refunding Series D	**395,840**	418,670	4.00-5.25	100
2003 Tax-exempt Refunding Series A	**335,030**	335,030	4.75-5.00	100
2004 Tax-exempt Improvement Series A	**434,610**	434,870	2.50.-5.00	100
2004 Taxable Improvement Series B	**17,635**	17,635	3.57-4.52	P&I Plus Make-Whole Premium
2004 Tax-exempt Improvement Series M - CIBS	**19,664**	19,756	4.25-4.90	100
2004 Tax-exempt Improvement Series M - CABS	**8,813**	8,557	4.375-5.00	Accreted Value
2005 Tax-exempt Refunding Series A	**125,295**	125,295	5.25-5.50	100
2005 Tax-exempt Refunding Series B	**278,005**	278,005	5.00	100
2005 Tax-exempt Refunding Series C	**78,150**	78,150	4.125-4.75	100
2005 Tax-exempt Improvement Series M - CIBS	**10,920**	10,925	3.65-4.35	100
2005 Tax-exempt Improvement Series M - CABS	**4,631**	4,474	4.00-4.35	Accreted Value
2006 Tax-exempt Improvement Series A	**470,765**	0	3.25-5.00	100
2006 Taxable Improvement Series B	**129,115**	0	4.90-5.05	P&I Plus Make-Whole Premium
2006 Tax-exempt Improvement Series M - CIBS	**7,268**	0	3.75-4.20	100
2006 Tax-exempt Improvement Series M - CABS	**2,654**	0	4.00-4.20	Accreted Value
2006 Tax-exempt Refunding Series C	**114,755**	0	4.00-5.00	100
Total Revenue Obligations	**3,032,560**	2,482,392		
Less: Current Portion - Long-term Debt	**79,136**	69,674		
Total Long-term Debt - (Net of current portion)	**$ 3,190,690**	$ 2,657,160		

(1) Apply only to bonds outstanding as of 12/31/2006.

Maturities of long- term debt are as follows:

Year Ending December 31,	Capitalized Leases	Revenue Bonds	Revenue Obligations	Total Principal	Total Interest	Total
			(Thousands)			
2007	$ 2,738	$ 750	$ 75,725	$ 79,213	$ 160,239	$ 239,452
2008	2,563	785	99,635	102,983	157,919	260,902
2009	2,383	825	94,400	97,608	152,936	250,544
2010	1,685	3,370	107,325	112,380	147,590	259,970
2011	1,444	10,685	102,300	114,429	141,386	255,815
2012 - 2016	2,471	74,890	655,928	733,289	608,079	1,341,368
2017 - 2021	0	57,350	846,007	903,357	394,955	1,298,312
2022 - 2026	0	8,425	440,120	448,545	216,486	665,031
2027 - 2031	0	62,580	254,605	317,185	133,067	450,252
2032 - 2036	0	7,710	259,525	267,235	57,542	324,777
2037 - 2039	0	0	96,990	96,990	5,380	102,370
Less: Capitalized Lease Cushion of Credit Account	(3,388)	0	0	(3,388)	0	(3,388)
Total	$ 9,896	$ 227,370	$ 3,032,560	$ 3,269,826	$ 2,175,579	$ 5,445,405

Refunded and defeased bonds outstanding, original loss on refunding, and the unamortized loss at December 31, 2006 are as follows:

Refunding Issue	Refunded Bonds	Refunded and Defeased Bonds Outstanding	Original Loss	Unamortized Loss
			(Thousands)	
Cash Defeasance	$ 20,000 of the 1982 Series A	$ 0	$ 2,763	$ 1,142
1997 Refunding Series A	$ 100,000 of the 1978 Series 68,325 of the 1991 Refunding & Improvement Series B 37,495 of the 1991 Series D	0	16,990	10,523
Commercial Paper	$ 76,050 of the 1973 Series 105,605 of the 1977 Series 81,420 of the 1978 Series	0	2,099	724
1998 Refunding Series B	$ 25,000 of the 1992 Series B	0	1,970	1,050
2002 Refunding Series A	$ 113,380 of the 1992 Refunding Series A	0	23,378	13,052
2002 Refunding Series D	$ 293,250 of the 1993 Refunding Series A 25,900 of the 1993 Refunding Series B-1 25,900 of the 1993 Refunding Series B-2 132,095 of the 1993 Refunding Series C	0	73,613	46,116
2003 Refunding Series A	$ 336,385 of the 1993 Refunding Series C 15,750 of the 1995 Refunding Series A	0	57,064	46,710
2005 Refunding Series A	$ 74,970 of the 1995 Refunding Series A 37,740 of the 1995 Refunding Series B 20,080 of the 1996 Refunding Series A	0	23,864	21,549
2005 Refunding Series B	$ 2,590 of the 1995 Refunding Series A 100,320 of the 1995 Refunding Series B 192,305 of the 1996 Refunding Series A 21,505 of the 1996 Refunding Series B	0	73,749	66,584
2005 Refunding Series C	$ 86,335 of the 1993 Refunding Series C	0	12,125	10,934
2006 Refunding Series C	$ 105,005 of the 1999 Series A 10,000 of the 2002 Series B	115,005	7,054	6,778
Total		$ 115,005	$ 294,669	$ 225,162

The fair value of the Authority's debt is estimated based on quoted market prices for the same or similar issues or on the current rates offered to the Authority for debt with the same remaining maturities. Based on the borrowing rates currently available to the Authority for debt with similar terms and average maturities, the fair value of debt was approximately $3.6 billion and $3.1 billion at December 31, 2006 and 2005, respectively.

On January 13, 2006, the Authority's Board authorized the sale of approximately $599.9 million Revenue Obligations, 2006 Series A & B (2006 A & B Bonds). The 2006 Tax-Exempt Series A (2006A Bonds) totaled approximately $470.8 million. The 2006 Taxable Series B (2006B Bonds) totaled approximately $129.1 million. The 2006B Bonds were issued as taxable bonds to comply with IRS Private Use Regulations. The 2006 A & B Bonds were issued February 1, 2006 at an all-in true interest cost of 4.64 percent (aggregate true interest cost). The 2006 A & B Bonds will mature between January 1, 2007 and January 1, 2039.

On October 20, 2006, the Authority's Board authorized the sale of approximately $9.9 million Revenue Obligations, 2006 Series M (2006M Bonds). The 2006M Bonds consisted of Current Interest Bearing Bonds issued in denominations of $500 and Capital Appreciation Bonds issued in denominations of $200. The 2006M Bonds were issued directly by the Authority to residents of the State, customers of the Authority, members of electric cooperatives organized under the laws of the State, and electric customers of the City of Bamberg and City of Georgetown. Interest rates ranged from 3.75 percent in 2013 to 4.20 percent on the 2023 maturity.

On November 1, 2006, the Authority's Board authorized the sale of approximately $114.8 million Revenue Obligations, 2006 Refunding Series C (2006C Bonds). This refunding reduced the Authority's total debt service over the life of its bonds by approximately $11.2 million, resulting in an economic gain of approximately $8.1 million. The debt was issued at an all-in true interest rate of 4.20 percent. Yields ranged from 3.71 percent in 2014 to 4.04 percent on the 2022 maturity.

As of December 31, 2006, the Authority is in compliance with all debt covenants. All Authority debt is secured by a lien upon and pledge of the Authority's revenues. The Authority's bond indentures provide for certain restrictions, the most significant of which are:

1. The Authority covenants to establish rates sufficient to pay all debt service, required lease payments, capital improvement fund requirements, and all costs of operation and maintenance of the Authority's electric system and all necessary repairs, replacements, and renewals thereof;
2. The Authority is restricted from issuing additional parity bonds unless certain conditions are met.

Note 5 - Commercial Paper:

The Board has authorized the issuance of commercial paper not to exceed $500.0 million. The paper is issued for valid corporate purposes with a term not to exceed 270 days. For the years ended December 31, 2006 and 2005, the information related to commercial paper was as follows:

	2006	2005
Effective interest rate (at December 31)	**3.61%**	3.22%
Average annual amount outstanding (000's)	**$ 195,831**	$ 230,471
Average maturity	**49 Days**	50 days
Average annual effective interest rate	**3.57%**	2.64%

At December 31, 2006 the Authority had a Revolving Credit Agreement with Dexia Credit Local and BNP Paribas for $450.0 million. This agreement is used to support the Authority's issuance of commercial paper. There were no borrowings under the agreement during 2006 or 2005.

Commercial Paper outstanding at December 31, was as follows:

	2006	2005
	(Thousands)	
Commercial Paper-Gross	**$ 195,131**	$ 285,617
Less: Unamortized Discount		
on Taxable Commercial Paper	**59**	168
Commercial Paper-Net	**$ 195,072**	$ 285,449

Note 6 - Summer Nuclear Station:

The Authority and South Carolina Electric and Gas (SCE&G) are parties to a joint ownership agreement providing that the Authority and SCE&G shall own the Summer Nuclear Station with undivided interests of 33 1/3 percent and 66 2/3 percent, respectively. SCE&G is solely responsible for the design, construction, budgeting, management, operation, maintenance, and decommissioning of the Summer Nuclear Station, and the Authority is obligated to pay its ownership share of all costs relating thereto. The Authority receives 33 1/3 percent of the net electricity generated. At December

31, 2006 and 2005, the plant accounts before depreciation included approximately $497.5 million and $488.1 million, respectively, representing the Authority's investment, including capitalized interest, in the Summer Nuclear Station. The accumulated depreciation at December 31, 2006 and 2005 was $272.0 million and $258.6 million, respectively. For the years ended December 31, 2006 and 2005, the Authority's operation and maintenance expenses included $53.4 million and $52.6 million, respectively, for the Summer Nuclear Station.

Nuclear fuel costs are being amortized based on energy expended, which includes a component for estimated disposal costs of spent nuclear fuel which represents the unit-of-production method. This amortization is included in fuel expense and is recovered through the Authority's rates.

In 2002, SCE&G commenced a re-racking project of the on-site spent fuel pool. The new pool storage capability will permit full core off-load through 2018. Further on-site storage, if required, will be accomplished through dry cask storage or other technology as it becomes available.

The Nuclear Regulatory Commission (NRC) requires a licensee of a nuclear reactor to provide minimum financial assurance of its ability to decommission its nuclear facilities. In compliance with the applicable NRC regulations, the Authority established an external trust fund and began making deposits into this fund in September 1990. In addition to providing for the minimum requirements imposed by the NRC, the Authority makes deposits into an internal fund in the amount necessary to fund the difference between a site-specific decommissioning study completed in 2006 and the NRC's imposed minimum requirement. Based on these estimates, the Authority's one-third share of the estimated decommissioning costs of the Summer Nuclear Station equals approximately $178.9 million in 2006 dollars. As deposits are made, the Authority debits FERC account 532 - Maintenance of Nuclear Plant, an amount equal to the deposits made to the internal and external trust funds. These costs are recovered through the Authority's rates. Based on current decommissioning cost estimates, these funds, which totaled approximately $128.6 million (adjusted to market) at December 31, 2006, along with investment earnings, are estimated to provide sufficient funds for the Authority's one-third share of the total decommissioning costs. As such, additional deposits were suspended in 2006. Deposits may be reinstated based on future studies and conditions.

In 2004, the NRC granted a twenty-year extension to Summer Nuclear Station's operating license, extending it to August 6, 2042.

The Energy Policy Act of 1992 gave the Department of Energy (DOE) the authority to assess utilities for the decommissioning of its facilities used for the enrichment of uranium included in nuclear fuel costs. In order to decommission these facilities, the DOE estimated that it would need to charge utilities a total of $150.0 million, indexed for inflation, annually for 15 years based on enrichment services used by utilities in past periods. Based on an estimate from SCE&G covering the 15 years, the Authority's remaining one-third share of the liability at December 31, 2006 totaled approximately $66,000. Such amount has been deferred and will be recovered through rates as paid. These costs are included on the accompanying balance sheets in "Deferred debits and other noncurrent assets - Other" and "Other deferred credits and noncurrent liabilities."

On October 20, 2006, the Authority's Board of Directors authorized management to expend up to $390.0 million through 2010 in continuing actions necessary to design, permit, procure, construct and install two 1100 MW units at Summer Nuclear Station. This authorization includes $31.0 million previously included in the capital improvement program for 2006 through 2008. Construction may not commence until the Board has approved a final budget and construction schedule. The Authority and SCE&G have entered into a short-term Bridge Agreement which contemplates an Authority ownership interest of 45 percent in the two units and governs the relationship of the Authority and SCE&G while proceeding toward obtaining a construction and operating license. The Authority anticipates the Bridge Agreement will be replaced by more permanent agreements governing construction, operation and decommissioning of the units. The Bridge Agreement allows either or both parties to withdraw from the project under certain circumstances.

Note 7 - Leases:

The Authority has capital lease contracts with Central Electric Power Cooperative, Inc. (Central), covering a steam electric generating plant, transmission facilities, and various other facilities. The remaining lease terms range from 1 to 8 years. Quarterly lease payments are based on a sum equal to the interest on and principal of Central's indebtedness to the Rural Utilities Service (formerly Rural Electrification Administration) for funds borrowed to construct the above mentioned facilities. The Authority has options to purchase the leased properties at any time during the period of the lease agreements for sums equal to Central's indebtedness remaining outstanding on the properties at the time the options are exercised or to return the properties at the termination of the lease. The Authority plans to exercise each and every option to acquire ownership of such facilities prior to expiration of the leases.

In addition, during 2004, the Authority became a joint participant with Central in the Rural Utilities Service (RUS) cushion of credit payments programs (COC). This program allows the borrower to build up a cushion of money for future application toward their debt while earning 5 percent interest. During 2006, approximately $833,000 in lease payments were made from the COC account. At December 31, 2006 and 2005, the balance in the Authority's portion of the joint account was approximately $3.4 million and $4.0 million, respectively.

Future minimum lease payments on Central leases at December 31, 2006 were as follows:

Year ending December 31,	(Thousands)
2007	$ 3,335
2008	3,038
2009	2,737
2010	1,934
2011	1,610
2012 - 2014	2,619
Total minimum lease payments	$ 15,273
Less amounts representing interest	1,989
Principal Balance	$ 13,284
Less: Cushion of Credit Account	3,388
Balance at December 31, 2006	$ 9,896

Property under capital leases and related accumulated amortization included in utility plant at December 31, 2006, totaled approximately $89.5 million and $81.9 million, respectively, and at December 31, 2005, totaled $89.6 million and $79.5 million, respectively.

Operating lease payments totaled approximately $7.3 million and $6.5 million during the years ended December 31, 2006 and 2005, respectively. Included in these operating lease payments are periodic expenses related to leased coal cars, which are initially reflected in fuel inventory and subsequently reported in fuel expense based on the tons burned. The terms of the current coal car leases vary from one month to twenty-six months, with the longest lease expiring in 2009. The approximate amounts for the coal car leases to be paid for the years 2007 through 2009 are $5.2 million, $4.9 million, and $296,000, respectively.

Note 8 - Contracts with Electric Power Cooperatives:

Central is a generation and transmission cooperative that provides wholesale electric service to each of the 15 distribution cooperatives and Saluda River Electric Cooperative, Inc. (Saluda) which are members of Central. Power supply and transmission services are provided to Central in accordance with a power system coordination and integration agreement (the Coordination Agreement). Under this agreement, the Authority is the sole supplier of energy needs for Central excluding energy Central and Saluda receive from the Southeastern Power Administration (SEPA) and Saluda's ownership interest in the Catawba Nuclear Station. Saluda is a generation cooperative that provides wholesale electric service to each of the five electric cooperatives (the "Saluda Cooperatives") that are members of Saluda. Under agreements between Central and the Saluda Cooperatives, each of the Saluda Cooperatives becomes a member of Central at the earlier of (i) such time as Saluda ceases its corporate existence or (ii) January 31, 2009. At such time the Saluda Cooperatives become all requirements customers of Central and receive their power requirements from the Authority under the Coordination Agreement.

Central, under the terms of the contract with the Authority, has the right to audit costs billed to them under the cost of service contract. Differences as a result of this process are accrued if they are probable and estimable under FASB Statement No. 5, "Accounting for Contingencies" (FASB 5). To the extent that differences arise due to this process, prospective adjustments are made to cost of service and are reflected in operating revenues in the accompanying Combined Statements of Revenues, Expenses and Changes in Net Assets. Such adjustments in 2006 and 2005 were not material to the Authority's overall operating revenue.

Note 9 - Commitments and Contingencies:

Budget - The Authority's capital budget provides for expenditures of approximately $686.4 million during the year ending December 31, 2007 and $1.2 billion during the two years thereafter. These expenditures include $1.2 billion for new generating units being constructed to begin operation in 2007, 2009, 2012, 2016 and 2019, and $49.3 million for environmental compliance expenditures. The total project costs of the new generating units to begin operation in 2007, 2009, and 2012 are $671.7 million, $755.0 million, and $998.0 million, respectively. Capital expenditures will be financed by internally generated funds and a combination of taxable and tax-exempt debt.

Purchase Commitments - The Authority has contracted for long-term coal purchases under contracts with estimated outstanding minimum obligations after December 31, 2006. The disclosure of minimum obligations below is based on the Authority's contract rates and represents management's best estimate of future expenditures under long-term arrangements.

Year ending December 31,	(Thousands)
2007	$ 387,262
2008	251,186
2009	164,366
2010	140,846
2011	119,346
2012 - 2016	65,491
Total	$ 1,128,497

The Authority has outstanding minimum obligations under an existing long-term and an existing short-term purchased power contract as of December 31, 2006. The obligations were approximately $72.9 million with a remaining term of 28 years and $75,150 with a remaining term of three months. Also, as of December 31, 2006, the Authority has entered into a lease agreement for output of a hydro electric generating facility. The lease agreement has been executed by the parties and is expected to become effective in 2007.

CSX Transportation, Inc. (CSX) provides substantially all rail transportation service for the Authority's coal-fired generating units. During 2002, a new agreement was signed with an effective date of January 1, 2003. This contract will continue to apply a price per ton of coal moved, with the minimum being set at four million tons per year.

The Authority has commitments for nuclear fuel enrichment and fabrication contracts which are contingent upon the operating requirements of the nuclear unit. As of December 31, 2006, these commitments total approximately $64.4 million over the next eight years.

In 2003, the Authority amended the Rainey Generating Station Long-Term Service Agreement (LTSA) with General Electric International, Inc. in the approximate amount of $90.0 million. The agreement provides a contract performance manager (CPM), initial spare parts, parts and services for specified planned maintenance outages, remote monitoring and diagnostics of the turbine generators, and combustion tuning for the gas turbines. In exchange for reduced pricing and added features, the contract term was extended to 2025, but can be terminated for convenience on Rainey 2A and 2B in 2008, and on Rainey 1 in 2013, depending on unit operation. The previous agreement was in the approximate amount of $76.0 million and was effective through 2009. The Authority's Board has approved recovery of the LTSA on a straight-line basis over the term of the agreement.

On January 31, 2005, the Authority entered a $4.0 million Parts and Services Agreement with General Electric International, Inc. (GEII) for maintenance of the Rainey 3, 4, and 5 gas turbines. GEII will supply parts, repair services, and technical direction for one combustion inspection and one hot gas path inspection for each of the three gas turbines. The term of the agreement, which is dependent upon unit operation, is expected to be nine years.

Effective November 1, 2000, the Authority contracted with Transcontinental Gas Pipeline Corporation (TRANSCO) to supply gas transportation needs for its Rainey Generating Station. This is a firm transportation contract covering a maximum of 80,000 decatherms per day for 15 years.

Risk Management - The Authority is exposed to various risks of loss related to torts; theft of, damage to, and destruction of assets; business interruption; and errors and omissions. The Authority purchases commercial insurance to cover these risks, subject to coverage limits and various exclusions. Settled claims resulting from these risks have not exceeded commercial insurance coverage in any of the past three years. Policies are subject to deductibles ranging from $5,000 to $1.0 million, with the exception of named storm losses which carry deductibles from $1.0 million up to $5.0 million. Also a $1.4 million general liability self-insured layer exists between the Authority's primary and excess liability policies. During 2006, there were no losses incurred or reserves recorded for general liability.

The Authority is self-insured for auto, dental, worker's compensation and environmental incidents that do not arise out of an insured event. The Authority purchases commercial insurance, subject to coverage limits and various exclusions, to cover automotive exposure in excess of $2.0 million per incident. Risk exposure for the dental plan is limited by plan provisions. There have been no third-party claims for environmental damages for 2006 or 2005. Claims expenditures and liabilities are reported when it is probable that a loss has occurred and the amount of the loss can be reasonably estimated.

At December 31, 2006, the amount of the self-insured liabilities for auto, dental, worker's compensation and environmental remediation was approximately $2.4 million. The liability is the Authority's best estimate based on available information.

Changes in the reported liability are as follows:

	2006	2005
	(Thousands)	
Unpaid claims and claim expense at beginning of year	**$ 2,597**	$ 2,375
Incurred claims and claim adjustment expenses:		
Provision for insured events of the current year	**1,375**	1,724
Payments for current and prior years	**1,570**	1,502
Total unpaid claims and claim expenses at end of year	**$ 2,402**	$ 2,597

The Authority pays insurance premiums to certain other State agencies to cover risks that may occur in normal operations. The insurers promise to pay to, or on behalf of, the insured for covered economic losses sustained during the policy period in accordance with insurance policy and benefit program limits. Several State funds accumulate assets, and the State itself assumes all risks for the following:

1. Claims of covered employees for health benefits (Employee Insurance Program); not applicable for worker's compensation injuries;
2. Claims of covered employees for basic long-term disability and group life insurance benefits (Retirement System).

Employees elect health coverage through either a health maintenance organization or through the State's self-insured plan. All other coverages listed above are through the applicable State self-insured plan except that additional group life and long-term disability premiums are remitted to commercial carriers. The Authority assumes the risk for claims of employees for unemployment compensation benefits and pays claims through the State's self-insured plan.

Nuclear Insurance - The maximum liability for public claims arising from any nuclear incident has been established at $10.9 billion by the Price-Anderson Indemnification Act. This $10.9 billion would be covered by nuclear liability insurance of about $300.0 million per site, with potential retrospective assessments of up to $100.6 million per licensee for each nuclear incident occurring at any reactor in the United States (payable at a rate not to exceed $15.0 million per incident, per year). Based on its one-third interest in Summer Nuclear Station, the Authority could be responsible for the maximum assessment of $33.5 million, not to exceed approximately $5.0 million per incident, per year. This amount is subject to further increases to reflect the effect of (i) inflation, (ii) the licensing for operation of additional nuclear reactors, and (iii) any increase in the amount of commercial liability insurance required to be maintained by the NRC.

Additionally, SCE&G and the Authority maintain, with Nuclear Electric Insurance Limited (NEIL), $500.0 million primary and $1.5 billion excess property and decontamination insurance to cover the costs of cleanup of the facility in the event of an accident. In addition to the premiums paid on the primary and excess policies, SCE&G and the Authority could also be assessed a retrospective premium, not to exceed 10 times the annual premium of each policy, in the event of property damage to any nuclear generating facility covered by NEIL. Based on current annual premiums and the Authority's one-third interest, the Authority's maximum retrospective premium would be $2.6 million for the primary policy and $2.9 million for the excess policy. SCE&G and the Authority also maintain accidental outage insurance to cover replacement power costs (within policy limits) associated with an insured property loss. This policy also carries a potential retrospective assessment of $1.5 million.

The Authority is self-insured for any retrospective premium assessments, claims in excess of stated coverage, or cost increases due to the purchase of replacement power associated with an uninsured event. Management does not expect any retrospective assessments, claims in excess of stated coverage, or cost increases for any periods through December 31, 2006.

Clean Air Act - The Authority endeavors to ensure that its facilities comply with applicable environmental regulations and standards.

In addition to the existing Clean Air Act (CAA) Federal Acid Rain ($SO2$) and the State NOx Implementation Plan (SIP) Call Programs, the EPA recently promulgated two Clean Air Regulations: Clean Air Interstate Rule (CAIR), and Clean Air Mercury Rule (CAMR). Both CAIR and CAMR were effective in July 2005. Together, they address further reductions in SO2, NOx, and Hg. The Authority, along with other utilities, has challenged the SO2 allocation portion of CAIR, and is participating in a stakeholders process to develop with South Carolina Department of Health and Environmental Control (DHEC) a SIP for CAIR and CAMR in South Carolina. The proposed SIP for CAIR and CAMR is currently undergoing review.

The Authority has been operating under a recent settlement agreement, called the Consent Decree, which became effective June 24, 2004. The settlement with the Environmental Protection Agency (EPA) and DHEC was related to certain environmental issues associated with coal-fired units. It involved the payment of a civil penalty, an agreement to perform certain environmentally beneficial projects, and the expenditure of capital costs of approximately $205.3 million to achieve emissions reductions over the period ending 2013. These capital costs are expected to be largely offset by savings resulting from a reduced need to purchase emission credits.

Safe Drinking Water Act - The Authority continues to monitor for Safe Drinking Water Act regulatory issues impacting electrical utilities. DHEC has primacy for regulatory authority of potable water systems in South Carolina. The State Primary Drinking Water Regulation, R.61-58, governs the design, construction, and operational management of all potable water systems in South Carolina subject to and consistent with the requirements of the Safe Drinking Water Act and the implementation of federal drinking water regulations. The Authority endeavors to manage its potable water systems for compliance with R.61-58.

Clean Water Act - The Clean Water Act (CWA) prohibits the discharge of pollutants, including heat, from point sources into waters of the United States, except as authorized in the National Pollutant Discharge Elimination System (NPDES) permit program. The CWA also requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. DHEC has been delegated NPDES permitting authority by the EPA and administers the program for the State. DHEC has stated that if there should be a delay in renewing permits beyond the expiration of the existing permits, the permits will be extended by operation of law and the Authority may still discharge pursuant to Section 1-23-370 of the Code of Laws of South Carolina 1976, as amended.

Each station's stormwater discharge is covered under the State's NPDES General Permit No. SCR000000. The Authority believes it is in compliance with this permit.

Industrial wastewater discharges from all stations are governed by individual NPDES permits. Cross Generating Station's NPDES permit was reissued on November 3, 2006 and it expires on August 31, 2010. The Grainger Generating Station NPDES permit was reissued effective October 1, 2002, with an expiration date of September 30, 2006. An application for renewal of the Grainger Generating Station NPDES permit was submitted on March 28, 2006. The Jefferies Generating Station NPDES permit was reissued effective March 1, 2003, with an expiration date of February 29, 2008. The Winyah Generating Station NPDES permit was reissued effective October 1, 2000, with an expiration date of September 30, 2005. An application for renewal of the Winyah Generating Station NPDES permit was submitted on March 29, 2005. The Rainey Generating Station NPDES permit was reissued effective August 1, 2003, with an expiration date of July 31, 2008. The Authority's Regional Water System's NPDES permit was reissued effective October 1, 2001 with an expiration date of October 31, 2006. An application for renewal was submitted April 24, 2006.

The EPA revised sections of the CWA relating to Spill Prevention Control and Counter-measures (SPCC). These revisions require that regulated facilities amend their current SPCC plans to meet the new standard. The Authority is in the process of compliance with the new standard before the regulatory required implementation date of July 1, 2009.

The EPA published regulations implementing Section 316(b) of the CWA for existing electric generating facilities in the Federal Register on July 9, 2004. These regulations require that cooling water intake structures reflect the Best Technology Available (BTA) for minimizing adverse environmental impacts such as the impingement of fish and shellfish on the intake structures and the entrainment of eggs and larvae through cooling water systems. These regulations, which became effective September 7, 2004, establish performance standards for reduction in impingement mortality and entrainment. The Jefferies Generating Station and the Grainger Generating Station are the Authority's only facilities affected by the new rule, and are currently in compliance with the requirements.

Hazardous Substances and Wastes - Section 311 of the CWA imposes substantial penalties for spills of Federal EPA-listed hazardous substances into water and for failure to report such spills. The Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) provides for the reporting requirements to cover the release of hazardous substances generally into the environment, including water, land and air. When these substances are processed, stored, or handled, reasonable and prudent methods are employed to prevent a release to the environment.

Additionally, the EPA regulations under the Toxic Substances Control Act impose stringent requirements for labeling, handling, storing and disposing of polychlorinated byphenyls (PCB) and associated equipment. There are regulations covering PCB notification and manifesting, restrictions on disposal of drained electrical equipment, spill cleanup record-keeping requirements, etc. The Authority has a comprehensive PCB management program in response to these regulations.

Under the CERCLA and Superfund Amendments and Reauthorization Act (SARA), the Authority could be held responsible for damages and remedial action at hazardous waste disposal facilities utilized by it, if such facilities become part of a Superfund effort. CERCLA liability, which is strict, joint and several, can be imposed on any generator of hazardous substances who arranged for disposal or treatment at the affected facility. Moreover, under SARA, the Authority must comply with a program of emergency planning and a "Community Right-To-Know" program designed to inform the public about more routine chemical hazards present at the facilities. Both programs have stringent enforcement provisions.

The Authority endeavors to comply with the applicable provisions of CERCLA and SARA, but it is not possible to determine if some liability may be imposed in the future for past waste disposal or compliance with new regulatory requirements. In addition to handling hazardous substances, the Authority generates solid waste associated with the combustion of coal, the vast majority of which is fly ash, bottom ash and scrubber sludge. These wastes are exempt from hazardous wastes regulation under the Resource Conservation and Recovery Act (RCRA).

Also under RCRA, the Authority may be required to undertake corrective action with respect to any leaking underground petroleum storage tank and is liable for the costs of any corrective action taken by the EPA, including compensating third parties for personal injuries and property damage. The Authority implemented a program which assessed all underground storage tanks (USTs). As a result of the assessment, the number of USTs has been significantly reduced. The Authority is required by the EPA and DHEC to maintain documentation of sufficient funds or insurance to cover environmental impacts.

Open Access Transmission Tariff - On April 24, 1996, the FERC issued Orders 888 and 889: the implementing rules for mandatory non-discriminatory open access over the transmission systems of jurisdictional entities. Order 888 required each jurisdictional transmission owner to file with FERC by July 9, 1996 a pro forma open access transmission tariff (OATT).

Order 888 also requires that a non-jurisdictional utility, such as the Authority, must agree to provide comparable transmission service over its transmission facilities in order to receive service from a jurisdictional utility under its OATT.

In order to ensure it would be able to receive transmission service from jurisdictional utilities, in 1997 the Authority adopted an open access transmission tariff substantially in conformance with the tariff required to be filed by jurisdictional utilities.

On May 19, 2006, the FERC issued a Notice of Proposed Rulemaking (NOPR) to consider possible reforms to Order 888 and the pro forma OATT. The purpose of the NOPR is to ensure that the OATT achieves its original purpose, namely, that transmission services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. This is the first comprehensive review of OATT since Order 888 was issued in 1996. FERC issued a Final Rule in this rule-making proceeding on February 16, 2007 (Order 890) making substantial revisions to the pro forma OATT. Among other things, Order 890 eliminates the existing wide discretion that transmission providers have in calculating Available Transfer Capability, requires transmission providers to participate in an open, transparent, and coordinated planning process and makes other modifications to improve and clarify ambiguous provisions, among other things.

Regional Transmission Organizations (RTOs) - Presently there are no active RTO development activities in the southeastern United States. Two previous efforts to develop a RTO for the southeastern United States have resulted in failure. In each case, the effort failed because of the lack of demonstrable benefits from forming a RTO and the lack of consensus support and acceptance from all applicable state and federal agencies for the proposed RTO structure.

Whether a new RTO development effort will arise in the southeastern United States is unknown at this time. Any potential impact on the Authority of such a new effort is likewise unknown.

Energy Policy Act of 2005 - On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 (EPACT 2005). EPACT 2005 is the first comprehensive energy legislation enacted by Congress since the Energy Policy Act of 1992 (EPACT 1992). However, unlike EPACT 1992, EPACT 2005 does not represent a fundamental change from the immediate past.

EPACT 2005 includes several provisions intended to promote the use of nuclear power, including the extension of the Price-Anderson Act for 20 years (until 2025), as well as on a limited basis, provisions intended to encourage the construction of advanced nuclear facilities including possible loan guarantees, standby support and production tax credits.

EPACT 2005 introduces a new Section 211A of the Federal Power Act (FPA), "Open Access by Unregulated Transmitting Utilities." Under Section 211A, FERC has authority to require an otherwise non-jurisdictional transmission owner owning or operating transmission facilities, such as Santee Cooper, to provide transmission services at (1) rates that are comparable to those they charge themselves, and (2) terms and conditions that are comparable to those they charge themselves and that are not unduly discriminatory or preferential. EPACT 2005 also introduces a new Section 217 of the FPA, "Native Load Service Obligation." Under this provision, any load-serving entity with a service obligation, including an otherwise non-jurisdictional transmission owner, is entitled to use its transmission capacity to meet its native load service obligation in preference to other uses of the grid.

EPACT 2005 introduces a new Section 215 of the FPA which authorizes the FERC to certify an entity as the nation's Electric Reliability Organization (ERO) that would propose reliability standards that would be reviewed by FERC before becoming final. On July 20, 2006, the FERC issued an order certifying the North American Electric Reliability Corporation (NERC) as ERO.

On April 4, 2006, NERC submitted certain proposed reliability standards to FERC for approval under Section 215 of the FPA. FERC has opened a rulemaking proceeding to consider those proposed standards. A Final Order acting on the proposed standards is expected to be issued in the first quarter of 2007.

Legal Matters - The Authority is a party in various claims and lawsuits that arise in the conduct of its business. Although the results of litigation cannot be predicted with certainty, in the opinion of management and Authority counsel, the ultimate disposition of these matters will not have material adverse effect on the financial position or results of operations of the Authority, except as described below.

Landowners located along the Santee River contend that the Authority is liable for damage to their real estate as a result of flooding that has occurred since the U.S. Army Corps of Engineers' Cooper River Rediversion Project was completed in 1985. A jury trial held in 1997 in the U.S. District Court, Charleston, SC, returned a verdict against the Authority on certain causes of action. The Authority appealed the decision to the Fourth Circuit Court of Appeals which, after oral arguments, remanded the case to the District Court. In 2006, the Corps moved to intervene and transfer the District Court action to the Court of Federal Claims. The Authority joined in this motion. The District Court denied the motion and the issue is on appeal to the United States Court of Appeals for the Federal Circuit. No estimate relative to potential loss to the Authority can be made at this time.

The U.S. Army Contract Board of Appeals has determined that the contract between the Corps and the Authority requires that the Corps indemnify the Authority for certain claims arising out of the construction and operation of the project.

Note 10 - Retirement Plan:

Substantially all Authority regular employees must participate in one of the components of the South Carolina Retirement System (System), a cost sharing, multiple-employer public employee retirement system, which was established by Section 9-1-20 of the South Carolina Code of Laws. The payroll for active employees covered by the System for each of the years ended December 31, 2006 and 2005 was approximately $101.0 million and $96.0 million, respectively.

Vested employees who retire at age 65 or with 28 years of service at any age are entitled to a retirement benefit, payable monthly for life. The annual benefit amount is equal to 1.82 percent of their average final compensation times years of service. Benefits fully vest on reaching five years of service. Reduced retirement benefits are payable as early as age 55 with 25 years of service. The System also provides death and disability benefits. Benefits are established by State statute.

Effective January 1, 2001, Section 9-1-2210 of the South Carolina Code of Laws allowed employees eligible for service retirement to participate in the Teacher and Employee Retention Incentive (TERI) Program. TERI participants may retire and begin accumulating retirement benefits on a deferred basis without terminating employment for up to five years. Upon termination of employment or at the end of the TERI period, whichever is earlier, participants will begin receiving monthly service retirement benefits which include any cost of living adjustments granted during the TERI period. Because participants are considered retired during the TERI period, they do not earn service credit or disability retirement benefits. Effective July 1, 2005, TERI employees began "re-contributing" to the System at the prevailing rate. However, no service credit is earned under the new regulations. The group life insurance of one times annual salary was re-established for TERI participants. Each participant is entitled to be paid for up to 45 days of accumulated unused annual vacation leave upon retirement.

Article X, Section 16 of the South Carolina Constitution requires that all State-operated retirement plans be funded on a sound actuarial basis. Title 9 of the South Carolina Code of Laws (as amended) prescribes requirements relating to membership, benefits, and employee/employer contributions.

All employees are required by State statute to contribute to the System at the prevailing rate (currently 6.50 percent). The Authority is required by the same statute to contribute 8.05 percent of total payroll for retirement and an additional 0.15 percent for group life. The contribution requirement for the years ended December 31, 2006 and 2005 was approximately $8.4 million and $7.7 million, respectively, from the Authority and $6.4 million and $5.9 million, respectively from employees. The Authority made 100 percent of the required contributions for each of the years ended December 31, 2006 and 2005.

The System issues a stand alone financial report that includes all required supplementary information. The report may be obtained by writing to: South Carolina Retirement System, P.O. Box 11960, Columbia, S.C. 29211.

Effective July 1, 2002, new employees have a choice of type of retirement plan in which to enroll. The State Optional Retirement Plan (State ORP) which is a defined contribution plan is an alternative to the System retirement plan which is a defined benefit plan. The contribution amounts are the same, (6.50 percent employee cost and 8.05 percent employer cost) however, 5 percent of the employer amount is directed to the vendor chosen by the employee and the remaining 3.05 percent is to the Retirement System. As of December 31, 2006, thirty-one of the Authority's employees were participants in the State ORP and consequently the related payments are not material.

The Authority is the non-operating owner (one-third share) of SCE&G's V.C. Summer Nuclear Station. As such, the Authority is responsible for funding its share of pension requirements for the nuclear station personnel in accordance with FASB Statement No. 87, "Employers' Accounting for Pensions" (FASB 87). The established pension plan generates earnings which are shared proportionately and used to reduce the allocated funding.

As of December 31, 2006 and 2005, the Authority had over-funded its share of the plan FASB 87 requirements by $10.5 million and $10.2 million, respectively. This receivable will be applied to future years as additional expenditures are required to meet the Authority's funding obligation. The pre-funded amounts are in "Other" within "Deferred debits and other noncurrent assets" on the balance sheet.

The Authority also provides retirement benefits to certain employees designated by management and the Board under supplemental executive retirement plans. Benefits are established and may be amended by management and the Authority's Board and include retirement benefit payments for a specified number of years and death benefits. The cost of these benefits is actuarially determined annually. Beginning in 2006, the supplemental executive retirement plans were segregated into the internal and external funds. The qualified benefits are funded externally with the annual cost set aside in a trust administered by a third party. The pre-2006 retiree benefits and the non-qualified benefits are funded internally with the annual cost set aside and managed by the Authority. The cost for 2006 and 2005 was approximately $2.1 million and $2.0 million, respectively. The accrued liability at December 31, 2006 and 2005 was approximately $5.7 million and $8.0 million, respectively.

Note 11 - Other Postretirement Benefits:

The South Carolina Retirement System provides certain health, dental, and life insurance benefits for retired employees of the Authority. Substantially all of the Authority's employees may become eligible for these benefits if they retire at any age with 28 years of service or at age 60 with at least 20 years of service. Currently, approximately 509 retirees meet these requirements. The cost of the health, dental and life insurance benefits are recognized as expense as the premiums are paid. For each of the years ended December 31, 2006 and 2005, these costs totaled approximately $2.3 million and $2.0 million, respectively. The Authority is the non-operating owner (one-third share) of SCE&G's V.C. Summer Nuclear Station. As such the Authority is responsible for funding its share of other post employment benefits costs for the station's employees. The liability balances as of December 31, 2006 and 2005 were approximately $7.7 million and $7.3 million, respectively.

During their first 10 years of service, full-time employees can earn up to 15 days vacation leave per year. After 10 years of service, employees earn an additional day of vacation leave for each year of service over 10 until they reach the maximum of 25 days per year. Employees earn annually two hours per pay period, plus twenty additional hours at year-end for sick leave.

Employees may carry forward up to 45 days of vacation leave and 180 days of sick leave from one calendar year to the next. Upon termination, the Authority pays employees for accumulated vacation leave at the pay rate then in effect. In addition, the Authority pays employees upon retirement 20 percent of their accumulated sick leave at the pay rate then in effect.

Note 12 - Credit Risk and Major Customers:

Sales to two major customers for the years ended December 31, 2006 and 2005 were as follows:

	2006	2005
	(Thousands)	
Central (including Saluda)	**$ 722,000**	$ 676,000
Alumax of South Carolina	**$ 147,000**	$ 143,000

No other customer accounted for more than 10 percent of the Authority's sales for either of the years ended December 31, 2006 or 2005.

The Authority maintains an allowance for uncollectible accounts based upon the expected collectibility of all accounts receivable.

Note 13 - Storm Damage:

In August 2004, the Authority's system sustained damages from Hurricanes Charley and Gaston. As of December 31, 2006, cost estimates to repair and replace the Authority's damaged facilities are approximately $9.2 million with $3.9 million representing damage to the Jefferies Steam and Hydro Generation facilities and $3.1 million representing damage to the East and West Dams in Pinopolis. The remaining costs reflect damage to other facilities including the transmission and distribution systems, seawalls at the Wampee and Somerset properties, dump truck bodies, and costs of clearing roads and subdivisions.

The Authority has filed for and anticipates disaster relief assistance from federal sources. This assistance is expected to be 75 percent of storm damage costs or approximately $6.8 million.

Through December 31, 2006, the Authority had received $3.1 million in federal assistance on both storms. The Authority does not expect to increase rates due to the impact of Hurricanes Charley and Gaston and foresees no measurable long-term impact on its operations or the demand for electricity by its customers.

Note 14 – Subsequent Event:

The Authority's new 600-MW pulverized coal-fired facility at Cross Generating Station Unit 3 began commercial operation on January 1, 2007.

998B unding eries	1999A Tax-Exempt Series		1999B Taxable Series		2001A Improvement Series		2002A Refunding Series		2002B Tax-Exempt Series		2002C Taxable Series		2002D Refunding Series		2003A Refunding Series		Int
Amt	Int. Rate	Amt	Int. Rate	Amt	Int. Rate	Amt	Int. Rate	Amt	Int. Rate	Amt	Int. Rate	Amt	Int. Rate	Amt	Int. Rate	Amt	Int
750	4.80	6,695	7.12	4,705	4.00	2,155	5.00	4,105			5.27	30,865	5.00	21,715			
785	5 1/2	7,070	7.17	4,980	4 1/2	2,240	5 1/2	7,860			5.51	20,970	4.00	28,690			
825	5 1/2	7,480	7.22	5,270	4 1/2	2,340	5 1/2	8,290	5.00	3,815			5.00	14,800			
865	5 1/2	7,940	7.27	5,590 *		2,450 (2)	5 1/2	8,745	5.00	6,835			5.00	30,430			
905	5 1/2	18,325	7.27	38,390 *			5 1/2	10,110					5 1/4	5,800			
955 *	5 5/8	10,910	7.32	1,465	5.00	2,565	5 1/2	11,555	5 3/8	7,175			5 1/4	30,095			
1,010 *	5 5/8	11,540	7.37	1,580	5.00	2,690	5 1/2	12,190	5 3/8	7,565			5 1/4	36,500			
1,065 *			7.42	1,700	5.00	2,830	5 1/2	7,310	5 3/8	7,970			5 1/4	42,160			
1,120 *					5 1/4	2,965	5 1/2	2,155	5 3/8	8,395			5 1/4	27,645	5.00	23,575	
1,180 *					5 1/4	3,125	5 1/2	2,315	5 3/8	8,850			5.00	18,340	5.00	27,285	
1,245 *					5 1/4	3,290	5 1/2	2,480	5 3/8	9,325			5.00	19,195	5.00	18,980	
1,310 *					5 1/4	2,800	5 1/2	2,615	5 3/8	9,825			5.00	20,095	5.00	13,985	
1,380 *					5 1/4	2,945	5 1/2	6,185	5.00	2,000			5.00	31,095	5.00	19,120	
1,455 *					5 1/4	3,100	5 1/8	8,700					5.00	40,860	5.00	22,960	
1,530 *					4 3/4	3,265 *	5 1/8	6,000					5.00	28,420	5.00	26,125	
1,615 *					4 3/4	3,420 *									5.00	28,380	
1,700 *																	
1,790 *																	
1,000 *																	
															5.00	29,920	
															5.00	25,355	
															4 3/4	20,565	
															4 3/4	21,540	
															4 3/4	22,555	
									5 1/8	2,555 *					4 3/4	23,630	
									5 1/8	30,280 *					4 3/4	11,055	
									5 1/4	31,835							
									5 1/8	33,505 *							
									5 1/8	35,220 *							
									5 1/8	27,025 *							
									5 1/8	38,965 *							
22,485		69,960		63,680		42,180		100,615		271,140		51,835		395,840		335,030	
4,330		23,355		61,640		4,105		7,420		0		39,940		44,920		0	
0		105,005		0		0		0		10,000		0		0		0	
-		-		-		-		-		-		-		-		-	
26,815		198,320		125,320		46,285		108,0[illegible]		281,140		91,775		440,760		335,030	

...pt	2005A Refunding Series		2005B Refunding Series		2005C Refunding Series		2005M Tax-Exempt Series		2006A Tax-Exempt Series		2006B Taxable Series		2006M Tax-Exempt Series		2006C Refunding Series	
Amt	Int. Rate	Amt	Int. Rate	Amt	Int. Rate	Amt	Int. Rate	Amt	Int. Rate	Amt	Int. Rate	Amt	Int. Rate	Amt	Int. Rate	Amt
									3 1/4	5,215						
			5.00	7,600					3 1/4	4,490	4.90	11,070				
									3 3/8	7,975	4.90	7,750				
			5.00	19,155					5.00	3,380	4.90	14,045				
			5.00	10,255					3.40	3,165	4.90	13,000				
			5.00	8,915			3.65	3,880	3 1/2	4,065	4.95	10,000				
			5.00	9,355					3.60	5,000	5.00	13,750	3 3/4	2,639		
	5 1/2	8,635	5.00	5,660					3 5/8	5,000	5.00	28,250				12,550 (7)
973	5 1/2	11,395							5.00	10,000	5.05	31,250				13,165 (8)
283 (3)	5 1/2	17,705					4.00	7,704 (3)	5.00	34,400					5.00	13,800
	5 1/4	4,880	5.00	18,690						39,655 (5)					5.00	14,515
	5 1/4	5,190	5.00	19,580					5.00	13,285			4.00	4,127 (3)	5.00	9,205
	5 1/4	14,520	5.00	20,505					5.00	21,700					5.00	9,685
	5 1/4	28,900	5.00	21,555					5.00	9,375					5.00	10,180
	5 1/4	23,890	5.00	43,650					4 1/8	4,880					5.00	10,710
	5 1/4	10,180	5.00	67,485					4.20	4,000					5.00	11,260
691			5.00	25,600	4 3/4	26,060	4.35	3,967 (3)	5.00	16,500			4.20	3,156 (3)		
530 (3)					4 3/4	25,440			5.00	24,700						
						26,650 (4)			5.00	25,000						
									5.00	18,000						
									5.00	19,000						
									5.00	23,400						
									5.00	24,600						
										26,080 (6)						
									5.00	24,565 *						
									5.00	9,870 *						
									5.00	10,370 *						
									5.00	10,870 *						
									5.00	11,370 *						
									5.00	11,955 *					4 1/2	9,685
									5.00	12,735 *						
									5.00	13,370 *						
									5.00	12,795 *						
477 (3)		125,295		278,005		78,150		15,551 (3)		470,765		129,115		9,922 (3)		114,755
398		0		0		0		32		0		0		0		0
0		0		0		0		0		0		0		0		0
921		-		-		-		216		-		-		21		-
954		125,295		278,005		78,150		15,367		470,765		129,115		9,901		114,755

Schedule of Refunded Bonds Outstanding
Unaudited
As of December 31, 2006
(In Thousands)

Call Date	January 1, 2010		January 1, 2010	
Series	1999A		2002B	
Original Maturity	Tax-Exempt Series		Tax-Exempt Series	
Jan 1	Int. Rate	Amt	Int. Rate	Amt
2007				
2008				
2009				
2010				
2011				
2012				
2013				
2014	5 3/4	12,220		
2015	5 3/4	12,940		
2016	5 1/2	13,690		
2017	5 1/2	14,470		
2018	5 1/2	9,230		
2019	5 1/2	9,755		
2020	5 1/2	10,305		
2021	5 1/2	10,890		
2022	5 1/2	11,505		
2023				
2024				
2025				
2026				
2027				
2028				
2029				
2030				
2031				
2032				
2033				
2034				
2035				
2036			5 1/2	10,000
2037				
Totals per Series		105,005		10,000
Totals per Call Date				115,005

See Schedule of Bonds Outstanding for footnotes.

Board of Directors

Santee Cooper is governed by an 11-member board of directors that is appointed by the governor, deemed fully qualified by the Senate Public Utilities Review Committee and confirmed by the state Senate. The board consists of directors representing each of the six congressional districts, each of the three counties where Santee Cooper serves retail customers directly, two directors with previous electric cooperative experience and the chairman appointed at-large.

O.L. Thompson III
Chairman
At-Large
Mt. Pleasant, S.C.

President and CEO of O.L. Thompson Construction Co., Inc, that includes Thompson Trucking Co., Inc and Wando Concrete.

G. Dial DuBose
1st Vice Chairman
3rd Congressional District
Easley, S.C.

Real estate consultant at Nalley Commercial Properties in Easley, S.C.

Clarence Davis
2nd Vice Chairman
2nd Congressional District
Columbia, S.C.

Partner in Nelson Mullins Riley & Scarborough LLP, a Columbia-based law firm.

Paul G. Campbell, Jr.
Berkeley County
Goose Creek, S.C.

Retired plant manager of Alcoa Mt. Holly. Alcoa is a producer and manager of primary aluminum, fabricated aluminum and alumina facilities.

William A. Finn
1st Congressional District
Charleston, S.C.

Chairman of AstenJohnsen, Inc., a specialty textile company for the printing and papermaking industries based in Charleston, S.C.

Board of Directors

J. Calhoun Land, IV
6th Congressional District
Manning, S.C.

Partner in Land, Parker and Welch, a general practice Manning law firm.

Dr. John Molnar
Horry County
Myrtle Beach, S.C.

Medical Director for Grand Strand Regional Medical Center, Emergency Department.

James W. Sanders, Sr.
5th Congressional District
Gaffney, S.C.

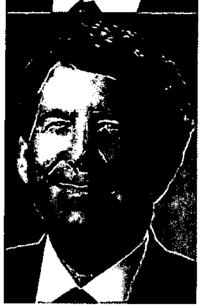
Pastor of Bethel Baptist Church in Gaffney for 56 years and active in numerous civic and business organizations.

David Springs
Georgetown County
Murrells Inlet, S.C.

Retired Consulting Engineer for electric cooperatives and municipal utilities with Southern Engineering Company of Georgia.

Cecil Viverette
At-Large
Hilton Head Island, S.C.

Retired President and CEO of Rappahannock Electric Cooperative in Virginia.



Barry Wynn
4th Congressional District
Spartanburg, S.C.

President of Colonial Trust Company, a private trust company specializing in investment management and estate services.

Advisory Board

Mark Sanford
Governor

Mark Hammond
Secretary of State

Henry D. McMaster
Attorney General

Richard A. Eckstrom
Comptroller General

Grady L. Patterson Jr. [1]
State Treasurer

Executive Management

Lonnie N. Carter	*President and Chief Executive Officer*
Bill McCall	*Executive Vice President and Chief Operating Officer*
Elaine G. Peterson	*Executive Vice President and Chief Financial Officer*
James E. Brogdon Jr.	*Senior Vice President and General Counsel*
R.M. Singletary	*Senior Vice President of Corporate Services*

Management

Senior Vice Presidents:

Terry L. Blackwell	*Power Delivery*
Maxie C. Chaplin	*Generation*

Vice Presidents:

S. Thomas Abrams	*Planning & Power Supply*
Jeffrey D. Armfield [2]	*Business Services and Treasurer*
Wm. Glen Brown	*Human Resource Management*
Zack W. Dusenbury	*Retail Operations*
Glenda W. Gillette	*Controller*
Thomas L. Kierspe	*Engineering and Construction Services*
L. Phil Pierce	*Fossil and Hydro Generation*
Suzanne H. Ritter	*Corporate Planning and Bulk Power*
Laura G. Varn	*Corporate Communications and Media Relations*

Thomas L. Richardson	*Auditor*
Pamela J. Williams	*Corporate Secretary & Associate General Counsel – Corporate Affairs*

1 In November 2006, Thomas Ravenel was elected State Treasurer and was sworn in January, 2007.

2 H. Roderick Murchinson retired from Santee Cooper on March 31, 2006. Jeffrey D. Armfield was promoted to VP Business Services and Treasurer.

Glossary

Availability – The amount of time that a system is available to provide service, usually expressed in percentage, for a specific period of time such as a month or year.

Base-load generating unit – A plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously. These units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs.

Btu (British thermal unit) – The standard unit for measuring quantity of heat energy, such as the heat content of fuel. It is the amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit.

Capacity – The load for which a generating unit, generating station, or other electrical apparatus is rated either by the user or by the manufacturer.

Combustion turbine – A jet-type turbine engine which burns gas or oil and propels a generator to produce electricity.

Commercial customer – All nonresidential retail customers served under the General Service rate schedules. Generally, these customers have a demand less than 1,000 kW per month.

Demand – The rate at which electric energy is delivered to or by a system, part of a system or a piece of equipment. It is expressed in kilowatts at a given instant or averaged over any designated period of time. The primary source of "demand" is the power-consuming equipment of the customers.

Distribution – The process of delivering electric energy from convenient points on the transmission or bulk power system to the consumers. Also, a functional classification relating to that portion of a utility plant used for the purpose of delivering electric energy from convenient points on the transmission system to consumers, or to expenses relating to the operation and maintenance of a distribution plant.

Electric cooperative – A private business entity owned by the customers it serves that supplies electric energy to a specified area. In South Carolina, there are 20 electric distribution co-ops, all of which receive Santee Cooper- generated power.

Energy sales – The sale of electric energy to wholesale and retail customers usually expressed in kilowatt-hours.

FERC (Federal Energy Regulatory Commission) – An independent federal agency created within the Department of Energy, FERC is vested with broad regulatory authority over wholesale electric, natural gas and oil production and the licensing of hydroelectric facilities. Among other things, the agency has regulatory authority over the safety of Santee Cooper's dams and dikes.

Fly ash – Gas-borne particles of matter resulting from the combustion of fuels and other materials.

Generating unit – A combination of equipment needed to produce electricity, such as a turbine-generator and its boiler. A generating station usually consists of several units.

Green power – Electricity generated by renewable resources like methane gas from decomposing garbage. These resources are replenished naturally and minimize harm to the environment.

Gypsum – This is both a naturally occurring and an artificially produced calcium **sulfate** (CaSO4) compound. It is used for a multitude of purposes including sheetrock, fertilizer and cement production. Artificial gypsum may be produced by utilities using forced-oxidation desulfurization systems.

Heat rate – A measure of generating station thermal efficiency, generally expressed in Btu per net kilowatt-hour. It is computed by dividing the total Btu content of fuel burned for electric generation by the resulting kilowatt-hour generation. The lower the heat rate, the more efficient the production.

Industrial customer – Very large retail customers served under Santee Cooper's Large Light and Power rate schedule (or associated riders). These customers have a demand greater than 1,000 kW.

Interchange - Power delivered to or received by one electric utility system from another through an interconnection or "tie."

Kilowatt (kW) – 1,000 watts.

Kilowatt-hour (kWh) – The basic unit of electric energy equal to one kilowatt (1,000 watts) of power flowing through an electric circuit steadily for one hour.
Load – The amount of electric power delivered or required at any specified point or points on a system.

Megawatt (MW) – One million watts or 1,000 kilowatts.

Megawatt-hour – The basic unit of electric energy equal to one megawatt (1,000 kilowatts) of power flowing through an electric circuit steadily for one hour.

Nuclear energy - Energy produced in the form of heat during the fission process in a nuclear reactor. When released in sufficient and controlled quantity, this heat energy may be used to produce steam to drive a turbine generator to produce electricity.

Peak demand – The maximum amount of electricity used by a utility customer at any instant during a specific time period. The peak is used to measure the amount of electric generating capacity that is required to meet that maximum demand.

Public power – Refers collectively to those utilities owned by municipalities or the state or federal government. Although not government owned, electric cooperatives are sometimes considered within the scope of public power.

Regional Transmission Organization (RTO) – A voluntarily created entity approved by the Federal Energy Regulatory Commission to efficiently coordinate transmission planning, operation and use on a regional and interregional basis. It

Reinvested earnings – Net revenues available for reinvestment in the business.

Reliability (electric system) – A measure of the ability of the system to continue operation while some lines or generators are out of service. Reliability deals with the performance of the system under stress.

Residential customer – The classification of customers to whom electricity is sold for household purposes.

Retail customer – These customers are the ultimate consumer of electric energy. Includes residential, commercial, small industrial and other non-wholesale customers.

Revenue bond – A bond payable solely from net or gross non-taxable revenues derived from the operation and charges paid by users of the system.

Service area - Territory in which a utility system is required or has the right to supply electric service to customers.

Substation – An assembly of equipment for the purpose of switching and/or changing or regulating the voltage of electricity.

Tax-exempt financing – A form of financing employed by publicly owned utilities that allows such utilities to issue bonds where the interest paid on the bonds is not generally subject to taxation. This policy, established in law, stems from the long-standing philosophical viewpoint that publicly owned utilities (electric, water, sewer) provide basic services to the citizens they serve and thus should not be taxed.

Transmission – The process of transporting electric energy in bulk from a source or sources of supply to other principal parts of the system or to other utility systems. Also, a functional classification relating to that portion of utility
plant used for the purpose of transmitting electric energy in bulk to other principal parts of the system or to other utility systems, or to expenses relating to the operation and maintenance of transmission plant.

Watt – The basic electrical unit of power or rate of doing work. The rate of energy transfer equivalent to one ampere flowing due to an electrical pressure of one volt at unity power factor. One watt is equivalent to approximately 1/746 horsepower, or one joule per second.

Wholesale customer – A customer who purchases all or part of his or her electricity from the electric utility for resale.

Conway Office
100 Elm Street
Conway, SC 29526
(843) 248-5755
(843) 248-7315 fax

Loris Office
3701 Walnut Street
Loris, SC 29569
(843) 756-5541
(843) 756-7008 fax

Moncks Corner Office
Santee Cooper Headquarters
One Riverwood Drive
Moncks Corner, SC 29461
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(843) 761-7060 fax

Myrtle Beach Office
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(843) 448-2411
(843) 626-1923 fax

Murrells Inlet /Garden City Office
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Section 8.1 Ref 9

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SCANA® POWER FOR LIVING

February 28, 2007

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Posted: D Duke
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Date: 3-1-07
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VIA HAND DELIVERY
The Honorable Charles Terreni
Chief Clerk & Administrator
Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, South Carolina 29210

Re: Annual Review of Base Rates for Fuel Costs for South Carolina Electric & Gas Company
Docket No. 2007-2-E

Dear Mr. Terreni:

Enclosed for filing, on behalf of South Carolina Electric & Gas Company, is the direct testimony of Thomas D. Gatlin, Joseph K. Todd, Gerhard Haimberger, Joseph M. Lynch, and John R. Hendrix. Please accept the original and twenty-five (25) copies of each for filing. Additionally, please acknowledge your receipt of these documents by file-stamping the extra copies that are enclosed and returning them to us via our courier.

By copy of this letter, we are serving all other parties of record with a copy of the enclosed direct testimony and attach a certificate of service to that effect.

If you have any questions regarding this matter, please do not hesitate to contact me.

Very truly yours,

K. Chad Burgess

K. Chad Burgess

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SC PUBLIC SERVICE COMMISSION

KCB/kms
Enclosures

cc: Shannon Bowyer Hudson, Esquire
Jeffrey Nelson, Esquire
Scott Elliott, Esquire
Mitchell Willoughby, Esquire
Belton T. Zeigler, Esquire
(all via hand delivery with enclosures)

DATE: OK D Duke
OK

SCANA® POWER FOR LIVING

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(all via hand delivery with enclosures)

DIRECT TESTIMONY OF
THOMAS D. GATLIN
ON BEHALF OF
SOUTH CAROLINA ELECTRIC & GAS COMPANY
DOCKET NO. 2007-2-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION WITHIN SOUTH CAROLINA ELECTRIC AND GAS COMPANY (SCE&G).

A. My name is Thomas D. Gatlin. My business address is P.O. Box 88, Jenkinsville, South Carolina. I am employed by SCE&G as the General Manager of Nuclear Operations at the Virgil C. Summer Nuclear Station (VCSNS or VC Summer).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I received a BS degree in Electrical Engineering from Christian Brothers University (Memphis, TN) in 1980. I have been a licensed, professional electrical engineer in South Carolina since 1984, and obtained a Senior Reactor Operator license at VCSNS in 1985.

I have been the plant manager at VC Summer for over two years. I was the operations manager for three years prior to my current assignment, and have served in various roles in the operations, engineering, and maintenance departments since joining the company in 1982. I worked at the Tennessee Valley Authority (TVA) for two years in the nuclear instrumentation division prior to working for SCE&G.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review the operating performance of VCSNS during the period from February 1, 2006 through January 31, 2007.

Q. WHAT ARE YOUR OBJECTIVES IN THE OPERATION OF VCSNS?

A. Our primary objective at VCSNS is always safe operation. We also strive for excellence in all phases of operation of the facility. The station's key focus areas of SAFETY, outage performance, equipment reliability, and constant improvement have facilitated the station's good performance through enhanced alignment of the organization. Our business objectives are focused on maintaining a competitive production cost for the generation of electricity using nuclear fuel.

Q. WHAT HAS BEEN THE COMPANY'S EXPERIENCE WITH THE PERFORMANCE OF THE VCSNS?

A. We continuously meet or exceed all Nuclear Regulatory Commission (NRC) requirements and Institute of Nuclear Power Operations (INPO) standards. VCSNS has performed well during the period from February 1, 2006 through January 31, 2007. Consistent with the provisions of Section 58-27-865 of the South Carolina Code of Laws, as amended, VC Summer's net capacity factor based on reasonable excludable nuclear system reductions during the review period was 101.6 % and the gross generation output was 7,518,135 MWH's.

Q. **HAS VCSNS EXPERIENCED ANY OUTAGES DURING THE REVIEW PERIOD?**

A. Yes, VCSNS has experienced the following:

- Reactor power was reduced to 75% on 05/26/2006 to repair a leak in the "C" feedwater booster pump inboard seal. The unit returned to full power operation on 05/29/2006 following the repair.
- Reactor power was reduced to approximately 80% on 06/16/2006 to repair the "C" feedwater booster pump inboard seal. The unit returned to full power operation on 06/19/2006 following the repair.
- Reactor power was reduced to 90% on 07/12/06 due to a trip of the "B" Main Feedwater Pump. The unit returned to full power operation on 07/13/06.
- Power was reduced to 93.6% on 09/13/06 due to a malfunction of the 'A' Reheater Drain Tank normal drain valve. The valve positioner was replaced and power was restored on 09/14/06.
- Refueling Outage 16 started as scheduled during this review period on 10/14/06. The reactor returned to criticality on 11/21/2006, and

the 39 day outage ended with the closure of the generator breaker on 11/22/2006. The planned schedule of 37 days was exceeded by two days due to a shortage of supplemental skilled labor, delays associated with testing, and a steam generator overfill event. The outage was completed under budget with no injuries and no significant safety events.

- The turbine was taken off line from 11/24/2006 to 11/25/06 to perform routine post-maintenance balancing on the generator due to vibration. Full reactor power was achieved on 11/28/2006.

Q. **WHEN WILL THE NEXT REFUELING OUTAGE OCCUR?**

A. Refueling outages are scheduled every 18 months to replace depleted fuel assemblies. Simultaneously, maintenance and testing that cannot be done with the plant on-line is conducted. Our next refueling outage will be Refuel 17 starting in April, 2008.

Q. **PLEASE EXPLAIN THE ROLES OF INPO AND THE NRC WITHIN THE NUCLEAR INDUSTRY AND DESCRIBE ANY RANKINGS RECEIVED BY VCSNS FROM THOSE AGENCIES.**

A. INPO is a nonprofit corporation established by the nuclear industry to promote the highest levels of nuclear safety and plant reliability. INPO promotes excellence in the industry in the operation of nuclear electric generating plants. For the applicable reporting period, INPO rated

VCSNS's overall performance as exemplary which is the highest rating awarded.

The NRC is responsible for the licensing and oversight of the civilian use of nuclear materials in the United States. The NRC has reported that VCSNS operated in a manner that preserved public health and safety and fully met all cornerstone objectives. During the reporting period, the NRC implemented one supplemental inspection beyond the base inspection scope. No deficiencies were noted.

Q. **DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

A. Yes.

DIRECT TESTIMONY OF
JOSEPH K. TODD
ON BEHALF OF
SOUTH CAROLINA ELECTRIC & GAS COMPANY
DOCKET NO. 2007-2-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH SOUTH CAROLINA ELECTRIC & GAS COMPANY (SCE&G).

A. Joseph Todd, 111 Research Drive, Columbia, South Carolina. I am employed by South Carolina Electric & Gas Company as General Manager, Fossil & Hydro Operations.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND YOUR BUSINESS EXPERIENCE.

A. My degree is a B.S. in Civil Engineering from Clemson University. I began my career with Duke Power in 1980 working as a structural engineer for several nuclear plants. I started working with SCE&G in 1981 as a Structural Engineer for V.C. Summer nuclear station in Jenkinsville, SC. In this capacity, I participated in the startup and initial operation of this facility and continued working at V.C. Summer until 1990. In 1990, I transferred to the Fossil/Hydro division of SCE&G and assumed a project management role for initial work on the Cope project along with a number of other environmental projects. I also served as Assistant Manager of McMeekin Station from 1995 to 1998 before returning to a project management role for several environmental projects including SCR installations at Williams and Wateree. Subsequent roles included Business Manager of the Company's power operations on the Savannah River Site, and Manager of Fossil/Hydro Outage Planning. I assumed the role of General Manager, Fossil & Hydro Operations in February of 2007. In this position, I report to the Vice President of Fossil Hydro Operations.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to review the operating performance of South Carolina Electric & Gas Company's fossil units and South Carolina Generating Company's (GENCO) Williams Electric Generating Station (Williams Station) during the period February 1, 2006 through January 31, 2007.

Q. PLEASE GIVE A SHORT DESCRIPTION OF SCE&G'S FOSSIL AND HYDRO ELECTRIC FACILITIES.

A. SCE&G owns and operates ten (10) coal-fired fossil fuel units (2,476 Mw), eight (8) combined cycle gas turbine/steam generator units (gas/oil fired, 1,352 Mw), eighteen (18) peaking turbines (365 Mw), four (4) hydroelectric generating plants (238 Mw), and one Pump Storage Facility (576 Mw). The total net non-nuclear summer generating capability rating of these facilities is 5,007 megawatts.

Q. PLEASE EXPLAIN TO THE COMMISSION GENCO AND ITS RELATIONSHIP TO SCE&G.

A. GENCO was incorporated October 1, 1984, as a SCANA subsidiary. GENCO owns the Williams Station. GENCO sells to SCE&G the entire capacity and output from the Williams Station under a Unit Power Sales Agreement approved by the Federal Energy Regulatory Commission. Hereafter when I refer to SCE&G's fossil steam plants, I include GENCO.

Q. HOW MUCH ELECTRICITY WAS GENERATED BY SCE&G IN THE TWELVE MONTH REVIEW PERIOD?

A. In the review period, SCE&G generated 26,069,000 megawatt hours of energy. Of this energy, the fossil steam plants generated 66%, the combined cycle units generated 11%, the gas peaking turbines and hydro facilities generated 4%, and the nuclear plant generated 19%. Exhibit No. ___ (JKT-1) provides a graphic display of how the generation met this review period's energy demand.

Q. PLEASE SUMMARIZE THE PERFORMANCE OF THE FOSSIL UNITS.

A. Overall, SCE&G's fossil units have operated efficiently and dependably in the twelve (12) month period of February 1, 2006 through January 31, 2007.

Our fossil units have received national recognition for their excellent heat rates. These measures will be covered later in my testimony. We also had a 95.06% availability factor for the peak summer load period between June 1st and September 30th.

Q. PLEASE DISCUSS SCE&G'S PLANNED OUTAGES FOR THE PERIOD UNDER REVIEW.

A. A major maintenance outage was scheduled on the Wateree Two unit during the review period. The Wateree Two outage included installation of a new high pressure (HP) turbine rotor, low pressure (LP) turbine rotor inspection and generator rewind, as well as waterwall replacements on the boiler. This outage was scheduled to start on September 17th and end on November 25th. The outage was extended due to additional work that was required to repair issues discovered during inspection of the low pressure turbine rotor blading. Initial startup of the unit from the planned outage occurred on December 22nd. The startup on this unit was further extended into January due to a number of forced outages associated with continuing problems with excessive vibration on the LP rotors along with tube leaks on the boiler. This vibration was determined to be the result of mis-alignment of the LP rotors by the contractor who also was the Original Equipment Manufacturer (OEM) for the turbine. The unit was returned to service on January 30, 2007.

In addition to this major outage, smaller maintenance outages were held for the Williams and McMeekin units. A three week outage was conducted for each of the McMeekin units during the Fall of 2006. The work performed during these outages included boiler feedpump replacement, bottom ash work, boiler inspections and various other maintenance work. Williams Station had a three week outage in March 2006 to repair ductwork, perform SCR maintenance and install ignitors.

Please note also that a major maintenance outage began during the review period at Canadys One on January 14, 2007. This outage involves a turbine overhaul and boiler repairs. This outage is scheduled to be complete by April 8, 2007.

Various one and two week preventative maintenance outages were held on the other units during the review period but none involved any extensive maintenance or repairs to the units.

Q. PLEASE DISCUSS ANY SIGNIFICANT FORCED OUTAGES FOR THE PERIOD UNDER REVIEW.

A. The Jasper steam turbine unit experienced a forced outage on February 27, 2006 due to a phase to ground short on the generator stator. This short was determined to be the result of excessive vibration on the end windings for the stator. SCE&G worked with the OEM to implement a fix to reinforce the end windings. Planned outages had been scheduled for the

Jasper units for routine maintenance during the time that it was off due to the forced outage. These planned outages were incorporated into the forced outage and the planned maintenance work was completed while the unit was down. The plant was returned to service on May 28, 2006.

During the outage SCE&G installed equipment to monitor vibration on the end winding connections. As a result of vibration readings obtained from the newly installed monitoring equipment, a decision was made on December 12th to remove the Jasper units from service in order to repair excessive vibration levels on a second end winding. This work was completed and the unit was returned to service on December 21st. SCE&G continues to monitor vibration levels on this unit closely.

Williams Station was removed from service on December 21, 2006 as a result of a localized fire beneath the generator. This fire was the result of a phase to ground short on the isophase bus at one of the normal station service transformers. The fire was quickly brought under control by plant personnel and there were no personnel injuries as a result of this incident. This incident required replacement of a neutral grounding transformer, current transformers for the generator, and generator electrical bushings. The generator did not receive significant damage as a result of this incident. The Williams unit was returned to service on February 28, 2007. In addition to the repair work associated with the phase to ground short, a number of other normal maintenance items were completed during this forced outage. As a result of this work, SCE&G was able to eliminate the need for a three week planned outage which had been scheduled for April 2007. Attached as Exhibit No. ___ (JKT-2) are photographs of the equipment needing repair during the outage.

The forced outages for Wateree during the review period were covered in the previous question on planned outages.

Q. WHAT HAS BEEN SCE&G'S SYSTEM FORCED OUTAGE RATE FOR THE PERIOD UNDER REVIEW?

A. SCE&G experienced a system forced outage rate on its fossil fueled steam units of 6.19% in the review period. "Forced outage rate" is the percentage of the total hours that generating units are forced out of service (for various reasons) compared with the total hours in service for a period. The North American Electric Reliability Council ("NERC") national five year (2001-2005) average for forced outage rate for similarly sized units is 5.69%. The amount in excess of the national average was primarily due to the forced outages at Williams and Wateree Two which have been covered under the earlier responses.

Q. PLEASE DISCUSS THE AVAILABILITY OF SCE&G'S FOSSIL PLANTS DURING THE REVIEW PERIOD.

A. SCE&G had an availability of its fossil plants of 86.42% for the review period. Availability is a measure of the actual hours that the generation units are available (overall readiness to provide electricity) divided by the total hours in the 12 twelve-month review period. Availability is not affected by how the unit is dispatched or by the demand from the system when connected to the grid. However, it is impacted by the planned and maintenance shutdown hours. The NERC national five year (2001-2005) average for availability from similar sized pulverized coal fired units was 90.15%. SCE&G's availability was slightly lower than the NERC national five-year average due to the forced outages for Wateree Two and Williams during the review period. However, during the peak period, June 1, 2006 through September 30, 2007, SCE&G operated at an availability of 95.06%.

Q. WHAT HAS BEEN THE HEAT RATE OF THE FOSSIL UNITS DURING THE REVIEW PERIOD?

A. Heat rate is a way to measure thermal efficiency of a power plant fuel cycle. It is the number of British Thermal Units (Btu) of fuel required to generate one (1) kilowatt-hour (kWh) of electricity. The combined steam unit's heat rate for the period February 1, 2006 through January 31, 2007 is 9772 Btu/kWh. Cope Station had the best heat rate in our system at 9286 Btu/kWh followed by Williams Station at 9547 Btu/kWh.

In the November 2006 issue of *Electric Light & Power*, SCE&G was recognized for having three of its plants listed in the top 20 most energy efficient coal fired plants in the nation for 2004. Cope Station ranked 4th at 9214 Btu/kWh, Williams Station ranked 11th at 9462 Btu/kWh and McMeekin Station was ranked 17th at 9552 BTU/Kwh. This ranking means that three of the six SCE&G coal fired plants representing over half of our fossil fired generating capacity are ranked in the top 20 plants in the country for efficiency.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

South Carolina Electric & Gas
2006 Generation Mix

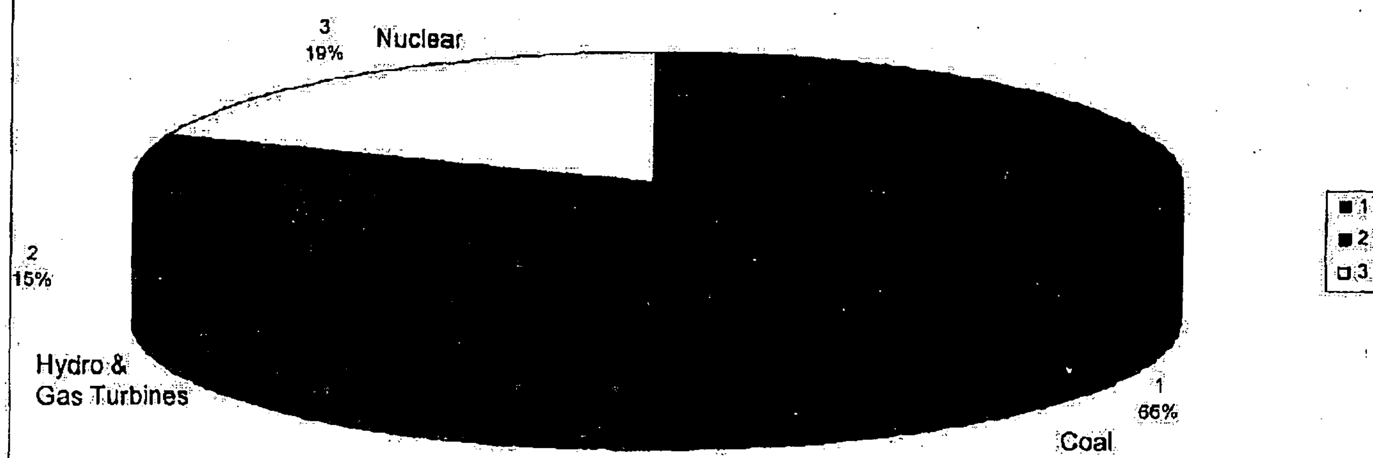


Exhibit No. ___ (JKT-1)

SCE&G
A SCANA COMPANY

Station Service Transformer

Exhibit No. ___
(JKT-2)

Generator Neutral Grounding Transformer

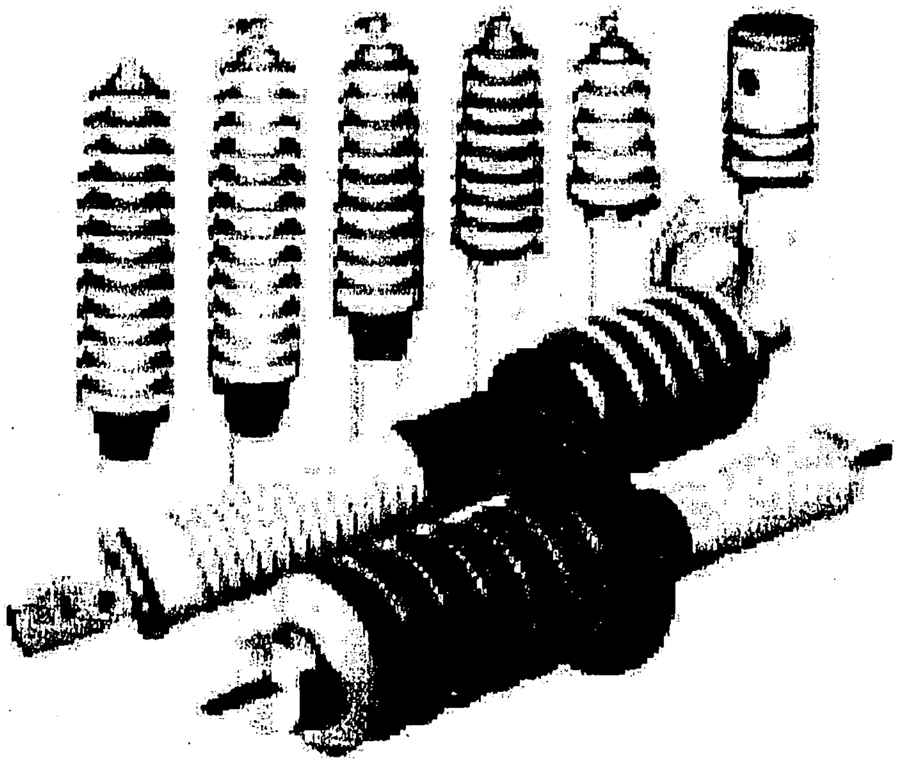
Exhibit No. ___
(JKT-2)

Cause

- Tracking across insulating surface of transformer bushing

Bushings

Exhibit No. ___
(JKT-2)



DIRECT TESTIMONY OF
GERHARD HAIMBERGER
ON BEHALF OF
SOUTH CAROLINA ELECTRIC & GAS COMPANY
DOCKET NO. 2007-2-E

Q. **PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND CURRENT POSITION.**

A. Gerhard Haimberger, 1426 Main Street, Columbia, South Carolina. I am employed by SCANA Services, Inc. as General Manager, Fuel Procurement and Asset Management, providing fuel and transportation purchasing on behalf of South Carolina Electric & Gas Company ("SCE&G" or the "Company").

Q. **DESCRIBE YOUR EDUCATIONAL BACKGROUND AND YOUR BUSINESS EXPERIENCE.**

A. I have a Bachelor of Science Degree in Mining Engineering from the Colorado School of Mines in Golden, Colorado, and am a registered professional engineer. I have been involved in fuel production or procurement for over thirty years. In July 2003, I was employed by the SCANA Services, Inc. in my current position and report directly to the Senior Vice-President, Fuel Procurement and Asset Management, SCANA Services, Inc.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to describe the procurement and delivery activities for fossil fuel (coal and oil) used in electric generation for SCE&G and GENCO's Williams Station for the period February 1, 2006 through January 31, 2007 (the "Review Period") and to comment on the current state of the U.S. coal industry.

Q. PLEASE EXPLAIN TO THE COMMISSION SOUTH CAROLINA GENERATING COMPANY ("GENCO") AND ITS RELATIONSHIP TO SCE&G.

A. South Carolina Generating Company, Inc., ("GENCO") was incorporated October 1, 1984. GENCO owns the Williams Electric Generating Station. GENCO sells to SCE&G the entire capacity and output from the Williams Station under a Unit Power Sales Agreement approved by the Federal Energy Regulatory Commission. Hereafter when I refer to SCE&G's fossil steam plants, I include GENCO.

Q. PLEASE SUMMARIZE SCE&G'S FUEL PROCUREMENT NEEDS AND PURCHASING PRACTICES.

A. The Fuel Procurement Department (coal and oil) ("Fuel Procurement") purchases all necessary coal, fuel oil and associated transportation for SCE&G's fossil plants focusing on reliability of supply, conformity with operational and environmental requirements, and securing reasonable prices. We also purchase EPA sulfur-dioxide emission allowances as determined by SCE&G.

Q. **HOW DOES THE COMPANY SECURE THE NECESSARY QUANTITIES OF COAL AND OIL AT COMPETITIVE PRICES?**

A. SCE&G maintains an active list of qualified suppliers of coal and fuel oil used to power its plants. Typically, as contracts expire or needs are identified, solicitations are mailed out for competitive sealed bids.

Q. **HOW DOES SCE&G APPROACH THE MARKETPLACE FOR COAL AND FUEL OIL?**

A. Coal is procured with long-term (more than one year) and spot purchase (up to one year) agreements to achieve a balance of reliable supplies and flexibility to react to market changes or short-term system needs. We seek to have long-term purchases representing approximately 75 to 80 percent of projected system demand and long-term coal contracts typically are written with variable quantity clauses when market leverage allows. Variable quantity clauses, when available, and spot purchases provide the mechanisms to manage inventories and react to short-term changes in the marketplace should prices become more competitive. By utilizing spot purchases, SCE&G has been successful in taking advantage of favorable spot market prices and managing its inventory.

Fuel oil contracts are requirements contracts that are competitively solicited biannually.

Q. HOW DOES SCE&G ASSURE THE RIGHT QUANTITY OF FUEL SUPPLIES TO MEET GENERATION DEMANDS?

A. SCE&G uses several methods to bring the fuel supply and demand factors together. Fuel usage levels are calculated and forecast for each of the generating plants. Coal and fuel oil inventories are then validated and contract quantities are summed to determine system needs going forward. With this information, Fuel Procurement looks at the coal requirements and the economics of exercising available variable quantity portions of long-term contracts or the possibility of going to the spot market to purchase any additional coal requirements at lower pricing. Throughout the years, SCE&G has been successful in leveraging long-term and short-term coal purchases to achieve reasonably low purchase prices while assuring the reliability of coal supplies necessary to support system needs. Fuel oil inventories are purchased to ensure adequate back up to natural gas for SCE&G's intermediate and peaking generators. Contracts are awarded on a biannual basis using competitive bids. Typically, fuel storage tanks are filled going into peak usage periods and reduced to lower levels throughout the shoulder months to protect fuel quality.

Q. HOW DOES THE COMPANY MANAGE COAL INVENTORIES TO INSURE RELIABILITY AND AVAILABILITY?

A. The Company attempts to maintain approximately a 925,000 ton inventory of coal based on an average of twelve months' ending monthly inventories to support anticipated consumption. This methodology allows an inventory of more than 925,000 tons at the beginning of high demand periods and less than 925,000 tons entering the shoulder months. This inventory level aids in protecting SCE&G against availability, production and delivery problems that may arise from time to time. It also affords the resources to meet our supply needs when short-term market prices are unfavorable. It is always important to balance short-term decisions against long-term requirements and future operating conditions.

Q. HOW DOES THE COMPANY DETERMINE THE "REASONABLE PRICE" FOR FUEL PURCHASES?

A. Fuel Procurement must look for an optimization between adequate supplies of acceptable quality at reasonable purchase prices with the ultimate value of the delivered fuel (coal or oil) determined by the actual measured heat rate efficiency in the operation of our generating plants. Markets are volatile and fluctuate due to such things as seasonality, political turmoil, national weather trends and supply/demand imbalances. SCE&G strives to use a variety of pricing mechanisms among coal contracts to mitigate or normalize the effects on prices created by changes in market conditions and indexes by staying close to market, balancing adequate inventories against long-term contract supplies, spot market purchases and variable quantity options. In addition to strategically managing our current assets, SCE&G stays current with developing trends and fundamental changes taking place in the industry and receives key marketing information. This information flow is integral in our ongoing analysis of current or prospective coal costs and market comparability.

Q. SUMMARIZE THE QUANTITY, QUALITY, AND TERM OF THE COMPANY'S COAL PURCHASES.

A. During the Review Period, the Company purchased approximately 5.9 million tons of coal under long term agreements and 1.1 million tons of spot purchases. Long term agreements represented approximately 84% of the requirement for the Company's five coal-fired stations, and GENCO's Williams Station. For the February 2007 through January 2008 period, the Company projects to have long-term contracts with 10 suppliers totaling 5 million tons of coal representing approximately 83% of the total receipts depending on final contract negotiations. The quality ranges are from 12,200 to 13,000 BTU per pound and sulfur contents from 1.0% to 1.3%. Most of these contracts are for a period of two to four years with some options to renew. The amount of coal under contract will vary from year to year. In some of our coal contracts, we have been successful in negotiating fixed pricing for the term of the contract. Other coal contracts contain predetermined price adjustments.

Q. WHAT HAS OCCURRED REGARDING COAL PRICES AND TRANSPORTATION RATES IN THE PAST YEAR?

A. Coal market prices have remained stable at elevated levels described in Dockets 2005-2-E and 2006-2-E until approximately November, 2006 when spot prices began to decline due to lack of demand caused partially by temperate weather, nationally, during the past year. SCE&G renegotiated three coal contracts early in the Review Period and has taken advantage of several spot opportunities recently.

Transportation rates are typically confidential. One small rail transportation contract expired during the review period and has not been renewed because the supplemental volumes it represented are no longer needed.

SCE&G continues to expand its coal specifications by purchasing lower qualities of coal and blending them with better quality to acceptable levels and continues to diversify its coal supply and transportation with some import coal purchases thereby protecting against possible domestic supply and transportation constraints as occurred in 2004.

Q. WHAT WERE SCE&G'S DELIVERED COAL COSTS FOR THE REVIEW PERIOD ?

A. Exhibit (GH-1), entitled "Coal Purchased For Steam Plants", displays the average cost in dollars per MMBTU (million British Thermal Units) for coal purchased during the Review Period. The highest delivered cost for any individual purchase during the Review Period was \$ 2.9627/MMBTU and the lowest was \$ 1.7054/MMBTU.

Q. WHAT HAS BEEN THE RECENT PRICING TREND IN THE NO. 2 FUEL OIL INDUSTRY?

A. Delivered fuel oil prices during the Review Period remained volatile reflecting the actions of OPEC, increasing domestic and global demand led by economic growth in China and India, political instability in Nigeria, Venezuela and the Middle East. Oil prices and volatility have been regularly reported in the public press. During the past year, delivered prices have varied from a monthly low of \$ 1.73/gallon in January 2007 to a monthly high of \$ 2.25/gallon in July 2006 (\$ 12.53/MMBTU to \$ 16.31/MMBTU on a calorific basis). Exhibit (GH-2) shows the average system delivered No. 2 fuel oil prices in \$/MMBTU for the Review Period.

Q. ARE THERE ANY OTHER THINGS THE COMPANY HAS DONE TO MITIGATE FUEL-RELATED EXPENSES THAT WILL IMPACT FUEL COSTS?

A. The Clean Air Act Amendment of 1990 called for electric utilities to reduce sulfur dioxide (SO2) emissions. An SO2 Emission Allowance Trading Market was established by the Environmental Protection Agency (EPA) to assist utilities in managing the costs of complying with these new regulations. The Company has purchased SO2 allowances as part of our overall strategy to compensate for our SO2 emissions. SO2 emission allowance prices have decreased during the Review Period due to active and announced SO2 scrubber projects and are currently approximately $500 per allowance. Price volatility reflects the depletion of available allowances, and actions of hedge funds and other financial organizations participating in the SO2 markets for speculative purposes which tend to increase allowance prices.

Q. HAS SCE&G MADE EVERY REASONABLE EFFORT TO MINIMIZE ITS FUEL COSTS?

A. Yes, the Fuel Procurement Department has made every reasonable effort to obtain reliable, high quality supplies of fuel and transportation at the lowest possible cost to SCE&G's customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit No._____(GH-1)

Coal Purchased for Steam Plants

$/MMBTU

Feb. 06	Mar.	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan. 07
$2.56	$2.54	$2.63	$2.54	$2.51	$2.54	$2.52	$2.59	$2.56	$2.50	$2.42	$2.38

Exhibit No.____ (GH-2)

No. 2 Fuel Oil Purchased for Steam Plants

$/MMBTU

Feb. 06	Mar.	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.	Jan. 07
$13.47	$13.91	$15.31	$15.61	$15.22	$16.31	$16.04	$13.58	$13.49	$13.70	$13.99	$12.53

DIRECT TESTIMONY OF
JOSEPH M. LYNCH
ON BEHALF OF
SOUTH CAROLINA ELECTRIC & GAS COMPANY
DOCKET NO. 2007-2-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND CURRENT POSITION.

A. Joseph M. Lynch, 1426 Main Street, Columbia, South Carolina. My current position is Manager of Resource Planning, SCANA Services, Inc.

Q. DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I graduated from St. Francis College in Brooklyn, New York with a Bachelor of Science degree in mathematics. From the University of South Carolina I received a Master of Arts degree in mathematics, an MBA and a Ph.D. in management science and finance. I was employed by South Carolina Electric & Gas Company ("SCE&G" or the "Company") as a Senior Budget Analyst in 1977 to develop econometric models to forecast electric sales and revenue. In 1980, I was promoted to Supervisor of the Load Research Department. In 1985, I became Supervisor of Regulatory Research where I was responsible for load research and electric rate design. In 1989, I became Supervisor of Forecasting and Regulatory Research, and, in 1991, I was promoted to my current position of Manager of Resource Planning.

Q. **BRIEFLY SUMMARIZE YOUR CURRENT DUTIES.**

A. As manager of Resource Planning I am responsible for producing SCE&G's forecast of energy, peak demand and revenue; for developing the Company's generation expansion plans; and for overseeing the Company's load research program.

Q. **WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

A. The purpose of my testimony is to discuss the Company's short-range energy sales forecast and to explain how we simulate the operation of our power plants to generate the required energy and project the resulting fuel requirements for the system.

Q. **DESCRIBE THE COMPANY'S SHORT-RANGE ENERGY FORECASTING PROCESS.**

A. Each summer the Company updates its short-range and long-range sales forecast as part of its annual planning cycle. The long-range sales forecast refers to the forecast for the full twenty year planning horizon. The short-range sales forecast refers to the forecast for the first two years of the planning horizon and is projected on a month-by-month basis. In preparing the short-range sales forecast, we divide our customers into detailed forecasting groups defined by rate and class. Where possible, customers are further divided into electric space heating and non-electric space heating groups. Residential customers are further separated into those living in either single-family, multi-family or mobile homes. We forecast consumption for about twenty of our largest industrial customers on an individual basis while the balance are separated into 2-digit SIC groups. Exhibit No.__ (JML-1) shows most of the detailed groups. Where a detailed customer group contains a large number of homogeneous customers, separate econometric models are developed to project the number of customers and the average use per customer based on such factors as population growth, and levels of economic activity within our service territory. All residential groups and small commercial groups are projected in this way. Weather is a significant factor in the residential and commercial models. Projections are based on normal weather where normal is defined as the average taken over the last 15 years. Overall, nearly 100 econometric and statistical models are utilized to develop the short-run forecast.

Q. IS YOUR ENERGY FORECASTING METHODOLOGY TYPICAL FOR THE INDUSTRY?

A. Yes, our use of multiple regression and statistical time-series models is fairly standard throughout the industry.

Q. HOW ACCURATE HAS YOUR ENERGY FORECASTING METHODOLOGY BEEN?

A. Over the past ten years the mean absolute percent error (MAPE) has been 1.3% when comparing the forecast to the weather-normalized actual consumption of energy on our system.

Q. WHAT IS YOUR ENERGY FORECAST FOR 2007?

A. We expect our territorial customers to consume 23,741 gigawatt hours of energy in 2007 with 34% being consumed by our residential customers, 32% by our commercial customers, 26% by our industrial customers and the balance of 8% by the combination of the remaining retail classes and our territorial wholesale customers.

Q. EXPLAIN HOW YOU TRANSLATE THIS ENERGY SALES FORECAST INTO A FORECAST OF FUEL REQUIREMENTS FOR THE ELECTRIC SYSTEM.

A. We simulate the dispatch of our generating units with the software program PROSYM. PROSYM is licensed with Global Energy Decisions, Inc. It is a well-accepted tool in the industry being used by over 100 utilities.

Q. DISCUSS THE PROSYM MODEL INPUTS.

A. The following are key inputs to the model:

1. Energy Sales Forecast
2. Fuel Price Data
3. Generator Operating Parameters; and
4. Market Prices.

Exhibit No. ___ (JML-2) graphically displays these inputs.

Energy Sales Forecast: I have already described the creation of the monthly energy sales forecast. This is used to create forecasts of hourly loads based on historical hourly load profiles.

Fuel Price Data: A forecast of monthly fuel prices for coal and oil are provided by the SCE&G Fossil/Hydro Procurement Department. Fuel data includes transportation costs and sulfur content of coal. A forecast of monthly nuclear fuel prices is provided by the SCE&G Nuclear Fuel Management Department. A gas price forecast is created using the Nymex natural gas futures prices. Expected gas transportation costs are added to the Nymex prices to create a forecast of the delivered cost of gas. In the forecast presented here, we are using the prices of the Nymex futures contracts from market close on February 7, 2007. The average price for the twelve contracts, May 2007 through April 2008, was $9.20 per DT.

Generator Operating Parameters: Generator operating parameters include heat rate, capacity, maintenance outage schedule, forced outage rate, and operating constraints. Operating constraints include variables such as minimum up and down times, ramp rates, and start costs. All of these variables control the cost and feasibility of dispatching each unit each hour.

Market Prices: The market prices for power are input into the model to reflect the opportunities that SCE&G has to purchase power at prices below its marginal cost of generation or to sell power above its marginal cost of generation. The market prices utilized in the model are determined using SCE&G's marginal costs and the marginal costs of utilities in the southeast.

Q. EXPLAIN HOW PROSYM MODELS THE ELECTRIC SYSTEM.

A. PROSYM is a chronological hourly dispatch model. In each hour of a study period, PROSYM arranges all the available supply sources from lowest cost to highest and then determines the least-cost way to meet the customer load in that hour while considering a complex set of operating constraints. As part of this dispatching process, PROSYM also simulates random unscheduled outages of our plants based on the forced outage rates that were part of the input database.

Q. WHAT ARE THE PROSYM RESULTS FOR 2007?

A. Based on the PROSYM simulations, we expect to supply 27,813 gigawatt hours of energy to the electric grid. This includes losses and energy required for pumping at our pumped storage plant. Of this total supply, we expect about 62% to come from coal, 20% from nuclear, 10% from natural gas, 5% from hydro and 3% from off-system purchases.

Q. HOW SENSITIVE ARE THE SYSTEM PRODUCTION COSTS TO THE SYSTEM ENERGY NEEDS?

A. Since we dispatch the most economical generating units first, an increase or decrease in sales will occur at the margin and will involve the more costly sources of power. We estimate that a 1% change in energy requirements, which is about our average forecast error, will result in about a 2% change in production costs assuming, of course, that the only input being changed is the energy needs of our customers.

Q. AFTER RUNNING THE PROSYM MODEL, WHAT IS THE NEXT STEP IN YOUR PROCESS?

A. For the purpose of these proceedings, the PROSYM model output that defines how the SCE&G electric system will meet the projected electric load is passed to the Rate Department, which develops the appropriate fuel factor for SCE&G rates. Mr. Hendrix will discuss this subject. The specific data items that are passed to the Rate Department are plant generation, plant average heat rate, heat content of the coal, capacity factors by unit, off system purchases and sales, and associated market prices. These model outputs form an appropriate basis for projecting fuel costs for the forecast period in this proceeding.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

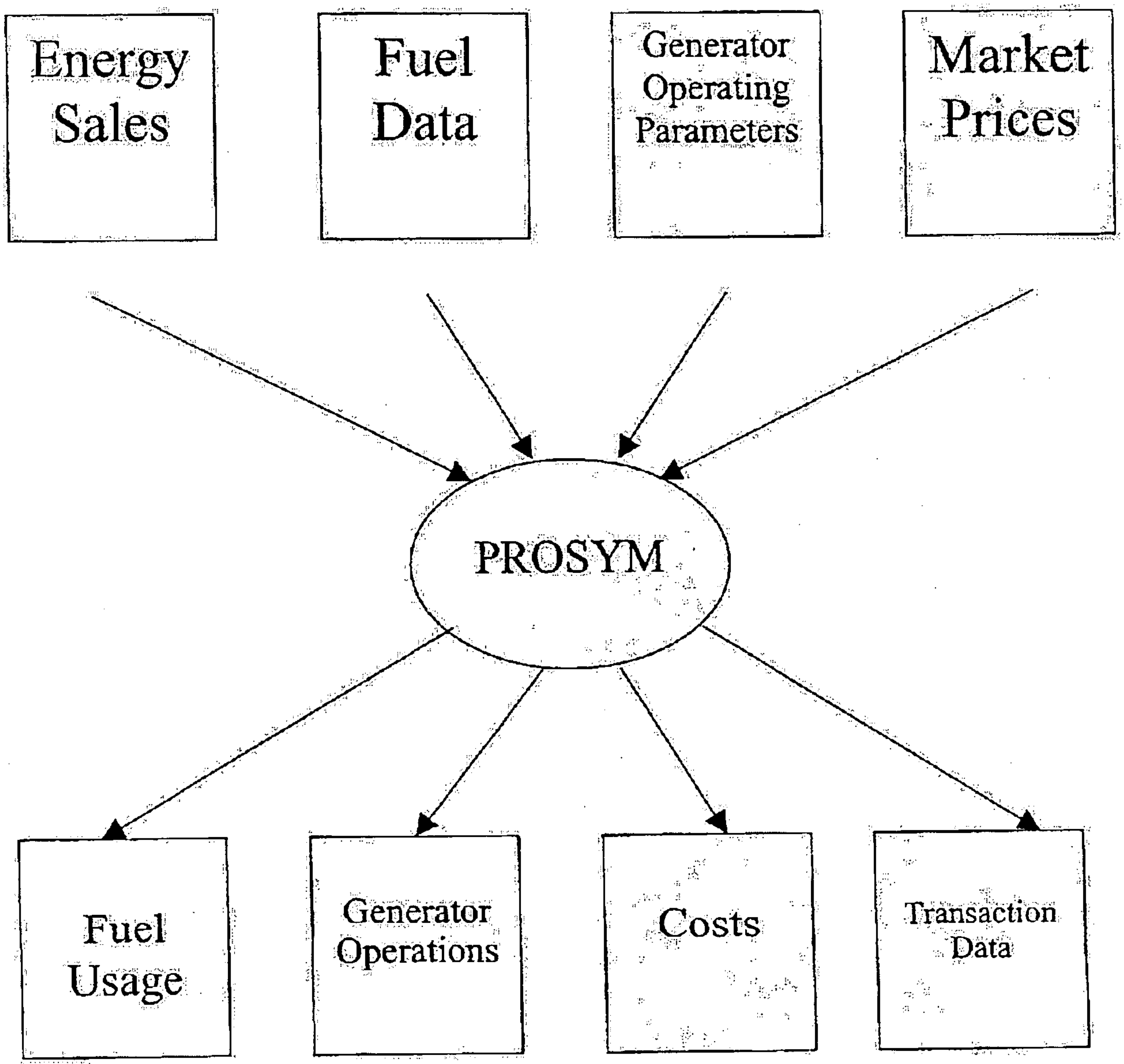
A. Yes it does.

Short-Term Forecasting Groups

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	Rates 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	Three 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.


Energy Sales
Fuel Data
Generator Operating Parameters
Market Prices
PROSYM
Fuel Usage
Generator Operations
Costs
Transaction Data

DIRECT TESTIMONY OF
JOHN R. HENDRIX
ON BEHALF OF
SOUTH CAROLINA ELECTRIC & GAS COMPANY
DOCKET NO. 2007-2-E

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. John R. Hendrix, 1426 Main Street, Columbia, South Carolina.

Q. **BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. I am Manager of Electric Pricing and Rate Administration at SCANA Services, Inc.

Q. **DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.**

A. I am a graduate of the University of South Carolina where I received a Bachelor of Science Degree in Business Administration with a major in marketing. Since joining South Carolina Electric & Gas Company in August 1983, I have held various positions within the Rate Department. In November 2002, I assumed my present position. I have participated in cost of service studies, rate development and design, and rate evaluation programs for both the electric and gas operations. I am a member of the Southeastern Electric Exchange Rate Section.

Q. WILL YOU BRIEFLY SUMMARIZE YOUR DUTIES WITH SOUTH CAROLINA ELECTRIC & GAS COMPANY?

A. I am responsible for the design and administration for the Company's electric rates and tariffs including the electric fuel adjustment. In addition, I am responsible for the Company's electric cost allocation studies.

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

A. The purpose of my testimony is to provide the actual fuel cost data for the period February 1, 2006 through January 31, 2007, the historical period under review in this proceeding. I will also provide the computations for the projected fuel cost per kilowatt-hour of sales for the period May 1, 2007 through April 30, 2008, along with the Company's recommended fuel rate for the period ending April, 2008.

Q. WHAT IS THE COMPANY'S CURRENTLY APPROVED RATE FOR FUEL COST?

A. In Order No. 2006-235(A), the Commission approved a 2.516 cents per KWH fuel component.

Q. WILL YOU PLEASE EXPLAIN EXHIBIT NO._____(JRH-1)?

A. Exhibit No._________(JRH-1) shows the actual fuel cost and over/under recovery of fuel revenue experienced by the Company for the months of February 2006 through January 2007, as well as the forecast for February, March and April 2007. As shown on this Exhibit, the Company has an actual under collection of $52,476,342 as of January 2007. The forecasted balance at April, 2007 is an under collection of $38,468,549. Carrying costs has been included in these calculations pursuant to the provisions of Order No. 2006-235(A).

Q. WILL YOU PLEASE EXPLAIN EXHIBIT NO.____(JRH-2)?

A. Exhibit No.____(JRH-2) contains the Company's fuel cost forecast and projected recovery calculations by month for May 2007 through April 2008. This exhibit reflects the monthly and cumulative over and under projected fuel cost collection expected by the Company using its recommended fuel rate. The projection shows an under recovery of $38,468,549 at April 2007 and a balance at period end as close to zero as possible.

Q. BY WHAT PROCESS DO YOU DEVELOP YOUR FUEL FACTOR FOR SCE&G'S RATES?

A. As Mr. Lynch indicates in his testimony, we receive the output from the PROSYM model from the Resource Planning Department. This data is loaded onto spreadsheets along with fuel ending inventories, emission allowances, forecasted fuel prices and information regarding operations to determine projected fuel costs for February, March and April 2007, as well as the twelve months ending April 2008.

Q. WILL YOU PLEASE EXPLAIN EXHIBIT NO._____(JRH-3)?

A. Exhibit No.______(JRH-3) provides the calculation of the projected fuel component for the twelve-month period May 2007 through April 2008, as well as the Company's fuel rate recommendation. For the twelve months May 2007 through April 2008 the base fuel rate is 2.632 cents per KWH, which includes 0.172 cents per KWH to recover the anticipated under collection.

Q. MR. HENDRIX, WHAT FUEL COMPONENT IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. The Company is proposing that the fuel component be set at 2.632 cents per KWH effective for bills rendered on and after the first billing cycle of May 2007 and continuing through the billing month of April 2008.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

SOUTH CAROLINA ELEC[illegible] GAS COMPANY

FUEL COSTS REPORT

LINE NO.		ACTUAL 2006 FEBRUARY $	MARCH $	APRIL $	MAY $	JUNE $	JULY $	AUGUST $
1.	TOTAL COST OF FOSSIL FUEL BURNED	32,489,281	34,531,775	26,869,142	35,571,611	47,290,050	58,812,476	67,273,246
2.	NUCLEAR FUEL	1,927,854	(3,868,674)	2,000,792	2,076,842	2,022,004	2,108,826	2,110,287
3.	PURCHASED AND INTERCHANGE POWER FUEL COSTS	8,468,162	5,169,991	11,237,662	10,979,975	10,462,576	11,259,496	11,562,584
4.	LESS FUEL RECOVERED THROUGH INTERSYSTEM SALES	5,719,505	4,914,875	2,720,610	4,944,197	7,719,347	8,428,976	10,699,932
5.	TOTAL FUEL COSTS (LINES 1+2+3-4)	37,165,792	30,916,217	37,246,986	43,684,231	52,055,283	63,751,822	70,254,187
6.	TOTAL SYSTEM SALES EXCLUDING INTERSYSTEM SALES (KWH)	1,762,946,768	1,778,180,419	1,641,714,242	1,800,037,126	2,128,012,318	2,252,592,119	2,427,170,905
7.	FOSSIL FUEL COST PER KWH SALES	0.021082	0.017388	0.022688	0.024269	0.024462	0.028302	0.028945
8.	LESS BASE COST PER KWH INCLUDED IN RATES	0.022560	0.022560	0.022560	0.025160	0.025160	0.025160	0.025160
9.	FOSSIL FUEL ADJUSTMENT PER KWH	(0.00148)	(0.00517)	0.00013	(0.00089)	(0.00070)	0.00314	0.00379
10.	RETAIL KWH	1,646,862,967	1,662,822,693	1,532,522,023	1,670,944,442	1,988,875,162	2,097,942,673	2,268,392,331
11.	OVER/UNDER RECOVERY REVENUE	(2,437,357)	(8,596,793)	199,228	(1,487,141)	(1,392,213)	6,587,540	8,597,207
12.	MONTHLY CARRYING COST COLLECTED	0	0	0	92,690	93,007	90,448	85,964
13.	ADJUSTMENTS	(473,141)	201,804	0	0	490,047	0	174,118
14.	FIXED CAPACITY CHARGES	(1,583,583)	(1,583,583)	(1,583,583)	(1,583,583)	(1,583,583)	(1,583,583)	(1,583,583)
15.	NET OVER/UNDER RECOVERY REVENUE	(4,494,081)	(9,978,572)	(1,384,355)	(2,978,025)	(2,386,742)	5,094,405	7,273,706
16.	CUMULATIVE UNDER(OVER) $54,648,833	50,154,752	40,176,180	38,791,825	35,813,800	33,427,058	38,521,463	45,795,169

Exhibit No. ___ (JRH-1)

SO CAROLINA ELECTRIC & GAS COMPANY

FUEL COSTS REPORT

LINE NO.		ACTUAL 2006 - 2007 SEPTEMBER $	OCTOBER $	NOVEMBER $	DECEMBER $	JANUARY $	FORECAST 2007 FEBRUARY $	MARCH $	APRIL $
1.	TOTAL COST OF FOSSIL FUEL BURNED	35,030,157	40,281,935	44,534,584	37,008,255	51,226,858	45,510,000	35,512,000	24,110,000
2.	NUCLEAR FUEL	2,051,441	856,293	401,776	2,368,612	2,105,971	1,836,000	2,038,000	1,969,000
3.	PURCHASED AND INTERCHANGE POWER FUEL COSTS	11,299,841	9,964,826	13,775,953	8,132,148	3,593,779	5,250,000	11,962,000	12,407,000
4.	LESS FUEL RECOVERED THROUGH INTERSYSTEM SALES	2,730,643	1,635,111	1,707,247	3,871,872	3,452,984	5,182,000	6,099,000	4,287,000
5.	TOTAL FUEL COSTS (LINES 1+2+3-4)	45,650,796	49,469,943	56,945,066	43,637,143	53,473,624	47,414,000	43,413,000	34,199,000
6.	TOTAL SYSTEM SALES EXCLUDING INTERSYSTEM SALES (KWH)	2,167,168,670	1,789,046,441	1,634,191,672	1,803,347,568	1,834,643,779	1,898,000,000	1,784,000,000	1,692,000,000
7.	FOSSIL FUEL COST PER KWH SALES	0.021065	0.027652	0.034846	0.024198	0.029147	0.024981	0.024335	0.020212
8.	LESS BASE COST PER KWH INCLUDED IN RATES	0.025160	0.025160	0.025160	0.025160	0.025160	0.025160	0.025160	0.025160
9.	FOSSIL FUEL ADJUSTMENT PER KWH	(0.00410)	0.00249	0.00969	(0.00096)	0.00399	(0.00018)	(0.00082)	(0.00495)
10.	RETAIL KWH	2,043,860,494	1,675,800,334	1,523,052,541	1,684,692,746	1,706,292,796	1,763,000,000	1,669,000,000	1,582,000,000
11.	OVER/UNDER RECOVERY REVENUE	(8,379,828)	4,172,743	14,758,379	(1,617,305)	6,808,108	(320,940)	(1,368,580)	(7,830,900)
12.	MONTHLY CARRYING COST COLLECTED	84,790	84,347	82,115	85,925	87,792	87,792	87,792	87,792
12.	ADJUSTMENTS	0	16,647	(20,398)	30,461	(1,594,686)	0	0	0
13.	FIXED CAPACITY CHARGES	(1,583,583)	(1,583,583)	(1,583,583)	(1,583,583)	(1,583,583)	(1,583,583)	(1,583,583)	(1,583,583)
14.	NET OVER/UNDER RECOVERY REVENUE	(9,878,621)	2,690,154	13,236,513	(3,084,502)	3,717,629	(1,816,731)	(2,864,371)	(9,326,691)
15.	CUMULATIVE UNDER(OVER) $45,795,169	35,916,548	38,606,702	51,843,215	48,758,713	52,476,342	50,659,611	47,795,240	38,468,549

Exhibit No. ___ (JRH-1)

SOUTH CAROLINA ELECTRIC & GAS COMPANY

FUEL COSTS REPORT

LINE NO.		2007 FORECAST MAY $	JUNE $	JULY $	AUGUST $	SEPTEMBER $	OCTOBER $
1.	TOTAL COST OF FOSSIL FUEL BURNED	39,005,000	51,242,000	61,265,000	61,363,000	43,620,000	34,174,000
2.	NUCLEAR FUEL	2,038,000	1,952,000	2,016,000	2,016,000	1,952,000	2,038,000
3.	PURCHASED AND INTERCHANGE POWER FUEL COSTS	12,435,000	14,996,000	17,186,000	15,899,000	11,859,000	11,202,000
4.	LESS FUEL RECOVERED THROUGH INTERSYSTEM SALES	6,436,000	7,988,000	10,305,000	11,082,000	7,985,000	5,142,000
5.	TOTAL FUEL COSTS (LINES 1+2+3-4)	47,042,000	60,202,000	70,152,000	68,196,000	49,752,000	42,272,000
6.	TOTAL SYSTEM SALES EXCLUDING INTERSYSTEM SALES (KWH)	1,808,000,000	2,141,000,000	2,357,000,000	2,380,000,000	2,202,000,000	1,899,000,000
7.	FOSSIL FUEL COST PER KWH SALES	0.026019	0.028119	0.029763	0.028582	0.022594	0.022260
8.	LESS BASE COST PER KWH INCLUDED IN RATES	0.026320	0.026320	0.026320	0.026320	0.026320	0.026320
9.	FOSSIL FUEL ADJUSTMENT PER KWH	(0.00030)	0.00180	0.00344	0.00226	(0.00373)	(0.00406)
10.	RETAIL KWH	1,683,000,000	2,003,000,000	2,202,000,000	2,238,000,000	2,073,000,000	1,785,000,000
11.	OVER/UNDER RECOVERY REVENUE	(504,900)	3,605,400	7,574,880	5,057,880	(7,732,290)	(7,247,100)
12.	MONTHLY CARRYING COST COLLECTED	87,792	87,792	87,792	87,792	87,792	87,792
13	ADJUSTMENTS	0	0	0	0	0	0
14.	FIXED CAPACITY CHARGES	(1,583,583)	(1,583,583)	(1,583,583)	(1,583,583)	(1,583,583)	(1,583,583)
15.	NET OVER/UNDER RECOVERY REVENUE	(2,000,691)	2,109,609	6,079,089	3,562,089	(9,228,081)	(8,742,891)
16.	CUMULATIVE UNDER(OVER) $38,468,549	36,467,858	38,577,467	44,656,556	48,218,645	38,990,564	30,247,673

Exhibit No. ___ (JRH-2)

SOUTH CAROLINA ELECTRIC & GAS COMPANY

FUEL COSTS REPORT

2007 - 2008 FORECAST

LINE NO.		NOVEMBER $	DECEMBER $	JANUARY $	FEBRUARY $	MARCH $	APRIL $
1.	TOTAL COST OF FOSSIL FUEL BURNED	39,565,000	41,347,000	43,807,000	34,206,000	36,978,000	32,721,000
2.	NUCLEAR FUEL	1,969,000	2,038,000	2,038,000	1,905,000	2,038,000	1,707,000
3.	PURCHASED AND INTERCHANGE POWER FUEL COSTS	6,974,000	11,928,000	12,145,000	12,025,000	10,061,000	12,134,000
4.	LESS FUEL RECOVERED THROUGH INTERSYSTEM SALES	5,283,000	7,482,000	7,332,000	4,701,000	5,156,000	5,566,000
5.	TOTAL FUEL COSTS (LINES 1+2+3-4)	43,225,000	47,831,000	50,658,000	43,435,000	43,921,000	40,996,000
6.	TOTAL SYSTEM SALES EXCLUDING INTERSYSTEM SALES (KWH)	1,699,000,000	1,879,000,000	2,051,000,000	1,941,000,000	1,823,000,000	1,731,000,000
7.	FOSSIL FUEL COST PER KWH SALES	0.025441	0.025456	0.024699	0.022378	0.024093	0.023683
8.	LESS BASE COST PER KWH INCLUDED IN RATES	0.026320	0.026320	0.026320	0.026320	0.026320	0.026320
9.	FOSSIL FUEL ADJUSTMENT PER KWH	(0.00088)	(0.00086)	(0.00162)	(0.00394)	(0.00223)	(0.00264)
10.	OVER/UNDER RECOVERY REVENUE KWI	1,588,000,000	1,750,000,000	1,917,000,000	1,824,000,000	1,706,000,000	1,620,000,000
11.	OVER/UNDER RECOVERY REVENUE	(1,397,440)	(1,505,000)	(3,105,540)	(7,186,560)	(3,804,380)	(4,276,800)
12.	MONTHLY CARRYING COST COLLECTED	87,792	87,792	87,792	87,792	87,792	87,792
13	ADJUSTMENTS	0	0	0	0	0	0
14.	FIXED CAPACITY CHARGES	(1,583,583)	(1,583,583)	(1,583,583)	(1,583,583)	(1,583,583)	(1,583,583)
15.	NET OVER/UNDER RECOVERY REVENUE	(2,893,231)	(3,000,791)	(4,601,331)	(8,682,351)	(5,300,171)	(5,772,591)
16.	CUMULATIVE UNDER(OVER) $30,247,673	27,354,442	24,353,651	19,752,320	11,069,969	5,769,798	(2,793)

Exhibit No. ___ (JRH-2)

Exhibit No. ___ (JRH-3)

SOUTH CAROLINA ELECTRIC & GAS COMPANY
CALCULATION OF BASE FUEL COMPONENT

	FORECAST MAY 07 - APR 08 12 MONTHS
1. PROJECTED DATA:	
COST OF FUEL ($000)	$607,682
SYSTEM SALES (GWH)	23,917
FUEL RATE (CENTS/KWH)	2.540
2. (OVER)/UNDER COLLECTION ($000) THROUGH APRIL 2007	$38,469
SOUTH CAROLINA RETAIL SALES (GWH)	22,389
(OVER)/UNDER COLLECTION RATE (CENTS/KWH)	0.172
3. BASE FUEL RATE (CENTS/KWH):	
PROJECTED FUEL RATE	2.540
FIXED TRANSPORTATION CHARGE & CARRYING COST RATE (CENTS/KWH)(a)	(0.080)
TOTAL PROJECTED FUEL RATE	2.460
(OVER)/UNDER RECOVERY RATE	0.172
TOTAL PROJECTED BASE FUEL RATE	2.632

Note (a): The calculation for the Fixed Transportation Charge and Carrying Cost Rate is (Fixed Transportation Cost) ($19,003) plus (Carrying Cost) $1,054 divided by (retail sales) 22,389 equals (0.080) (Cents/KWH).

Section 8.1 Ref/0

South Carolina Code of Laws
(Unannotated)
Current through the end of the 2006 Regular Session

Title 58 - Public Utilities, Services and Carriers

CHAPTER 3.

PUBLIC SERVICE COMMISSION

ARTICLE 1.

GENERAL PROVISIONS

SECTION 58-3-5. Definitions.

As used in this chapter:

(1) "Business with which he is associated" means a business of which the person or a member of his immediate family is a director, an officer, owner, employee, a compensated agent, or holder of stock.

(2) "Immediate family" means an individual who is:

(a) a child residing in the person's household;

(b) a spouse of the person; or

(c) an individual claimed by the person or the person's spouse as a dependent for income tax purposes.

(3) "Commission" means the Public Service Commission.

(4) "Hearing officer" means a person employed by the commission to serve as a presiding officer in an adjudicative proceeding before the commission.

(5) "Regulatory staff" means the executive director or the executive director and employees of the Office of Regulatory Staff.

(6) "Public utility" means public utility as defined in Section 58-5-10, telephone utility as defined in Section 58-9-10, government-owned telecommunications service provider as defined in Section 58-9-2610, radio common carrier as defined in Section 58-11-10, carriers governed by Chapter 13 of Title 58, railroads and railways as defined in Section 58-17-10, motor vehicle carrier as defined in Section 58-23-10, or electrical utility as defined in Section 58-27-10.

(7) "Review committee" means the State Regulation of Public Utilities Review Committee.

SECTION 58-3-10. Continuation of Public Service Commission.

(A) The commission, as constituted under law in effect before the date this act is approved by the Governor, is reconstituted to continue in existence with the appointment and qualification of the members as prescribed in this article and with the changes in duties and powers as prescribed in this title.

(B) Nothing in this act affects the commission's jurisdiction over matters pending before the commission, on or before February 18, 2004.

SECTION 58-3-20. Membership; election and qualifications; Review Committee; terms; vacancies.

(A) The commission is composed of seven members to be elected by the General Assembly in the manner prescribed by this chapter. For any term beginning after June 30, 2006, each member must have:

(1) a baccalaureate or more advanced degree from:

(a) a recognized institution of higher learning requiring face-to-face contact between its students and instructors prior to completion of the academic program;

(b) an institution of higher learning that has been accredited by a regional or national accrediting body; or

(c) an institution of higher learning chartered before 1962; and

(2) a background of substantial duration and an expertise in at least one of the following:

(a) energy issues;

(b) telecommunications issues;

(c) consumer protection and advocacy issues;

(d) water and wastewater issues;

(e) finance, economics, and statistics;

(f) accounting;

(g) engineering; or

(h) law.

(B) The review committee may find a candidate qualified although the candidate does not have a background of substantial duration and expertise in one of the eight enumerated areas contained in subsection (A)(2) of this section if three-fourths of the review committee vote to qualify such candidate and provide written justification of their decision in the report as to the qualifications of the candidates.

(C) The qualification provisions of subsection (A) of this section do not apply to the reelection of any commissioner elected by the General Assembly on March 3, 2004, so long as there is no break in service.

(D) Beginning in 2004, the members of the Public Service Commission must be elected to staggered terms. In 2004, the members representing the second, fourth, and sixth congressional districts must be elected for terms ending on June 30, 2006, and until their successors are elected and qualify. Thereafter, members representing the second, fourth, and sixth congressional districts must be elected to terms of four years and until their successors are elected and qualify. In 2004, the members representing the first, third, and fifth congressional districts and the State at-large must be elected for terms ending on June 30, 2008, and until their successors are elected and qualify. Thereafter, members representing the first, third, and fifth congressional districts and the State at-large must be elected to terms of four years and until their successors are elected and qualify.

(E) The General Assembly must provide for the election of the seven-member commission and elect its members based upon the congressional districts established by the General Assembly pursuant to the latest official United States Decennial Census. If the number of congressional districts is less than seven, additional members must be elected at large to provide for a seven-member commission.

(F) The Governor may fill vacancies in the office of commissioner until the successor in the office for a full term or an unexpired term, as applicable, has been elected by the General Assembly. In cases where a vacancy occurs on the commission when the General Assembly is not in session, the Governor may fill the vacancy by an interim appointment. The Governor must report the interim appointment to the General Assembly and must forward a formal appointment at its next ensuing regular session.

SECTION 58-3-21. Repealed by 1993 Act No. 181, Section 1617(A), eff July 1, 1993.

SECTION 58-3-22. Repealed by 1993 Act No. 181, Section 1617(A), eff July 1, 1993.

SECTION 58-3-23. Repealed by 1993 Act No. 181, Section 1617(A), eff July 1, 1993.

SECTION 58-3-24. General Assembly members and immediate family ineligible for election to commission.

No member of the General Assembly or member of his immediate family shall be elected to the commission while the member is serving in the General Assembly; nor shall a member of the General Assembly or a member of his immediate family be elected to the Public Service Commission for a period of four years after the member either:

(1) ceases to be a member of the General Assembly; or

(2) fails to file for election to the General Assembly in accordance with Section 7-11-15.

SECTION 58-3-25. Conflict of interest; commission members and employees.

(A) Unless otherwise provided by law, no person may serve as a member of the commission if the commission regulates any business with which that person is associated.

(B) If the commission regulates a business with which an employee of the commission is associated, the employee must annually file a statement of economic interests notwithstanding the provisions of Section 8-13-1110.

(C) No person may be an employee of the commission if the commission regulates a business with which the employee is associated, and this relationship creates a continuing or frequent conflict with the performance of his official responsibilities.

SECTION 58-3-26. Repealed by 2004 Act No. 175, Section 10, eff March 4, 2004.

SECTION 58-3-30. Oaths; Code of Judicial Conduct applicable; ethics and the Administrative Procedure Act workshop.

(A) The commissioners shall take the oath of office provided by the Constitution and the oaths prescribed by law for state officers.

(B) The commissioners and commission employees are bound by the Code of Judicial Conduct, as contained in Rule 501 of the South Carolina Appellate Court Rules, except as provided in Section 58-3-260, and the State Ethics Commission must enforce and administer those rules pursuant to Section 8-13-320. In addition, commissioners and commission employees must comply with the applicable requirements of Chapter 13 of Title 8.

(C) Each year, the commissioners and their employees must attend a workshop of at least six contact hours concerning ethics and the Administrative Procedures Act. This workshop must be developed with input from the review committee.

SECTION 58-3-40. Election of chairman; hearing officer.

(A) The commission must elect one of its members as chairman for a period of two years.

(B) The chairman is the chief executive and administrative officer of the commission.

(C)(1) Upon the request of any party or any commissioner, the commission may employ a hearing officer who may hear and determine procedural motions or other matters not determinative of the merits of the proceedings and made prior to hearing; and, at the hearing, shall make all rulings on nondispositive motions and objections. If qualified pursuant to item (3), a commission staff attorney may serve as hearing officer.

(2) The hearing officer has full authority, subject to being overruled by the commission, to rule on questions concerning the conduct of the case and the admission of evidence but may not participate in the determination on the merits of any case.

(3) The hearing officer must be an attorney qualified to practice in all courts of this State with a minimum of eight years' practice experience.

SECTION 58-3-50. Administration of oaths.

The clerk of the commission may administer oaths.

SECTION 58-3-60. Employment of clerk, attorneys and other staff; salaries; travel authorization and approval; exception as to functions of Office of Regulatory Staff

(A) The commission is authorized and empowered to employ: a chief clerk and deputy clerk; a commission attorney and assistant commission attorneys; hearing officers; hearing reporters; and such other professional, administrative, technical, and clerical personnel as the commission determines to be necessary in the proper discharge of the commission's duties and responsibilities as provided by law. The chairman must organize and direct the work of the commission staff. The salaries of the chairman, the commissioners, and the chief clerk shall not be construed as limiting the maximum salary which may be paid to other employees of the Public Service Commission. The commission staff shall not appear as a party in commission proceedings and shall not offer testimony on issues before the commission.

(B) Subject to Section 58-3-580, the commission must be staffed and equipped to perform the functions set forth in this title except for those responsibilities and functions reserved to the Office of Regulatory Staff. The expenses must be paid from the assessments collected pursuant to Section 58-3-100. The chairman, within allowed budgetary limits and as otherwise allowed by law, must authorize and approve travel, subsistence, and related expenses of personnel incurred while traveling on official business.

(C) The commissioners shall not supervise the Office of Regulatory Staff.

(D) The commission shall not inspect, audit, or examine public utilities. The inspection, auditing, and examination of public utilities is solely the responsibility of the Office of Regulatory Staff.

SECTION 58-3-70. Compensation of commission members; limitations on other employment.

The chairman and members of the commission shall receive annual salaries payable in the same manner as the salaries of other state officers are paid. Each commissioner must devote full time to his duties as a commissioner and must not engage in any other employment, business, profession, or vocation during the normal business hours of the commission.

SECTION 58-3-80. Repealed by 2004 Act No. 175, Section 10, eff February 18, 2004.

SECTION 58-3-90. Meetings of Commission; quorum.

The commission must meet at least once each month, and the chairman must call a meeting at any other time upon the written request of any two members of the commission. A majority of the commissioners constitutes a quorum for the transaction of all business pertaining to their office.

SECTION 58-3-95. Repealed by 2004 Act No. 175, Section 10, eff January 1, 2005.

SECTION 58-3-100. Assessment for expenses of Commission; Commission an other-funded agency.

Except as specifically provided in Sections 58-5-940 and 58-27-50, all other expenses of the Public Service Commission must be borne by the public utilities subject to the commission's jurisdiction. On or before the first day of July in each year, the Department of Revenue must assess each public utility, railway company, household goods carrier, and hazardous waste for disposal carrier its proportion of the expenses in proportion to its gross income from operation in this State in the year ending on the thirtieth day of June preceding that on which the assessment is made which is due and payable on or before July fifteenth. The assessments must be charged against the companies by the Department of Revenue and collected by the department in the manner provided by law for the collection of taxes from the companies including the enforcement and collection provisions of Article 1, Chapter 54 of Title 12 and paid, less the department's actual incremental increase in the cost of administration into the state treasury as other taxes collected by the department.

The commission must certify to the South Carolina Department of Revenue annually, but no later than May first, the amounts to be assessed.

The commission shall operate as an other-funded agency.

SECTION 58-3-110. Advance of funds for office of Commission.

The appropriation for the commission's office must be advanced by the State until it has been collected from the corporations liable therefor and, when collected, must be placed in the state treasury.

SECTION 58-3-120. Repealed by 2004 Act No. 175, Section 10, eff January 1, 2005.

SECTION 58-3-130. State agencies and the like shall supply records and information to Commission.

Upon demand by the Office of Regulatory Staff, each state department, board, and commission, and each officer or agent of the State must furnish to the Office of Regulatory Staff, for inspection and confidential use, any record or information on file with the department, board, commission, or officer, as appropriate, concerning the property values, operation, income, or other matter of any person doing business as a public utility in this State.

SECTION 58-3-140. Powers to regulate public utilities.

(A) Except as otherwise provided in Chapter 9 of this title, the commission is vested with power and jurisdiction to supervise and regulate the rates and service of every public utility in this State and to fix just and reasonable standards, classifications, regulations, practices, and measurements of service to be furnished, imposed, or observed, and followed by every public utility in this State.

(B) The commission must develop and publish a policy manual which must set forth guidelines for the administration of the commission. All procedures must incorporate state requirements and good management practices to ensure the efficient and economical utilization of resources.

(C) The commission must facilitate access to its general rate request orders in contested matters involving more than one hundred thousand dollars by publishing an order guide which indexes and cross-references orders by subject matter and case name. The order guide must be made available for public inspection.

(D) The commission must promulgate regulations to require the direct testimony of witnesses appearing on behalf of utilities and of witnesses appearing on behalf of persons having formal intervenor status, such testimony to be reduced to writing and prefiled with the commission in advance of any hearing.

(E) Nothing in this section may be interpreted to repeal or modify specific exclusions from the commission's jurisdiction pursuant to Title 58 or any other title.

(F) When required to be filed, tariffs must be filed with the office of the chief clerk of the commission and, on that same day, provided to the Executive Director of the Office of Regulatory Staff.

SECTION 58-3-142. Limitation on appearance of members of General Assembly in rate fixing proceedings.

No member of the General Assembly or any member of a member's law firm shall appear before the commission in any rate-fixing proceeding by representing any party in the proceeding for any purposes including political purposes, and it is the duty of the presiding commissioner or hearing officer to enforce the provisions of this section. However, this section does not apply to any member of the General Assembly appearing as a witness on either side of any hearing.

SECTION 58-3-145. Repealed by 2004 Act No. 175, Section 10, eff February 18, 2004.

SECTION 58-3-150. Repealed by 2004 Act No. 175, Section 10, eff January 1, 2005.

SECTION 58-3-160. Repealed by 2004 Act No. 175, Section 10, eff February 18, 2004.

SECTION 58-3-170. Commission empowered to fix agreements, contracts and the like between common carriers and telephone and telegraph companies.

In case of failure of common carriers and telephone and telegraph companies to agree, the commission must supervise and fix all agreements, contracts, rates, or the divisions thereof and regulations between or among common carriers and telephone and telegraph companies, of whatever kind, placed under the control or supervision of the commission.

Except for rates, transactions affecting rates, or transactions affecting service areas, the provisions of this section do not apply to transactions between a telephone cooperative association and its subsidiary corporation or cooperative association.

SECTION 58-3-180. Promulgation of regulations to effectuate Section 58-3-170.

The commission must promulgate regulations as necessary to effectuate the provisions of Section 58-3-170.

SECTION 58-3-190. Reports by entities subject to commission jurisdiction; audits by Office of Regulatory Staff.

(A) The commission has the authority to require periodic written reports to be submitted by persons or entities subject to its jurisdiction. Such reports must relate to matters within the jurisdiction of the commission and must be filed with the commission and provided to the Office of Regulatory Staff.

(B) If, in the judgment of the commission, any report referred to in subsection (A) is not furnished within a reasonable time or does not satisfactorily address the matters the commission requires to be addressed in such reports, the commission must give the person or entity written notice of the reasons why the report is not satisfactory, and the person or entity shall have a reasonable time period in which to comply with the requirements of the notice.

(C) The commission may request the Office of Regulatory Staff to make, pursuant to Section 58-4-50(A)(2), an inspection, audit, or examination of the persons or entities referred to in subsection (A) regarding matters the commission requires to be addressed in the reports referred to in subsection (A).

SECTION 58-3-200. Inspections, audits and examinations.

The commission has the authority to initiate inspections, audits, and examinations of all persons and entities subject to its jurisdiction. Such inspections, audits, and examinations must relate to matters within the commission's jurisdiction. Notwithstanding any other provision of law, the commission must not conduct such inspections, audits, and examinations itself, but must request that they be conducted by the Office of Regulatory Staff pursuant to Section 58-4-50(A)(2).

SECTION 58-3-210. Repealed by 2004 Act No. 175, Section 10, eff January 1, 2005.

SECTION 58-3-220. Disposition of penalties and forfeitures for failure to comply with orders of commission.

One-half of all penalties and forfeitures collected from railroad, express, telegraph, and telephone companies for failure to comply with orders of the commission must be paid into the state treasury, and the other half into the county treasury of the county in which the suit is brought imposing the penalty or forfeiture collected. The revenues accruing from these collections must be used for general state and county purposes.

SECTION 58-3-225. Conduct of hearings; absence of commissioner; ejection of disruptive party; contempt; withdrawal of petition.

(A) Hearings conducted before the commission must be conducted under dignified and orderly procedures designed to protect the rights of all parties. If a commissioner is absent from or leaves the hearing for fifteen consecutive minutes or longer, the commission must recess the hearing until the commissioner is present, or the commissioner may not participate in the deliberations or vote on the matter. If a commissioner is absent from or leaves the hearing for less than fifteen consecutive minutes, the commission shall cause the record of the proceeding to reflect the absence and the duration of the absence.

(B) All persons appearing in a representative capacity before the commission in its proceedings should conform to the standards of ethical conduct required of attorneys practicing before the courts of this State.

(C) Any person, firm, or corporation who disregards commission orders after due notice or who engages in conduct calculated to bring the due and orderly course of commission proceedings into disrespect or disregard, or to interfere with or prejudice parties or their witnesses during the proceedings may, by order of the commission or its presiding officer, be ejected for the remainder of that day from the proceedings. If that person, firm, or corporation engages in further conduct resulting in ejection for a second day or portion thereof in the same proceeding, he must also be declared in contempt and cited to any circuit judge, who may punish by a fine not to exceed five hundred dollars or imprisonment not to exceed thirty days, or both. The proscribed conduct includes, but is not limited to, any person, firm, or corporation intentionally delaying the proceedings by the injection of matters determined not to be relevant after a proper warning that the matters shall not be pursued.

(D) The provisions of this section must not be construed as limiting any powers of the commission under existing law.

(E) A party may withdraw its petition, application, complaint, counterclaim, cross-claim, or third-party claim from any commission docket one time as a matter of right, and without prejudice, provided that it does so prior to the later of the date that responsive pleadings are filed or the date that the withdrawing party's direct testimony addressing such petition, application, complaint, counterclaim, cross-claim, or third-party claim is due to be filed with the commission. A party may thereafter withdraw its petition, application, complaint, counterclaim, cross-claim, or third-party claim from any commission docket only upon order of the commission and upon such terms and conditions as the commission considers proper.

SECTION 58-3-230. Unauthorized change of utility provider service; authorization; penalties; "customer" defined.

(A) A utility, as defined in Sections 58-5-10, 58-9-10, and 58-27-10, may not submit a change request for a customer's utility service until the customer's authorization for the change is obtained by using marketing or anti-slamming guidelines approved by the appropriate federal and state regulatory agencies. In the case of utilities defined by Section 58-9-10, the appropriate regulatory agencies are the Federal Communications Commission and the South Carolina Public Service Commission. If a utility other than that directly receiving the customer authorization subsequently effects the change into billing or operational systems, it is not:

(1) required to secure additional customer authorization; and

(2) liable pursuant to this section for errors, omissions, or unauthorized changes submitted by the utility originating the request.

(B) A utility defined in Sections 58-5-10 and 58-27-10 that violates subsection (A) is liable to the customer for all charges incurred by the customer, in excess of those normally incurred through his designated provider, during the period of the unauthorized change.

(C) A utility defined in Section 58-9-10 that violates subsection (A) is liable as specified in Federal Communications Commission guidelines promulgated pursuant to the United States Code of Laws, Chapter 1, Title 47.

(D) A utility, as defined in Sections 58-5-10, 58-9-10, and 58-27-10, that wilfully, knowingly, or repeatedly violates the provisions of subsection (A) is subject to a fine of not less than two thousand dollars nor more than ten thousand dollars for each violation. The fines collected by the Public Service Commission pursuant to this section must remain with the commission and be used to offset costs associated with this section.

(E) As used in this section "customer" means:

(1) the party identified in the account records of a utility as the one responsible for payment of the utility bill;

(2) an adult person authorized by the responsible party to change utility services or to charge services to the account; or

(3) a person contractually or otherwise lawfully authorized to represent the responsible party.

SECTION 58-3-240. Definitions; exemption from certain regulations for certain utility services.

(A) As used in this section:

(1) "Privately-owned industrial park" means a privately- owned tract of real property which is used solely for industrial uses, in which the provider of utility services owns or operates an industrial premises and owns or operates facilities for the provision of utility services and on which there is located one or more industrial users. " Privately-owned industrial park" also means those additional tracts as may be subsequently incorporated into the industrial park.

(2) "Industrial premises" means a building, structure, plant, or facility which is located in a privately-owned industrial park and is owned or leased by an industrial user.

(3) "Industrial user" means any person, corporation, or association which is engaged in the business of manufacturing, processing, assembling, fabricating, or related work.

(4) "Provider of utility services" means a person, corporation, or association, other than a regulated public utility or its affiliates, that offers or provides, or both, utility services to the public or any portion of it outside a privately-owned industrial park, which provides any or all of those services which are defined in Chapters 5 and 7 of this title, excluding gas, and subject to regulation by the commission and where the services are provided to an industrial user in a privately-owned industrial park.

(5) "Jurisdictional utilities" means those persons, corporations, associations, or political subdivisions which provide services subject to the jurisdiction of the commission under Chapters 5 and 7 of this title, excluding gas.

(B) The provisions of Chapters 5 and 7 of this title, excluding gas, are not applicable to the provision of utility services to industrial users of these services where the industrial users are located in a privately-owned industrial park where the provider of utility services and the industrial user have agreed in writing to the terms and conditions for the provision of utility services and where all jurisdictional utilities which would have a right to provide any or all of the utility services have agreed in writing to waive their right to further notice and opportunity for hearing with respect to the written agreement and the provision of the services under the terms of the agreement.

(C) Within twenty days after the execution of a written agreement between a provider of utility services and an industrial user pursuant to subsection (B), the provider of utility services must file with the commission and provide to the Office of Regulatory Staff, for information only, the written agreement and all waivers executed by jurisdictional utilities pursuant to subsection (B).

SECTION 58-3-250. Final orders and decisions; contents; service on parties.

(A) All final orders and decisions of the commission must be sufficient in detail to enable the court on appeal to determine the controverted questions presented in the proceedings and must include:

(1) findings and conclusions, and the reasons or bases therefor, upon all the material issues of fact or law presented in the record; and

(2) the appropriate rule, order, sanction, relief, or statement of denial thereof.

(B) A copy of every final order or decision under the seal of the commission must be served by registered or certified mail upon all parties to the proceeding or their attorneys. Service upon a party or upon the attorney must be made by mailing a copy to him at his last known address. If no address is known, however, service shall be made by leaving a copy with the chief clerk of the commission. The order takes effect and becomes operative when served unless otherwise designated and continues in force either for a period designated by the commission or until changed or revoked by the commission. If, in the judgment of the commission, an order cannot be complied with within the time designated, the commission may grant and prescribe additional time as is reasonably necessary to comply with the order and, on application and for good cause shown, may extend the time for compliance fixed in its order.

SECTION 58-3-260. Communications between commission and parties prohibited; exempt communications; disclosure of improper communications; penalties.

(A) For purposes of this section:

(1) "Proceeding" means a contested case, generic proceeding, or other matter to be adjudicated, decided, or arbitrated by the commission.

(2) "Person" means a party to a proceeding pending before the commission, a member of the Office of Regulatory Staff, a representative of a party to a proceeding pending before the commission, individuals, corporations, partnerships, limited liability companies, elected officials of state government, and other public and elected officials.

(3) "Communication" means the transmitting of information by any mode including, but not limited to, oral, written, or electronic.

(4) "Allowable ex parte communication briefing" means any communication that is conducted pursuant to the procedure outlined in subsection (C)(6) of this section.

(5) "Communication of supplemental legal citation" means the submission, subsequent to the submission of post-hearing briefs or proposed orders in a proceeding, of statutes, regulations, judicial or administrative decisions that are enacted, promulgated, or determined after the submission of post-hearing briefs or proposed orders.

(B) Except as otherwise provided herein or unless required for the disposition of ex parte matters specifically authorized by law, a commissioner, hearing officer, or commission employee shall not communicate, directly or indirectly, regarding any issue that is an issue in any proceeding or can reasonably be expected to become an issue in any proceeding with any person without notice and opportunity for all parties to participate in the communication, nor shall any person communicate, directly or indirectly, regarding any issue that is an issue in any proceeding or can reasonably be expected to become an issue in any proceeding with any commissioner, hearing officer, or commission employee without notice and opportunity for all parties to participate in the communication.

(C) The following communications are exempt from the prohibitions of subsection (B) of this section:

(1) a communication concerning compliance with procedural requirements if the procedural matter is not an area of controversy in a proceeding;

(2) statements made by a commission employee who is or may reasonably be expected to be involved in formulating a decision, rule, or order in a proceeding, where the statements are limited to providing publicly available information about pending proceedings;

(3) inquiries relating solely to the status of a proceeding, unless the inquiry: (a) states or implies a view as to the merits or outcome of the proceeding; (b) states or implies a preference for a particular party or which states why timing is important to a particular party; (c) indicates a view as to the date by which a proceeding should be resolved; or (d) is otherwise intended to address the merits or outcome or to influence the timing of a proceeding;

(4) a communication made by or to commission employees that concerns judicial review of a matter that has been decided by the commission and is no longer within the commission's jurisdiction; however, if the matter is remanded to the commission for further action, the provisions of this section shall apply during the period of the remand;

(5) where circumstances require, ex parte communications for scheduling, administrative purposes, or emergencies that do not deal with substantive matters or issues on the merits are authorized provided:

(a) the commissioner, hearing officer, or commission employee reasonably believes that no party will gain a procedural or tactical advantage as a result of the ex parte communication; and

(b) the commissioner, hearing officer, or commission employee makes provision promptly to notify all other parties of the substance of the ex parte communication and, where possible, allows an opportunity to respond;

(6)(a) subject to the provisions of Chapter 4 of Title 30, communications, directly or indirectly, regarding any fact, law, or other matter that is or can reasonably be expected to become an issue in a proceeding for the purposes of an allowable ex parte communication briefing if:

(i) the Executive Director of the Office of Regulatory Staff or his designee attends the briefing and files a written certification, within seventy-two hours of the briefing, attaching copies of all statements and all other matters filed by all persons pursuant to subsubitems (ii), (iii), and (iv) of this subsection, with the chief clerk of the commission that such briefing was conducted in compliance with the provisions of this section and that each party, person, commissioner, or commission employee present has complied with the reporting and certification requirements of subsubitems (ii), (iii), and (iv); and within twenty-four hours of the submission by the executive director, the commission posts on its web site the written certification, statements, and other matters filed by the executive director;

(ii) each party, person, commissioner, and commission employee present files a written, certified statement with the Executive Director of the Office of Regulatory Staff within forty-eight hours of the briefing accurately summarizing the discussions in full and attaching copies of any written materials utilized, referenced, or distributed;

(iii) each party, person, commissioner, and commission employee present, within forty-eight hours of the briefing, files a certification with the Executive Director of the Office of Regulatory Staff that no commitment, predetermination, or prediction of any commissioner's action as to any ultimate or penultimate issue or any commission employee's opinion or recommendation as to any ultimate or penultimate issue in any proceeding was requested by any person or party nor any commitment, predetermination, or prediction was given by any commissioner or commission employee as to any commission action or commission employee opinion or recommendation on any ultimate or penultimate issue;

(iv) each commissioner or commission employee present at the allowable ex parte communication briefing grants to every other party or person requesting an allowable ex parte communication briefing on the same or similar matter that is or can reasonably be expected to become an issue in a proceeding, similar access and a reasonable opportunity to communicate, directly or indirectly, regarding any fact, law, or other matter that is or can reasonably be expected to become an issue in a proceeding under the provisions of subsection (C)(6) of this section and files a written, certified statement with the Executive Director of the Office of Regulatory Staff within forty-eight hours of the briefing stating that the commissioner or commission employee will comply with this provision;

(v) the commission posts on its web site, at least five business days prior to the proposed briefing, a notice of each request for an allowable ex parte communication briefing that includes the date and time of the proposed briefing, the name of the person or party who requested the briefing, the name of each commissioner and commission employee whom the person or party has requested to brief, and the subject matter to be discussed at the briefing;

(vi) the person or party initially seeking the briefing requests the briefing with sufficient notice, as required in subsubitem (v), to allow the initial briefing to be held at least twenty business days prior to the hearing in the proceeding at which the matter that is the subject of the briefing is or can reasonably be expected to become an issue, and the initial briefing must be held at least twenty business days prior to the hearing in the proceeding; and

(vii) any person or party desiring to have a briefing on the same or similar matter as provided for in subsubitem (vi) requests a briefing with sufficient notice, as required in subsubitem (v), to allow the briefing to be held at least ten business days prior to the hearing in the proceeding at which the matter that is the subject of the briefing is or can reasonably be expected to become an issue, and any such briefing must be held at least ten business days prior to the hearing in the proceeding;

(b) any person or party may object to the attendance of the Executive Director of the Office of Regulatory Staff at an allowable ex parte communication briefing on the grounds of bias or a conflict of interest on the part of the executive director. Any such objection must be made in writing and must be filed with the executive director no later than twenty-four hours prior to the scheduled briefing. If the objecting person or party and the executive director agree upon a neutral person, that person shall serve in the executive director's stead and shall comply with the reporting and certification requirements of the executive director contained in subsubitem (i) and the executive director shall comply with the requirements contained in subsubitems (ii) and (iii). The costs of such person's services shall be charged to the party requesting the briefing and may be an allowable cost of the proceedings. If the objecting person or party and the executive director cannot agree upon a neutral person, the objecting person or party shall petition the Administrative Law Judge Division for the appointment of a neutral person to serve in the executive director's stead, and the petition shall be given priority over all other matters within the jurisdiction of the Administrative Law Judge Division. In the petition, the objecting party shall set forth the specific grounds supporting the objecting person's or party's allegation of bias or conflict on the part of the executive director and shall generally describe the matters to be discussed at the briefing. It shall not be sufficient grounds that the executive director is or is likely to be a party to a proceeding. The executive director shall be given an opportunity to respond. Part of the executive director's response shall include recommendations as to the experience required of the person to act in his stead. Upon a showing of actual bias or conflict of interest, the administrative law judge shall designate a person to act in the executive director's stead and that person shall comply with the reporting and certification requirements of the executive director contained in subsubitem (i) and the executive director shall comply with the requirements contained in subsubitems (ii) and (iii). Such person must have the expertise to act in the executive director's stead. The decision of the administrative law judge shall be considered interlocutory and not immediately appealable and may be appealed with the final order of the commission. The costs of such person's services shall be charged to the party requesting the briefing and may be an allowable cost of the proceedings;

(c) should the Executive Director of the Office of Regulatory Staff desire to conduct an allowable ex parte communication briefing, the chief clerk of the commission shall appoint a neutral person who shall serve in the executive director's stead and that person shall comply with the reporting and certification requirements of the Executive Director of the Office of Regulatory Staff contained in subsubitem (i). The Executive Director of the Office of Regulatory Staff shall comply with the requirements contained in subsubitems (ii) and (iii);

(d) nothing in subsection (C)(6) of this section requires any commissioner or commission employee to grant a request for an allowable ex parte communication briefing, except as provided in subsection (C)(6)(a)(iv) of this section;

(7) a communication of supplemental legal citation if the party files copies of such documents, without comment or argument, with the chief clerk of the commission and simultaneously provides copies to all parties of record;

(8) subject to the provisions of Chapter 4 of Title 30, communications between and among commissioners regarding matters pending before the commission; provided, further, that any commissioner, hearing officer, or commission employee may receive aid from commission employees if the commission employees providing aid do not:

(a) receive ex parte communications of a type that the commissioner, hearing officer, or commission employee would be prohibited from receiving; or

(b) furnish, augment, diminish, or modify the evidence in the record.

(D) If before serving in a proceeding, a commissioner, hearing officer, or commission employee receives an ex parte communication of a type that may not properly be received while serving, the commissioner, hearing officer, or commission employee must disclose the communication in the following manner: a commissioner, hearing officer, or a commission employee who receives an ex parte communication in violation of this section must promptly after receipt of the communication or, in the case of a communication prior to a filing, as soon as it is known to relate to a filing, place on the record of the matter all written and electronic communications received, all written and electronic responses to the communications, and a memorandum stating the substance of all oral communications received, all responses made, and the identity of each person from whom the commissioner, hearing officer, or commission employee, as appropriate, received an ex parte communication and must advise all parties that these matters have been placed on the record. Within ten days after receipt of notice of the ex parte communication, any party who desires to rebut the contents of the communication must request and shall be granted the opportunity to rebut the contents. Parties affected by a violation may agree to a resolution of any claim regarding such violation, including the waiver of a hearing and the waiver of the obligation to report violations under subsection (I) of this section.

(E) Any person who makes an inadvertent ex parte communication must, as soon as it is known to relate to an issue in a proceeding, disclose the communication by placing on the record of the matter the communication made, if written or electronic, or a memorandum stating the substance of an inadvertent oral communication, and the identity of each person to whom the inadvertent ex parte communication was made or given. Within ten days after receipt of notice of the ex parte communication, any party who desires to rebut the contents of the communication must request and shall be granted the opportunity to rebut the contents. If no party rebuts the inadvertence of the ex parte communication within ten days after notice of the ex parte communication, the ex parte communication shall be presumed inadvertent. Parties affected by a violation may agree to a resolution of any claim regarding such violation, and the provisions of subsection (J) of this section shall not apply.

(F) If necessary to eliminate the effect of an ex parte communication received in violation of this section, a commissioner, hearing officer, or commission employee who receives the communication may be disqualified by the commission, and the portions of the record pertaining to the communication may be sealed by protective order.

(G) Nothing in this section alters or amends Section 1-23-320(i).

(H) Nothing in this section prevents a commissioner, hearing officer, or commission employee from attending educational seminars sponsored by state, regional, or national organizations and seminars not affiliated with any utility regulated by the commission; however, the provisions of this section shall apply to any communications that take place outside any formal sessions.

(I) Subject to any privilege under Rule 501 of the South Carolina Rules of Evidence, any commissioner, hearing officer, commission employee, party, or any other person must report any wilful violation of this section on the part of a commissioner, hearing officer, or commission employee to the review committee.

(J) Any commissioner, hearing officer, commission employee, or person who wilfully violates the provisions of this section is guilty of a misdemeanor and, upon conviction, must be fined not more than two hundred fifty dollars or imprisoned for not more than six months. If a commissioner wilfully communicates with any party or person or if any person or party wilfully communicates with a commissioner regarding any fact, law, or other matter that is or can reasonably be expected to become an issue in a proceeding less than ten business days prior to the scheduled hearing on the merits, during the hearing or after the hearing but prior to the issuance of a final order, including an order on rehearing, in a proceeding where such facts, law, or other matter is or can reasonably be expected to become an issue, the commissioner shall be removed from office. If a hearing officer or commission employee wilfully communicates with any party or person or any party or person wilfully communicates with a hearing officer or commission employee regarding any fact, law, or other matter that is or can reasonably be expected to become an issue in a proceeding less than ten days prior to the scheduled hearing on the merits, during the hearing or after the hearing but prior to the issuance of a final order, including an order on rehearing, in a proceeding where such facts, law, or other matter is or can reasonably be expected to become an issue, the hearing officer or commission employee shall be terminated from employment by the commission. For purposes of this section: (1) "wilful" means an act done voluntarily and intentionally with the specific intent to do something the law forbids, or with specific intent to fail to do something the law requires to be done, that is to say with bad purpose either to disobey or disregard the law, and (2) a violation of the provisions of this section must be proved by clear and convincing evidence before a commissioner, hearing officer, or commission employee can be removed from office or terminated from employment.

SECTION 58-3-270. Obtaining remedial relief from violation of prohibited communications; hearing before administrative law judge.

(A) Any party seeking remedial relief from alleged violations of Section 58-3-260 may file a complaint with the Administrative Law Judge Division.

(B) A complaint seeking sanctions must include the following:

(1) the name and address of the complainant;

(2) the name and address of complainant's counsel, if any;

(3) the name and address of each person alleged to have violated the ex parte prohibition, hereinafter referred to as respondent;

(4) the name and address of each respondent's counsel, if known;

(5) the facts constituting the alleged violation; and

(6) the sanctions sought by the complainant.

(C) A complaint filed under this section must be served on the commission, each respondent, respondent's counsel, if known, and all persons on the commission's service list for the proceeding that is the subject of the ex parte complaint.

(D) Within seven days of service of the complaint, a respondent must file an answer with the Administrative Law Judge Division and serve it on the complainant, the commission, and all persons on the commission's service list for the proceeding that is the subject of the ex parte complaint.

(E) The administrative law judge assigned to the ex parte communication complaint proceeding by the Administrative Law Judge Division may issue an order tolling any deadlines imposed by any state statute for a decision by the commission on the proceeding that is the subject of the ex parte communication complaint. The administrative law judge assigned to the ex parte communication complaint proceeding by the Administrative Law Judge Division must conduct a hearing and must issue a decision within sixty days after the complaint is filed.

(F) The decision of the administrative law judge must describe the relevant facts of the case and must set forth the judge's findings as to whether the ex parte communication was in violation of Section 58-3-260. The judge also must impose sanctions in accordance with subsection (G) of this section. In imposing these sanctions, the judge, as a matter of equity, must protect: (1) the rights and interests of parties who are not alleged to have violated Section 58-3-260, and (2) the public interest in general.

(G) In his decision, the administrative law judge may impose the following sanctions:

(1) dismiss the proceeding if the prohibited ex parte communication has so prejudiced the proceeding that the commission cannot consider the matter impartially;

(2) issue an adverse ruling on a pending issue that is the subject of the prohibited ex parte communication if other parties are prejudiced by the prohibited ex parte communication;

(3) strike evidence or pleadings if the evidence or pleadings are tainted by the prohibited ex parte communication;

(4) issue a public statement of censure or explanation, if it is determined that the prohibited ex parte communication occurred but mitigating circumstances exist that:

(a) negate the need for a more severe sanction;

(b) indicate that the proceeding was not prejudiced to the extent that the commission is unable to consider the matter in the proceeding impartially;

(c) indicate that the ex parte communication did not prejudice other parties; or

(d) indicate that the ex parte communication did not taint the evidence or pleadings.

(H) If the administrative law judge finds the complainant's allegation of an ex parte violation was interposed for any improper purpose, such as to harass or cause unnecessary delay or increase the cost of the proceeding, the administrative law judge may issue an appropriate sanction against the complainant.

(I) Any decision of an administrative law judge pursuant to this section shall be considered interlocutory in nature and is not immediately appealable until a final order of the commission has been issued. Any appeal of a decision of an administrative law judge pursuant to this section must be included in and made in the same manner as an appeal of the final order of the commission in the subject proceeding.

SECTION 58-3-280. Restriction on employment of former commissioners by public utility.

A commissioner must not be employed or retained by a public utility for a period of at least one year following his service as a commissioner. A person who violates this provision is guilty of a misdemeanor and, upon conviction, must be fined not more than five thousand dollars or be imprisoned for not more than one year, or both.

ARTICLE 3.

LAW ENFORCEMENT DEPARTMENT

SECTION 58-3-310. Transportation Division Inspectors; commission and removal of inspectors.

The law enforcement department of the Office of Regulatory Staff shall consist of such officers, inspectors, and agents as the Executive Director of the Office of Regulatory Staff considers necessary and proper for the enforcement of the Motor Vehicle Carrier Law and other related laws, the enforcement of which is devolved upon the department. The title of such officers, inspectors, and agents shall be "Transportation Division Inspectors". The inspectors shall be commissioned by the Governor upon the recommendation of the Executive Director of the Office of Regulatory Staff. The Executive Director of the Office of Regulatory Staff may remove an inspector if he finds that the inspector is unfit for the position.

SECTION 58-3-320. Bond of inspectors.

Each inspector shall execute a bond with a licensed surety company in the amount of not less than ten thousand dollars.

The bond shall be filed with the Office of Regulatory Staff and shall be conditioned for the faithful performance of his duties, for the prompt and proper accounting of funds coming into his hands and for the payment of any judgment rendered against him in any court of competent jurisdiction upon a cause of action arising out of breach or abuse of official duty or power and damages sustained by any member of the public from any unlawful act of the inspector. The coverage under the bond shall not include damage to persons or property arising out of the negligent operation of a motor vehicle. The bond may be individual, schedule, or blanket, and shall be approved by the Attorney General. The premiums on the bonds shall be paid by the Office of Regulatory Staff from appropriated funds.

SECTION 58-3-330. Oath of inspectors.

Before entering upon the duties of his office, each inspector shall take and subscribe before a notary public, or other officer authorized to administer an oath, an oath to faithfully perform the duties of his office and to properly execute the laws of this State.

SECTION 58-3-340. Inspectors to possess and exercise powers and authority of constables.

The inspectors shall possess and exercise all of the powers and authority held by constables at common law.

SECTION 58-3-350. Enforcement authority of inspectors.

When acting in their official capacity, inspectors shall have statewide authority for the enforcement of all motor vehicle carrier laws and related laws.

SECTION 58-3-360. Inspectors to insure that violators are prosecuted.

Inspectors shall enforce the Motor Vehicle Carrier Law, and related laws and insure that all persons violating any provision of these laws are properly prosecuted.

SECTION 58-3-370. Arrest procedure.

When any person is apprehended by an inspector upon a charge of violating the Motor Vehicle Carrier Law or related laws, the following procedure shall be followed:

(1) The person being charged shall be served by the arresting inspector with an official summons and arrest report. The report shall give the appropriate judicial officer jurisdiction to dispose of the case.

(2) The person being charged may deposit with the arresting inspector a sum of money not to exceed one hundred dollars as bail in lieu of being immediately brought before the magistrate or other judicial officer; provided, that an official summons and arrest report may be issued without requiring any sum of money as bail.

(3) The official summons and arrest report shall indicate the amount of bail deposited with the inspector and shall serve as a receipt for the sum.

(4) The arresting inspector shall transmit any sum of money received from the person charged to the appropriate magistrate or other judicial officer.

(5) Upon receipt of the sum of money, if any is required, as bail, the arresting inspector may release the person charged so that he may appear before the proper judicial officer at a time and place stated in, and required by, the official summons and arrest report.

ARTICLE 5.

STATE REGULATION OF PUBLIC UTILITIES REVIEW COMMITTEE

SECTION 58-3-510. State Regulation of Public Utilities Review Committee established.

There is hereby established a committee to be known as the State Regulation of Public Utilities Review Committee, hereinafter called the review committee, which must exercise the powers and fulfill the duties described in this article.

SECTION 58-3-520. Membership; election of chairman; meetings; nomination of candidates for Public Service Commission and Executive Director of Office of Regulatory Staff.

(A) The review committee shall be composed of ten members, three of whom shall be members of the House of Representatives, including the Chairman of the Labor, Commerce and Industry Committee, or his designee, three of whom shall be members of the Senate, including the Chairman of the Judiciary Committee or his designee, two of whom shall be appointed by the Chairman of the Senate Judiciary Committee from the general public at large, and two of whom appointed by the Speaker of the House of Representatives from the general public at large. The Speaker of the House of Representatives shall determine how its legislative members shall be selected. The Chairman of the Senate Judiciary Committee will select the members of the Senate. Provided, however, that in making appointments to the joint committee, race, gender, and other demographic factors should be considered to assure nondiscrimination, inclusion, and representation to the greatest extent possible of all segments of the population of the State. The members of the general public appointed by the Speaker and the Chairman of the Senate Judiciary Committee must be representative of all citizens of this State and must not be members of the General Assembly.

(B) The review committee must meet as soon as practicable after appointment and organize itself by electing one of its members as chairman and such other officers as the review committee may consider necessary. Thereafter, the review committee must meet at least annually and at the call of the chairman or by a majority of the members. A quorum consists of six members.

(C) Unless the review committee finds a candidate qualified and nominates the candidate for a seat on the Public Service Commission or for the Executive Director of the Office of Regulatory Staff, the candidate must not be elected to the Public Service Commission or appointed to serve as Executive Director of the Office of Regulatory Staff.

SECTION 58-3-530. Powers and duties.

The review committee has the following powers and duties:

(1) to nominate:

(a) no more than three candidates for each seat on the Public Service Commission to be elected by the General Assembly. In order to be nominated, a candidate must be found qualified by meeting the requirements as provided in Sections 58-3-20 and 58-3-560;

(b) no more than one qualified candidate for the Governor to consider in appointing the Executive Director of the Office of Regulatory Staff. In order to be nominated, a candidate must be found qualified by meeting the minimum requirements as provided in Section 58-4-30. The review committee must give due consideration to a candidate's experience and expertise in matters related to public utilities. A person must not be appointed to serve as Executive Director of the Office of Regulatory Staff unless nominated by the review committee. If the Governor rejects a person nominated for the position of executive director by the review committee, the review committee must nominate another candidate for the Governor to consider, until the Governor makes an appointment;

(2) notwithstanding any other provision of law, to set the salary of the Executive Director of the Office of Regulatory Staff;

(3) to conduct an annual performance review of each member of the commission, which must be submitted to the General Assembly. A draft of the member's performance review must be submitted to the member, and the member must be allowed an opportunity to be heard before the review committee before the final draft of the performance review is submitted to the General Assembly. The final performance review must be made a part of the member's record for consideration if the member seeks reelection to the commission;

(4) to evaluate the actions of the commission, to the end that the members of the General Assembly may better judge whether these actions serve the best interests of the citizens of South Carolina, both individual and corporate;

(5) to develop and distribute to each party and its representatives appearing before the commission an anonymous and confidential survey evaluating the commissioners. At a minimum, the survey must include the following:

(a) knowledge and application of substantive utility issues; ability to perceive relevant issues;

(b) absence of influence by political considerations;

(c) absence of influence by identities of lawyers;

(d) absence of influence by identities of litigants;

(e) courtesy to all persons appearing before the commission; and

(f) temperament and demeanor in general, preparation for hearings, and attentiveness during hearings;

(6) to submit to the General Assembly, on an annual basis, the review committee's evaluation of the performance of the commission. A proposed draft of the evaluation must be submitted to the commission prior to submission to the General Assembly, and the commission must be given an opportunity to be heard before the review committee prior to the completion of the evaluation and its submission to the General Assembly;

(7) to conduct an annual performance review of the Executive Director of the Office of Regulatory Staff, which must be submitted to the General Assembly. A draft of the executive director's performance review must be submitted to the executive director, and the executive director must be allowed an opportunity to be heard before the review committee before the final draft of the performance review is submitted to the General Assembly;

(8) to submit to the General Assembly, on an annual basis, the review committee's evaluation of the performance of the Office of Regulatory Staff. A proposed draft of the evaluation must be submitted to the Office of Regulatory Staff prior to submission to the General Assembly, and the Office of Regulatory Staff must be given an opportunity to be heard before the review committee prior to the completion of the evaluation and its submission to the General Assembly;

(9) to assist in developing an annual workshop of at least six contact hours concerning ethics and the Administrative Procedures Act for the commissioners and employees of the Public Service Commission and the executive director and employees of the Office of Regulatory Staff;

(10) to make reports and recommendations to the General Assembly on matters relating to the powers and duties set forth in this section;

(11) to submit a letter with the annual budget proposals of the Office of Regulatory Staff and the Public Service Commission, indicating the review committee has reviewed and approved the proposals;

(12) to appoint a committee from the general public at large to advise the review committee on any of its powers and duties. Members must not be members of the General Assembly, members or employees of the Public Service Commission, or the executive director or employees of the Office of Regulatory Staff; and

(13) to undertake such additional studies or evaluations as the review committee considers necessary.

(14) to review candidates for appointment to the South Carolina Public Service Authority Board of Directors as submitted by the Governor to determine whether the candidates meet the qualifications set forth in Section 58-31-20.

SECTION 58-3-540. Expenses.

(A) The review committee members are entitled to such mileage, subsistence, and per diem as authorized by law for members of boards, committees, and commissions while in the performance of the duties for which appointed. These expenses shall be paid from the general fund of the State on warrants duly signed by the chairman of the review committee and payable by the authorities from which they are appointed, except as provided in subsection (B) of this section.

(B) The expenses associated with the review committee's duties to qualify and nominate candidates for the commission and the Executive Director of the Office of Regulatory Staff, to develop and distribute surveys, to develop an annual workshop on ethics and the Administrative Procedures Act, and to undertake studies shall be borne by the public utilities subject to the jurisdiction of the Public Service Commission. On or before the first day of July in each year, the Department of Revenue must assess each public utility its proportion of the expenses in proportion to its gross income from operation in this State in the year ending on the thirtieth day of June preceding that on which the assessment is made which is due and payable on or before July fifteenth. The assessments must be charged against the companies by the Department of Revenue and collected by the department in the manner provided by law for the collection of taxes from the companies including the enforcement and collection provisions of Article 1, Chapter 54 of Title 12 and paid, less the Department of Revenue actual incremental increase in the cost of administration into the state treasury as other taxes collected by the Department of Revenue for the State. The review committee must certify to the Department of

Revenue annually on or before May first the amounts to be assessed. The expenses of the review committee shall be advanced by a legislative body and the legislative body incurring such expense shall be reimbursed by the State at such time as the funds have been collected from the corporations liable therefor and, when collected, placed in the state treasury.

SECTION 58-3-550. Staffing; identification of Executive Director candidates.

(A) The review committee must use clerical and professional employees of the General Assembly for its staff, who must be made available to the review committee.

(B) The review committee may employ or retain other professional staff, upon the determination of the necessity for other staff by the review committee.

(C) The review committee may employ consultants to assist in identifying candidates for the Executive Director of the Office of Regulatory Staff.

(D) Except as provided in Section 58-3-540(B), the costs and expenses of the review committee must be funded in the annual state General Appropriations Act.

SECTION 58-3-560. Election of commission members; screening and qualification of candidates.

(A) Whenever an election is to be held by the General Assembly in joint session to elect a person to serve on the commission, the review committee must conduct its screening pursuant to the provisions of Section 2-20-10, et seq.; however, Section 2-20-40 is not applicable to a screening by the review committee.

(B) In order to be nominated for a seat on the commission, candidates must meet the requirements of Section 58-3-20 and this section. In screening candidates for the commission and making its findings, the review committee must seek to find the best qualified people by giving due consideration to:

(1) ability, dedication, compassion, common sense, and integrity of the candidates; and

(2) the race and gender of the candidates and other demographic factors to assure nondiscrimination to the greatest extent possible of all segments of the population of the State.

SECTION 58-3-570. Study of other state commission structures, responsibilities, etc; report and recommendations.

The review committee may conduct a comprehensive study of other states' commissions' structures, responsibilities, qualifications, and compensation. The review committee may prepare and deliver this report along with its recommendations to the General Assembly on or before January 15, 2006.

SECTION 58-3-580. Organization of and allocation of staff to commission or Office of Regulatory Staff.

The review committee must allocate personal service positions and other appropriations within the commission to either the commission or the Office of Regulatory Staff. The review committee must organize appropriate divisions within the commission and, as submitted by the executive director, within the Office of Regulatory Staff. Notwithstanding any other provision of law, the review committee is authorized to approve position descriptions and compensation schedules for each position within the Office of Regulatory Staff. Notwithstanding any other provision of law, the salary of the Executive Director of the Office of Regulatory Staff shall not be construed as limiting the maximum salary that may be paid to other employees of the Office of Regulatory Staff. The review committee's authority to reorganize the agencies and assign personal service positions and other appropriations supersedes any provision of law to the contrary. In effectuating the review committee's assignment of positions between agencies, the Budget and Control Board is directed to assign through transfer both the position and the appropriation for the position. Notwithstanding this section or any other provision of law, the Executive Director of the Office of Regulatory Staff has sole authority to select and employ personnel of the Office of Regulatory Staff. On and after June 30, 2004, a commission employee whose position is transferred to the Office of Regulatory Staff is, upon application to the executive director, entitled only to due consideration for the position.

Section 8.1 Ref 11

South Carolina Code of Laws
(Unannotated)
Current through the end of the 2006 Regular Session

Title 58 - Public Utilities, Services and Carriers

CHAPTER 4.

OFFICE OF REGULATORY STAFF

SECTION 58-4-5. Definitions.

As used in this chapter:

(1) "Business with which he is associated" means a business of which the person or a member of his immediate family is a director, an officer, owner, employee, a compensated agent, or holder of stock.

(2) "Immediate family" means an individual who is:

(a) a child residing in the person's household;

(b) a spouse of the person; or

(c) an individual claimed by the person or the person's spouse as a dependent for income tax purposes.

(3) "Commission" means the Public Service Commission.

(4) "Hearing officer" means a person employed by the commission to serve as a presiding officer in an adjudicative

proceeding before the commission.

(5) "Regulatory staff" means the executive director or the executive director and employees of the Office of Regulatory Staff.

(6) "Public utility" means public utility as defined in Section 58-5-10, telephone utility as defined in Section 58-9-10, government-owned telecommunications service provider as defined in Section 58-9-2610, radio common carrier as defined in Section 58-11-10, carriers governed in Chapter 13 of Title 58, railroads and railways as defined in Section 58-17-10, motor vehicle carrier as defined in Section 58-23-10, or electrical utility as defined in Section 58-27-10.

(7) "Review committee" means the State Regulation of Public Utilities Review Committee.

SECTION 58-4-10. Office of Regulatory Staff created; representation of "public interest" in actions before commission; restrictions of communications.

(A) There is hereby created the Office of Regulatory Staff as a separate agency of the State with the duties and organizations as hereinafter provided.

(B) Unless and until it chooses not to participate, the Office of Regulatory Staff must be considered a party of record in all filings, applications, or proceedings before the commission. The regulatory staff must represent the public interest of South Carolina before the commission. For purposes of this chapter, "public interest" means a balancing of the following:

(1) concerns of the using and consuming public with respect to public utility services, regardless of the class of customer;

(2) economic development and job attraction and retention in South Carolina; and

(3) preservation of the financial integrity of the state's public utilities and continued investment in and maintenance of utility facilities so as to provide reliable and high quality utility services.

(C) The Office of Regulatory Staff is subject to the provision of Section 58-3-260 prohibiting ex parte communications with the commission, and any advice given to the commission by the regulatory staff must be given in a form, forum, and manner as may lawfully be given by any other party or person.

SECTION 58-4-20. Staff makeup, supervision and location.

(A) The Office of Regulatory Staff shall consist of the executive director, transportation inspectors, pipeline safety inspectors, railway safety inspectors, and other professional, administrative, technical, and clerical personnel as may be necessary in order for the regulatory staff to represent the public interest, as hereinafter provided. All such personnel must be appointed, supervised, and directed by the executive director.

(B) The regulatory staff is not subject to the supervision, direction, or control of the commission, the chairman, or members of the commission.

(C) The Office of Regulatory Staff must not be physically housed in the same location as the Public Service Commission. The review committee must approve the location of the Office of Regulatory Staff.

SECTION 58-4-30. Appointment of executive director; qualifications; term of office; removal; vacancies; oath of office.

(A) The Executive Director of the Office of Regulatory Staff must be an attorney qualified to practice in all courts of this State with a minimum of eight years' practice experience and must be appointed pursuant to the procedure set forth in Section 58-3-530(1)(b).

(B) The review committee must nominate one candidate as qualified to serve as executive director for the Governor's consideration.

1) A person must not be appointed to serve as Executive Director of the Office of Regulatory Staff unless the review committee nominates the person.

(2) If the Governor rejects a person nominated by the review committee for executive director, the review committee must nominate another candidate for the Governor to consider, until the Governor makes an appointment.

(C) The executive director must be appointed by the Governor for a term of six years and until his successor is appointed.

(D) The executive director must be initially appointed by the Governor on or before May 1, 2004. Thereafter, the executive director must be appointed by the Governor on or before April first of the year in which the term of the executive director begins.

(E) The initial term of office for the executive director begins July 1, 2004.

(F) The executive director may be removed from office by the Governor in the event of his incapacity to serve. In addition, the executive director may be removed for cause from office by the Governor pursuant to Section 1-3-240(C).

(G) In case of a vacancy in the office of executive director for any reason prior to the expiration of his term of office, the name of a nominee for the executive director's successor must be submitted by the review committee to the Governor.

(H) The executive director must take the oath of office provided by the Constitution and the oaths prescribed by law for state officers.

(I) The Office of Regulatory Staff shall be subject to annual review by the review committee; however, decisions of the Office of Regulatory Staff with respect to duties and responsibilities contained in Section 58-4-50 are in the sole discretion of the executive director, except as modified by order of a court of competent jurisdiction.

(J) The salary of the executive director must be set by the review committee.

SECTION 58-4-40. Conflict of interest.

(A) Unless otherwise provided by law, no person may serve as the Executive Director of the Office of Regulatory Staff if the commission regulates any business with which that person is associated.

(B) If the commission regulates a business with which an employee of the Office of Regulatory Staff is associated, the employee must annually file a statement of economic interests notwithstanding the provisions of Section 8-13-1110.

(C) No person may be an employee of the Office of Regulatory Staff if the Public Service Commission regulates a business with which he is associated and this relationship creates a continuing or frequent conflict with the performance of his official responsibilities.

SECTION 58-4-50. Regulatory staff duties and responsibilities; providing assistance to commission; ethics and Administrative Procedures Act workshop attendance.

(A) It is the duty and responsibility of the regulatory staff to:

(1) when considered necessary by the Executive Director of the Office of Regulatory Staff and in the public interest, review, investigate, and make appropriate recommendations to the commission with respect to the rates charged or proposed to be charged by any public utility;

(2) when considered necessary by the Executive Director of the Office of Regulatory Staff and in the public interest, make inspections, audits, and examinations of public utilities regarding matters within the jurisdiction of the commission. The regulatory staff has sole responsibility for this duty but shall also make such inspections, audits, or examinations of public utilities as requested by the commission;

(3) when considered necessary by the Executive Director of the Office of Regulatory Staff and in the public interest, review, investigate, and make appropriate recommendations to the commission with respect to the service furnished or proposed to be furnished by any public utility;

(4) represent the public interest in commission proceedings, hearings, rulemakings, adjudications, arbitrations, and other regulatory matters unless the Executive Director of the Office of Regulatory Staff chooses to opt out as a participant under the provisions of item 10;

(5) investigate complaints affecting the public interest generally, including those which are directed to the commission, commissioners, or commission employees, and where appropriate, make recommendations to the commission with respect to these complaints;

(6) upon request by the commission, make studies and recommendations to the commission with respect to standards, regulations, practices, or service of any public utility pursuant to the provisions of this title;

(7) make recommendations to the commission with respect to standards, regulations, practices, or service of any public utility pursuant to the provisions of this title;

(8) when considered necessary by the Executive Director of the Office of Regulatory Staff and in the public interest, provide legal representation of the public interest before state courts, federal regulatory agencies, and federal courts in proceedings that could affect the rates or service of any public utility;

(9) to serve as a facilitator or otherwise act directly or indirectly to resolve disputes and issues involving matters within the jurisdiction of the commission;

(10) when considered appropriate by the Executive Director of the Office of Regulatory Staff and not adverse to the public interest, choose to not participate in any commission proceeding; and

(11) when considered necessary by the Executive Director of the Office of Regulatory Staff and in the public interest, educate the public on matters affecting public utilities which are of special interest to consumers.

(B) Subject to the provisions of Section 58-3-260 and, upon request, the Executive Director of the Office of Regulatory Staff must employ the resources of the regulatory staff to furnish to the commission, or its members, such information and reports or conduct such investigations and provide other assistance as may reasonably be required in order to supervise and control the public utilities of the State and to carry out the laws providing for their regulation.

(C) Each year, the Executive Director of the Office of Regulatory Staff and the regulatory staff employees must attend a workshop of at least six contact hours concerning ethics and the Administrative Procedures Act. This workshop must be developed with input from the review committee.

SECTION 58-4-55. Production of books, records and other information; noncompliance; inspections, audits and examinations; costs.

(A) The regulatory staff, in accomplishing its responsibilities under Section 58-4-50, may require the production of books, records, and other information that, upon request of the regulatory staff, must be submitted under oath. If the books, records, or other information provided do not appear to disclose full and accurate information and, if such apparent deficiencies are not cured after reasonable notice, the regulatory staff may require the attendance and testimony under oath of the officers, accountants, or other agents of the parties having knowledge thereof at such place as the regulatory staff may designate and the expense of making the necessary examination or inspection for the procuring of the information must be paid by the party examined or inspected, to be collected by the regulatory staff by suit or action, if necessary. If, however, the examination and inspection and the reports thereof disclose that full and accurate information had previously been made, the expense of making the examination and inspection must be paid out of the funds of the regulatory staff.

(B) If the regulatory staff initiates an inspection, audit, or examination of a public utility, the public utility that is the subject of the inspection, audit, or examination may petition the commission to terminate or limit the scope of such inspection, audit, or examination. The commission must grant such petition if it finds that such inspection, audit, or examination is arbitrary, capricious, unnecessary, unduly burdensome, or unrelated to the public utility's regulated operations.

(1) If such an inspection, audit, or examination is not part of a contested case proceeding, the public utility may also raise objections or seek relief available under the South Carolina Rules of Civil Procedure to a party upon whom discovery is served or to a person upon whom a subpoena is served. The commission shall provide the regulatory staff reasonable notice to respond to any such objection or request. Absent the consent of the public utility raising such an objection or request and the Office of Regulatory Staff, the commission must rule on such an objection or request within sixty days of the date it was filed. During the pendency of the commission's ruling, the public utility making such an objection or request is not required to produce or provide access to any documents or information that is the subject of the objection or request.

(2) If such an inspection, audit, or examination is part of a contested case proceeding, the commission shall address objections to information sought by the regulatory staff in the same manner in which it addresses objections to discovery issued by the parties to the contested case proceeding.

(C) Any public utility that provides the regulatory staff with copies of or access to documents or information in the course of an inspection, audit, or examination that is not part of a contested case proceeding may designate any such documents or information as confidential or proprietary if it believes in good faith that such documents or information would be entitled to protection from public disclosure under the South Carolina Rules of Civil Procedure or any provision of South Carolina or federal law. The regulatory staff may petition the commission for an order that some or all of the documents so designated are not entitled to protection from public disclosure and it shall be incumbent on the utility to prove that such documents are entitled to protection from public disclosure under the South Carolina Rules of Civil Procedure or any provision of South Carolina or federal law. The commission shall rule on such petition after providing the regulatory staff and the utility an opportunity to be heard. Unless the commission's order on such a petition contains a finding to the contrary, all documents or information designated as confidential or proprietary pursuant to this subsection are exempt from public disclosure under Sections 30-4-10, et seq. and the regulatory staff shall not disclose such documents and information, or the contents thereof, to any member of the commission or to any other person or entity; provided, however, that, if the commission determines that it is necessary to view such documents or information in order to rule on such a petition, it shall order the regulatory staff to file the documents or information with the commission under seal, and such documents or information shall not be available for public inspection during the pendency of the petition.

(D) Nothing in this section restricts the regulatory staff's ability to serve discovery in a contested case proceeding that seeks the type of documents or information the regulatory staff has obtained in the course of any review, investigation, inspection, audit, or examination, nor does anything in this section restrict the ability of any public utility to object to such discovery or to seek relief regarding such discovery, including without limitation the entry of a protective order.

SECTION 58-4-60. Expenses to be borne by regulated utilities; assessment and collection.

(A) The Office of Regulatory Staff must be staffed and equipped to perform the functions described in Section 58-4-50. The expenses of the office must be paid as set forth in Section 58-3-100 and this section. The executive director, within established budgetary limits and as allowed by law, must authorize and approve travel, subsistence, and related necessary expenses of the executive director or regulatory staff incurred while traveling on official business.

(B) The expenses of the Transportation Department of the Office of Regulatory Staff, with the exception of the expenses incurred in its railway jurisdiction, must be borne by the revenues from license fees derived pursuant to Sections 58-23-530 through 58-23-630, and assessments to the carriers of household goods and hazardous waste for disposal carriers. The expenses of the railway section of the Office of Regulatory Staff must be borne by the railroad companies subject to the commission's jurisdiction according to their gross income from operations in this State.

All other expenses of the Office of Regulatory Staff must be borne by the public utilities subject to the jurisdiction of the commission. On or before the first day of July in each year, the Department of Revenue must assess each public utility, railway company, household goods carrier, and hazardous waste for disposal carrier its proportion of the expenses in proportion to its gross income from operation in this State in the year ending on the thirtieth day of June preceding that on which the assessment is made which is due and payable on or before July fifteenth. The assessments must be charged against the companies by the Department of Revenue and collected by the department in the manner provided by law for the collection of taxes from the companies including the enforcement and collection provisions of Article 1, Chapter 54 of Title 12 and paid, less the Department of Revenue actual incremental increase in the cost of administration into the state treasury as other taxes collected by the Department of Revenue for the State.

(C) The Office of Regulatory Staff must certify to the Department of Revenue annually on or before May first the amounts to be assessed; however, the deadline shall not apply to the certification made to the Department of Revenue in 2004.

(D) The Office of Regulatory Staff shall operate as an other-funded agency.

(E) The appropriation for the Office of Regulatory Staff shall be advanced by the State until such time as funds have been collected from the corporations liable therefor and, when collected, must be placed in the state treasury.

SECTION 58-4-80. Actions for judicial review of commission orders; intervention.

The executive director representing the regulatory staff is considered to have an interest sufficient to maintain actions for judicial review from commission orders or decisions and may, as of right and in a manner prescribed by law, intervene or otherwise participate in any civil proceeding which involves the review or enforcement of commission action that the executive director determines may substantially affect the public interest. This right includes intervention in any action for judicial review from commission orders or decisions that are pending at any stage of the action. The executive director representing the regulatory staff has the same rights of appeal from commission orders or decisions as other parties to commission proceedings.

SECTION 58-4-90. Discretion of executive director as to initiation of actions.

Except as required by Section 58-4-50, decisions relating to whether, when, or how to initiate, continue, participate, or intervene in proceedings pursuant to Section 58-4-50 are in the sole discretion of the executive director, except as modified by order of a court of competent jurisdiction.

SECTION 58-4-100. Employment of expert witnesses.; compensation.

To the extent necessary to carry out regulatory staff responsibilities, the executive director is authorized to employ expert witnesses and other professional expertise as the executive director may consider necessary to assist the regulatory staff in its participation in commission proceedings. The compensation paid to these persons may not exceed compensation generally paid by the regulated industry for such specialists. The compensation and expenses therefor must be paid by the public utility or utilities participating in the proceedings upon agreement between the public utility or utilities participating in the proceedings and the Office of Regulatory Staff or upon approval by the Review Committee or from the regulatory staff's budget. If paid by the public utility or utilities, the compensation and expenses must be treated by the commission, for ratemaking purposes, in a manner generally consistent with its treatment of similar expenditures incurred by utilities in the presentation of their cases before the commission. An accounting of compensation and expenses must be reported annually to the review committee, the Speaker of the House of Representatives, and the Chairman of the Senate Judiciary Committee.

SECTION 58-4-110. Annual reports.

The regulatory staff must make and publish annual reports to the General Assembly on its activities in the interest of the using and consuming public.

SECTION 58-4-120. Promulgation of rules governing internal administration and operations.

Rules governing the internal administration and operations of the Office of the Regulatory Staff must be promulgated by the office and subject to review by the General Assembly as are rules of procedure promulgated by the Supreme Court under Article V of the Constitution. After submission to the House of Representatives, the Speaker shall refer the rules to the Labor, Commerce and Industry Committee. After submission to the Senate, the President shall refer the rules to the Judiciary Committee.

SECTION 58-4-130. Restriction on outside employment of executive director.

The executive director must not interview or seek employment with a public utility while serving as executive director. The executive director may not represent or appear on behalf of a public utility in any proceeding before the commission in any matter within the commission's jurisdiction for one year after serving as executive director. A person who violates this provision is guilty of a misdemeanor and, upon conviction, must be fined not more than five thousand dollars or be imprisoned for not more than one year, or both.

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South Carolina Code of Laws
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Current through the end of the 2006 Regular Session

Title 58 - Public Utilities, Services and Carriers

CHAPTER 33.

UTILITY FACILITY SITING AND ENVIRONMENTAL PROTECTION

ARTICLE 1.

SHORT TITLE; DEFINITIONS

SECTION 58-33-10. Short title.

This chapter shall be known, and may be cited, as the "Utility Facility Siting and Environmental Protection Act".

SECTION 58-33-20. Definitions.

The following words, when used in this chapter, has the following meanings, unless otherwise clearly apparent from the context:

(1) The term "commission" means Public Service Commission.

(2) The term "major utility facility" means:

(a) electric generating plant and associated facilities designed for, or capable of, operation at a capacity of more than seventy-five megawatts.

(b) an electric transmission line and associated facilities of a designed operating voltage of one hundred twenty-five kilovolts or more; provided, however, that the words "major utility facility" shall not include electric distribution lines and associated facilities, nor shall the words "major utility facility" include electric transmission lines and associated facilities leased to and operated by (or which upon completion of construction are to be leased to and operated by) the South Carolina Public Service Authority.

(3) The term "commence to construct" means any clearing of land, excavation, or other action that would adversely affect the natural environment of the site or route of a major utility facility, but does not include surveying or changes needed for temporary use of sites or routes for nonutility purposes, or uses in securing geological data, including necessary borings to ascertain foundation conditions.

(4) The term "municipality" means any county or municipality within this State.

(5) The term "person" includes any individual, group, firm, partnership, corporation, cooperative, association, government subdivision, government agency, local government, municipality, any other organization, or any combination of any of the foregoing, but shall not include the South Carolina Public Service Authority.

(6) The term "public utility" or " utility" means any person engaged in the generating, distributing, sale, delivery, or furnishing of electricity for public use.

(7) The term "land" means any real estate or any estate or interest therein, including water and riparian rights, regardless of the use to which it is devoted.

(8) The term "certificate" means a certificate of environmental compatibility and public convenience and necessity.

(9) The term "regulatory staff" means the executive director or the executive director and the employees of the Office of Regulatory Staff.

ARTICLE 3.

CERTIFICATION OF MAJOR UTILITY FACILITIES

SECTION 58-33-110. Certificate required before construction of major utility facility; transfer and amendment of certificate; exceptions; emergency certificates.

(1) No person shall commence to construct a major utility facility without first having obtained a certificate issued with respect to such facility by the Commission. The replacement of an existing facility with a like facility, as determined by the Commission, shall not constitute construction of a major utility facility. Any facility, with respect to which a certificate is required, shall be constructed, operated and maintained in conformity with the certificate and any terms, conditions and modifications contained therein. A certificate may only be issued pursuant to this chapter; provided, however, any authorization relating to a major utility facility granted under other laws administered by the Commission shall constitute a certificate if the requirements of this chapter have been complied with in the proceeding leading to the granting of such authorization.

(2) A certificate may be transferred, subject to the approval of the Commission, to a person who agrees to comply with the terms, conditions and modifications contained therein.

(3) A certificate may be amended.

(4) This chapter shall not apply to any major utility facility:

(a) The construction of which is commenced within one year after January 1, 1972; or

(b) For which, prior to January 1, 1972, an application for the approval has been made to any Federal, State, regional or local governmental agency which possesses the jurisdiction to consider the matters prescribed for finding and determination in subsection (1) of Section 58-33-160.

(c) For which, prior to January 1, 1972, a governmental agency has approved the construction of the facility and indebtedness has been incurred to finance all or part of the cost of such construction; or

(d) Which is a hydroelectric generating facility over which the Federal Power Commission has licensing jurisdiction.

(5) Any person intending to construct a major utility facility excluded from this chapter pursuant to subsection (4) of this section may elect to waive the exclusion by delivering notice of the waiver to the Commission. This chapter shall thereafter apply to each major utility facility identified in the notice from the date of its receipt by the Commission.

(6) The Commission shall have authority to waive the normal notice and hearing requirements of this chapter and to issue a certificate on an emergency basis if it finds that immediate construction of a major utility facility is justified by public convenience and necessity; provided, that the Public Service Commission shall notify all parties concerned under Section 58-33-140 prior to the issuance of such certificate; provided, further, that the Commission may subsequently require a modification of the facility if, after giving due consideration to the major utility facility, available technology and the economics involved, it finds such modification necessary in order to minimize the environmental impact.

(7) The Commission shall have authority, where justified by public convenience and necessity, to grant permission to a person who has made application for a certificate under Section 58-33-120 to proceed with initial clearing, excavation, dredging and construction; provided, however, that in engaging in such clearing, excavation, dredging or construction, the person shall proceed at his own risk, and such permission shall not in any way indicate approval by the Commission of the proposed site or facility.

SECTION 58-33-120. Application for certificate; service on and notice to municipalities, government agencies and other persons of application.

(1) An applicant for a certificate shall file an application with the commission, in such form as the commission may prescribe. The application must contain the following information:

(a) a description of the location and of the major utility facility to be built;

(b) a summary of any studies which have been made by or for applicant of the environmental impact of the facility;

(c) a statement explaining the need for the facility; and

(d) any other information as the applicant may consider relevant or as the commission may by regulation or order require. A copy of the study referred to in item (b) above shall be filed with the commission, if ordered, and shall be available for public information.

(2) Each application shall be accompanied by proof of service of a copy of the application on the Office of Regulatory Staff, the chief executive officer of each municipality, and the head of each state and local government agency, charged with the duty of protecting the environment or of planning land use, in the area in the county in which any portion of the facility is to be located. The copy of the application shall be accompanied by a notice specifying the date on or about which the application is to be filed.

(3) Each application also must be accompanied by proof that public notice was given to persons residing in the municipalities entitled to receive notice under subsection (2) of this section, by the publication of a summary of the application, and the date on or about which it is to be filed, in newspapers of general circulation as will serve substantially to inform such persons of the application.

(4) Inadvertent failure of service on, or notice to, any of the municipalities, government agencies, or persons identified in subsections (2) and (3) of this section may be cured pursuant to orders of the commission designed to afford them adequate notice to enable their effective participation in the proceeding. In addition, the commission may, after filing, require the applicant to serve notice of the application or copies thereof, or both, upon such other persons, and file proof thereof, as the commission may deem appropriate.

(5) An application for an amendment of a certificate shall be in such form and contain such information as the commission shall prescribe. Notice of the application shall be given as set forth in subsections (2) and (3) of this section.

SECTION 58-33-130. Hearings.

(1) Upon the receipt of an application complying with Section 58-33-120, the Commission shall promptly fix a date for

the commencement of a public hearing, not less than sixty nor more than ninety days after the receipt, and shall conclude the proceedings as expeditiously as practicable. The testimony presented at the hearing may be presented in writing or orally, provided that the Commission may make rules designed to exclude repetitive, redundant or irrelevant testimony.

(2) On an application for an amendment of a certificate, the Commission shall hold a hearing in the same manner as a hearing is held on an application for a certificate if the proposed change in the facility would result in any significant increase in any environmental impact of the facility or a substantial change in the location of all or a portion of the facility; provided, that the Public Service Commission shall forward a copy of the application to all parties upon the filing of an application.

SECTION 58-33-140. Parties to certification proceedings; limited appearances; intervention.

(1) The parties to a certification proceeding shall include:

(a) the applicant;

(b) the Office of Regulatory Staff, the Department of Health and Environmental Control, the Department of Natural Resources, and the Department of Parks, Recreation and Tourism;

(c) each municipality and government agency entitled to receive service of a copy of the application under subsection (2) of Section 58-33-120 if it has filed with the commission a notice of intervention as a party within thirty days after the date it was served with a copy of the application; and

(d) any person residing in a municipality entitled to receive service of a copy of the application under subsection (2) of Section 58-33-120, any domestic nonprofit organization, formed in whole or in part to promote conservation or natural beauty, to protect the environment, personal health, or other biological values, to preserve historical sites, to promote consumer interest, to represent commercial and industrial groups, or to promote the orderly development of the area in which the facility is to be located; or any other person, if such a person or organization has petitioned the commission for leave to intervene as a party, within thirty days after the date given in the published notice as the date for filing the application, and if the petition has been granted by the commission for good cause shown.

(2) Any person may make a limited appearance in the sixty days after the date given in the published notice as the date for filing the application. No person making a limited appearance shall be a party or shall have the right to present oral testimony or argument or cross-examine witnesses.

(3) The commission may, in extraordinary circumstances for good cause shown, and giving consideration to the need for timely start of construction of the facility, grant a petition for leave to intervene as a party to participate in subsequent phases of the proceeding, filed by a municipality, government agency, person, or organization which is identified in paragraphs (b) or (c) of subsection (1) of this section, but which failed to file a timely notice of intervention or petition for leave to intervene, as the case may be.

SECTION 58-33-150. Record of proceedings; consolidation of representation of parties.

A record shall be made of the hearing and of all testimony taken and the cross-examination thereon. Upon request of a party, either before or after the decision, a State agency which proposes to or does require a condition to be included in the certificate as provided for in Section 58-33-160 shall furnish for the record all factual findings, documents, studies, rules, regulations, standards, or other documentation, supporting the condition. The Commission may provide for the consolidation of the representation of parties having similar interests.

SECTION 58-33-160. Decision of Commission.

(1) The Commission shall render a decision upon the record either granting or denying the application as filed, or granting it upon such terms, conditions or modifications of the construction, operation or maintenance of the major utility facility as the Commission may deem appropriate; such conditions shall be as determined by the applicable State agency having jurisdiction or authority under statutes, rules, regulations or standards promulgated thereunder, and the conditions shall become a part of the certificate. The Commission may not grant a certificate for the construction, operation and maintenance of a major utility facility, either as proposed or as modified by the Commission, unless it shall find and determine:

(a) The basis of the need for the facility.

(b) The nature of the probable environmental impact.

(c) That the impact of the facility upon the environment is justified, considering the state of available technology and the nature and economics of the various alternatives and other pertinent considerations.

(d) That the facilities will serve the interests of system economy and reliability.

(e) That there is reasonable assurance that the proposed facility will conform to applicable State and local laws and regulations issued thereunder, including any allowable variance provisions therein, except that the Commission may refuse to apply any local law or local regulation if it finds that, as applied to the proposed facility, such law or regulation is unreasonably restrictive in view of the existing technology, or of factors of cost or economics or of the needs of consumers whether located inside or outside of the directly affected government subdivisions.

(f) That public convenience and necessity require the construction of the facility.

(2) If the Commission determines that the location of all or a part of the proposed facility should be modified, it may condition its certificate upon such modification, provided that the municipalities and persons residing therein affected by the modification shall have been given reasonable notice.

(3) A copy of the decision and any opinion shall be served by the Commission upon each party.

SECTION 58-33-170. Opinion of Commission.

In rendering a decision on an application for a certificate, the Commission shall issue an opinion stating its reasons for the action taken. If the Commission has found that any regional or local law or regulation, which would be otherwise applicable, is unreasonably restrictive pursuant to paragraph (e) of subsection (1) of Section 58-33-160, it shall state in its opinion the reasons therefor.

ARTICLE 5.

JUDICIAL REVIEW

SECTION 58-33-310. Appeal from final order or decision.

Any party may appeal, in accordance with Section 1-23-380, from all or any portion of any final order or decision of the commission, including conditions of the certificate required by a state agency under Section 58-33-160 as provided by Section 58-27-2310. Any appeals may be called up for trial out of their order by either party. The commission must not be a party to an appeal.

SECTION 58-33-320. Jurisdiction of courts.

Except as expressly set forth in Section 58-33-310, no court of this State shall have jurisdiction to hear or determine any issue, case, or controversy concerning any matter which was or could have been determined in a proceeding before the commission under this chapter or to stop or delay the construction, operation, or maintenance of a major utility facility, except to enforce compliance with this chapter or the provisions of a certificate issued hereunder, and any such action shall be brought only by the Office of Regulatory Staff. Provided, however, nothing herein contained shall be construed to abrogate or suspend the right of any individual or corporation not a party to maintain any action which he might otherwise have been entitled.

ARTICLE 7.

MISCELLANEOUS PROVISIONS

SECTION 58-33-410. Authority of other agencies or local governments; application of other laws.

Notwithstanding any other provision of law, no State or regional agency, or municipality or other local government may require any approval, consent, permit, certificate or other condition for the construction, operation or maintenance of a major utility facility authorized by a certificate issued pursuant to the provisions of this chapter; provided, that nothing herein shall prevent the application of State laws for the protection of employees engaged in the construction, operation or maintenance of such facility; provided, however, that State agencies shall continue to have authority to enforce compliance with applicable State statutes, rules, regulations or standards promulgated within their authority.

SECTION 58-33-420. Joint hearings with agencies from other states; agreements and compacts; joint investigations.

The commission, in the discharge of its duties under this chapter or any other statute, is authorized to hold joint hearings within or without the State and issue joint or concurrent orders in conjunction or concurrence with any official or agency of any other state of the United States, whether in the holding of any hearings, or in the making of such orders, the commission shall function under agreements or compacts between states or under the concurrent power of states to regulate interstate commerce or as an agency of the United States, or otherwise. The commission, in the discharge of its duties under this chapter, is authorized to enter into agreements or compacts with agencies of other states, pursuant to any consent of Congress, for cooperative efforts in certificating the construction, operation, and maintenance of major utility facilities in accord with the purposes of this chapter and for the enforcement of the respective state laws regarding same. The commission may request the Office of Regulatory Staff to make joint investigations with any official board or commission of any state or of the United States.

SECTION 58-33-430. Annual reports shall be furnished by public utilities.

Each public utility shall annually furnish a report to the commission and provide to the Office of Regulatory Staff for its review containing a ten-year forecast of loads and resources; provided, however, this section shall not apply to any electric cooperative. The report shall list the major utility facilities which, in the judgment of such utility, will be required to supply system demands during the forecast period. The forecast shall cover the ten-year period next succeeding the date of the report, shall be made available to the public, and furnished upon request to municipalities and government agencies charged with the duty of protecting the environment or of planning land use.

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Title 58 - Public Utilities, Services and Carriers

CHAPTER 31.

PUBLIC SERVICE AUTHORITY

ARTICLE 1.

GENERAL PROVISIONS

SECTION 58-31-10. Creation of South Carolina Public Service Authority; offices.

There is hereby created a body corporate and politic to be known as the South Carolina Public Service Authority (herein called the "Public Service Authority"), with a principal office in the town of Moncks Corner near the Santee-Cooper power dam and navigation locks in Berkeley County, and with such branch offices in the State of South Carolina as the directors may determine.

SECTION 58-31-20. Board of directors; advisory board.

(A) The Public Service Authority consists of a board of eleven directors who reside in South Carolina and who shall have the qualifications stated in this section, as determined by the State Regulation of Public Utilities Review Committee pursuant to Section 58-3-530(14), before being appointed by the Governor with the advice and consent of the Senate as follows: one from each congressional district of the State; one from each of the counties of Horry, Berkeley, and Georgetown who reside in authority territory and are customers of the authority; and two from the State at large, one of whom shall be chairman. Two of the directors shall have substantial work experience within the operations of electric cooperatives or substantial experience on an electric cooperative board, but must not serve as an employee or board member of an electric cooperative during their term as director. Each director shall serve for a term of seven years, except as provided in this section. At the expiration of the term of each director and of each succeeding director, the Governor must appoint with the advice and consent of the Senate a successor, who shall hold office for a term of seven years or until his successor has been appointed and qualified. In the event of a director vacancy due to death, resignation, or otherwise, the Governor must appoint the director's successor, with the advice and consent of the Senate, and the successor-director shall hold office for the unexpired term. No director shall receive a salary for services as director until the authority is in funds, but each director must be paid his actual expense in the performance of his duties hereunder, the actual expense to be advanced from the contingent fund of the Governor until such time as the Public Service Authority is in funds, at which time the contingent fund shall be reimbursed. After the Public Service Authority is in funds, the compensation and expenses of each member of the board shall be paid from such funds, and the compensation and expenses must be fixed by the advisory board hereinafter established. Members of the board of directors may be removed for cause, as established in Section 1-3-240(C), by the Governor of the State, the advisory board, or a majority thereof. No member of the General Assembly of the State of South Carolina shall be eligible for appointment as director of the Public Service Authority during the term of his office. No more than two members from the same county shall serve as directors at any time.

(B) Candidates for appointment to the board must be screened by the State Regulation of Public Utilities Review Committee and, prior to confirmation by the Senate, must be found qualified by meeting the minimum requirements contained in subsection (C). The review committee must submit a written report to the Clerk of the Senate setting forth its findings as to the qualifications of each candidate. A candidate must not serve on the board, even in an interim capacity, until he is screened and found qualified by the State Regulation of Public Utilities Review Committee.

(C) Each member must possess abilities and experience that are generally found among directors of energy utilities serving this State and that allow him to make valuable contributions to the conduct of the authority's business. These abilities include substantial business skills and experience, but are not limited to:

(1) general knowledge of the history, purpose, and operations of the Public Service Authority and the responsibilities of being a director of the authority;

(2) the ability to interpret legal and financial documents and information so as to further the activities and affairs of the Public Service Authority;

(3) with the assistance of counsel, the ability to understand and apply federal and state laws, rules, and regulations including, but not limited to, Chapter 4 of Title 30 as they relate to the activities and affairs of the Public Service Authority; and

(4) with the assistance of counsel, the ability to understand and apply judicial decisions as they relate to the activities and affairs of the Public Service Authority.

(D) For the assistance of the board of directors of the Public Service Authority, there is hereby established an advisory board to be known as the advisory board of the South Carolina Public Service Authority, to be composed of the Governor of the State, the Attorney General, the State Treasurer, the Comptroller General, and the Secretary of State, as ex officio members, who must serve without compensation other than necessary traveling expenses. The advisory board must perform any duties imposed on it pursuant to this chapter, and must consult and advise with the board of directors on any and all matters which by the board of directors may be referred to the advisory board. The board of directors must make annual reports to the advisory board, which reports must be submitted to the General Assembly by the Governor, in which full information as to all of the acts of said board of directors shall be given, together with financial statement and full information as to the work of the authority. On July first of each year, the advisory board must designate a certified public accountant or accountants, resident in the State, for the purpose of making a complete audit of the affairs of the authority, which must be filed with the annual report of the board of directors. The Public Service Authority must submit the audit to the General Assembly.

SECTION 58-31-30. Powers of Authority.

(A) The Public Service Authority has power to develop the Cooper River, the Santee River, and the Congaree River in this State, as instrumentalities of intrastate, interstate, and foreign commerce and navigation; to produce, distribute, and sell electric power; to acquire, treat, distribute, and sell water at wholesale; to reclaim and drain swampy and flooded lands; and to reforest the watersheds of rivers in this State; and also has all powers which may be necessary or convenient for the exercise of these powers including, without limiting the generality of the foregoing, the following powers:

(1) to have perpetual succession as a corporation;

(2) to sue and be sued;

(3) to adopt, use, and alter a corporate seal;

(4) to acquire, purchase, hold, use, lease, mortgage, sell, transfer, and dispose of any property, real, personal, or mixed, or any interest therein;

(5) to divert water from the Tail Race Canal by means of canals, flumes, or otherwise and to build, construct, maintain, and operate canals, dams, locks, aqueducts, reservoirs, draw-spans, ditches, drains, and roads, and to lay and construct any tunnels, penstocks, culverts, flumes, conduits, mains, and other pipes necessary or useful in connection therewith;

(6) to divert waters from the Santee River by means of a canal or canals, flume or flumes, or otherwise, and to construct and maintain a dam of any height or size for the purpose of impounding said waters and to discharge the same into the Cooper River, or otherwise;

(7) to build, acquire, construct, and maintain power houses and any and all structures, ways and means, necessary, useful or customarily used and employed in the manufacture, generation, and distribution of water power, steam electric power, hydroelectric power, and any and all other kinds of power, including power transmission lines, poles, telephone lines, substations, transformers, and generally all things used or useful in the manufacture, distribution, purchase, and sale of power generated by water, steam, or otherwise;

(8) to manufacture, produce, generate, transmit, distribute, and sell water power, steam electric power, hydroelectric power, or mechanical power within and without the State of South Carolina;

(9) to reclaim and drain swampy and flooded lands;

(10) to reforest the watersheds of the Cooper, Santee, and Congaree Rivers and to prevent soil erosion and floods;

(11) to make bylaws for the management and regulation of its affairs;

(12) to appoint officers, agents, employees, and servants, to prescribe their duties, and to fix their compensation;

(13) to fix, alter, charge, and collect tolls and other charges for the use of their facilities of, or for the services rendered by, or for any commodities furnished by, the Public Service Authority at rates to be determined by it, these rates to be at least sufficient to provide for payment of all expenses of the Public Service Authority, the conservation, maintenance, and operation of its facilities and properties, the payment of principal and interest on its notes, bonds, and other evidences of indebtedness or obligation, and to fulfill the terms and provisions of any agreements made with the purchasers or holders of any such notes, bonds, or other evidences of indebtedness or obligation;

(14) as necessary to borrow money, make and issue negotiable notes, bonds, and other evidences of indebtedness including refunding and advanced refunding notes, bonds, and other evidences of indebtedness, of the Public Service Authority; to secure the payment of these obligations or any part of them by mortgage, lien, pledge, or deed of trust, on all or any of its property, contracts, franchises, or revenues including the proceeds of the refunding and advanced refunding notes, bonds, and other evidences of indebtedness and the investments in which these proceeds are invested and the earning on and income from them; to invest its monies including without limitation its revenues and the proceeds of these notes, bonds, or other evidences of indebtedness, in obligations of, or obligations the principal of and interest on which are guaranteed by or are fully secured by contracts with, the United States of America, in obligations of any agency, instrumentality, or corporation which has been or may be created by or pursuant to an act of Congress of the United States as an agency, instrumentality, or corporation of them, in direct and general obligations of the State of South Carolina, and in certificates of deposit issued by any bank, trust company, or national banking association. The authority, when investing in certificates of deposit, shall invest in certificates of deposit issued by institutions authorized to do business in South Carolina if the institutions offer terms which, in the opinion of the authority, are equal to or better than those offered by other institutions; to make such agreements with the purchasers or holders of the notes, bonds, or other evidences of indebtedness, or with others in connection with any of these notes, bonds, or other evidences of indebtedness, whether issued or to be issued, as the Public Service Authority shall deem advisable; and in general to provide for the security for said notes, bonds, or other evidences of indebtedness and the rights of the holders of them; provided, that in the exercise of the powers in this section granted to issue advanced refunding notes, bonds, or other evidences of indebtedness, the Public Service Authority may, but is not required to, avail itself of or comply with any of the provisions of the Advanced Refunding Act, Sections 11-21-10 to 11-21-80;

(15) to endorse or otherwise guarantee the obligations of a corporation all of the voting stock of which the Public Service Authority may own or acquire;

(16) without limitation of the foregoing, to borrow money from the United States Government or any corporation or agency created, designed, or established by the United States;

(17) to make contracts of every name and nature and to sue and be sued thereon; to enter into agreements providing for binding arbitration between the parties thereto; and to execute all instruments necessary or convenient for the carrying on of its business;

(18) to have power of eminent domain;

(19) to mortgage, pledge, hypothecate, or otherwise encumber all or any of the property, real, personal, or mixed, or facilities, or revenues of the Public Service Authority as security for notes, bonds, evidences of indebtedness, or other obligations of the Public Service Authority;

(20) to do all acts and things necessary or convenient to carry out the powers granted to it by this chapter or any other law;

(21) to investigate, study, and consider all undeveloped power sites and navigation projects in the State and to acquire or develop the same as need may arise in the same manner as herein provided. Provided, always, nevertheless, that said investigations, studies, and considerations of said South Carolina Public Service Authority herein created shall be limited to the Congaree River and its tributaries below the confluence of the Broad and Saluda Rivers and the Wateree tributary of the Santee River at and near a point at or near Camden, South Carolina. Provided, however, that the Public Service Authority shall have no power at any time or in any manner to pledge the credit and the taxing power of the State or any of its political subdivisions, nor shall any of its obligations or securities be deemed to be obligations of the State or of any of its political subdivisions; nor shall the State be legally, equitably, or morally liable for the payment of principal of and interest on such obligations or securities. The State of South Carolina does hereby pledge to and agree with any person, firm, or corporation, the government of the United States and any corporation or agency created, designated, or established by the United States, subscribing to or acquiring the notes, bonds, evidences of indebtedness, or other obligations to be issued by the Public Service Authority for the construction of any project, that the State will not alter or limit the rights hereby vested in the Public Service Authority until the said notes, bonds, evidences of indebtedness, or other obligations, together with the interest thereon, are fully met and discharged; provided, that nothing herein contained shall preclude such limitation or alteration if and when and after adequate provisions shall be made by law for the protection of those subscribing to or acquiring such notes, bonds, evidences of indebtedness, or other obligations of the Public Service Authority. The State of South Carolina or any political subdivision shall in no way be responsible for any debts or obligations contracted by or for the authority, and the board of directors of the authority, the advisory board, and the officers shall make no debt whatsoever for the payment of which the State or any political subdivision shall in any way be bound. It is intended that the project to be developed hereunder and any and all projects undertaken by the provisions of this chapter shall be financed as self-liquidating projects and that the credit and taxing powers of the State, or its political subdivisions, shall never be pledged to pay said debts and obligations;

(22) to acquire or purchase, if requested to do so, or to construct, operate, and maintain all structures and facilities necessary, useful, or customarily used and employed in the treatment and distribution of water for industrial, commercial, domestic, or agricultural purposes within the counties of Berkeley, Calhoun, Charleston, Clarendon, Colleton, Dorchester, Orangeburg, and Sumter. The provisions of this section do not apply to the acquisition or purchase of existing electric systems;

(23) to acquire, treat, transmit, distribute, and sell water at wholesale within the counties of Berkeley, Calhoun, Charleston, Clarendon, Colleton, Dorchester, Orangeburg, and Sumter if requested in writing to do so by the governing body of any incorporated municipality, by the governing body of any special purpose district providing water service in the unincorporated areas of each county, or by the governing body of each county for those unincorporated areas not so provided water service by a special purpose district. The authority may not transfer water from one river basin to another except for those located in the counties specified in this item. However, the authority shall prepare and maintain its books and records for its water supply operations separate and apart from its books and records for the generation, transmission, and distribution of electric power. The costs of water supply operations, including the loss of the generation of hydroelectric power, may not affect rates and charges for electric service. Water must be offered for sale by the authority on a nondiscriminatory basis without regard to whether electricity is also purchased from the authority.

Without limiting the generality of the foregoing, the Public Service Authority shall have power and is authorized as necessary to issue its negotiable bonds and to secure the payment of the same by mortgage, lien, pledge, or deed of trust on or of all or any of its property, contracts, franchises, or revenues. These bonds must be authorized by resolution of the board of directors and bear the date or dates, be in the forms, and contain the provisions as the board of directors may determine. Any resolution or resolutions authorizing any notes, bonds, or other evidences of indebtedness may contain provisions, which must be a part of the contract with the holders of them, as to (a) the rates of tolls and other charges for use of the facilities of, or for the services rendered by, or for the commodities furnished by the Public Service Authority, (b) the setting aside of reserves or sinking funds and the regulation and disposition of them, (c) reserving the right to redeem the notes, bonds, or other evidences of indebtedness at such prices, not exceeding one hundred five per cent of the principal amount of them and accrued interest, as may be provided, (d) limitations on the issuance of additional bonds, (e) the terms and provisions of any mortgage or deed of trust securing the bonds or under which the same may be issued, and (f) any other or additional agreements with the holders of the notes, bonds, or other evidences of indebtedness.

The Public Service Authority may enter into any mortgages, deeds of trust, or other agreements with any bank or trust company or other person or persons in the United States having power to enter into the same, including the United States Government or any agency or creature thereof, as security for the notes, bonds, or other evidences of indebtedness and may transfer, convey, mortgage, or pledge all or any of the property, contracts, franchises, or revenues of the Public Service Authority thereunder. Such mortgage, deed of trust, or other agreement may contain provisions as may be customary in the instruments or as the Public Service Authority may authorize including, but without limitation, provisions as to (a) the construction, operation, maintenance, and repair of the properties or facilities of the Public Service Authority, (b) the application of funds and the safeguarding of funds on hand or on deposit, (c) the rights and remedies of the trustee and the holders of the bonds, (d) possession of the mortgaged properties, and (e) the terms and provisions of the bonds, and also may provide for a franchise for operation of the property and business of the Public Service Authority, or any part thereof, to any person, firm, or corporation, including the United States Government, or any agency thereof, acquiring the mortgaged property or any part thereof upon foreclosure for a period of not to exceed twenty years from the date of the acquisition.

(B) The powers conferred by subsection (A) upon the board of directors may not be construed to give the board of directors the power to sell, lease, or dispose of, except by way of mortgage or deed of trust, all of the property, real, personal, or mixed, of the authority, but the board of directors may sell, lease, or dispose of any surplus property which it may acquire and which the board of directors deems not to be necessary for the purpose of the development. Without prior approval from the General Assembly by act, the authority must not sell, transfer, lease, dispose of, or convey any property, real, personal, or mixed, of the authority used in the generation, transmission, or distribution of electricity, beyond that property considered to be surplus. However, the authority may lease property owned by the authority, including property within the authority's Federal Energy Regulatory Commission Project boundaries, provided the lease does not substantially or materially impair its ability to meet electricity generation, transmission, and distribution needs of its ongoing operation including an adequate reserve capacity and such growth in needs as reasonably may be forecasted. Further, the lease must be in the best interests of the authority as defined in Section 58-31-55(A)(3).

Without prior approval from the General Assembly by act, the authority must not inquire into the feasibility of the sale, transfer, lease, disposal, or conveyance of property, real, personal, or mixed, of the authority that is used in the generation, transmission, or distribution of electricity unless the sale, transfer, lease, disposition, or conveyance would not materially impair the authority's ability to meet generation, transmission, and distribution needs of its ongoing operation including an adequate reserve capacity and such growth in needs as reasonably may be forecasted.

SECTION 58-31-40. Remedies upon default of obligations; appointment of receiver.

Any resolution authorizing any notes, bonds or other evidences of indebtedness, and any mortgage or trust indenture or other agreement entered into pursuant thereto, may, whether or not any such obligations are or are to be secured by mortgage, provide that in the event that (a) default shall be made in the payment of the interest on any or all such obligations when and as the same shall become due and payable, (b) default shall be made in the payment of the principal of any or all such obligations when and as the same shall become due and payable, whether at the maturity thereof, by call for redemption or otherwise or (c) default shall be made in the performance of any agreement made with the purchasers or successive holders of any such obligations, and such default shall have continued for such period, if any, as may be prescribed by said resolution or said mortgage, trust indenture or other agreement in respect thereof, the trustees under such mortgage, trust indenture or other agreement entered into in respect of the obligations authorized thereby (or, if there shall be no such mortgage, trust indenture or other agreement, or trustee thereunder, a trustee appointed in the manner provided in such resolution or resolutions by the holders of not less than twenty-five per centum in aggregate principal amount of the obligations authorized thereby and at the time outstanding) may, and upon the written request of the holders of twenty-five per centum in aggregate principal amount of the obligations authorized by such resolution or resolutions at the time outstanding, shall, in his or its own name, but for the equal and proportionate benefit of the holders of all of such obligations, and with or without having possession thereof:

(1) By mandamus or other suit, action or proceeding at law or in equity, enforce all rights of the holders of such obligations;

(2) Bring suit upon such obligations, the coupons appurtenant thereto, or both;

(3) By action or suit in equity, require the Authority to account as if it were the trustee of an express trust for the holders of such obligations;

(4) By action or suit in equity, enjoin any acts or things which may be unlawful or in violation of the rights of the holders of such obligations;

(5) After such notice to the Authority as such resolution may provide, declare the principal of all such obligations due and payable, and if all defaults shall have been made good, then with the written consent of the holder or holders of twenty-five per centum in aggregate principal amount of such obligations at the time outstanding, annul such declaration and its consequences;

Provided, however, that the holders of a majority in principal amount of such obligations at the time outstanding shall, by instrument or instruments in writing delivered to such trustee, have the right to direct and control any and all action taken or to be taken by such trustee under this section.

Any such resolution, mortgage, indenture or agreement may likewise provide that in any such suit, action or proceeding, any such trustee, whether or not all of such obligations have been declared due and payable, and with or without possession of any thereof, shall be entitled as of right to the appointment of a receiver who may enter upon and take possession of all or any part of the properties of the Authority and operate and maintain the same, and fix, collect and receive rates, tolls, and charges sufficient to provide revenues to pay the items specified in clause 13 of Section 58-31-30 hereof and all costs and disbursements of such suit, action or proceeding, such revenues to be applied in conformity with the provisions of this chapter and the resolution or resolutions authorizing such obligations, or the mortgage, indenture or other agreement pursuant to which the same shall have been issued. In any suit, action or proceeding by any such trustee, the reasonable fees, counsel fees and expenses of such trustee and of the receiver or receivers, if any, shall constitute taxable disbursements, and all costs and disbursements allowed by the court shall be a first charge upon any revenues pledged to secure the payment of such obligations. The circuit court of the county of Richland, and the circuit court of any other county wherein is located the principal office or any branch office of the Authority or wherein any of its property or facilities may be located, or any of such courts, shall have jurisdiction of any such suit, action or proceeding by any such trustee, and of all property involved therein. In addition to the powers hereinafter specifically provided for, each such trustee shall have and possess all powers necessary or appropriate for the exercise of any thereof, or necessary or appropriate for the general representation of the holders of such obligations in the enforcement of their right or rights.

None of the remedies provided for in this section shall be deemed to be exclusive, and any one or more than one or all thereof shall be available in connection with any default and with any subsequent default.

SECTION 58-31-50. Right to and procedure for acquisition of property by Authority.

The Public Service Authority may acquire by purchase, gift, condemnation, or in any other manner, any lands, waters, water rights, riparian rights, flowage rights, easements, licenses, franchises, engineering data, construction plans, or estimates prepared for the development of the Cooper River and Santee River or any other real or personal property necessary or useful in carrying out any of its purposes or exercising any of its powers; but before the board of directors may acquire and pay for, without condemnation any plans, specifications, franchises, or any kind of property, belonging to or to belong to any private corporation previously chartered by this State or any other state for the purpose of developing the Santee-Cooper project, a full report of the proposed purchase must be submitted in writing to the advisory board, which shall order a public hearing on the proposed purchase and due notice of the hearing must be given by advertisement to be published in at least three daily papers published in the State twice each week for two consecutive weeks. The advisory board shall carefully investigate the proposed purchase, and shall file its report in writing with the Secretary of State and the board of directors of the Public Service Authority. If the report recommends a price for the proposed purchase, the board of directors may enter into a contract for the purchase; if the report disapproves the proposed purchase, the board of directors may submit any amended proposed agreement, which must be heard by the advisory board in the same manner, or shall proceed with condemnation; the price to be paid to any private corporation for any of its property is subject to the approval of the original purchaser of the first notes, bonds, or other evidence of indebtedness issued under this chapter. The Public Service Authority shall have the right of eminent domain to carry out the purposes of this chapter.

SECTION 58-31-55. Standards for director's discharge of duties; immunity.

(A) A director shall discharge his duties as a director, including his duties as a member of a committee:

(1) in good faith;

(2) with the care an ordinarily prudent person in a like position would exercise under similar circumstances; and

(3) in a manner he reasonably believes to be in the best interests of the Public Service Authority. As used in this chapter, "best interests" means a balancing of the following:

(a) preservation of the financial integrity of the Public Service Authority and its ongoing operation of generating, transmitting, and distributing electricity to wholesale and retail customers on a reliable, adequate, efficient, and safe basis, at just and reasonable rates, regardless of the class of customer;

(b) economic development and job attraction and retention within the Public Service Authority's present service area or areas within the State authorized to be served by an electric cooperative or municipally owned electric utility that is a direct or indirect wholesale customer of the authority; and

(c) subject to the limitations of Section 58-31-30(B) and item (3)(a) of this section, exercise of the powers of the authority set forth in Section 58-31-30 in accordance with good business practices and the requirements of applicable licenses, laws, and regulations.

(B) In discharging his duties, a director is entitled to rely on information, opinions, reports, or statements, including financial statements and other financial data, if prepared or presented by:

(1) one or more officers or employees of the Public Service Authority whom the director reasonably believes to be reliable and competent in the matters presented;

(2) legal counsel, public accountants, or other persons as to matters the director reasonably believes are within the person's professional or expert competence; or

(3) a committee of the board of directors of which he is not a member if the director reasonably believes the committee merits confidence.

(C) A director is not acting in good faith if he has knowledge concerning the matter in question that makes reliance otherwise permitted by subsection (B) unwarranted.

(D) A director is not liable for any action taken as a director, or any failure to take any action, if he performed the duties of his office in compliance with this section.

(E) An action against a director for failure to perform the duties imposed by this section must be commenced within three years after the cause of action has occurred, or within two years after the time when the cause of action is discovered or should reasonably have been discovered, whichever occurs sooner. This limitations period does not apply to breaches of duty which have been concealed fraudulently.

SECTION 58-31-56. Conflict of interest transactions.

(A) A conflict of interest transaction is a transaction with the Public Service Authority in which a director of the Public Service Authority has a direct or indirect interest. A conflict of interest transaction is not voidable by the Public Service Authority solely because of the director's interest in the transaction if any one of the following is true:

(1) the material facts of the transaction and the director's interest were disclosed or known to the board of directors or a committee of the board of directors, and the board of directors or a committee authorized, approved, or ratified the transaction; or

(2) the transaction was fair to the Public Service Authority and its customers.

If item (1) has been accomplished, the burden of proving unfairness of any transaction covered by this section is on the party claiming unfairness. If item (1) has not been accomplished, the party seeking to uphold the transaction has the burden of proving fairness.

(B) For purposes of this section, a director of the Public Service Authority has an indirect interest in a transaction if:

(1) another entity in which he has a material financial interest or in which he is a general partner is a party to the transaction; or

(2) another entity of which he is a director, officer, or trustee is a party to the transaction and the transaction is or should be considered by the board of directors of the Public Service Authority.

(C) For purposes of subsection (A)(1), a conflict of interest transaction is authorized, approved, or ratified if it receives the affirmative vote of a majority of the directors on the board of directors (or on the committee) who have no direct or indirect interest in the transaction, but a transaction may not be authorized, approved, or ratified under this section by a single director. If a majority of the directors who have no direct or indirect interest in the transaction vote to authorize, approve, or ratify the transaction, a quorum is present for the purpose of taking action under this section. The presence of, or a vote cast by, a director with a direct or indirect interest in the transaction does not affect the validity of any action taken under subsection (A)(1) if the transaction is otherwise authorized, approved, or ratified as provided in that subsection.

SECTION 58-31-57. Suits for breach of duty.

Wholesale and retail customers of the Public Service Authority and electric cooperatives that are indirect customers of the Public Service Authority may bring suit against Public Service Authority directors asserting a breach of any duty arising under Sections 58-31-55 and 58-31-56. If it is proved that a director violated the provisions of Section 58-31-55 or Section 58-31-56, he is subject to liability under the same theories of liability as for a breach of duty by a corporate director pursuant to Title 33 and South Carolina common law. Liability under this section shall be limited to disgorgement of any ill-gotten gain and damages of not more than fifty thousand dollars per occurrence and reasonable attorney's fees and costs. If the customer prevails, the court may also grant appropriate equitable relief and may award reasonable attorney's fees and costs. Any remedy granted or damages awarded pursuant to this section do not relieve a director from criminal liability or preclude criminal prosecution.

SECTION 58-31-60. Duties and powers of board of directors.

The powers of the Public Service Authority shall be exercised by the board of directors, with the exception of such duties as this chapter shall impose upon the advisory board. A majority of the members of the board of directors shall constitute a quorum of the board for the purpose of organizing the Public Service Authority and conducting the business thereof and for all other purposes and all action may be taken by vote of a majority of directors present unless in any case the bylaws shall require a larger number. The board of directors shall have full authority to manage the property and business of the Public Service Authority, and to prescribe, amend and repeal bylaws, rules and regulations governing the manner in which the general business of the Public Service Authority may be conducted and the powers granted to it may be exercised and embodied. The board of directors shall fix and determine the number of officers, agents, employees and servants of the Public Service Authority and their respective compensation and duties, and may delegate to one or more of their number, or to one or more of such officers, agents, employees or servants, such powers and duties as it may deem proper. Each director shall give bond for the faithful performance of his duties as such director in the penal sum of at least ten thousand dollars, the premium for the first bonds to be paid by the Governor from his contingent fund to be reimbursed when the Authority is in funds, and all subsequent premiums to be paid from funds of the Authority. The board of directors shall require similar bonds in such amounts as they may determine from any or all officers, agents and employees in position of responsibility or trust. The position of director of the Public Service Authority is not a public office, and the State shall in no wise be responsible for the acts of the directors, but each director and his surety and the Public Service Authority shall be responsible for all acts of the director in connection with the functions herein provided for.

Forthwith upon the appointment and organization of the Public Service Authority it shall proceed with the improvement and development of the Cooper River, the Santee River, the Congaree River and their tributaries upstream to the confluence of the Broad and Saluda Rivers and upstream on the Wateree River to a point at or near Camden for the aid and benefit of commerce and navigation, flood control and drainage, and for the development of the hydroelectric power inherent therein. The Authority shall investigate other power and navigation projects in the State and shall have power to acquire or develop desirable ones as early as practicable.

SECTION 58-31-70. Use of facilities and operation of business of Authority.

The use of the facilities of the Public Service Authority and the operation of its business shall be subject to the rules and regulations from time to time adopted by the Public Service Authority; provided, however, that the Public Service Authority shall not be authorized to do anything which will impair the security of the holders of the notes, bonds or other evidences of indebtedness of the Public Service Authority or violate any agreement with them or for their benefit.

SECTION 58-31-80. Purpose of Authority; exemption from taxation; Authority shall make certain payments in lieu of taxes.

The Public Service Authority is created primarily for the purpose of developing the Cooper River, the Santee River, the Congaree River, and their tributaries upstream to the confluence of the Broad and Saluda Rivers and upstream on the Wateree River to a point at or near Camden and other similar projects as instrumentalities of intrastate, interstate, and foreign commerce and navigation; of reclaiming wastelands by the elimination or control of flood waters, reforesting the watersheds of the rivers and improving public health conditions in those areas. It is found that the project authorized by this chapter is for the aid of intrastate, interstate, and foreign commerce and navigation, and that the aid and improvement of intrastate, interstate, and foreign commerce and navigation, the development, sale, and distribution of hydroelectric power, and the treatment, sale, and distribution of water at wholesale are in all respects for the benefit of all the people of the State, for the improvement of their health and welfare and material prosperity, and are public purposes, and being a corporation owned completely by the people of the State, the Public Service Authority is required to pay no taxes or assessments upon any of the property acquired by it for this project or upon its activities in the operation and maintenance of the project, except as provided in this section. The securities and other obligations issued by the Public Service Authority, their transfer and the income from them at all times are free from taxation. However, unless otherwise provided in any contract with an agency of the United States Government as assists in financing the projects contemplated in this section or any other agency from which the funds may be secured, all electrical energy developed by the authority must be sold at rates in the determination of which the taxes which the project would pay if privately owned, to the extent provided in this section, as well as other rate-making factors properly entering into the manufacture and distribution of the energy must be considered. After payment of necessary operating expenses and all annual debt requirements on bonds, notes, or other obligations at any time outstanding and the discharge of all annual obligations arising under finance agreements with the United States or any agency or corporation of the United States and indentures or other instruments under which bonds have been, or may be issued, the authority shall pay annually to the various counties of the State a sum of money equivalent to the amount paid for taxes on properties at the time of their acquisition by the authority, acquired, or to be acquired, in the counties, and the authority shall pay to all municipalities and school districts in the counties in which the authority has acquired, or may acquire properties, a sum of money equivalent to the amount paid for taxes to the school districts and municipalities on the properties at the time of their acquisition by the authority; and no other taxes may be considered in the fixing of the rates of the authority. From the funds to be paid under this section the counties, school districts, and municipalities annually shall apply a sum sufficient for the debt requirements for bonds and other obligations of the counties, school districts, and municipalities for which the properties were taxed at the time of their acquisition by the authority, with the remainder of the funds to be expended in accordance with law.

SECTION 58-31-90. Payments in lieu of taxes to certain counties and school districts.

Beginning with the tax year 1965, after the payment of all necessary operating expenses and all annual debt requirements on bonds, notes or other obligations at any time outstanding and the discharge of all obligations arising under finance agreements and indentures or other instruments under which bonds or obligations have been or may be issued, and after payment into the general fund of the State the sum of at least two hundred twenty-five thousand dollars annually, the South Carolina Public Service Authority shall pay annually to the counties of Orangeburg, Calhoun, Sumter, Clarendon, Berkeley, Horry and Georgetown and school districts therein additional sums of money in lieu of taxes on lands acquired prior to the year 1950 for reservoirs, lakes, canals, structures and adjoining properties of the Santee-Cooper Hydroelectric and Navigation Project in amounts equivalent to that paid in 1964 for sums in lieu of taxes on such lands to the counties and school districts therein. Provided, that all additional sums to be paid under this section shall be used for the support of the public schools within the counties and districts involved.

SECTION 58-31-100. Payment of additional sums in lieu of taxes.

Beginning with the fiscal year 1974-75 and in each fiscal year thereafter, after payment of the sums in lieu of taxes provided for by Sections 58-31-80 and 58-31-90, the Public Service Authority shall make the following additional payments in lieu of taxes:

(1) To any county in which it holds legal title to lands developed for commercial or residential purposes, a sum equal to ten percent of the annual rentals received from the lease of those lands during the fiscal year.

(2) To the counties in which it owns, or leases and operates, electric generating facilities, a sum equal to fifteen percent of the amount paid in the fiscal year into the General Fund of the State, which sum shall be allocated among the counties concerned in the proportion which the generating capacity of the Public Service Authority located and in operation in each such county bears to the total of the Public Service Authority's generating capacity located and in operation in all such counties.

(3) To the counties of Berkeley, Horry and Georgetown, a sum equal to ten percent of the amount paid during the fiscal

year into the General Fund of the State, which sum shall be allocated among those counties in the proportion which the kilowatt hour sales, excluding sales for resale, made by the Public Service Authority in each such county bears to the total of the kilowatt hour sales, excluding sales for resale, made by the Public Service Authority in all such counties.

SECTION 58-31-110. Net earnings; disposition and use thereof.

The South Carolina Public Service Authority is a corporation, completely owned by and to be operated for the benefit of the people of this State. Any and all net earnings of the Public Service Authority not necessary for the prudent conduct and operation of its business in the best interests of the Public Service Authority as defined by Section 58-31-55(A)(3) or to pay the principal of and interest on its bonds, notes, or other evidences of indebtedness or other obligations, or to fulfill the terms and provisions of any agreements made with the purchasers or holders thereof or others must be paid over semiannually to the State Treasurer for the general funds of the State and must be used to reduce the tax burdens on the people of this State. Nothing in this section shall prohibit the authority from paying to the State each year up to one percent of its projected operating revenues, as such revenues would be determined on an accrual basis, from the combined electric and water systems.

SECTION 58-31-120. Authority shall use labor and materials from this State.

As far as may be practicable and not in conflict with any statute of the United States or the rules or regulations of any agency thereof which may assist in financing any project undertaken pursuant to this chapter, the Public Service Authority shall use and give preference to South Carolina workmen and South Carolina materials. As far as may be practicable, and not to conflict with any rules of the United States Government or any agency thereof which may assist in financing the development herein proposed, the Public Service Authority shall use South Carolina materials and shall make purchases within the State where possible. As far as may be practicable, the labor to be employed on the development herein provided for shall be resident South Carolina workmen, and the same shall be allocated to each county in the State ratably, as the need for employment may exist, and, as far as may be practicable, as reflected by the rolls of the unemployed in the various public employment offices in each county in South Carolina.

SECTION 58-31-130. Credit and taxing power of the State and its subdivisions shall not be involved; liability for payment of securities.

Nothing contained in the provisions of this chapter shall, at any time or in any manner, involve the credit and taxing power of the State, or of any of its political subdivisions; nor shall any of the securities or other evidences of indebtedness authorized to be issued in and by this chapter ever be or constitute obligations of the State or of any of its political subdivisions; nor shall the State or any of its political subdivisions ever be liable or responsible, in any way, for the payment of the principal or interest of or on such security or other evidences of indebtedness.

SECTION 58-31-140. State and its subdivisions shall never levy taxes or appropriate funds for project.

It is hereby declared that the State and any of its political subdivisions shall never levy any tax to pay any obligations incurred in building this project or make any appropriation to carry on the work of developing the Santee-Cooper power project.

SECTION 58-31-150. Amendments or repeal of chapter; effect.

The right to alter, amend, or repeal this chapter is hereby expressly reserved and disclosed, but no such amendment or repeal shall operate to impair the obligation of any contract made by said corporation under any power conferred by this chapter.

SECTION 58-31-160. Authority may construct Santee-Cooper project.

The Public Service Authority may construct the Santee-Cooper hydroelectric and navigation project as outlined and described in the license issued by the Federal Power Commission to Columbia Railway and Navigation Company for the construction of project No. S. C. 199, dated April 2, 1926 and amended February 14, 1927, May 31, 1933 and May 13, 1937, and on license drawings prepared and filed with said Commission at the time of the issuance of said license and said amendments and thereafter as required by the terms and provisions of said license and the amendatory plans and drawings filed or to be filed by the Public Service Authority with said Commission and approved or to be approved by said Commission or as outlined and described in any new license or licenses that the Authority may obtain from said Commission under the terms of this chapter.

SECTION 58-31-170. Designation of Lake Moultrie and Lake Marion.

One of the lakes belonging to the State, constructed by the South Carolina Public Service Authority on the Cooper River near Pinopolis, in Berkeley County, shall hereafter be known as Lake Moultrie, and the other lake belonging to the State, constructed by the Authority on the Cooper River in the same area, shall be known as Lake Marion.

SECTION 58-31-180. Diversion of water from Sampit River, Penney Royal Creek and their tributaries for use in operation of generating plant.

(1) The South Carolina Public Service Authority is hereby authorized to divert water from the Sampit River, Penney Royal Creek and their tributaries for use in connection with the operation of an electric generating plant to be constructed in Georgetown County between the Sampit River, Penney Royal Creek and Winyah Bay and to discharge such water, or so much thereof as is not consumed, into Winyah Bay. Such diversion shall not exceed two thousand cubic feet of water per second each day, and may be accomplished by canals, conduits, ditches, pipes or other proper structures.

(2) Nothing contained in this section shall be construed to waive the public law or regulations of the State of South Carolina as to pollution control.

(3) This section shall not affect the right of any person to recover, in a court of competent jurisdiction, damages sustained as a result of the diversion of water permitted by this section.

SECTION 58-31-190. Diversion of water from Santee River and its tributaries for use in operation of generating plant.

The South Carolina Public Service Authority is hereby authorized to divert water from the Santee River, and its tributaries for use in connection with the operation of an electric generating plant to be constructed in Georgetown County between the Sampit River, Penney Royal Creek and Winyah Bay and to discharge such water, or so much thereof as is not consumed into Turkey Creek, and thereto Penney Royal Creek and thereto into Sampit River. Such diversion shall not exceed one hundred cubic feet of water per second each day, and shall be accomplished by pipes or other underground structures. Such diversion shall not in any manner reduce the water level or flow rate of the Santee River and its tributaries.

Nothing contained in this section shall be construed to waive the public law or regulations of the State of South Carolina as to pollution control.

This section shall not affect the right of any person to recover, in a court of competent jurisdiction, damages sustained as a result of the diversion of water permitted by this section.

SECTION 58-31-200. Joint ownership of nuclear electric generating station in Fairfield County.

The South Carolina Public Service Authority shall have the power to become a joint owner with one or more privately owned electric utilities in existing or future nuclear electric generation units, and related transmission facilities, to be constructed on a site at or near Parr Shoals in Fairfield County and specifically the power to plan, finance, acquire, own, operate, and maintain joint ownership interest in such plants and facilities necessary or incidental to the generation and transmission of electric power generated at the plant, and to make such plans and enter into such contracts or other agreements as are necessary or convenient for the planning, financing, acquisition, construction, ownership, operation, and maintenance of the plant and facilities; provided, however, that the Public Service Authority's joint ownership interest shall be equal to the percentage of the money furnished or the value of property supplied by it for the acquisition and construction of the plant and facilities and the Public Service Authority shall own and control a like percentage of the electrical output thereof; provided, further, that the Public Service Authority shall be severally liable, in proportion to its joint ownership interest in the plant and facilities, for the acts, omissions, or obligations performed, omitted, or incurred by the operator or other owners of the plant while acting as the designated agent of the Public Service Authority for purposes of constructing, operating, or maintaining the plant and facilities or any of them, but shall not otherwise be liable, jointly or severally, for the acts, omissions, or obligations of the operator or other owners of the plant; nor shall any money or property of the Public Service Authority be credited or otherwise applied to the account of the operator or other owners of the plant, or be charged with any debt, lien, or mortgage as a result of any debt or obligation of the operator or other owners of the plant.

SECTION 58-31-210. Public Service Authority empowered to enter joint ownership of electric generation and transmission facilities with Central Electric Power Cooperative.

The South Carolina Public Service Authority shall have the power to become a joint owner with Central Electric Power Cooperative, Inc., of electric generation and transmission facilities, the power to plan, finance, acquire, own, operate and maintain an undivided interest in such plants and facilities necessary or incidental to the generation and transmission of electric power and the power to make plans and enter into such contracts as are necessary or convenient for the planning, financing, acquisition, construction, ownership, operation and maintenance of such plants and facilities; provided, however, that the Public Service Authority shall own a percentage of such plants and facilities equal to the percentage of the money furnished or the value of property supplied by it for the acquisition and construction of the plants and facilities and shall own and control a like percentage of the electrical output thereof; provided, further, that the Public Service Authority shall be severally liable in proportion to its ownership share of such plants and facilities for the acts, omissions or obligations performed, omitted or incurred by Central Electric Power Cooperative, Inc., while acting as the designated agent of the Public Service Authority for purposes of constructing, operating or maintaining the plants and facilities or any of them, but shall not otherwise be liable, jointly or severally, for the acts, omissions or obligations of Central Electric Power Cooperative, Inc.; nor shall any money or property of the Public Service Authority be credited or otherwise applied to the account of Central Electric Power Cooperative, Inc., or be charged with any debt, lien or mortgage as a result of any debt or obligation of Central Electric Power Cooperative, Inc. Nothing in this section shall be construed to prevent the Public Service Authority from leasing facilities or interests therein from Central Electric Power Cooperative, Inc., and incurring obligations under such leases.

SECTION 58-31-220. Authorization for Public Service Authority to adopt calendar year as its fiscal year.

The Public Service Authority may adopt the calendar year as its fiscal year, but the adoption does not affect payments made by the Authority to the general fund of the State.

ARTICLE 3.

PROVIDING ELECTRIC SERVICE

SECTION 58-31-310. Definitions.

The following words and phrases as used in this article, unless a different meaning is plainly required by the context, shall have the following meanings:

(1) The term "electrical utility" includes persons and corporations, their lessees, assignees, trustees, receivers or other successors in interest owning or operating in this State equipment or facilities for generating, transmitting, delivering or furnishing electricity for street, railway or other public uses or for production of light, heat or power to or for the public for compensation; but it shall not include an electric cooperative or municipality and shall not include a person, corporation furnishing electricity only to himself or itself, their residents, employees or tenants when such electricity is not resold or used by others.

(2) The term "present service area" means the area or areas hereinafter described, within which the Public Service Authority shall have the right to furnish electrical service to the exclusion of other electrical utilities.

(3) The term "premises" means the building, structure or facility including any expansions or additions thereto, to which electricity is being or is to be furnished; provided, that two or more buildings, structures or facilities which are located on one tract or contiguous tracts of land and are utilized by one electric consumer for farming, business, commercial, industrial, institutional or governmental purposes, shall together constitute one "premises" regardless of whether they are separately metered and the charges for such service are calculated independently of charges for service to any other building, structure or facility.

Premises are considered as being served by the Public Service Authority if on July 9, 1973 a contract between the electric consumer and the Public Service Authority has been signed, or any of the facilities for electric service belonging to the Public Service Authority are attached to such premises.

(4) The term "line" means any electric conductors operating at a nominal voltage level of 25 KV or less, measured phase-to-phase, except (a) in the case of overhead construction, conductors from the pole or tower nearest the premises of a consumer to the premises, or conductors from a line tap to the premises, and (b) in the case of underground construction, conductors from the transformer (or junction point, if there is one) nearest, on or in the premises of the consumer to the premises. The term "line" includes any electric conductor operating at a nominal voltage level in excess of 25 KV when it is agreed between the Public Service Authority and an affected electric cooperative serving in the county where the conductor is located that the primary purpose and use of the conductor on January 1, 1984, was for the distribution of electric power and not for the transmission of bulk power from one area to another.

SECTION 58-31-320. Customers to whom Authority shall provide electric service.

After July 9, 1973, the Public Service Authority shall have the right to provide electric service only to, and it shall have the right to serve:

(1) Central Electric Power Cooperative, Inc., including:

(a) all electric cooperatives that are members of Central Electric Power Cooperative, Inc., on July 9, 1973;

(b) any electric cooperative which after July 9, 1973, becomes a member of Central Electric Power Cooperative, Inc.;

(c) any electric cooperative which after July 9, 1973, ceases to be a member of Central Electric Power Cooperative, Inc.; and

(d) in the event Central Electric Power Cooperative, Inc., ceases to exist as a corporate entity, any electric cooperative which was a member of Central Electric Power Cooperative, Inc., at the time of its dissolution;

(2) all premises, customers, and electric cooperatives served by it on July 9, 1973;

(3) its present service area as defined in Section 58-31-330;

(4) those areas owned, leased, or controlled by the Public Service Authority adjacent to the lakes and waterways of Federal Power Commission Project No. 199.

If, after July 9, 1973, any customers, premises, or electric cooperatives located outside the present service area of the Public Service Authority as defined in Section 58-31-330 and being served by the Public Service Authority, including any subsequent expansions or additions by such customers, premises, or cooperatives, ceases or discontinues accepting electrical service from the Public Service Authority, the Public Service Authority may subsequently sell and furnish electrical service to new customers, premises, or electric cooperatives from its major transmission lines in an amount not exceeding the amount of power the sale of which was lost by reason of such discontinuation of service.

Nothing contained herein shall be construed to restrict the right of the Public Service Authority to furnish electric service to its own premises; to exchange or interchange electric service with, purchase electric energy from, or sell electric energy to any other electrical utility or any joint agency organized and operating pursuant to Chapter 23 of Title 6; to construct additional facilities, within or without its present service area, as defined in Section 58-31-330; to construct additional delivery points to or for any of the premises or customers it is authorized to serve as provided for in this section; or to fulfill the growth needs of any customer legally served by it.

SECTION 58-31-330. Service area of authority.

Except as set forth in this article, the present service area of the Public Service Authority consists of the counties of Berkeley, Georgetown, and Horry; but the following described areas are not included in the Public Service Authority's present service area as defined herein:

(1) That portion of Berkeley County now being served by South Carolina Electric and Gas Company as indicated by crosshatching on Authority Drawing No. E-1851, entitled "Map of Berkeley County Showing Crosshatched Area being served by S.C.E. & G." and that portion of Berkeley County served by Berkeley Electric Cooperative, Inc., as the service area of Berkeley Electric Cooperative, Inc., is shown on Authority Drawing No. 5032-E08-0047A entitled "Map of Berkeley County showing Designated Areas Served by South Carolina Public Service Authority and Berkeley Electric Cooperative".

(2) That portion of Georgetown County now being served by Carolina Power and Light Company as indicated by crosshatching on Authority Drawing No. E-1850, entitled "Map of Georgetown County Showing Crosshatched Area being served by C. P. & L. Co." and that portion of Georgetown County served by Santee Electric Cooperative, Inc., as the service area of Santee Electric Cooperative, Inc., is shown on Authority Drawing No. 5032-E08-0046 entitled "Map of Georgetown County Showing Designated Areas Served by South Carolina Public Service Authority and Santee Electric Cooperative, Inc.".

(3) That portion of Horry County now being served by Carolina Power and Light Company as indicated by crosshatching on Authority Drawing No. E-1849, entitled "Map of Horry County Showing Crosshatched Area being served by C. P. & L. Co." and that portion of Horry County served by Horry Electric Cooperative, Inc., as the service area of Horry Electric Cooperative, Inc., is shown on Authority Drawing No. 5032-E08-0048 entitled "Map of Horry County Showing Designated Areas Served by South Carolina Public Service Authority and Horry Electric Cooperative, Inc.".

The above described drawings, and all explanatory notes, symbols, and legends thereon, as approved by the general manager of the Public Service Authority or his designee and the president of the electrical utility or electric cooperative involved or his designee, are made a part of this article by reference, and must be filed, safeguarded, and maintained as provided in Section 58-31-340.

SECTION 58-31-340. Filing and correcting drawings; acquisition of facilities outside service area.

Each of the drawings referred to in Section 58-31-330 must be filed in the place provided by law for recording the real estate records of the county concerned, and a certified copy of each drawing must be filed in the office of the Secretary of State. Certified copies of the drawing must be kept available for examination by the public in the principal office of the Public Service Authority, and must be furnished to the electrical utility or electric cooperative concerned.

Inaccuracies in the drawings discovered after certification and filing must be corrected by preparing revised drawings and approving and filing the revised drawings in the same manner as provided for original drawings.

Nothing contained in Sections 58-31-310 through 58-31-370 may be construed to prevent the Public Service Authority from acquiring, by purchase, the electric facilities, or any part of them, owned by another electrical utility and located in any of the crosshatched areas described in Section 58-31-330. The areas served by facilities purchased by the Public Service Authority shall become a part of the present service area of the Public Service Authority and must be evidenced by revised drawings approved and filed as provided in this section.

SECTION 58-31-350. Acquisition of facilities within service area.

Distribution facilities belonging to another electrical utility which, after July 9, 1973, are located in the present service area of the Public Service Authority as defined in Section 58-31-330, shall be acquired by the Public Service Authority within two years of July 9, 1973 and upon payment to the electrical utility concerned of just compensation therefor. Pending the acquisition of such facilities by the Public Service Authority, electrical service shall continue to be furnished by the electrical utility owning the facilities.

For the purposes of this section, "just compensation" shall consist of the total of the following:

(a) Reproduction cost, new, of the facilities being acquired, less depreciation on a straight line basis;

(b) Cost of reintegrating the system of the selling electrical utility after detaching the portion to be sold including allowance for idle substation capacity caused in the remaining portion of the system.

Just compensation shall otherwise be determined as provided in Section 58-27-1360.

SECTION 58-31-360. State covenant with holders of obligations of Authority.

In order to protect those subscribing to, purchasing or acquiring the notes, bonds, evidences of indebtedness or other obligations of the Public Service Authority, the State of South Carolina does hereby covenant and agree with any person, firm or corporation, the government of the United States of America, and any corporation or agency created, designated or established by the United States, subscribing to, purchasing or acquiring the notes, bonds, evidences of indebtedness or other obligations heretofore or hereafter issued or incurred by the Public Service Authority for any authorized purpose, that the State will not alter, limit or restrict the power of the Public Service Authority to, and the Authority shall, fix, establish, maintain and collect rents, tolls, rates and charges for the use of the facilities of or for the services rendered or for any commodities furnished by the Public Service Authority, at least sufficient to provide for payment of all expenses of the Public Service Authority, the conservation, maintenance and operation of its facilities and properties and the payment of the principal of and interest on its notes, bonds, evidences of indebtedness or other obligations, and to fulfill the terms and provisions of any agreements made with the purchasers or holders of any such notes, bonds, evidences of indebtedness or obligations heretofore or hereafter issued or incurred. Provided, however, that prior to putting into effect any increase in rates the Public Service Authority shall give at least sixty days' notice of such increase to all customers who will be affected by the increase.

SECTION 58-31-370. Jurisdiction of circuit court.

The circuit court of this State shall have exclusive jurisdiction to hear and determine any dispute arising under Sections 58-31-310 through 58-31-360.

SECTION 58-31-380. Annual report of Authority as to rates.

The Public Service Authority shall annually report to the Office of Regulatory Staff in the same manner as electric cooperatives as to the rates charged by it.

SECTION 58-31-390. Authority not to service new premises assigned to electric cooperative; exception.

Except as provided in Section 58-31-320(1), the Public Service Authority shall serve no new premises within the territory assigned by the Public Service Commission to any electric cooperative.

SECTION 58-31-400. Submission of annual budget.

The Public Service Authority shall submit its annual budget to the House Ways and Means Committee to be printed as a regular part of the General Appropriation Act. The annual budget is submitted for information purposes only.

SECTION 58-31-420. Laws applicable to electric service within municipal limits not repealed or modified.

The authority granted in this article shall not repeal or modify other laws applicable to electric service within municipal corporate limits, and any provisions of this article inconsistent with other laws are not applicable within the municipal limits.

SECTION 58-31-430. Service area to be exclusively served by Authority; reservations; agreements between suppliers.

The Public Service Commission may not assign any portion of the present service area of the Public Service Authority to any electrical utility or electric cooperative and this service area must be exclusively served by the Public Service Authority. Santee Electric Cooperative, Inc., Berkeley Electric Cooperative, Inc., and Horry Electric Cooperative, Inc. may serve those areas reserved to them as provided in Section 58-31-330. The Public Service Commission is directed to conform the present assignment under Section 58-27-620 to the mandates of this article. Nothing contained in this article may be construed as preventing the Public Service Commission from exercising its jurisdiction over electric cooperative service areas in the manner provided by law. Upon customer choice either the Public Service Authority or an electric cooperative mentioned above may furnish electric service to any new premises which the other supplier has the right to serve pursuant to the provisions of this article, upon agreement of the affected suppliers.

SECTION 58-31-440. Maintenance of existing lines; customer choice in certain circumstances.

Lines of the Public Service Authority in existence on July 1, 1984, which extend into the service areas of Berkeley Electric Cooperative, Santee Electric Cooperative, and Horry Electric Cooperative, and lines of those cooperatives which extend into the service area of the Public Service Authority may continue to be operated and maintained by the owner of the lines, and premises served by the lines on July 1, 1984, must continue to be so served. The owner of a line in another supplier's service area may exclusively serve any new premises located wholly or partially within three hundred feet of the line. Where the premises are located wholly or partially within three hundred feet of a line of both the Public Service Authority and an electric Cooperative, the customer may choose between those suppliers, and the supplier originally chosen shall continue to have the exclusive right to serve such premises.

SECTION 58-31-450. Erosion control.

The Public Service Authority shall provide proper vegetation or other method of erosion control on any existing or future rights-of-way.

ARTICLE 5.

TERMINATION OF ELECTRIC SERVICE DUE TO NONPAYMENT

SECTION 58-31-510. Definitions.

For purposes of this article:

(1) "Licensed health care provider" means a licensed medical doctor, physician's assistant, nurse practitioner, or advanced-practice registered nurse.

(2) "Special needs account customer" means the account of a residential customer where the customer can furnish to the Public Service Authority a certificate on a form provided by the Public Service Authority and signed by a licensed

health care provider that states that termination of electric service would be dangerous to the health of the customer or a member of his household at the premises to which electric service is rendered.

SECTION 58-31-520. Termination procedures; contents.

(A) The Public Service Authority must establish written procedures for termination of service due to nonpayment for a special needs account customer at any time and for all residential customers during weather conditions marked by extremely cold or hot temperatures. The Public Service Authority must submit its procedures to the Office of Regulatory Staff by November 1, 2006. Any subsequent revisions must be submitted semiannually by March first or September first.

(B) The procedures for termination must include the following:

(1) notification procedures so that the customer is made aware of an impending termination and the time within which he must make arrangements for payment prior to termination;

(2) arrangements for a payment arrangement plan to enable a residential customer, who has a satisfactory payment history as determined by the Public Service Authority, to pay by installments where the customer is unable to pay the full amount due for electric service;

(3) a procedure to advise customers who are unable to pay the full amount due or who are not approved for a payment arrangement plan that they may contact local social service agencies to determine the availability of public or private assistance with the payment of electric bills;

(4) a schedule of termination that takes into account the availability of the acceptance of payment and the reconnection of service; and

(5) the standards for determining weather conditions marked by extremely cold or hot temperatures.

SECTION 58-31-530. Third-party notification program.

The Public Service Authority must consider establishing and maintaining a third-party notification program to allow a residential customer to designate a third party to be notified if the electric service is scheduled for termination.

SECTION 58-31-540. Disconnection when public safety emergency exists.

Notwithstanding another provision of this article, the Public Service Authority may disconnect a customer when it is determined that a public safety emergency exists.

SECTION 58-31-550. Private right of action; duty of care.

This article does not create a new private right of action or a new duty of care. This article does not diminish, increase, affect, or evidence any duty of care existing under the laws of this State prior to the effective date of this article.

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Title 58 - Public Utilities, Services and Carriers

CHAPTER 37.

ENERGY SUPPLY AND EFFICIENCY

SECTION 58-37-10. Definitions.

As used in this chapter unless the context clearly requires otherwise:

(1) "Demand-side activity" means a program conducted or proposed by a producer, supplier, or distributor of energy for the reduction or more efficient use of energy requirements of the producer's, supplier's, or distributor's customers, including, but not limited to, conservation and energy efficiency, load management, cogeneration, and renewable energy technologies.

(2) "Integrated resource plan" means a plan which contains the demand and energy forecast for at least a fifteen-year period, contains the supplier's or producer's program for meeting the requirements shown in its forecast in an economic and reliable manner, including both demand-side and supply-side options, with a brief description and summary cost-benefit analysis, if available, of each option which was considered, including those not selected, sets forth the supplier's or producer's assumptions and conclusions with respect to the effect of the plan on the cost and reliability of energy service, and describes the external environmental and economic consequences of the plan to the extent practicable. For electrical utilities subject to the jurisdiction of the South Carolina Public Service Commission, this definition must be interpreted in a manner consistent with the integrated resource planning process adopted by the commission. For electric cooperatives subject to the regulations of the Rural Electrification Administration, this definition must be interpreted in a manner consistent with any integrated resource planning process prescribed by Rural Electrification Administration regulations.

SECTION 58-37-20. Public Service Commission; adoption of procedures encouraging energy efficiency and conservation.

The South Carolina Public Service Commission may adopt procedures that encourage electrical utilities and public utilities providing gas services subject to the jurisdiction of the commission to invest in cost-effective energy efficient technologies and energy conservation programs. If adopted, these procedures must: provide incentives and cost recovery for energy suppliers and distributors who invest in energy supply and end-use technologies that are cost-effective, environmentally acceptable, and reduce energy consumption or demand; allow energy suppliers and distributors to recover costs and obtain a reasonable rate of return on their investment in qualified demand-side management programs sufficient to make these programs at least as financially attractive as construction of new generating facilities; require the Public Service Commission to establish rates and charges that ensure that the net income of an electrical or gas utility regulated by the commission after implementation of specific cost-effective energy conservation measures is at least as high as the net income would have been if the energy conservation measures had not been implemented. For purposes of this section only, the term "demand-side activity" means a program conducted by an electrical utility or public utility providing gas services for the reduction or more efficient use of energy requirements of the utility or its customers including, but not limited to, utility transmission and distribution system efficiency, customer conservation and efficiency, load management, cogeneration, and renewable energy technologies.

SECTION 58-37-30. Reports on demand-side activities of gas and electric utilities; forms.

(A) The South Carolina Public Service Commission must report annually to the General Assembly on available data regarding the past, on-going, and projected status of demand-side activities and purchase of power from qualifying facilities, as defined in the Public Utilities Regulatory Policies Act of 1978, by electrical utilities and public utilities providing gas services subject to the jurisdiction of the Public Service Commission.

(B) Electric cooperatives providing resale or retail services, municipally-owned electric utilities, and the South Carolina Public Service Authority shall report annually to the State Energy Office on available data regarding the past, on-going, and projected status of demand-side activities and purchase of power from qualifying facilities. For electric cooperatives, submission to the State Energy Office of a report on demand-side activities in a format complying with then current Rural Electrification Administration regulations constitutes compliance with this subsection. An electric cooperative providing resale services may submit a report in conjunction with and on behalf of any electric cooperative which purchases electric power and energy from it. The State Energy Office must compile and submit this information annually to the General Assembly.

(C) The State Energy Office may provide forms for the reports required by this section to the Public Service Commission and to electric cooperatives, municipally-owned electric utilities, and the South Carolina Public Service Authority. The office shall strive to minimize differing formats for reports, taking into account the reporting requirements of other state and federal agencies. For electrical utilities and public utilities providing gas services subject to the jurisdiction of the commission, the reporting form must be in a format acceptable to the commission.

SECTION 58-37-40. Integrated resource plans.

(A) Electrical utilities and the South Carolina Public Service Authority must prepare integrated resource plans. The South Carolina Public Service Authority and electrical utilities regulated by the Public Service Commission must submit their plans to the State Energy Office. The plan submitted by the South Carolina Public Service Authority must be developed in consultation with electric cooperatives and municipally-owned electric utilities purchasing power and energy from the authority and must include the effect of demand-side management activities of electric cooperatives and municipally-owned electric utilities which directly purchase power and energy from the authority or sell power and energy which the authority generates. All plans must be submitted every three years and must be updated on an annual basis. The first integrated resource plan of the South Carolina Public Service Authority must be submitted no later than June 30, 1993. An integrated resource plan may be patterned after the integrated resource planning process developed by the Public Service Commission. For electrical utilities subject to the jurisdiction of the commission, submission of their plans as required by the commission constitutes compliance with this section. Nothing in this subsection may be construed as requiring interstate natural gas companies whose rates and services are regulated only by the federal government or gas utilities subject to the jurisdiction of the South Carolina Public Service Commission to prepare and submit an integrated resource plan.

(B) Electric cooperatives and municipally-owned electric utilities must submit integrated resource plans to the State Energy Office whenever they are required by federal law to prepare these plans or if they plan to acquire, by purchase or construction, ownership of additional generating capacity greater than twelve megawatts per unit. An integrated resource plan must be submitted to the State Energy Office by an electric cooperative or municipally-owned electric utility twelve months before the acquisition, by purchase or construction, of additional generating capacity in excess of twelve megawatts per unit. For an electric cooperative, submission to the State Energy Office of its plan in a format complying with the then current Rural Electrification Administration regulations constitutes compliance with this section.

(C) The State Energy Office, to the extent practicable, shall evaluate and comment on external environmental and economic consequences of each integrated resource plan submitted and on the environmental and economic consequences for suppliers and distributors.

(D) The State Energy Office shall coordinate the preparation of an integrated resource plan for the State and shall coordinate with regional groups, including the Southern States Energy Board.

(E) The State Energy Office must not exercise any regulatory authority with regard to the requirements set forth in this chapter.

Section 81 Ref 15

ARW BLS
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fmood@sinklerboyd.com

October 3, 2001

S. C. PUBLIC SERVICE COMMISSION
OCT 0 3 2001
RECEIVED

S. C. PUBLIC SERVICE COMMISSION
RECEIVED
UTILITIES DEPARTMENT

VIA HAND-DELIVERY

Mr. Gary E. Walsh, Executive Director
Public Service Commission of South Carolina
Koger Executive Center, Saluda Building
101 Executive Center Drive
Columbia, South Carolina 29210

Re: Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity for Jasper County Generating Facility

Dear Mr. Walsh:

Enclosed please find an original and twenty-five (25) copies of the Application of South Carolina Electric & Gas Company for a Certificate of Environmental Compatibility and Public Convenience and Necessity in the above-referenced matter.

Additionally, please find an original and twenty-five (25) copies of Direct Testimony and exhibits of Neville O. Lorick, Joseph M. Lynch, Stephen M. Cunningham, and John W. Preston, Jr. being filed on behalf of South Carolina Electric & Gas Company.

Very truly yours,

Francis P. Mood

FPM:gpc
Enclosures
cc: All parties of record

CEG-211

Section 8.1 Ref/6

POWER FOR LIVING

For Immediate Release

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Eric Boomhower
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SCANA Reports Fourth Quarter and Full Year 2006 Financial Results, Affirms 2007 Earnings Guidance

Columbia, SC, February 9, 2007...SCANA Corporation (NYSE: SCG) today announced financial results for the fourth quarter and full year 2006 and affirmed its previous guidance for 2007 earnings.

FULL YEAR RESULTS

For the year ended December 31, 2006, SCANA reported earnings on a GAAP basis of $310 million, or $2.68 per share, compared to $320 million, or $2.81 per share, in 2005. Excluding certain items listed in the table below, GAAP-adjusted net earnings from operations for 2006 were $299 million, or $2.59 per share, compared to $316 million, or $2.78 per share, in 2005.

"There were several unfavorable factors that resulted in the decline in earnings," said Jimmy Addison, senior vice president and chief financial officer. "In our regulated electric operations, margins were impacted by milder weather, which reduced earnings by 11 cents per share, and by lower sales to industrial and wholesale customers. In addition, we incurred charges during 2006 totaling 8 cents per share - 2 cents per share in the third quarter and 6 cents per share in the fourth quarter – related to a settlement agreement with the Federal Energy Regulatory Commission (FERC) regarding the use of South Carolina Electric & Gas Company's electric transmission system by its power marketing division. Also, one of our non-regulated businesses, Primesouth, recorded reduced royalties related to the operation of a non-affiliated synthetic fuel production facility. Finally, earnings per share were negatively impacted by dilution resulting from the issuance of approximately 2 million new shares of common stock through the Company's stock plans during the year. Effective January 1, 2007, these plans were converted to open market purchase and we currently have no plans to issue any new equity during the next several years."

Addison noted that these adverse factors more than offset the favorable impact on earnings of 2.7 percent customer growth in the Company's regulated businesses, lower operation and interest expenses, improved earnings in the Company's non-regulated natural gas marketing business in Georgia, and a slightly higher margin on consolidated sales of natural gas, primarily reflecting general rate increases in the Company's regulated retail natural gas businesses in South Carolina and North Carolina.

"We are looking forward to delivering improved financial results in 2007 and beyond by continuing to focus on the cornerstones of our strategic plan - providing safe, reliable and efficient energy products and services to customers and a competitive long-term return on investment to shareholders," said Addison.

Total kilowatt-hour sales of electricity in 2006 declined 3.1 percent compared to 2005. Residential sales were down about 1 percent, with the impact of milder weather offsetting customer growth. Commercial sales increased 1.8 percent while industrial sales were down 6.0 percent for the year, primarily reflecting the closure of two large textile plants early in the year as well as reduced demand by several other customers. Wholesale, or off-system, sales were down 14 percent for the year, also reflecting the milder weather. At December 31, 2006, the Company was serving approximately 623,000 electric customers, a 2.1 percent increase compared to year-end 2005.

Driven by a 15 percent increase in sales to industrial customers and a 21 percent increase in transportation volumes, total dekatherm sales of natural gas were up 6.6 percent in 2006 compared to 2005. Sales to residential customers, however, declined 12 percent, primarily due to milder weather in the first and fourth quarters. The number of natural gas customers in the Company's three-state service area increased 2.1 percent to approximately 1.2 million at year-end 2006.

SCANA's reported earnings are prepared in accordance with Generally Accepted Accounting Principles (GAAP). SCANA's management believes that, in addition to reported earnings under GAAP, the GAAP-adjusted net earnings from operations provide a meaningful representation of the Company's fundamental earnings power and can aid in performing period-over-period financial analysis and comparison with peer group data. In management's opinion, GAAP-adjusted net earnings from operations is a useful indicator of the financial results of the Company's primary businesses. This measure is also a basis for management's provision of earnings guidance and growth projections, and it is used by management in making resource allocation and other budgetary and operational decisions. This non-GAAP performance measure is not intended to replace the GAAP measure of net earnings, but is offered as a supplement to it. A reconciliation of reported (GAAP) earnings per share to GAAP-adjusted net earnings per share from operations for the three months and twelve months ended December 31, 2006 and 2005 is provided in the following table:

	Quarter Ended December 31,		Year Ended December 31,	
	2006	2005	2006	2005
Reported (GAAP) Earnings per Share	$.57	$.65	$2.68	$2.81
Deduct:				
Gain on Sale of Telecommunications Investment	--	--	--	(.03)
Reduction of Accrual Related to Propane Litigation Settlement	--	--	(.04)	--
Cumulative Effect of Accounting Change, re: SFAS 123(R)	--	--	(.05)	--
GAAP-Adjusted Net Earnings per Share From Operations	$.57	$.65	$2.59	$2.78

FOURTH QUARTER RESULTS

SCANA's reported (GAAP) earnings in the fourth quarter of 2006 were $65 million, or 57 cents per share, compared to $75 million, or 65 cents per share for the same quarter in 2005.

"The 8 cents per share decline in fourth quarter earnings was due primarily to lower margins on sales of electricity and the charge related to the FERC settlement agreement, which more than offset the favorable impact of an improved natural gas sales margin, lower operation and interest expenses and customer growth," said Addison. "The decline in the electric margin primarily reflects weather that was 16 percent milder than the fourth quarter of last year as well as lower industrial and off-system sales. The higher natural gas sales margin was primarily attributable to rate increases at South Carolina Electric & Gas Company and PSNC Energy, partially offset by lower usage by residential customers due to the milder weather."

Total kilowatt-hour sales of electricity in the fourth quarter of 2006 were down 10 percent compared to the fourth quarter of 2005. Driven by the milder weather, sales to residential customers declined

6.1 percent. Commercial and industrial sales decreased 1.8 percent and 7.5 percent, respectively. Off-system sales of electricity during the fourth quarter were down nearly 43 percent, also reflecting the milder weather.

Total dekatherm sales of natural gas in the fourth quarter of 2006 were up 28 percent compared to the same quarter of 2005. Sales to residential and commercial customers were each down 9 percent, primarily reflecting the milder weather. However, those declines were more than offset by increased sales to industrial and wholesale customers and increased transportation volumes.

FINANCIAL RESULTS BY MAJOR LINES OF BUSINESS

South Carolina Electric & Gas Company

Reported earnings for 2006 at South Carolina Electric & Gas Company (SCE&G), SCANA's principal subsidiary, were $234 million, or $2.02 per share, compared to $256 million, or $2.25 per share, in 2005. For the fourth quarter of 2006, SCE&G had reported earnings of $40 million, or 34 cents per share, compared to $60 million, or 52 cents per share in the same quarter in 2005. The lower per share earnings in both periods were due primarily to lower electric margins, the charges related to the FERC settlement agreement, and share dilution.

PSNC Energy

PSNC Energy, the Company's North Carolina-based retail natural gas distribution subsidiary, reported 2006 earnings of $26 million, or 23 cents per share, unchanged compared to 2005. Reported earnings in the fourth quarter of 2006 were $13 million, or 12 cents per share, compared to $9 million, or 8 cents per share, in the fourth quarter of 2005. That improvement was due primarily to customer growth and a 2.6 percent increase in base rates that was effective November 1, 2006. At year end, PSNC Energy was serving approximately 442,000 customers, an increase of 3.8 percent over the last twelve months.

Carolina Gas Transmission

Effective November 1, 2006, SCANA's two natural gas transmission companies, SCG Pipeline and South Carolina Pipeline Corporation (SCPC), merged to form Carolina Gas Transmission Corporation (CGT). CGT's earnings, which reflect combined results for both SCG Pipeline and SCPC, totaled $15 million, or 13 cents per share, in 2006, compared to $12 million, or 11 cents per share, in 2005. That improvement was due to higher transportation revenues, partially offset by lower margins on competitive sales of natural gas to industrial customers. For the fourth quarter of 2006, CGT reported earnings of $2 million, or 2 cents per share, compared to $3 million, or 3 cents per share in the fourth quarter of 2005.

SCANA Energy – Georgia

SCANA Energy, the Company's retail natural gas marketing business in Georgia, reported 2006 earnings of $30 million, or 27 cents per share, compared to $24 million, or 21 cents per share, in 2005. Earnings in the fourth quarter of 2006 were $9 million, or 8 cents per share, compared to $4 million, or 3 cents per share in the fourth quarter of 2005. The improved earnings in both periods reflect lower operating and customer service expenses, which more than offset lower sales margins due primarily to milder weather. SCANA Energy was serving more than 450,000 customers at year-end 2006, maintaining its position as the second largest natural gas marketer in Georgia with about a 30 percent market share.

Corporate and Other Non-Regulated

Reported earnings in 2006 for SCANA's corporate and other non-regulated businesses, which include Primesouth, SCANA Communications, ServiceCare, SCANA Energy Marketing and the holding company, were $4 million, or 3 cents per share, compared to $1 million, or 1 cent per share, in 2005. Excluding from reported earnings in both periods the items described below, these companies recorded a GAAP-adjusted net loss from operations of $1 million, or 1 cent per share, in 2006, compared to a loss of $3 million, or 2 cents per share, in 2005. For the fourth quarter of 2006, these businesses reported combined earnings of $1 million, or 1 cent per share, compared to a reported loss of $1 million, or 1 cent per share, in the same quarter in 2005. Higher interest income contributed to the earnings improvement in both comparative periods.

EXPLANATION OF ITEMS INCLUDED IN REPORTED (GAAP) EARNINGS BUT EXCLUDED FROM GAAP-ADJUSTED NET EARNINGS FROM OPERATIONS

In the first quarter of 2006, the Company recorded an after-tax gain of $6 million, or 5 cents per share, reflecting the cumulative effect of a change in accounting for equity-based compensation resulting from the Company's adoption of SFAS No. 123(R). In the second quarter of 2006, the Company reduced a prior loss accrual by $5 million, or 4 cents per share, upon the favorable settlement of litigation associated with the 1999 sale of the Company's propane assets. In the second quarter of 2005, the Company recorded an after-tax gain of $4 million, or 3 cents per share, related to the monetization of the Company's telecommunications investments.

2007 EARNINGS OUTLOOK

The Company affirms its previous guidance that 2007 earnings will be in the range of $2.70 to $2.85 per share. This estimate assumes normal weather in the Company's electric and natural gas service areas and excludes any potential impact from changes in accounting principles and gains or losses from certain investing activities, litigation, and sales of assets. Other factors and risks that could impact future earnings are discussed in the Company's filings with the Securities and Exchange Commission and below under the Safe Harbor Statement. The Company continues to target a long-term average annual earnings growth rate of 4 to 6 percent.

CONFERENCE CALL NOTICE

SCANA will host its quarterly conference call for security analysts at 10:00 a.m. Eastern Time today. The call-in numbers for the conference call are 1-866-700-6067 (US/Canada) and 1-617-213-8834 (International). The event code is 79358478. Participants should call in 5 to 10 minutes prior to the scheduled start time. A replay of the conference call will be available approximately 2 hours after conclusion of the call through February 23, 2007. To access the telephone replay, call 1-888-286-8010 (US/Canada) or 1-617-801-6888 (International) and enter the event code 24249099.

All interested persons, including investors, media and the general public, may listen to a live web cast of the conference call at the Company's web site at www.scana.com. A copy of this press release and other presentation materials relating to projected capital expenditures and cash flow will be available on the web site. Participants should go to the web site at least 5 to 10 minutes prior to the call start time and follow the instructions. A replay of the web cast will also be available on the Company's web site approximately 2 hours after conclusion of the call through February 23, 2007.

PROFILE

SCANA Corporation, a Fortune 500 company headquartered in Columbia, SC, is an energy-based holding company principally engaged, through subsidiaries, in electric and natural gas utility operations and other energy-related businesses. Information about SCANA and its businesses is available on the Company's web site at www.scana.com.

SAFE HARBOR STATEMENT

Statements included in this press release which are not statements of historical fact are intended to be, and are hereby identified as, "forward-looking statements" for purposes of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Forward-looking statements include, but are not limited to, statements concerning key earnings drivers, customer growth, environmental regulations and expenditures, leverage ratio, projections for pension fund contributions, financing activities, access to sources of capital, impacts of the adoption of new accounting rules, estimated construction and other expenditures and factors affecting the availability of synthetic fuel tax credits. In some cases, forward-looking statements can be identified by terminology such as "may," "will," "could," "should," "expects," "plans," "anticipates," "believes," "estimates," "projects," "predicts," "potential" or "continue" or the negative of these terms or other similar terminology. Readers are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties, and that actual results could differ materially from those indicated by such forward-looking statements. Important factors that could cause actual results to differ materially from those indicated by such forward-looking statements include, but are not limited to, the following: (1) the information is of a preliminary nature and may be subject to further and/or continuing review and adjustment; (2) regulatory actions, particularly changes in rate regulation and environmental regulations; (3) current and future litigation; (4) changes in the economy, especially in areas served by subsidiaries of SCANA Corporation (SCANA, and together with its subsidiaries, the "Company"); (5) the impact of competition from other energy suppliers, including competition from alternate fuels in industrial interruptible markets; (6) growth opportunities for the Company's regulated and diversified subsidiaries; (7) the results of financing efforts; (8) changes in accounting principles and in the Company's accounting policies; (9) weather conditions, especially in areas served by the Company's subsidiaries; (10) payment by counterparties as and when due; (11) the availability of fuels such as coal, natural gas and enriched uranium used to produce electricity; the availability of purchased power and natural gas for distribution; the level and volatility of future market prices for such fuels and purchased power; and the ability to recover the costs for such fuels and purchased power; (12) performance of the Company's pension plan assets; (13) inflation; (14) compliance with regulations; and (15) the other risks and uncertainties described from time to time in the Company's periodic reports filed with the United States Securities and Exchange Commission. The Company disclaims any obligation to update any forward-looking statements.

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FINANCIAL AND OPERATING INFORMATION

Condensed Consolidated Statements of Income

(Millions, except per share amounts) (Unaudited)

	Quarter Ended December 31,		Year Ended December 31,	
Operating Revenues:	2006	2005	2006	2005
Electric	$433	$442	$1,877	$1,918
Gas-Regulated	343	532	1,257	1,405
Gas-Nonregulated	392	521	1,429	1,463
Total Operating Revenues	1,168	1,495	4,563	4,786
Operating Expenses:				
Fuel Used in Electric Generation	151	136	615	618
Purchased Power	8	10	28	46
Gas Purchased for Resale-Regulated	234	416	899	1,059
Gas Purchased for Resale - Nonregulated	357	499	1,314	1,340
Other Operation and Maintenance	160	172	619	632
Depreciation and Amortization (1)	81	87	333	510
Other Taxes	37	31	152	145
Total Operating Expenses (1)	1,028	1,351	3,960	4,350
Operating Income (1)	140	144	603	436
Other Income, Net (1)	9	10	52	57
Interest charges, Net	(51)	(52)	(209)	(212)
Income Tax (Expense) Benefit (1)	(26)	(22)	(119)	118
Losses from Equity Method Investments (1)	(5)	(3)	(16)	(72)
Preferred Stock Cash Dividends of SCE&G	(2)	(2)	(7)	(7)
Cumulative Effect of Accounting Change	-	-	6	-
Net Income (1)	$65	$75	$310	$ 320
Common Stock Data:				
Wgt. Avg. Common Shares Outstanding	116.5	114.5	115.8	113.8
Basic & Diluted Earnings Per Share	$.57	$.65	$2.68	$2.81

Note (1): In January 2005, the Public Service Commission of South Carolina approved an accounting methodology which allows the Company to recover the cost of the Lake Murray back-up dam project through the application of net synthetic fuel tax credits generated from its synthetic fuel partnerships. Under this methodology, beginning January 1, 2005, the Company recognized its accumulated synthetic fuel tax credits to offset an equal amount of accelerated depreciation on the dam project, net of partnership losses and income tax benefits. Recognition of accelerated depreciation related to the back-up dam costs will continue quarterly to the extent net synthetic fuel tax credits are available. While these entries result in a reduction in operating income, there is no impact on net income. The Company is allowed to record non-cash carrying costs on the un-recovered investment. The impact of these entries in the Consolidated Income Statement and Balance Sheet is shown in the tables below:

Income Statement Impact (millions) :

	Quarter Ended December 31, 2006	Quarter Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2005
Synthetic fuel tax credits recognized	$6	$11	$30	$179
Partnership losses recognized	(5)	(5)	(20)	(76)
Tax benefit of depreciation and partnership losses	4	7	18	111
Accelerated depreciation recognized	(5)	(13)	(28)	(214)
Impact to Net Income	$ 0	$ 0	$ 0	$ 0
Carrying costs recognized	$ 2	$ 3	$ 7	$ 11

Balance Sheet Impact (millions):

	December 31, 2006	December 31, 2005
Dam costs incurred, including Allowance for Funds Used During Construction and Carrying Costs	$ 311	$303
Accelerated depreciation recognized	(242)	(214)
Unrecovered Dam Costs	$ 69	$ 89

Condensed Consolidated Balance Sheets

(Millions) (Unaudited)

	December 31, 2006	December 31, 2005
ASSETS:		
Utility Plant, Net	$7,004	$6,744
Other Property and Investments	276	247
Current Assets	1,381	1,417
Regulatory Assets and Deferred Debits	1,158	1,121
Total Assets	$9,819	$9,529
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Common Equity	$2,846	$2,677
Preferred Stock	114	114
Long-term Debt, Net	3,067	2,948
Total Capitalization	6,027	5,739
Current Liabilities:		
Short-Term Borrowings	487	427
Current Portion of Long-Term Debt	43	188
Other Current Liabilities	857	885
Total Current Liabilities	1,387	1,500
Regulatory Liabilities and Deferred Credits	2,405	2,290
Total Capitalization and Liabilities	$9,819	$9,529

Reported Earnings (Loss) per Share by Company (GAAP Basis):
(Unaudited)

	Quarter Ended December 31, 2006	Quarter Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2005
SC Electric & Gas	$.34	$.52	$2.02	$2.25
PSNC Energy	.12	.08	.23	.23
Carolina Gas Transmission (2)	.02	.03	.13	.11
SCANA Energy-Georgia	.08	.03	.27	.21
Corporate and Other	.01	(.01)	.03	.01
Basic and Diluted Reported (GAAP) Earnings per Share	$.57	$.65	$2.68	$2.81

GAAP-Adjusted Net Earnings (Loss) per Share From Operations by Company:
(Unaudited)

	Quarter Ended December 31, 2006	Quarter Ended December 31, 2005	Year Ended December 31, 2006	Year Ended December 31, 2005
SC Electric & Gas	$.34	$.52	$1.99 (3)	$2.25
PSNC Energy	.12	.08	.22 (3)	.23
Carolina Gas Transmission (2)	.02	.03	.13	.11
SCANA Energy-Georgia	.08	.03	.26 (3)	.21
Corporate and Other	.01	(.01)	(.01) (4)	(.02) (5)
Basic and Diluted GAAP-Adjusted Net Earnings per Share from Operations	$.57	$.65	$2.59	$2.78

Note (2): Current and prior periods reflect earnings for South Carolina Pipeline Corporation and SCG Pipeline, Inc., which merged to form Carolina Gas Transmission Corporation effective November 1, 2006
Note (3): Excludes impact of accounting change
Note (4): Excludes impact of litigation settlement
Note (5): Excludes impact of sale of telecommunications investment

Variances in Reported (GAAP) Earnings per Share (6):
(Unaudited)

	Quarter Ended December 31,	Year Ended December 31,
2005 Basic and Diluted Reported (GAAP) Earnings Per Share	$.65	$2.81
Variances:		
Electric Margin	(.11)	(.10)
Natural Gas Margin	.03	.01
O&M Expense	.07	.07
Depreciation Expense	(.01)	(.04)
Property Taxes	(.03)	(.03)
Interest Expense	.01	.01
Additional Shares Outstanding (Dilution)	(.01)	(.04)
Other	(.03)	(.07)
Variance in GAAP-Adjusted Net Earnings per Share From Operations	(.08)	(.19)
Cumulative Effect of Accounting Change, re: SFAS 123 (R)	–	.05
Reduction of Accrual Related to Propane Litigation Settlement	–	.04
Gain on Sale of Telecommunications Investment	–	(.03)
Variance in Reported (GAAP) Earnings per Share	(.08)	(.13)
2006 Basic and Diluted Reported (GAAP) Earnings Per Share	$.57	$2.68

Note (6): This variance analysis reflects earnings per share (EPS) components on an after-tax basis, with income tax benefits applied as per the January 6, 2005 electric rate order. See Note (1) to the Condensed Consolidated Statements of Income.

Consolidated Operating Statistics

	Quarter Ended December 31, 2006	Quarter Ended December 31, 2005	% Change	Year Ended December 31, 2006	Year Ended December 31, 2005	% Change
Electric Operations:						
Sales (Million KWH):						
Residential	1,703	1,813	(6.1)	7,598	7,634	(0.5)
Commercial	1,650	1,681	(1.8)	7,248	7,117	1.8
Industrial	1,483	1,603	(7.5)	6,183	6,581	(6.0)
Other	125	127	(1.6)	532	528	0.8
Total Retail Sales	4,961	5,224	(5.0)	21,561	21,860	(1.4)
Wholesale	477	829	(42.5)	2,962	3,450	(14.2)
Total Sales	5,438	6,053	(10.2)	24,523	25,310	(3.1)
Customers (Period-End, Thousands)				623	610	2.1

	Quarter Ended December 31, 2006	Quarter Ended December 31, 2005	% Change	Year Ended December 31, 2006	Year Ended December 31, 2005	% Change
Natural Gas Operations:						
Sales (Thousand Dekatherms):						
Residential	20,962	23,026	(9.0)	59,409	67,733	(12.3)
Commercial	11,816	13,002	(9.1)	37,453	39,711	(5.7)
Industrial	35,507	25,907	37.1	141,990	124,042	14.5
Total Retail Sales	68,285	61,935	10.3	238,852	231,486	3.2
Sales for Resale	5,552	4,221	31.5	16,052	16,728	(4.0)
Transportation Volumes	31,662	16,097	96.7	85,210	70,719	20.5
Total Sales	105,499	82,253	28.3	340,114	318,933	6.6
Customers (Period-End, Thousands)				1,222	1,197	2.1

Weather Data – Electric Service Territory:

	Quarter Ended December 31, Actual 2006	Quarter Ended December 31, Percent Change vs 2005	Quarter Ended December 31, Percent Change vs Normal	Year Ended December 31, Actual 2006	Year Ended December 31, Percent Change vs 2005	Year Ended December 31, Percent Change vs Normal
Heating Degree Days	760	(15.9)	(11.7)	1,981	(11.6)	(6.5)
Cooling Degree Days	98	(47.6)	(29.2)	2,268	(2.5)	(1.9)

Security Credit Ratings (as of 02/09/07):

	Standard & Poor's	Moody's	Fitch
SCANA Corporation:			
Corporate / Issuer Rating	A-	A3	-
Senior Unsecured	BBB+	A3	A-
Outlook	Stable	Stable	Stable
South Carolina Electric & Gas Company:			
Corporate / Issuer Rating	A-	A2	-
Senior Secured	A-	A1	A+
Senior Unsecured	BBB+	A2	A
Commercial Paper	A-2	P-1	F1
Outlook	Stable	Stable	Stable
PSNC Energy:			
Senior Unsecured	A-	A2	A
Commercial Paper	A-2	P-1	F1
Outlook	Stable	Stable	Stable

Section 8.1 Ref 17

1 ~~105150~~

K. Chad Burgess
Senior Counsel

chad.burgess@scana.com

SCANA® POWER FOR LIVING

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SA
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7:30

April 30, 2007

VIA HAND DELIVERY
The Honorable Charles Terreni
Public Service Commission of South Carolina
101 Executive Center Drive
Columbia, South Carolina 29210

RE: Least-Cost Planning Procedures for Electric Utilities
Docket No. ~~87-223-E~~ 2006-103-E

Dear Mr. Terreni:

In accordance with S.C. Code Ann. §58-37-40 (1976, as amended) and Order No. 98-502 enclosed you will find ten (10) copies of the 2007 Integrated Resource Plan of South Carolina Electric & Gas Company ("SCE&G"). 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. Please acknowledge your receipt of this document by file-stamping the extra copy that is enclosed and returning it to us via our courier.

By copy of this letter we are also serving the South Carolina Office of Regulatory Staff with a copy of SCE&G's 2007 Integrated Resource Plan and attach a certificate of service to that effect.

If you should have any questions or need additional information, please do not hesitate to contact me.

Very truly yours,

K. Chad Burgess

K. Chad Burgess

RECEIVED
2007
PSC SC
DOCKETING DEPT.

KCB/kms
Enclosures

cc: Shannon Bowyer Hudson, Esquire
Dan F. Arnett
John W. Flitter

BEFORE THE

PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 87-223-E

Least-Cost Planning Procedures for Electric Utilities	))))	**CERTIFICATE OF SERVICE**

This is the certify that I have caused to be served this day one (1) copy of the **2007 Integrated Resource Plan of South Carolina Electric & Gas Company** via hand delivery to the person named below at the addresses set forth:

Shannon Bowyer Hudson, Esquire
Office of Regulatory Staff
1441 Main Street, Suite 300
Columbia, South Carolina 29201

Dan F. Arnett
Office of Regulatory Staff
1441 Main Street, Suite 300
Columbia, South Carolina 29201

John W. Flitter
Office of Regulatory Staff
1441 Main Street, Suite 300
Columbia, South Carolina 29201

Karen Scruggs

Karen M. Scruggs

Columbia, South Carolina

This 30th day of April 2007

2007

Integrated

Resource

Plan

SCE&G®

A SCANA COMPANY

Introduction

This document presents South Carolina Electric & Gas Company's (SCE&G) Integrated Resource Plan (IRP) for meeting the energy needs of its customers over the next fifteen years, 2007 through 2021. The Company's objective is to provide reliable and economically priced energy to its customers.

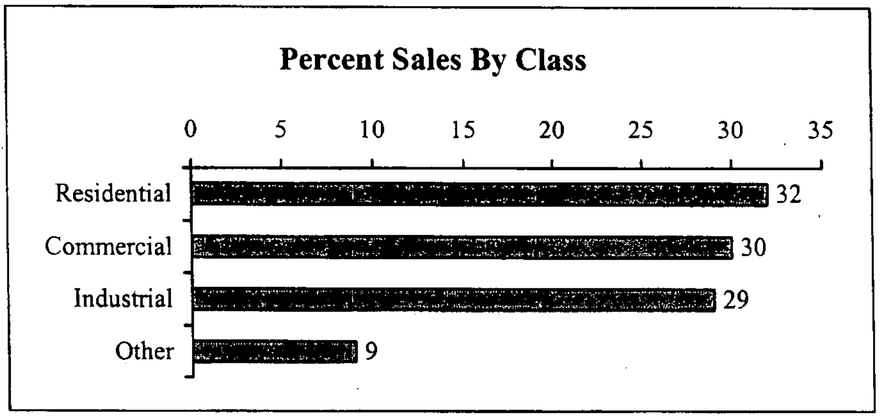
The Load Forecast

Total territorial energy sales on the SCE&G system are expected to grow at an average rate of 2.0% per year over the next 15 years. The summer peak demand and winter peak demand will increase at 2.0% per year over this forecast horizon. The table below contains the projected loads.

	Summer Peak (MW)	Winter Peak (MW)	Energy Sales (GWH)
2007	4,823	4,322	23,741
2008	4,919	4,405	24,277
2009	5,012	4,483	24,790
2010	5,060	4,523	24,994
2011	5,167	4,619	25,482
2012	5,269	4,712	25,956
2013	5,375	4,810	26,457
2014	5,493	5,918	27,006
2015	5,615	5,032	27,588
2016	5,732	5,144	28,157
2017	5,854	5,257	28,734
2018	5,976	5,373	29,323
2019	6,098	5,491	29,927
2020	6,228	5,615	30,559
2021	6,355	5,738	31,187

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 91% of our sales. The following bar chart shows the relative contribution to territorial sales of each class in 2006. 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. Short-range is defined as the next two years. 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.

Demand-Side Management at SCE&G

The Demand-Side Management Programs at SCE&G can be divided into three major categories: Customer Information Programs, Energy Conservation Programs and Load Management Programs.

CUSTOMER INFORMATION PROGRAMS

SCE&G's customer information programs fall under two headings: the annual energy campaigns and the web-based information initiative. Following is a brief description of each.

1. The 2006 Energy Campaigns: In 2006 SCE&G continued to proactively educate its customers and create awareness of issues related to energy and conservation management.

- Weatherline – energy saving tips promoted on the Weatherline.
- Bill Inserts – bill insert issued to targeted customers promoting the Low-Income Home Energy Assistance Program (LIHEAP).

- Brochures/Printed Materials – energy saving tips available on various printed materials in business offices.
- News Releases – distributed to print and broadcast media throughout SCE&G's service territory.
- Featured News Guests – SCE&G energy experts conducted several interviews with the media regarding energy conservation and useful tips.
- Web site – energy saving tips and other conservation information placed on the company's Web site. The address for the Web site was promoted in most of the communication channels mentioned above.
- Weatherization Project – SCE&G partners targeted low-income homes in Beaufort and Sumter for weatherization. SCE&G employees volunteer their time to assist the effort.
- Speakers Bureau – Representatives from SCE&G talked to local organizations about energy conservation. Also used were company-produced videos that highlight energy conservation.
- Energy Awareness Month – company used the month as an opportunity to send information to the media discussing energy costs and savings tips.

2. WEB-Based Information and Services Programs: SCE&G has available a Web-based tool which allows customers to access current and historical consumption data and compare their energy usage month-to-month and year-to-year, noting trends, temperature impact and spikes in their consumption. Feedback on this tool has been positive and over 166,000 customers have registered to access this tool as well as other account related information. The SCE&G Web site supports all communication efforts to promote energy savings tips. The "Manage Energy Use" section of the SCE&G Web site, which features an interactive bill estimator tool, video instruction on weatherization and other useful content, is currently averaging almost 12,000 visits per year. For business customers, online information includes: power quality technical assistance, conversion assistance, new construction information, expert energy assistance and more.

ENERGY CONSERVATION PROGRAMS

There are three energy conservation programs: the Value Visit Program, the Conservation Rate and our use of seasonal rate structures. A description of each follows:

1. Value Visit Program: The Value Visit Program is designed to assist residential electric customers that are considering an investment in upgrading their home's energy efficiency. We visit the customer's home and guide them in their purchase of energy related equipment and materials such as heating and cooling systems, duct insulation, attic insulation, storm windows, etc. Our representative explains the benefits of upgrading different areas of the home and what affect upgrading these areas will have on energy bills and comfort levels as well as informing the customer on the many rebates we offer for upgrading certain areas of the home (see attached rebate schedule). We also offer financing for qualified customers which makes upgrading to a higher energy efficiency level even easier. The Value Visit Program is often used in conjunction with our Rate 6 Program to achieve the maximum benefit for customers wanting to reduce their energy usage, make their homes more comfortable and to increase their home's overall value. There is a $25 charge for the program, but this charge is reimbursed if the customer implements any suggested upgrade within 90 days of the visit. Information on this program is available on our website and by brochure.

   0 to R30 attic insulation - $6.00 per 100 sq. ft.
   R11 to R30 attic insulation - $3.00 per 100 sq. ft.
   Storm windows - $30.00 per house
   Duct insulation - $60.00 per house
   Wall Insulation - $80.00 per house

2. Rate 6 Energy Saver / Energy Conservation Program: The Rate 6 Energy Saver / Energy Conservation Program rewards homeowners and home builders who upgrade their existing homes or build their new homes to a high level of energy efficiency with a reduced electric rate. This reduced rate, combined with a significant reduction in energy usage, provide for considerable savings for our customers. Participation in the program is very easy as the requirements are prescriptive and do not require a large monetary investment which is beneficial to all of our customers and trade allies. Homes built to this standard also have improved comfort levels and increased re-sale value over homes

built to the minimum building code standards which are also a significant benefit to our customers. Information on this program is available on our website and by brochure.

3. Seasonal Rates: Many of our rates are designed with components that vary by season. Energy provided in the peak usage season is charged a premium to encourage conservation and efficient use.

LOAD MANAGEMENT PROGRAMS

SCE&G's load management programs have as their primary goal the reduction of the need for additional generating capacity. There are four load management programs: Standby Generator Program, Interruptible Load Program, Real Time Pricing Rate and the Time of Use Rates. A description of each follows:

1. Standby Generator Program: The Standby Generator I Program for retail customers was introduced in 1990 to serve as a load management tool. General guidelines authorize SCE&G to initiate a standby generator run request when reserve margins are stressed due to a temporary reduction in system generating capability, or high customer demand. The Standby Generator II Program for retail customers was developed in 2000, authorizing standby generator runs for revenue producing opportunities during times of high market prices. Through consumption avoidance, generator customers release capacity back to SCE&G where it is then used to satisfy system demand. Qualifying customers (able to defer a minimum of 200 kW) receive financial credits determined initially by recording the customer's demand during a load test. Future demand credits are based on what the customer actually delivers when SCE&G requests them to run their generator(s). This program allows customers to reduce their monthly operating costs, as well as earn a return on their generating equipment investment. There is also a wholesale standby generator program that is similar to the retail programs.
2. Interruptible Load Program: SCE&G has over 200 megawatts of interruptible customer load under contract. Participating customers receive a discount on their demand charges for shedding load when SCEG is short of capacity.
3. Real Time Pricing (RTP) Rate: A number of customers receive power under our real time pricing rate. During peak usage periods throughout the year when capacity is low in

the market, the RTP rate sends a high price signal to participating customers which encourages conservation and load shifting. Of course during low usage periods, prices are lower.

4. Time of Use Rates: Our time of use rates contain higher charges during the peak usage periods of the day to encourage conservation and load shifting during these periods. All our customers have the option of a time of use rate.

Load Impact of Load Management Programs

The Company relies on the standby generator program and the interruptible service program to help maintain the reliability of its electrical system. There are currently 206 megawatts of capacity made available to the system through these programs. This is expected to increase to 250 megawatts by 2009. 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)
2007	5029	206	4823
2008	5148	228	4920
2009	5262	250	5012
2010	5310	250	5060
2011	5418	250	5168
2012	5520	250	5270
2013	5625	250	5375
2014	5743	250	5493
2015	5865	250	5615
2016	5982	250	5732
2017	6105	250	5855
2018	6226	250	5976
2019	6349	250	6099
2020	6478	250	6228
2021	6605	250	6355

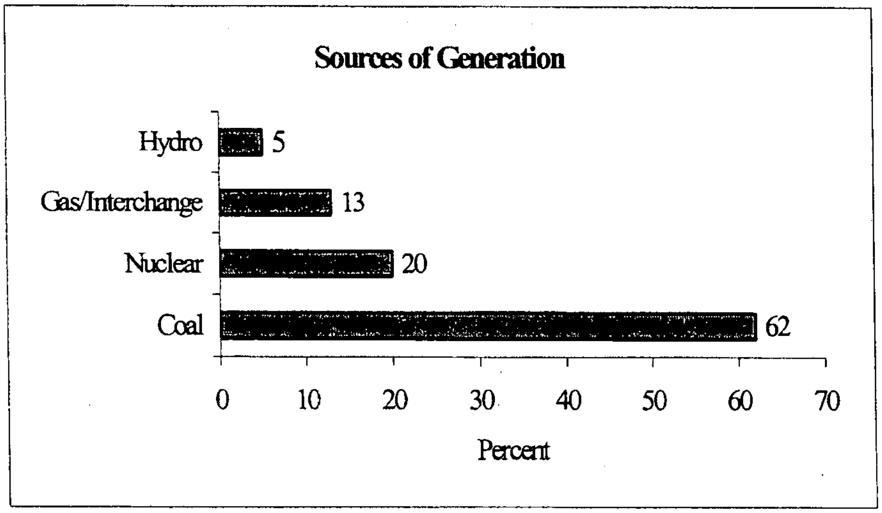
Existing Supply Capacity

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

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	397
Wateree – Eastover, SC	1970	700
*Williams – Goose Creek, SC	1973	615
Cope - Cope, SC	1996	420
Cogen South – Charleston, SC	1999	90
Total Coal-Fired Steam Capacity		2,566
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	472
Jasper Combined Cycle – Jasper, SC	2004	880
Total I. C. Turbines Capacity		1717
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	576
Total Hydro Capacity		823
Other: Long-Term Purchases		25
SEPA		33
Grand Total:		5,808

* Williams Station is owned by GENCO, a wholly owned subsidiary of SCANA and Columbia Canal is owned by the City of Columbia. All of this capacity is operated by SCE&G to meet its load obligations.

The bar chart below shows the projected 2007 relative energy generation by fuel source. SCE&G generates the majority of its energy from coal and nuclear fuel.



Supply Reserve Margin and Operating Reserves

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. Mitigation of these two types of risk is 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. While it varies by a megawatt or two each year, SCE&G's prorata share of this capacity is always around 200 megawatts.

Supply reserves are needed to balance the "supply risk" that some SCE&G generation capacity may be forced out on any particular day because of mechanical failures, wet coal problems, environmental limitations or other force majeure/unforeseen events. 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 one of our generating units except the two largest: Summer Station and Williams Station.

Another component of reserve margin is the demand reserve. This is needed to cover "demand risk" related to unexpected increases in customer 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 to 18 percent range, the Company addresses the uncertainties related to load and to the availability of generation on its system. It also allows the Company 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.

The Need for Base Load Capacity

As our customers' need for energy continues to grow, so does the need for generating capacity to serve those customers. In particular SCE&G projects the need for additional baseload capacity around the year 2016. Currently about 56% of the Company's generation fleet is baseload. When the last coal plant, Cope Station, came online in 1996, the percentage of baseload capacity was about 74%. The choice among baseload, intermediate and peaking capacity is an economic one and depends on how much energy the new capacity will need to generate. Baseload capacity typically dispatches at a capacity factor in excess of 70%.

Nuclear Capacity and Fuel Diversity

SCE&G and Santee Cooper are currently planning to jointly build an AP1000 Westinghouse nuclear unit at the VC Summer site. The Westinghouse unit is preferred because of the size of the unit, about 1100 MWs, and because of the progress that Westinghouse has made in its engineering and design. The Westinghouse design was approved by the Nuclear Regulatory Commission (NRC) on September 13, 2004. The AP1000 design uses passive safety systems to enhance the safety of the unit and to satisfy the NRC safety criteria. In addition to the environmental benefits associated with the nuclear option, it also offers an opportunity to diversify our capacity. SCE&G's current capacity is about 43% coal fired, 30% gas fired, and 11% nuclear. Adding more nuclear capacity can provide a better balance among fuel types. While SCE&G is currently pursuing the nuclear option and believes it to be in the best interest of its rate payers, the Company does have several years before it is financially committed.

Role of Purchased Power

SCE&G constantly monitors the markets for electric energy and capacity and at times is an active purchaser and seller in those markets. Where it appears that market resources may be able to meet supply needs for its system appropriately, SCE&G polls the market, in some cases informally, and in other cases through the issuance of formal RFPs. In cases where the market resources can be an appropriate part of SCE&G's supply mix, SCE&G includes those resources in its comparative analysis of alternative supply options.

On December 8, 2006 SCE&G issued an RFP to purchase capacity and has received responses. An evaluation of those responses against other options available to the Company is currently underway.

Non-Traditional Generation Sources

SCE&G considers non-traditional sources of generation in its planning. In fact it depends on 90 MWs of co-generation capacity in its Cogen South facility. This facility co-fires with coal the biomass waste from a paper manufacturing plant. Also, SCE&G is increasing its attention on renewable sources of generation while at the same time policy makers are considering new energy efficiency standards and renewable portfolio standards. Some proposed bills in congress have defined renewable as: geothermal, hydro, wind, solar and biomass. Unfortunately there are no sites for geothermal generation available in South Carolina. SCE&G generates about 5% of its energy from hydro power. The Company has invested in its existing hydro sites and increased hydro output as a result and will continue to pursue other such economic opportunities but no sites have been identified for a new hydro facility. Both wind and solar have been considered but because of the high capital costs and the limited energy production caused by low wind speeds and insufficient solar radiation, these generation sources are not economical within the SCE&G service territory. SCE&G has also evaluated potential biomass applications in recent years, but none have proven economically feasible and operationally practical yet, but we continue to examine proposals and opportunities as they are identified.

Projected Loads and Resources

The table on the following page shows SCE&G's projected loads and resources for the next 15 years. The resource plan shows the need for additional capacity and identifies, at least, on a preliminary basis whether the need is for peaking/intermediate capacity or baseload capacity.

The resource plan shows the need for the addition of almost 500 MWs of peaking/intermediate capacity in the 2009 - 2015 timeframe. Some or all of this capacity may be supplied as purchased power. The plan also calls for baseload capacity in 2016 and 2019. As discussed previously one or both of these units may be nuclear powered. The Company has a number of years before it needs to make these decisions.

The Company believes that its supply plan, summarized in the following table, will be as benign to the environment as possible because of the Company's continuing efforts to utilize state-of-the-art emission reduction technology in compliance with state and federal laws and regulations. The supply plan will also help SCE&G keep its cost of energy service at a minimum since the generating units being added are competitive with other units being added in the market.

SCE&G Forecast of Summer Loads and Resources - 2007 IRP

	YEAR	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Load Forecast																
1	Gross Territorial Peak	5029	5148	5262	5310	5418	5520	5625	5743	5865	5982	6105	6226	6349	6478	6605
2	Less: DSM	206	228	250	250	250	250	250	250	250	250	250	250	250	250	250
3	Net Territorial Peak	4823	4920	5012	5060	5168	5270	5375	5493	5615	5732	5855	5976	6099	6228	6355
4	Firm Contract Sales	350	250	250	250	250	250									
5	Total Firm Obligation	5173	5170	5262	5310	5418	5520	5375	5493	5615	5732	5855	5976	6099	6228	6355
System Capacity																
6	Existing	5808	5808	5808	5808	5997	5997	5997	5997	5997	5997	6597	6597	6597	7197	7197
	Additions															
7	Peaking/Intermediate				200											
8	Baseload										600			600		
9	Other				-11											
10	Total System Capacity	5808	5808	5808	5997	5997	5997	5997	5997	5997	6597	6597	6597	7197	7197	7197
11	Firm Annual Purchase			90		70	190	25	160	290			100			
12	Total Production Capability	5808	5808	5898	5997	6067	6187	6022	6157	6287	6597	6597	6697	7197	7197	7197
Reserves With DSM																
13	Margin	635	638	636	687	649	667	647	664	672	865	742	721	1098	969	842
14	% Reserve Margin	12.3%	12.3%	12.1%	12.9%	12.0%	12.1%	12.0%	12.1%	12.0%	15.1%	12.7%	12.1%	18.0%	15.6%	13.2%
15	% Capacity Margin	10.9%	11.0%	10.8%	11.5%	10.7%	10.8%	10.7%	10.8%	10.7%	13.1%	11.2%	10.8%	15.3%	13.5%	11.7%
Reserves Without DSM																
16	Margin	429	410	386	437	399	417	397	414	422	615	492	471	848	719	592
17	% Reserve Margin	8.0%	7.6%	7.0%	7.9%	7.0%	7.2%	7.1%	7.2%	7.2%	10.3%	8.1%	7.6%	13.4%	11.1%	9.0%
18	% Capacity Margin	7.4%	7.1%	6.5%	7.3%	6.6%	6.7%	6.6%	6.7%	6.7%	9.3%	7.5%	7.0%	11.8%	10.0%	8.2%

Transmission Planning

SCE&G's transmission planning practices develop and coordinate a program that provides for timely modifications to the SCE&G transmission system to ensure a reliable and economical delivery of power. This program includes the determination of the current capability of the electrical network and a ten-year schedule of future additions and modifications to the network. These additions and modifications are required to support customer growth, provide emergency assistance and maintain economic opportunities for our customers while meeting SCE&G and industry performance standards.

SCE&G has an ongoing process to determine the performance level of the SCE&G transmission system. Numerous internal studies are undertaken that address the service needs of our customers. These needs include: 1) distributed load growth in existing residential, commercial, industrial, and wholesale customers, 2) new residential, commercial, industrial, and wholesale customers and 3) transmission only customers.

SCE&G has developed and adheres to a set of internal Long Range Planning Criteria which can be summarized as follows:

> *The requirements of the SCE&G "LONG RANGE PLANNING CRITERIA" will be satisfied if the system is designed so that during any of the following contingencies, only short-time overloads, low voltages and local loss of load will occur and that after appropriate switching and re-dispatching, all non-radial load can be served with reasonable voltages and that lines and transformers are operating within acceptable limits.*
>
> a. *Loss of any bus and associated facilities operating at a voltage level of 115kV or above*
> b. *Loss of any line operating at a voltage level of 115kV or above*
> c. *Loss of entire generating capability in any one plant*
> d. *Loss of all circuits on a common structure*
> e. *Loss of any transmission transformer*
> f. *Loss of any generating unit simultaneous with the loss of a single transmission line*
>
> *Outages more severe are considered acceptable if they will not cause equipment damage or result in uncontrolled cascading outside the local area.*

Furthermore, SCE&G is an active member of the SERC Reliability Corporation, which has adopted the North American Electric Reliability Corporation (NERC) Reliability Standards as approved by the NERC Board of Trustees. SCE&G tests and designs its transmission system to be compliant with the requirements as set forth in these standards. A copy of the NERC Reliability Standards is available at the NERC homepage http://www.nerc.com/.

As a member of the Virginia-Carolinas (VACAR) Reliability Group, SCE&G participates in joint studies with other utilities to determine the reliability of the integrated systems throughout Virginia, North Carolina and South Carolina. As a member of the SERC Reliability Corporation, SCE&G participates with other utilities in the SERC Regional Planning Process, including the SERC Regional Studies Executive Committee, the SERC Long-Term Power Flow Study Group, the SERC Near-Term Power Flow Study Group, the SERC Dynamics Study Group, the SERC Short Circuit Database Working Group and the SERC Inter-regional studies efforts.

SCE&G also participates in the SERC power flow database development efforts and the NERC Multi-area Modeling Working Group (MMWG) annual model development process. These processes develop computer models of the transmission grid across the VACAR area, SERC area, and other portions of NERC (Eastern Interconnection). All participants' models are merged together to produce current and future models of the integrated electrical network. Using these models, SCE&G evaluates its' current and future transmission system for compliance with the SCE&G Long Range Planning Criteria and the NERC Reliability Standards.

The SCE&G transmission system is interconnected with Progress Energy – Carolinas, Duke Power, South Carolina Public Service Authority (Santee Cooper), Georgia Power Company, Savannah Electric Power Company, and the Southeastern Electric Power Administration (SEPA) systems.

The following is a list of regional and sub-regional studies conducted over the past year:

1. VACAR 2007 Summer Study
2. VASTE 2006 Summer Reliability Study
3. VASTE 2006/2007 Winter Reliability Study
4. VSTE 2011 Summer Future Year Study
5. VEM 2006 Summer Reliability Study
6. VEM 2006/2007 Winter Reliability Study
7. 2006 January-March OASIS Study
8. 2006 April-June OASIS Study
9. 2006 July-September OASIS Study
10. 2006 October-December OASIS Study
11. SCEG-Santee-Southern 2011 Joint Study
12. VACAR Stability Study of Projected 2012 Summer Peak Conditions
13. Evaluation of the Under-Frequency Load Shedding (UFLS) Program of the SERC Region

These activities, as discussed above, provide for a reliable and cost effective transmission system for SCE&G customers.