TEN YEAR SITE PLAN
1994-2003

FOR ELECTRIC GENERATING FACILITIES
AND
ASSOCIATED TRANSMISSION LINES

CLEAN AIR ACT COMPLIANCE PLAN

1994 UPDATE

APRIL, 1994

GULF POWER COMPANY

GULF POWER COMPANY'S SYSTEM PLANNING PROCESS

Gulf participates in a coordinated pool operation of generating resources with the other operating companies of the Southern electric system (Alabama Power, Georgia Power, Mississippi Power, and Savannah Electric and Power). In order to maximize the benefits of pool operations, the planning of additional resource facilities and Clean Air Act Compliance is also done on a coordinated basis. Although Gulf participates in the development of its integrated resource plan in this manner, Gulf remains the final decision-maker on any plan for its own system.

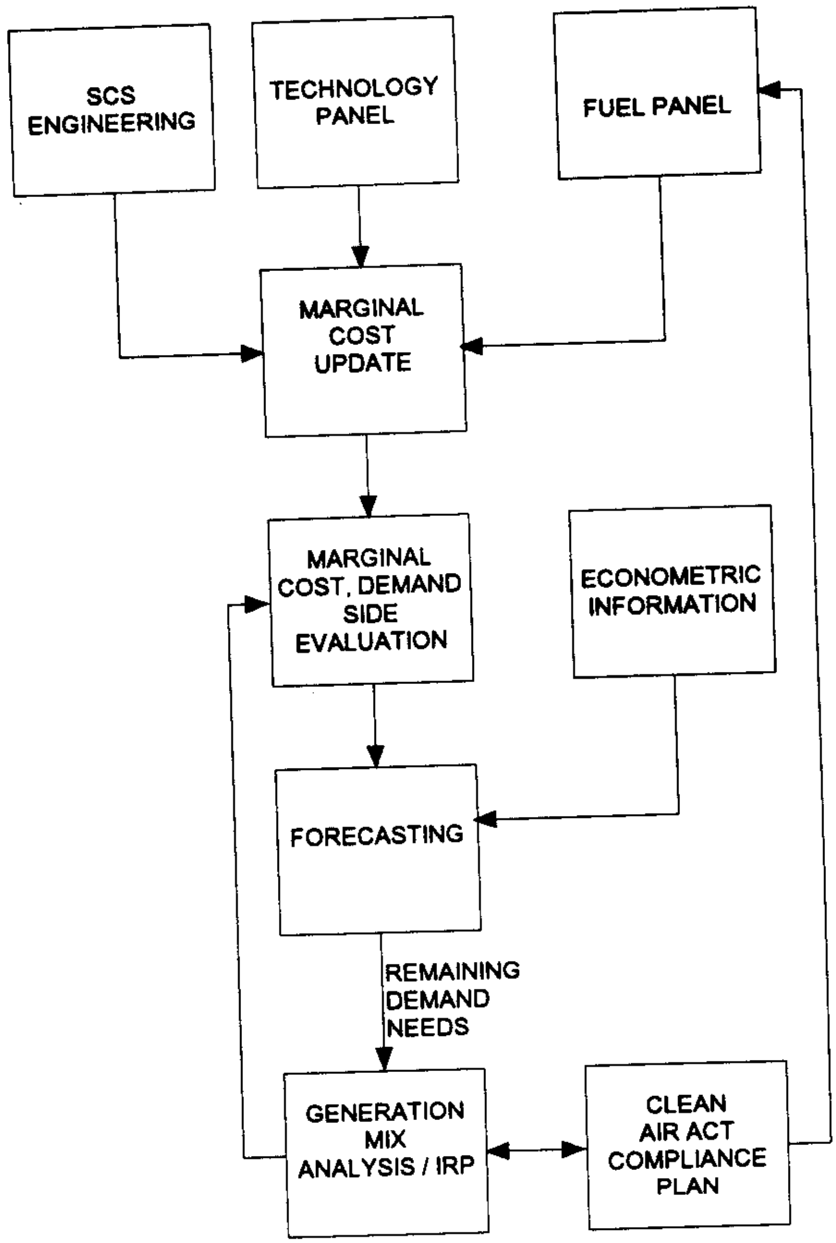
In order to predict future electrical energy and demand requirements of the customers served by Gulf Power Company, a load forecast is developed which includes a 25 year projection of the expected growth in customer requirements. Gulf Power Company then develops an IRP that provides the optimal mix of demand-side and supply-side resources to meet this projected load growth. This planning process, which by its very nature is an iterative process, recurs annually through distinct but overlapping phases.

The Integrated Resource Planning process culminates with a mix of future generating capacity which, for the next 20 years, is confined to natural gas-fired combustion turbines and combined cycle units. Another important product emerging from the Integrated Resource Planning process is the production costing run generated by the program which involves all existing and future generating capacity. This production cost run is the major input for the system's analysis for Phase I and Phase II compliance with the Clean Air Act Amendments of 1990 (CAA). The compliance analysis evaluates the relative cost over the planning horizon of fuel switching and other SO_2 compliance options in order to determine the least-cost compliance strategy. The wide diversity of the system's existing units, i.e., fuel burn capability, emission allowances, proximity to low-sulfur coal, etc., permit the development of this least-cost system solution to our obligation to comply with the Federal Clean Air Act as amended in 1990. With regard to the evaluation associated with the Integrated Resource Plan contained in Gulf's Ten Year Site Plan for 1994, the compliance strategy remains basically the same as previously filed--a market strategy that takes advantage of the company's fuel switching options and minimizes the sulfur dioxide compliance cost in both Phase I and Phase II. Also, the strategy minimizes nitrogen oxide control costs and provides the flexibility to make a number of decisions later when additional information is available on rule-makings, technologies, and the allowance market.

Pursuant to Order No. PSC-93-1376-FOF-EI issued in Docket No. 921155-EI, Gulf files its 1994 Ten Year Site Plan and its 1994 Clean Air Act Compliance Plan update with the Florida Public Service Commission. Copies of both of these documents are enclosed herein.

Attachment

INTEGRATED RESOURCE PLANNING PROCESS



TEN YEAR SITE PLAN
1994 - 2003

FOR ELECTRIC GENERATING FACILITIES
AND
ASSOCIATED TRANSMISSION LINES

APRIL, 1994

GULF POWER

GULF POWER COMPANY
TEN YEAR SITE PLAN

FOR ELECTRIC GENERATING FACILITIES
AND
ASSOCIATED TRANSMISSION LINES

Submitted To The
State Of Florida
Department Of Community Affairs
Division of Resource Planning and Management
Bureau of State Planning
Power Plant Siting Program

APRIL 1, 1994

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CHAPTER I

DESCRIPTION OF EXISTING FACILITIES

UTILITY: GULF POWER COMPANY
EXISTING GENERATING FACILITIES

(1) Plant Name	(2) Unit No.	(3) Location	(4) Type	(5) Fuel Pri	(6) Fuel Alt	(7) Com'l In-Service Mo/Yr	(8) Exptd Retrmnt Mo/Yr	(9) Gen Max Nameplate KW	(10) Net Capability Summer MW	(11) Net Capability Winter MW	(12) Fuel Transp Pri	(13) Fuel Transp Alt
Crist		Escambia County 25/1N/30W						1,229,000	1105.2	1105.2		
	1		FS	NG	HO	1/45	12/04	28,125	24.0	24.0	PL	TK
	2		FS	NG	HO	6/49	12/04	28,125	25.1	25.1	PL	TK
	3		FS	NG	HO	9/52	12/04	37,500	37.0	37.0	PL	TK
	4		FS	C	NG	7/59	12/14	93,750	88.0	88.0	WA	PL
	5		FS	C	NG	6/61	12/16	93,750	87.0	87.0	WA	PL
	6		FS	C	NG	5/70	12/15	369,750	327.0	327.0	WA	PL
	7		FS	C	--	8/73	12/18	578,000	517.1	517.1	WA	--
Lansing Smith		Bay County 36/2S/15W						381,850	390.8	399.2		
	1		FS	C	--	6/65	12/15	149,600	162.0	162.0	WA	--
	2		FS	C	--	6/67	12/17	190,400	193.6	193.6	WA	--
	A		CT	LO	--	5/71	12/01	41,850	35.2	43.6	TK	--
Scholz		Jackson County 12/3N/7W						98,000	98.1	98.1		
	1		FS	C	--	3/53	12/08	49,000	49.6	49.6	RR	WA
	2		FS	C	--	10/53	12/08	49,000	48.5	48.5	RR	WA
(A) Daniel		Jackson County, MS 42/5S/6W						548,250	540.7	540.7		
	1		FS	C	HO	9/77	12/22	274,125	268.0	268.0	RR	TK
	2		FS	C	HO	6/81	12/26	274,125	272.7	272.7	RR	TK
(A) Scherer	3	Monroe County, GA	FS	C	--	1/87	12/27	222,750	209.7	209.7	RR	--
						Total System as of December 31, 1993			2344.5	2352.9		

Abbreviations:

Fuel

FS - Fossil Steam
CT - Combustion Turbine
NG - Natural Gas
C - Coal
LO - Light Oil
HO - Heavy Oil

Fuel Transportation

PL - Pipeline
WA - Water
TK - Truck
RR - Railroad

NOTE: (A) Unit capabilities shown represent Gulf's portion of Daniel Units 1 & 2 (50%) and Scherer Unit 3 (25%).

Utility: Gulf Power Company TYP FORM 1B

Existing Generating Facilities (A)

Land Use and Investment

(1) Plant Name	(2) Land Area Owned: Total Acres	(3) Land Area Owned: In Use Acres	(4) Plant Capital Investment in ($1,000): Land & Land Rights	(5) Site Improvements (B)	(6) Buildings & Equipment	(7) Total
Steam Total			6,908		852,064	858,972
Crist	680	350	1,792		352,977	354,769
Lansing Smith	1,340	400	612		93,370	93,982
Scholz	293	168	45		30,486	30,531
Daniel	2,657 (C)	500 (C)	3,666 (D)		201,460 (D)	205,126 (D)
Scherer	12,158 (E)	9,500 (E)	793 (F)		173,771 (F)	174,564 (F)
Caryville (Weather Station)					0	0
Combustion Turbine Total					4,251	4,251
Lansing Smith CT					4,251	4,251

(A) As of 12/31/93.
(B) Included in column 6.
(C) Daniel Plant information refers to total area owned jointly by Gulf and Mississippi Power.
(D) Gulf Power's portion of Plant Daniel only.
(E) Scherer Plant information refers to total area owned by Georgia Power and area owned jointly by Gulf and Georgia Power. "In Use Acres" includes cooling water lake.
(F) Gulf Power's portion of Plant Scherer only. Excludes acquisition adjustment in the amount of $7,137,148.

Utility: Gulf Power Company

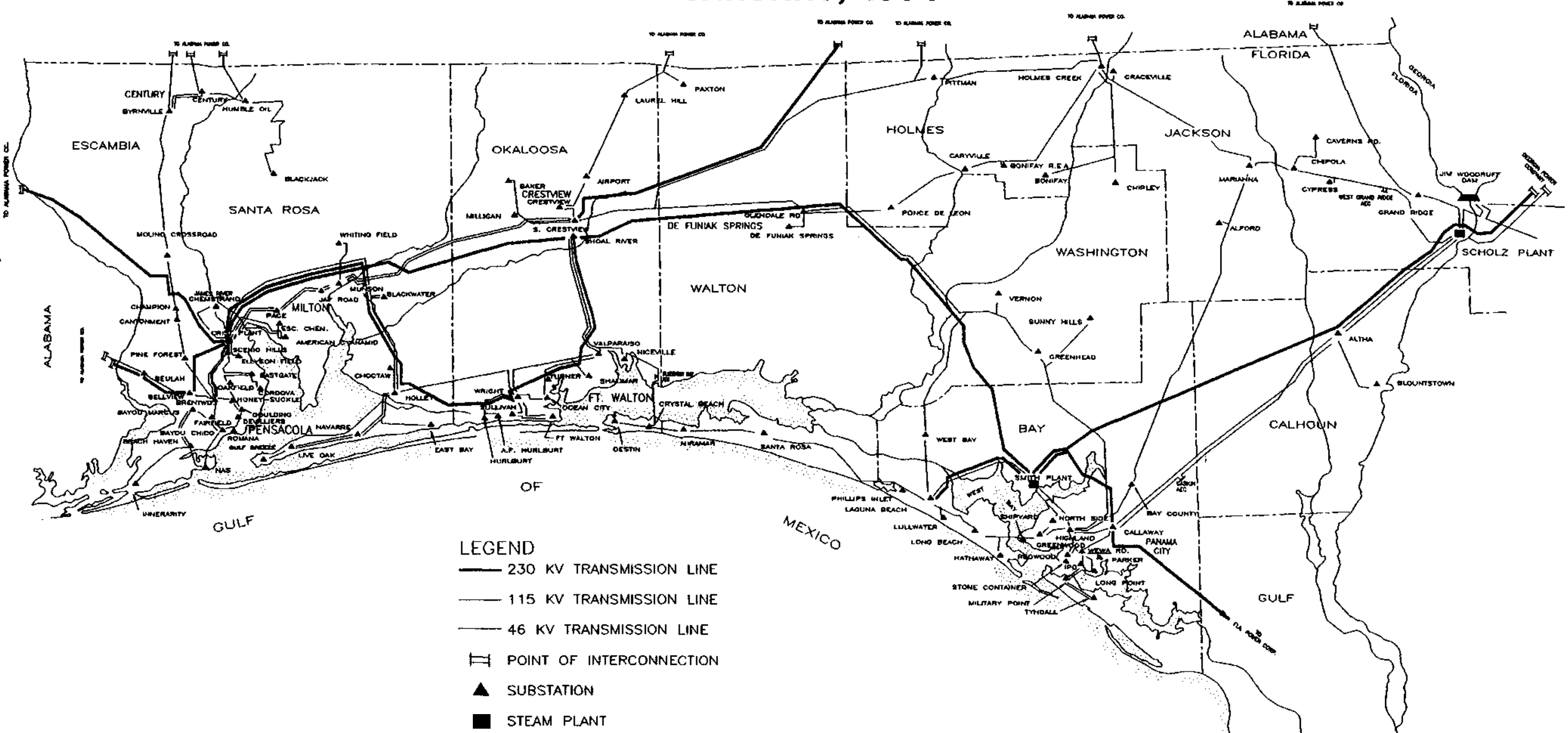
Existing Generating Facilities
Environmental Considerations for Steam Generating Units

(1)	(2)	(3)	(4)	(5)	(6)
		Flue Gas Cleaning			
Plant Name	Unit	Particulate	SOx	NOx	Cooling Type
Crist	1	no	no	no	WCTM
	2	no	no	no	WCTM
	3	no	no	no	WCTM
	4	EP	no	no	WCTM
	5	EP	no	no	WCTM
	6	EP	no	no	WCTM
	7	EP	no	LNB	WCTM
Lansing Smith	1	EP	no	no	OTS
	2	EP	no	LNB	OTS
Scholz	1	EP	no	no	OTF
	2	EP	no	no	OTF
Daniel	1	EP	no	no	CP
	2	EP	no	no	CP
Scherer	3	EP	no	no	NDCT

Abbreviations:

- EP - Electrostatic Precipitator
- WCTM - Wet cooling tower, mechanical draft
- OTS - Once-through, saline
- OTF - Once-through, fresh
- CP - Cooling pond
- NDCT - Natural Draft Cooling Tower
- LNB - Low NOx Burners

GULF POWER COMPANY
SYSTEM MAP
JANUARY, 1994



Gulf Power

CHAPTER II

FORECAST OF ELECTRIC POWER DEMAND

UTILITY: GULF POWER COMPANY

HISTORY AND FORECAST OF ENERGY CONSUMPTION AND NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
	RURAL AND RESIDENTIAL					COMMERCIAL		
YEAR	POPULATION *	MEMBERS PER HOUSEHOLD	GWH	AVERAGE NO. OF CUSTOMERS	AVERAGE KWH CONSUMPTION PER CUSTOMER	GWH	AVERAGE NO. OF CUSTOMERS	AVERAGE KWH CONSUMPTION PER CUSTOMER
1984	516,095	2.43	2,561	212,379	12,057	1,559	27,336	57,044
1985	531,204	2.37	2,736	223,908	12,221	1,777	28,983	61,326
1986	543,337	2.33	2,964	232,816	12,729	1,913	30,576	62,570
1987	552,797	2.31	3,055	239,362	12,763	1,986	31,821	62,422
1988	559,857	2.29	3,155	244,859	12,883	2,089	32,757	63,760
1989	567,022	2.27	3,294	250,038	13,173	2,169	33,500	64,761
1990	573,606	2.25	3,361	255,129	13,173	2,218	33,957	65,305
1991	582,196	2.24	3,455	259,395	13,320	2,273	34,372	66,120
1992	594,400	2.24	3,597	265,374	13,553	2,369	36,009	65,796
1993	604,610	2.23	3,713	271,594	13,671	2,433	38,477	63,242
1994	615,442	2.21	3,763	277,893	13,542	2,484	39,697	62,575
1995	624,092	2.20	3,828	283,551	13,501	2,537	40,500	62,633
1996	631,410	2.19	3,893	288,616	13,489	2,593	41,280	62,809
1997	638,882	2.18	3,960	293,585	13,488	2,646	42,048	62,922
1998	647,252	2.17	4,044	298,609	13,542	2,720	42,825	63,517
1999	656,468	2.16	4,109	303,716	13,531	2,782	43,618	63,779
2000	666,344	2.16	4,194	308,825	13,580	2,852	44,413	64,220
2001	676,677	2.15	4,269	314,039	13,595	2,916	45,227	64,475
2002	687,142	2.15	4,345	319,420	13,603	2,976	46,068	64,606
2003	697,491	2.15	4,402	324,679	13,557	3,026	46,892	64,539

* HISTORICAL AND PROJECTED FIGURES INCLUDE PORTIONS OF ESCAMBIA, SANTA ROSA, OKALOOSA, BAY WALTON, WASHINGTON, HOLMES, AND JACKSON COUNTIES SERVED BY GULF POWER COMPANY.

UTILITY: GULF POWER COMPANY

HISTORY AND FORECAST OF ENERGY CONSUMPTION AND NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(10)	(11)	(12)	(13)	(14)	(15)	(16)
	INDUSTRIAL					
YEAR	GWH	AVERAGE NO. OF CUSTOMERS	AVERAGE KWH CONSUMPTION PER CUSTOMER	STREET AND HIGHWAY LIGHTING GWH	OTHER SALES TO ULTIMATE CONSUMERS GWH	TOTAL SALES TO ULTIMATE CONSUMERS GWH
1984	1,771	179	9,894,417	14	0	5,905
1985	1,771	181	9,782,246	14	0	6,299
1986	1,745	195	8,949,099	14	0	6,636
1987	1,840	204	9,019,271	14	0	6,896
1988	1,968	206	9,553,842	15	0	7,226
1989	2,095	229	9,147,029	16	0	7,574
1990	2,178	247	8,817,297	17	0	7,774
1991	2,117	260	8,143,878	16	0	7,861
1992	2,179	262	8,318,456	16	0	8,161
1993	2,030	268	7,574,388	16	0	8,192
1994	1,971	278	7,090,713	17	0	8,235
1995	2,003	282	7,103,871	17	0	8,385
1996	2,016	285	7,073,144	17	0	8,519
1997	2,020	288	7,014,004	17	0	8,643
1998	2,032	291	6,982,237	18	0	8,813
1999	2,043	294	6,949,608	18	0	8,953
2000	2,048	297	6,894,812	18	0	9,112
2001	2,054	300	6,845,255	19	0	9,258
2002	2,060	303	6,797,589	19	0	9,400
2003	2,062	306	6,737,463	19	0	9,509

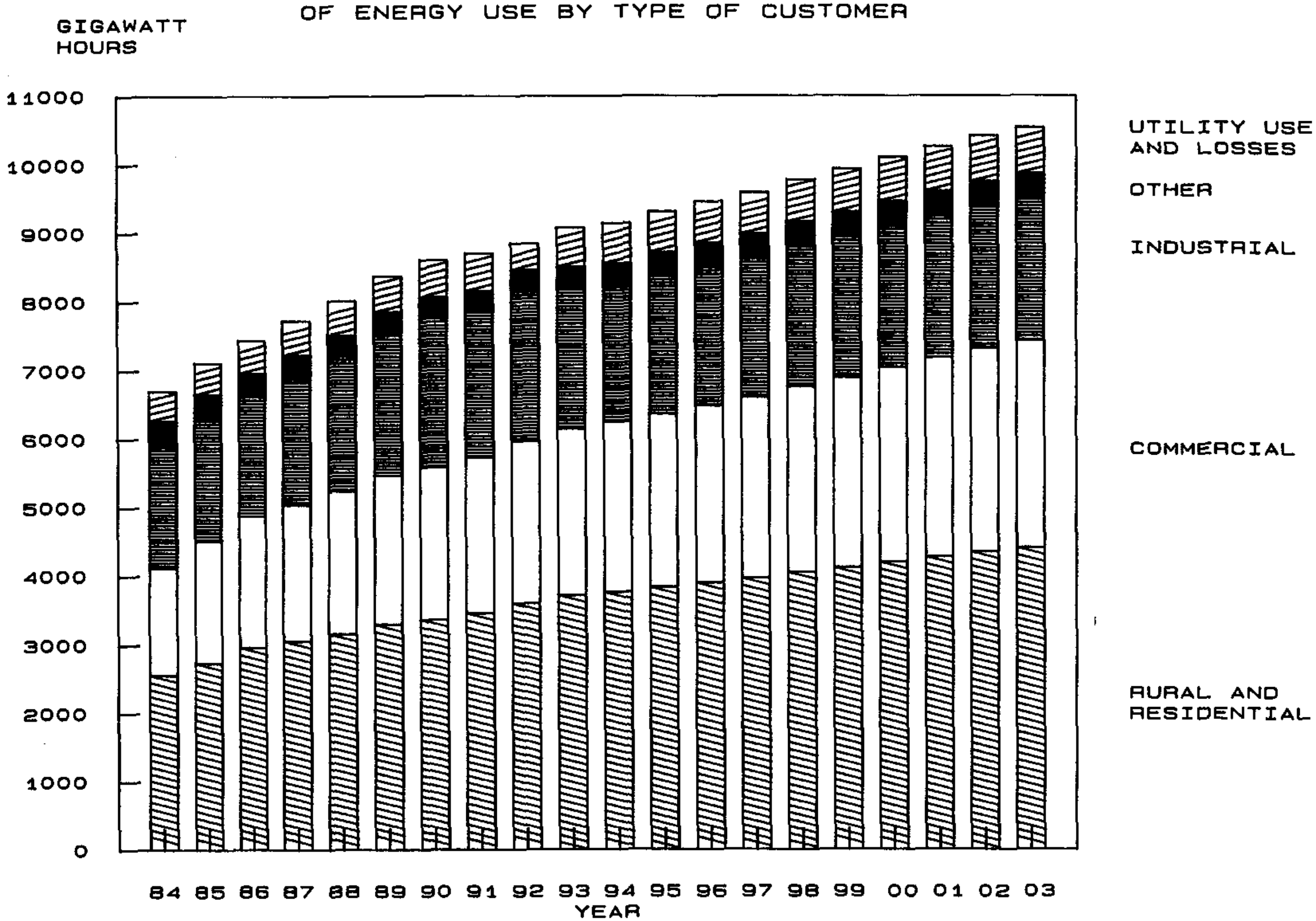
HISTORY AND FORECAST OF ENERGY CONSUMPTION AND NUMBER OF CUSTOMERS BY CUSTOMER CLASS

(17) YEAR	(18) SALES FOR RESALE GWH	(19) UTILITY USE AND LOSSES GWH	(20) NET ENERGY FOR LOAD GWH	(21) OTHER CUSTOMERS (AVERAGE NO.)	(22) TOTAL NO. OF CUSTOMERS
1984	364	433	6,703	63	239,956
1985	359	458	7,115	63	253,135
1986	324	475	7,435	62	263,646
1987	328	499	7,723	62	271,449
1988	283	507	8,016	59	277,881
1989	276	528	8,378	63	283,830
1990	294	545	8,612	68	289,400
1991	296	547	8,704	68	294,095
1992	299	389	8,849	74	301,719
1993	317	565	9,074	79	310,419
1994	323	583	9,140	78	317,945
1995	332	594	9,311	79	324,412
1996	336	603	9,458	79	330,259
1997	339	612	9,594	79	336,000
1998	343	624	9,780	79	341,804
1999	346	633	9,932	79	347,707
2000	349	644	10,106	79	353,613
2001	352	655	10,264	79	359,644
2002	354	664	10,419	79	365,870
2003	357	672	10,538	79	371,955

NOTE: SALES FOR RESALE AND NET ENERGY FOR LOAD INCLUDE CONTRACTED ENERGY ALLOCATED TO CERTAIN CUSTOMERS BY SOUTHEASTERN POWER ADMINISTRATION (SEPA).

GRAPH 1

HISTORY AND FORECAST
OF ENERGY USE BY TYPE OF CUSTOMER



Utility: Gulf Power Company
(a) (b)
Energy Sources

Energy Sources			Actual 1992	Actual 1993	1994	1995	1996	1997
Annual Energy Interchange		GWH	(982)	(484)	(1,687)	(2,003)	(2,033)	(2,479)
Nuclear		GWH	None	None	None	None	None	None
Coal		GWH	9,821	9,497	10,812	11,292	11,448	12,017
Residual	-Total	GWH	0	0	0	0	0	0
	Steam	GWH	0	0	0	0	0	0
	CC	GWH	None	None	None	None	None	None
	CT	GWH	None	None	None	None	None	None
	Diesel	GWH	None	None	None	None	None	None
Distillate	-Total	GWH	1	3	2	1	2	2
	Steam	GWH	None	None	None	None	None	None
	CC	GWH	None	None	None	None	None	None
	CT	GWH	1	3	2	1	2	2
	Diesel	GWH	None	None	None	None	None	None
Natural Gas	-Total	GWH	9	58	13	21	41	54
	Steam	GWH	9	58	13	21	41	54
	CC	GWH	None	None	None	None	None	None
	CT	GWH	None	None	None	None	None	None
	Diesel	GWH	None	None	None	None	None	None
Other		GWH	None	None	None	None	None	None
Net Energy for Load		GWH	8,849	9,074	9,140	9,311	9,458	9,594

(a) Includes contracted energy allocated to certain resale customers by Southeastern Power Administration (SEPA)
(b) Includes energy generated and sold under existing power sales contracts.

Utility: Gulf Power Company
(a) (b)
Energy Sources

Energy Sources			1998	1999	2000	2001	2002	2003
Annual Energy Interchange		GWH	(2,316)	(2,593)	(2,589)	(2,601)	(3,175)	(3,307)
Nuclear		GWH	None	None	None	None	None	None
Coal		GWH	11,961	12,230	12,440	12,508	13,006	13,155
Residual	-Total	GWH	0	0	0	0	0	0
	Steam	GWH	0	0	0	0	0	0
	CC	GWH	None	None	None	None	None	None
	CT	GWH	None	None	None	None	None	None
	Diesel	GWH	None	None	None	None	None	None
Distillate	-Total	GWH	2	2	1	2	0	0
	Steam	GWH	None	None	None	None	None	None
	CC	GWH	None	None	None	None	None	None
	CT	GWH	2	2	1	2	0	0
	Diesel	GWH	None	None	None	None	None	None
Natural Gas	-Total	GWH	133	293	254	355	588	690
	Steam	GWH	75	109	92	126	126	132
	CC	GWH	None	None	None	None	239	316
	CT	GWH	58	184	162	229	223	242
	Diesel	GWH	None	None	None	None	None	None
Other		GWH	None	None	None	None	None	None
Net Energy for Load		GWH	9,780	9,932	10,106	10,264	10,419	10,538

(a) Includes contracted energy allocated to certain resale customers by Southeastern Power Administration (SEPA)
(b) Includes energy generated and sold under existing power sales contracts.

Utility: Gulf Power Company

Fuel Requirements

Fuel Requirements			Actual 1992	Actual 1993	1994	1995	1996	1997
Nuclear		$BTUx10^{12}$	None	None	None	None	None	None
Coal		1000 TON	4,277	4,135	4,861	5,252	5,318	5,557
Residual	-Total	1000 BBL	0	0	0	0	0	0
	Steam	1000 BBL	0	0	0	0	0	0
	CC	1000 BBL	None	None	None	None	None	None
	CT	1000 BBL	None	None	None	None	None	None
	Diesel	1000 BBL	None	None	None	None	None	None
Distillate	-Total	1000 BBL	22	31	34	32	30	30
	Steam	1000 BBL	19	22	30	29	25	26
	CC	1000 BBL	None	None	None	None	None	None
	CT	1000 BBL	3	9	4	3	5	4
	Diesel	1000 BBL	None	None	None	None	None	None
Natural Gas	-Total	1000 MCF	357	1,125	182	302	608	792
	Steam	1000 MCF	357	1,125	182	302	608	792
	CC	1000 MCF	None	None	None	None	None	None
	CT	1000 MCF	None	None	None	None	None	None
	Diesel	1000 MCF	None	None	None	None	None	None
Other		$BTUx10^{6}$	None	None	None	None	None	None
Annual Avg. Fossil Net H.R.		BTU/KWH	10,347	10,390	10,236	10,298	10,290	10,307

Utility: Gulf Power Company

Fuel Requirements

Fuel Requirements			1998	1999	2000	2001	2002	2003
Nuclear		$BTUx10^{12}$	None	None	None	None	None	None
Coal		1000 TON	5,538	5,627	5,674	5,691	5,892	5,972
Residual	-Total	1000 BBL	0	0	0	0	0	0
	Steam	1000 BBL	0	0	0	0	0	0
	CC	1000 BBL	None	None	None	None	None	None
	CT	1000 BBL	None	None	None	None	None	None
	Diesel	1000 BBL	None	None	None	None	None	None
Distillate	-Total	1000 BBL	31	30	30	27	26	24
	Steam	1000 BBL	26	25	27	23	26	24
	CC	1000 BBL	None	None	None	None	None	None
	CT	1000 BBL	5	5	3	4	0	0
	Diesel	1000 BBL	None	None	None	None	None	None
Natural Gas	-Total	1000 MCF	1,855	3,980	3,436	4,799	6,591	7,500
	Steam	1000 MCF	1,113	1,613	1,357	1,867	1,874	1,943
	CC	1000 MCF	None	None	None	None	1,861	2,453
	CT	1000 MCF	742	2,367	2,079	2,932	2,856	3,104
	Diesel	1000 MCF	None	None	None	None	None	None
Other		$BTUx10^{6}$	None	None	None	None	None	None
Annual Avg. Fossil Net H.R.		BTU/KWH	10,322	10,345	10,292	10,323	10,269	10,253

HISTORY AND FORECAST OF SEASONAL PEAK DEMAND AND ANNUAL NET ENERGY FOR LOAD

	SUMMER PEAK DEMAND – MW					ANNUAL NET ENERGY FOR LOAD			ANNUAL LOAD FACTOR
	FIRM					GWH			
YEAR	RETAIL	WHOLESALE	TOTAL	INTERRUPT	TOTAL	RETAIL	WHOLESALE	TOTAL	%
1984	1,315	80	1,395	0	1,395	6,338	364	6,703	54.7%
1985	1,367	87	1,454	0	1,454	6,757	359	7,115	55.9%
1986	1,611	73	1,684	0	1,684	7,110	324	7,435	50.4%
1987	1,551	73	1,624	0	1,624	7,395	328	7,723	54.3%
1988	1,565	55	1,620	0	1,620	7,733	283	8,016	56.3%
1989	1,638	60	1,698	0	1,698	8,102	276	8,378	56.3%
1990	1,716	69	1,785	0	1,785	8,319	294	8,612	55.1%
1991	1,684	64	1,748	0	1,748	8,409	296	8,704	56.8%
1992	1,765	71	1,836	0	1,836	8,550	299	8,849	54.9%
1993	1,830	76	1,906	0	1,906	8,758	317	9,074	54.3%
1994	1,828	72	1,900	0	1,900	8,818	323	9,140	54.9%
1995	1,869	75	1,944	0	1,944	8,979	332	9,311	54.7%
1996	1,908	76	1,984	0	1,984	9,122	336	9,458	54.3%
1997	1,932	76	2,008	0	2,008	9,255	339	9,594	54.5%
1998	1,965	77	2,042	0	2,042	9,437	343	9,780	54.7%
1999	1,990	78	2,068	0	2,068	9,586	346	9,932	54.8%
2000	2,019	78	2,097	0	2,097	9,757	349	10,106	54.9%
2001	2,043	79	2,122	0	2,122	9,912	352	10,264	55.2%
2002	2,065	79	2,144	0	2,144	10,064	354	10,419	55.5%
2003	2,080	80	2,160	0	2,160	10,181	357	10,538	55.7%

NOTE: Wholesale and total columns include contracted capacity and energy allocated to certain resale customers by Southeastern Power Administration (SEPA).

HISTORY AND FORECAST OF SEASONAL PEAK DEMAND AND ANNUAL NET ENERGY FOR LOAD

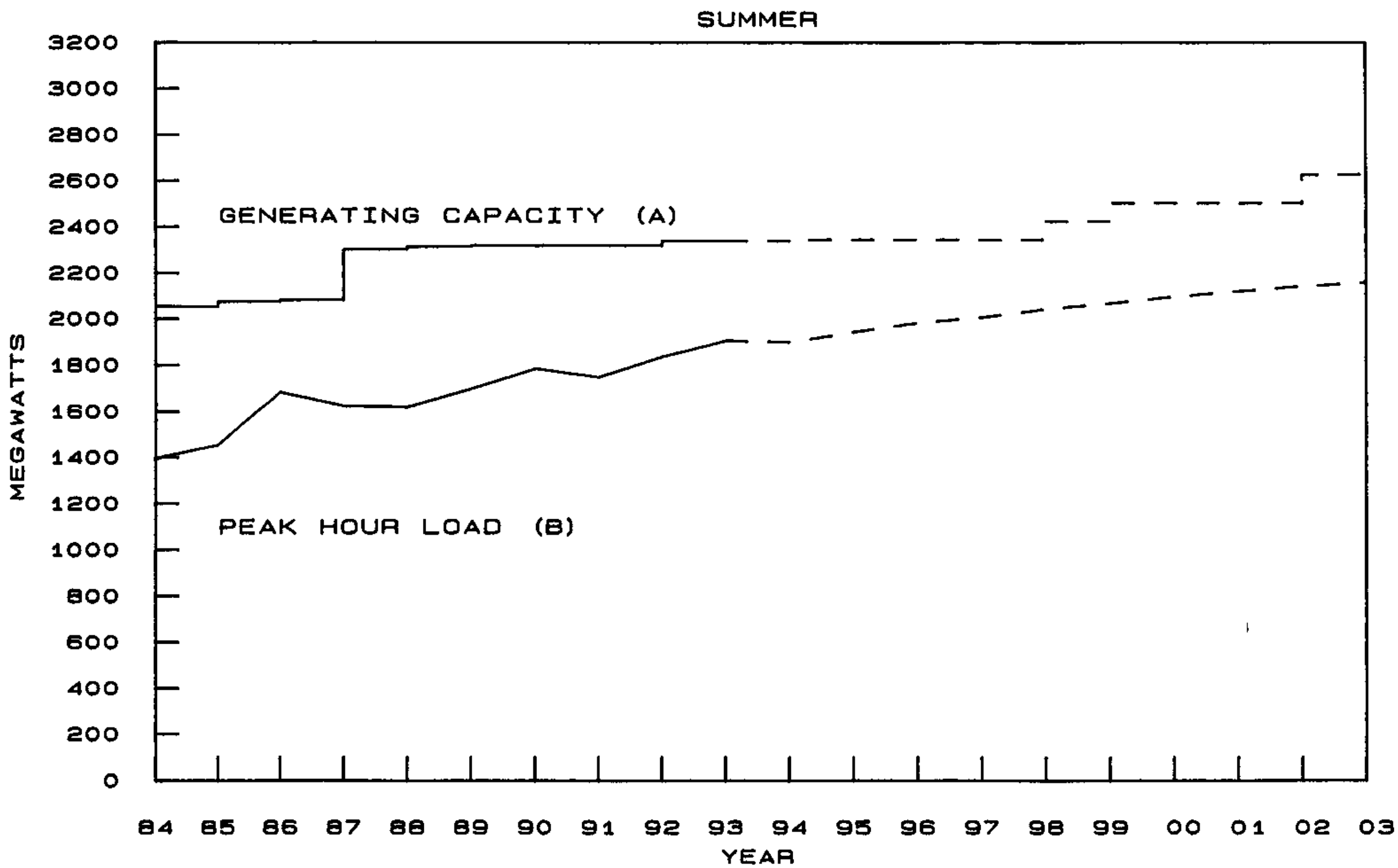
WINTER PEAK DEMAND – MW

	FIRM				
YEAR	RETAIL	WHOLESALE	TOTAL	INTERRUPT	TOTAL
1983–84	1,234	72	1,306	0	1,306
1984–85	1,450	81	1,531	0	1,531
1985–86	1,365	47	1,412	0	1,412
1986–87	1,303	57	1,360	0	1,360
1987–88	1,342	60	1,402	0	1,402
1988–89	1,498	56	1,554	0	1,554
1989–90	1,764	57	1,821	0	1,821
1990–91	1,375	50	1,425	0	1,425
1991–92	1,481	60	1,541	0	1,541
1992–93	1,518	61	1,579	0	1,579
1993–94	1,623	61	1684	0	1,684
1994–95	1,653	63	1716	0	1,716
1995–96	1,720	64	1784	0	1,784
1996–97	1,746	65	1811	0	1,811
1997–98	1,782	65	1847	0	1,847
1998–99	1,809	66	1875	0	1,875
1999–00	1,841	67	1908	0	1,908
2000–01	1,870	67	1937	0	1,937
2001–02	1,900	68	1968	0	1,968
2002–03	1,919	68	1987	0	1,987

NOTE: Wholesale and total columns include contracted capacity and energy allocated to certain resale customers by Southeastern Power Administration (SEPA).

GRAPH 2

HISTORY AND FORECAST OF LOAD AND
CAPACITY ADDITIONS

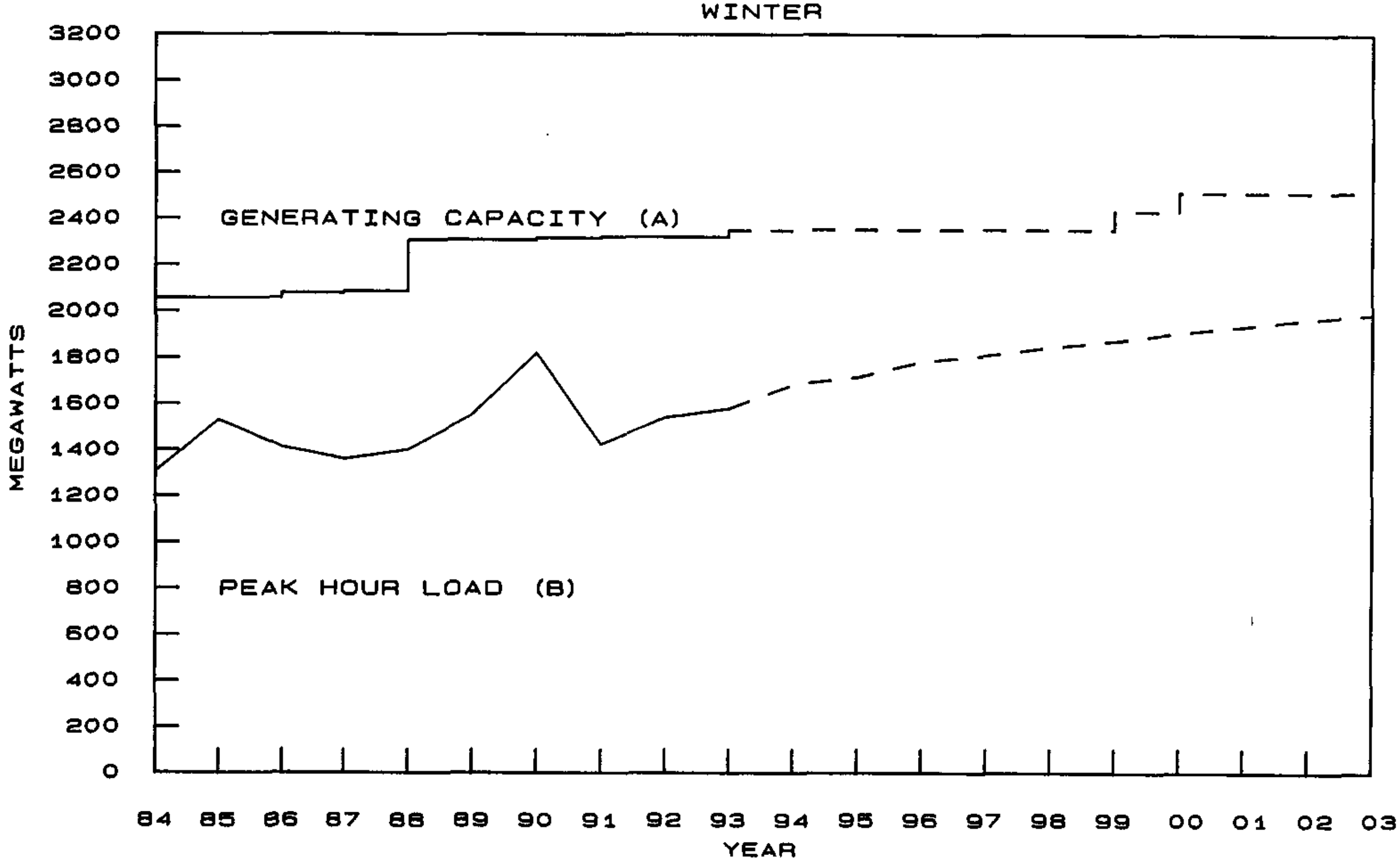


NOTE: (A) SHOWS INSTALLED GENERATING CAPACITY ONLY; REFER TO FORM 7A FOR NET AVAILABLE CAPACITY.
(B) INCLUDES CAPACITY ALLOCATED TO CERTAIN RESALE CUSTOMERS BY SEPA.

GRAPH 2

HISTORY AND FORECAST OF LOAD AND CAPACITY ADDITIONS

WINTER



NOTE: (A) SHOWS INSTALLED GENERATING CAPACITY ONLY; REFER TO FORM 7B FOR NET AVAILABLE CAPACITY.
(B) INCLUDES CAPACITY ALLOCATED TO CERTAIN RESALE CUSTOMERS BY SEPA.

UTILITY: GULF POWER COMPANY

TYP FORM 5

PREVIOUS YEAR ACTUAL AND TWO-YEAR FORECAST OF PEAK DEMAND AND NET ENERGY FOR LOAD BY MONTH

	ACTUAL		FORECAST			
	1993		1994		1995	
MONTH	PEAK DEMAND MW	NEL GWH	PEAK DEMAND MW	NEL GWH	PEAK DEMAND MW	NEL GWH
JAN	1,383	669	1,684	773	1,716	787
FEB	1,579	634	1,549	625	1,574	635
MAR	1,568	681	1,402	660	1,432	674
APR	1,049	599	1,206	604	1,234	616
MAY	1,458	724	1,558	757	1,600	777
JUN	1,770	906	1,871	928	1,909	947
JUL	1,906	1,018	1,900	967	1,944	989
AUG	1,866	985	1,889	968	1,933	990
SEP	1,741	827	1,783	833	1,769	826
OCT	1,391	679	1,356	667	1,394	685
NOV	1,343	629	1,266	616	1,297	631
DEC	1,479	721	1,628	742	1,653	753
TOTAL		9,074		9,140		9,311

NOTE: *Includes contracted capacity and energy allocated to certain* resale customers by Southeastern Power Administration (SEPA).

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FORECASTING DOCUMENTATION

GULF POWER COMPANY

LOAD FORECASTING METHODOLOGY

OVERVIEW

Gulf Power Company views the forecasting effort as a dynamic process requiring ongoing efforts to yield results which allow informed planning and decision-making. The total forecast is an integration of different techniques and methodologies, each applied to the task for which it is best suited. Many of the techniques take advantage of the extensive data made available through the Company's marketing efforts, which are predicated on the philosophy of knowing and understanding the needs, perceptions and motivations of our customers and actively promoting wise and efficient uses of energy which satisfy customer needs. Gulf is recognized as an industry leader in the successful implementation of cost-effective conservation programs, beginning with the introduction of the highly successful Good ¢ents Home concept in 1976, and continuing with concerted efforts to meet the mandates of the 1980 Florida Energy Efficiency and Conservation Act (FEECA). This philosophy entails focused market research efforts, coupled with field marketing efforts that maintain an open line of communication with our customers, and yields increased knowledge and understanding of changes in the marketplace. Also included in these efforts is continued research support for promising new energy technologies, including solar photovoltaics, electric vehicles, fuel cells and high efficiency equipment.

The Forecasting and Marketing Planning section of the Marketing and Load Management Department is responsible for preparing forecasts of customers, energy and peak demand. A description of the methods used in the development of these forecasts follows.

I. CUSTOMER FORECAST

A. RESIDENTIAL CUSTOMER FORECAST

The immediate short-term forecast (0-2 years) of customers is based primarily on projections prepared by division personnel. The divisions remain abreast of local market and economic conditions within their service territories through direct contact with economic development agencies, developers, builders, lending institutions and other key contacts. The immediate short-term forecasts prepared by the divisions, which are developed through various forecasting methods, are analyzed for consistency and the incorporation of major construction projects and business developments is reviewed. The end result is a near-term forecast of residential customers by type of dwelling.

For the remaining forecast horizon (3-25 years), the Gulf Economic Model, a competition-based econometric model, is used in the development of residential customer projections. Projections of births, deaths, and population by age groups are determined by past and projected trends. Migration is determined by economic growth relative to surrounding areas.

The forecast of residential customers is an outcome of the final section of the migration/demographic element of the model. The number of residential customers Gulf expects to serve is calculated by multiplying the total number of households located in the eight counties in which Gulf provides service by the percentage of customers in these eight counties for which Gulf currently provides service.

The number of households referred to above is computed by applying a household formation trend to the previously mentioned population by age group, and then by summing the number of households in each of five adult age categories. As indicated, there is a relationship between households, or residential customers, and the age structure of the population of the area, as well as household formation trends. The household formation trend is the product of initial year household formation rates in the Gulf service area and projected U.S. trends in household formation.

B. COMMERCIAL CUSTOMER FORECAST

The immediate short-term forecast (0-2 years) of commercial customers, as in the residential sector, is prepared by the divisions. A review of the assumptions, techniques and results for each division is undertaken, with special attention given to the incorporation of major commercial development projects.

Beyond the immediate short-term period, commercial customers are forecast as a function of residential customers, reflecting the growth of commercial services to meet the needs of new residents. Implicit in the commercial customer forecast is the relationship between growth in total real disposable income and growth in the commercial sector.

II. ENERGY SALES FORECAST

A. RESIDENTIAL SALES FORECAST

The residential energy sales forecast is prepared using the Residential End-Use Energy Planning System (REEPS), a model developed for the Electric Power Research Institute (EPRI) by Cambridge Systematics, Incorporated, under Project RP1211-2. The REEPS model integrates elements of both econometric and engineering end-use approaches to energy forecasting. Market penetrations and energy consumption rates for major appliance end-uses are treated explicitly. REEPS produces forecasts of appliance installations, operating efficiencies and utilization patterns for space heating, water heating, air conditioning and cooking, as well as other major end-uses. Each of these decisions is responsive to energy prices and demand-side initiatives, as well as household/dwelling characteristics and geographical variables.

The major behavioral responses in the simulation model have been estimated statistically from an analysis of household survey data. Surveys provide the data source required to identify the responsiveness of household energy decisions to prices and other variables.

The REEPS model forecasts energy decisions for a large number of different population segments. These segments represent households with different demographic and dwelling characteristics. Together, the population segments reflect the full distribution of characteristics in the customer population. The total service area forecast of residential energy decisions is represented as the sum of the choices of various segments. This approach enhances evaluation of the distributional impacts of various demand-side initiatives.

For each of the major end-uses, REEPS forecasts equipment purchases, efficiency and utilization choices. The model distinguishes among appliance installations in new housing, retrofit installations and purchases of portable units. Within the simulation, the probability of installing a given appliance in a new dwelling depends on the operating and performance characteristics of the competing alternatives, as well as household and dwelling features. The installation probabilities for certain end-use categories are highly interdependent.

The functional form of the appliance installation models is the multinomial logit or its generalization, the nested logit. The parameters of these models quantify the sensitivity of appliance installation choices to costs and other characteristics. The magnitudes of these parameters have been estimated statistically from household survey data.

Appliance operating efficiency and utilization rates are simulated in the REEPS model as interdependent decisions. Efficiency choice is dependent on operating cost at the planned utilization rate, while actual utilization depends on operating cost given the appliance efficiency. Appliance and building standards affect efficiency directly by mandating higher levels than those otherwise expected.

The sensitivity of efficiency and utilization decisions to costs, climate, household and dwelling size, and income has been estimated from historical survey data. Energy prices, income, and household and dwelling size significantly affect space conditioning and residual energy use. Household and dwelling size also influence water heating usage. Climate significantly impacts space heating and air conditioning.

Major appliance base year unit energy consumption (UEC) estimates are based on either metered appliance data or conditioned energy demand regression analysis. The latter is a technique employed in the absence of metered observations of individual appliance usage, and involves the disaggregation of total household demand for electricity into appliance specific demand functions.

Conditional energy demand models are multivariate regressions which explain residential customers' demands for electricity as functions of the energy-using equipment that they own, weather conditions, demographic and dwelling characteristics, and other factors playing a major role in total household energy consumption. The mathematics underlying this method rely upon the premise that consumption through a particular end-use must be zero if the end-use is not present, and if the end-use is present, energy consumption levels are represented as dependent on weather, demographics, income and other variables.

The total electrical energy consumption, E, of a household can be represented as:

$$E = E_o + \sum_{i=1}^{N} E_i$$

Where E_i is the electrical energy consumed by a specified major appliance i, and E_o is the electrical energy consumed by the remaining, unspecified set of appliances. The methodology of conditional energy demand analysis produces cross sectional, ordinary least squares regression estimates of the appliance coefficients. The regressions were performed using input data from the Gulf Power Company 1988 Residential Market Survey, billing cycle monthly energy data, and billing cycle monthly weather data.

The residential sales forecast reflects the continued impacts of Gulf Power's Good ¢ents Home program and efficiency improvements undertaken by customers as a result of ¢entsable Energy Check audits, as well as conversions to higher efficient outdoor lighting. Additional information on the Residential Conservation programs and program features are provided in the Conservation section.

B. COMMERCIAL SALES FORECAST

COMMEND, a commercial end-use model developed by the Georgia Institute of Technology through EPRI Project RP1216-06, serves as the basis for the major portion of Gulf's commercial energy sales forecast.

The COMMEND model is an extension of the capital-stock approach used in most econometric studies. This approach views the demand for energy as a product of three factors. The first of these factors is the physical stock of energy-using capital, the second factor is base year energy use, and the third is a utilization factor representing utilization of equipment relative to the base year.

Changes in equipment utilization are modeled using short-run econometric fuel price elasticities. Fuel choice is forecast with a life-cycle cost/behavioral microsimulation submodel, and changes in equipment efficiency are determined using engineering and cost information for space heating, cooling and ventilation equipment and econometric elasticity estimates for the other end-uses (lighting, water heating, ventilation, cooking, refrigeration, and others).

Three characteristics of COMMEND distinguish it from traditional modeling approaches. First, the reliance on engineering relationships to determine future heating and cooling efficiency provides a sounder basis for forecasting long-run changes in space heating and cooling energy requirements than a pure econometric approach can supply. Second, the simulation model uses a variety of engineering data on the energy-using characteristics of commercial buildings. Third, COMMEND provides estimates of energy use detailed by end-use, fuel type and building type.

DRI McGraw Hill's annual building data and Gulf's most recent Commercial Market Survey provided much of the input data required for the COMMEND model. The model produces forecasts of energy use for the end-uses mentioned above, within each of the following business categories:

1.	Food Stores	7.	Elementary/Secondary Schools
2.	Offices	8.	Colleges/Trade Schools
3.	Retail and Personal Services	9.	Hospitals/Health Services
4.	Public Utilities	10.	Hotels/Motels
5.	Automotive Services	11.	Religious Organizations
6.	Restaurants	12.	Miscellaneous

The Commercial Sales forecast reflects the continued impacts of Gulf Power's Commercial Good ¢ents building program and efficiency improvements undertaken by customers as a result of Commercial Energy Audits and Technical Assistance Audits, as well as conversions to higher efficient outdoor lighting. Additional information on the Commercial Conservation programs and program features are provided in the Conservation section.

C. INDUSTRIAL SALES FORECAST

The short-term industrial energy sales forecast is developed using a combination of on-site surveys of major industrial customers, trending techniques, and multiple regression analysis. Forty-nine of Gulf's largest industrial customers are interviewed to identify load changes due to equipment addition, replacement or changes in operating characteristics.

The short-term forecast of monthly sales to these major industrial customers is a synthesis of the detailed survey information and historical monthly load factor trends. The forecast of short-term sales to the remaining smaller industrial customers is developed using multiple regression analysis.

The long-term forecast of industrial energy sales is based on econometric models of the chemical, pulp and paper, other manufacturing, and non-manufacturing sectors. The industrial forecast is further refined by accounting for expected self generation installations, and a supplemental energy rate.

D. STREET LIGHTING SALES FORECAST

The forecast of monthly energy sales to street lighting customers is based on projections of the number of fixtures in service, for each of the following fixture types:

HIGH PRESSURE SODIUM VAPOR	MERCURY VAPOR
5,400 Lumen	3,200 Lumen
8,800 Lumen	7,000 Lumen
20,000 Lumen	9,400 Lumen
25,000 Lumen	17,000 Lumen
46,000 Lumen	48,000 Lumen

In the short-term, the estimated monthly kilowatt-hour consumption for each fixture type is multiplied by the projected number of fixtures in service to produce total monthly sales for a given type of fixture. This methodology allows Gulf to explicitly evaluate the impacts of lighting programs, such as mercury to high pressure sodium conversions. In the long-term, kilowatt-hour consumption grows at the same rate as projected fixture growth which, in itself, is modeled as a function of projected residential customer growth.

E. WHOLESALE ENERGY FORECAST

The short-term forecast of energy sales to wholesale customers is based on interviews with these customers, as well as recent historical data. A forecast of total monthly energy requirements at each wholesale delivery point is produced.

The long-term forecast is based on estimates of annual growth rates for each delivery point, according to future growth potential.

F. COMPANY USE & INTERDEPARTMENTAL ENERGY

The 1994 Annual Forecast for Company and Interdepartmental energy usage was based on recent historical values, with appropriate adjustments to reflect increases in energy requirements through 1993, for new Company facilities. The 1994 forecasted Company usage was then projected through the year 2003, at the same growth rate each year as the growth in residential customers. The monthly spreads were derived using historical relationships between monthly and annual energy usage.

III. PEAK DEMAND FORECAST

The peak demand forecast is prepared using the Hourly Electric Load Model (HELM), developed by ICF, Incorporated, for EPRI under Project RP1955-1. The model forecasts hourly electrical loads over the long-term.

Load shape forecasts have always provided an important input to traditional system planning functions. Forecasts of the pattern of demand have acquired an added importance due to structural changes in the demand for electricity and increased utility involvement in influencing load patterns for the mutual benefit of the utility and its customers.

HELM represents an approach designed to better capture changes in the underlying structure of electricity consumption. Rapid increases in energy prices during the 1970's and early 1980's brought about changes in the efficiency of energy-using equipment. Additionally, sociodemographic and microeconomic developments have changed the composition of electricity consumption, including changes in fuel shares, housing mix, household age and size, construction features, mix of commercial services, and mix of industrial products.

In addition to these naturally occurring structural changes, utilities have become increasingly active in offering customers options which result in modified consumption patterns. An important input to the design of such demand-side programs is an assessment of their likely impact on utility system loads.

HELM has been designed to forecast electric utility load shapes and to analyze the impacts of factors such as alternative weather conditions, customer mix changes, fuel share changes, and demand-side programs. The structural detail of HELM provides forecasts of hourly class and system load curves by weighting and aggregating load shapes for individual end-use components.

Model inputs include energy forecasts and load shape data for the user-specified end-uses. Inputs are also required to reflect new technologies, rate structures and other demand-side programs. Model outputs include hourly system and class load curves, load duration curves, monthly system and class peaks, load factors and energy requirements by season and rating period.

The methodology embedded in HELM may be referred to as a "bottom-up" approach. Class and system load shapes are calculated by aggregating the load shapes of component end-uses. The system demand for electricity in hour i is modeled as the sum of demands by each end-use in hour i:

$$L_i = \sum_{R=1}^{N_R} L_{R,i} + \sum_{C=1}^{N_C} L_{C,i} + \sum_{I=1}^{N_I} L_{I,i} + Misc_i$$

Where: L_i = system demand for electricity in hour i;
N_R = number of residential end-use loads;
N_C = number of commercial end-use loads;
N_I = number of industrial end-use loads;
$L_{R,i}$ = demand for electricity by residential end-use R in hour i;
$L_{C,i}$ = demand for electricity by commercial end-use R in hour i:
$L_{I,i}$ = demand for electricity by industrial end-use R in hour i;
$Misc_i$ = other demands (wholesale, street lighting, losses, Company use) in hour i.

IV. CONSERVATION PROGRAMS

As mentioned earlier, Gulf's forecast of energy sales and peak demand reflect the continued impacts of our conservation programs. The following provides a listing of the conservation programs and program features in effect and estimates of reductions in peak demand and net energy for load reflected in the forecast as a result of these programs.

A. RESIDENTIAL CONSERVATION

In the residential sector, Gulf's Good ¢ents New Home program is designed to make cost effective increases in the efficiencies of the new home construction market. This is being achieved by placing greater requirements on cooling and water heating equipment efficiencies, proper HVAC sizing, increased insulation levels in walls, ceilings, and floors, and tighter restrictions on glass area and infiltration reduction practices. In addition, Gulf monitors proper quality installation of all the above energy features.

Gulf's Good ¢ents Improved Home program is designed to make cost effective increases in efficiencies in the existing home market by requiring improvements in the insulation levels in walls, ceilings, and floors, and increased efficiency requirements on heating and cooling systems, air distribution system leakage, and water heating systems.

Further conservation benefits are achieved in the existing home market with Gulf's Residential Energy Audit program which is designed to provide existing residential customers with cost-effective energy conserving recommendations and options that increase comfort and reduce energy operating costs. The goal of this program is to upgrade the customer's home to the Good ¢ents Improved Home standard by providing specific whole house recommendations, a list of qualified companies who provide installation services, and information on "low-interest" financing.

Additional conservation benefits are realized in the residential sector through Gulf's Outdoor Lighting program by conversion of existing less efficient mercury vapor lighting to higher efficient high pressure sodium lighting.

B. COMMERCIAL CONSERVATION

In the commercial sector, Gulf's Good ¢ents Building program is designed to make cost effective increases in efficiencies in both new and existing commercial buildings with requirements resulting in energy conserving investments that address the thermal efficiency of the building envelope, interior lighting, heating and cooling equipment efficiency, and solar glass area. Additional recommendations are made, where applicable, on energy conserving options that include thermal storage, heat recovery systems, water heating heat pumps, solar applications, energy management systems, and high efficiency outdoor lighting.

The Commercial Energy Audit (EA) and Technical Assistance Audit (TAA) programs are designed to provide commercial customers with assistance in identifying cost effective energy conservation opportunities and introduce them to various technologies which will lead to improvements in the energy efficiency level of their business. The program is designed with enough flexibility to allow for a simple walk through analysis (EA) or a detailed economic evaluation of potential energy improvements through a more in-depth audit process (TAA) which includes equipment energy usage monitoring, computer energy modeling, life cycle equipment cost analysis, and feasibility studies.

C. STREET LIGHTING CONVERSION

Gulf's Street Lighting program is designed to achieve additional conservation benefits by conversion of existing less efficient mercury vapor lighting to higher efficient high pressure sodium lighting.

D. CONSERVATION RESULTS SUMMARY

The following table provides direct estimates of the energy savings (reductions in peak demand and net energy for load) realized by Gulf's conservation programs. These numbers reflect estimates of conservation undertaken by customers as a result of Gulf Power Company's involvement. The conservation without Gulf's involvement has contributed to further unquantifiable reductions to demand and net energy for load. These unquantifiable additional reductions are captured in the time series regressions in our demand and energy forecasts.

HISTORICAL
TOTAL CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS
AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1992	181,372	229,546	439,016,314

1994 BUDGET FORECAST
TOTAL CONSERVATION PROGRAMS
INCREMENTAL ANNUAL REDUCTIONS
AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1993	8,622	9,312	19,012,654
1994	9,706	11,531	21,538,923
1995	10,579	12,753	23,796,375
1996	11,299	13,244	25,716,249
1997	13,299	13,125	25,665,795
1998	12,430	13,628	25,915,403
1999	14,586	14,246	26,233,251
2000	15,645	14,529	26,356,851
2001	16,692	14,753	26,408,006
2002	16,739	14,975	26,494,126
2003	16,681	14,697	26,368,679

1994 BUDGET FORECAST
TOTAL CONSERVATION PROGRAMS
CUMULATIVE ANNUAL REDUCTIONS
AT GENERATOR

	SUMMER PEAK (KW)	WINTER PEAK (KW)	NET ENERGY FOR LOAD (KWH)
1993	189,995	238,858	458,028,968
1994	199,700	250,388	479,567,891
1995	210,279	263,141	503,364,266
1996	221,578	276,385	529,080,515
1997	234,877	289,510	554,746,310
1998	247,307	303,138	580,661,713
1999	261,893	317,384	606,894,964
2000	277,538	331,913	633,251,815
2001	294,230	346,666	659,659,821
2002	310,969	361,640	686,153,947
2003	327,650	376,337	712,522,626

V. SMALL POWER PRODUCTION

The current forecasts also consider Gulf's active position in the promotion of renewable energy resources. Following is a list of the cumulative small power producer capability anticipated in the base case forecast. This includes both waste-to-energy projects and other renewable fuel projects.

Small Power Producers
Net Capability

Year	MW
1993	11
1994	11
1995	11
1996	32
1997	32
1998	37
1999	37
2000	37
2001	37
2002	37
2003	37

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CHAPTER III

FORECAST
OF
FACILITIES REQUIREMENTS

TYP FORM 6

UTILITY: GULF POWER COMPANY

PLANNED AND PROSPECTIVE GENERATING FACILITY ADDITIONS AND CHANGES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
				Fuel		Const	Com'l In-	Gen Max	Net Capability		Fuel Transp		
	Unit					Start	Service	Nameplate	Summer	Winter			
Plant Name	No.	Location	Type	Pri	Alt	Mo/Yr	Mo/Yr	KW	MW	MW	Pri	Alt	Status
Scholz	A	Jackson County 12/3N/7W	CT	NG	LO	06/95	05/98		80.0	80.0	PL	TK	P
Scholz	B	Jackson County 12/3N/7W	CT	NG	LO	06/96	05/99		80.0	80.0	PL	TK	P
Intermediate Unit (25%)		Unknown	CC	NG	LO	06/97	05/02		158.0	158.0	PL	TK	P
Lansing Smith	A	Bay County 36/2S/15W	CT	LO	--	--	(12/01)		(35.2)	(43.6)	TK	--	R
							TOTAL		282.8	274.4			

Abbreviations:
CT - Combustion Turbine
CC - Combined Cycle
NG - Natural Gas
LO - Light Oil
PL - Pipeline
TK - Truck

P - Planned, but not authorized by utility
R - To be retired

TYP FORM 7A

UTILITY: GULF POWER COMPANY

FORECAST OF CAPACITY, DEMAND, AND SCHEDULED MAINTENANCE
AT TIME OF SUMMER PEAK (A)

					MARGIN BEFORE MAINTENANCE			MARGIN AFTER MAINTENANCE	
YEAR	TOTAL INSTALLED CAPACITY MW	FIRM CAPACITY IMPORT MW (B)	TOTAL AVAILABLE CAPACITY MW	FIRM PEAK DEMAND MW	MW	PER CENT OF PEAK	SCHEDULED MAINTENANCE MW	MW	PER CENT OF PEAK
1994	2345	(201)	2144	1900	244	12.8%	NONE	244	12.8%
1995	2345	(200)	2145	1944	201	10.3%		201	10.3%
1996	2345	(179)	2166	1984	182	9.2%		182	9.2%
1997	2345	(179)	2166	2008	158	7.9%		158	7.9%
1998	2425	(179)	2246	2042	204	10.0%		204	10.0%
1999	2505	(179)	2326	2068	258	12.5%		258	12.5%
2000	2505	(179)	2326	2097	229	10.9%		229	10.9%
2001	2505	(179)	2326	2122	204	9.6%		204	9.6%
2002	2628	(179)	2449	2144	305	14.2%		305	14.2%
2003	2628	(179)	2449	2160	289	13.4%		289	13.4%

NOTE: (A) CAPACITY ALLOCATIONS AND CHANGES MUST BE MADE BY JUNE 30 TO BE CONSIDERED IN EFFECT AT THE TIME OF THE SUMMER PEAK. ALL VALUES ARE SUMMER NET MW.

(B) INCLUDES CAPACITY SOLD IN ALL EXISTING UNIT POWER SALES CONTRACTS, CONTRACTED CAPACITY ALLOCATED TO CERTAIN RESALE CUSTOMERS BY THE SOUTHEASTERN POWER ADMINISTRATION (SEPA), FIRM PURCHASES, AND ESTIMATED CONTRACTED DEMAND SIDE OPTIONS.

UTILITY: GULF POWER COMPANY

FORECAST OF CAPACITY, DEMAND, AND SCHEDULED MAINTENANCE
AT TIME OF WINTER PEAK (A)

YEAR	TOTAL INSTALLED CAPACITY MW	FIRM CAPACITY IMPORT MW (B)	TOTAL AVAILABLE CAPACITY MW	FIRM PEAK DEMAND MW	MARGIN BEFORE MAINTENANCE MW	MARGIN BEFORE MAINTENANCE PER CENT OF PEAK	SCHEDULED MAINTENANCE MW	MARGIN AFTER MAINTENANCE MW	MARGIN AFTER MAINTENANCE PER CENT OF PEAK
1993-94	2353	(201)	2152	1684	468	27.8%	NOT	468	27.8%
1994-95	2353	(201)	2152	1716	436	25.4%	AVAILABLE	436	25.4%
1995-96	2353	(200)	2153	1784	369	20.7%		369	20.7%
1996-97	2353	(179)	2174	1811	363	20.0%		363	20.0%
1997-98	2353	(179)	2174	1847	327	17.7%		327	17.7%
1998-99	2433	(179)	2254	1875	379	20.2%		379	20.2%
1999-00	2513	(179)	2334	1908	426	22.3%		426	22.3%
2000-01	2513	(179)	2334	1937	397	20.5%		397	20.5%
2001-02	2513	(179)	2334	1968	366	18.6%		366	18.6%
2002-03	2627	(179)	2448	1987	461	23.2%		461	23.2%
2003-04	2627	(179)	2448	2013	435	21.6%		435	21.6%

NOTE: (A) CAPACITY ALLOCATIONS AND CHANGES MUST BE MADE BY NOVEMBER 30 TO BE CONSIDERED IN EFFECT AT THE TIME OF WINTER PEAK. ALL VALUES ARE WINTER NET MW.

(B) INCLUDES CAPACITY SOLD IN ALL EXISTING UNIT POWER SALES CONTRACTS, CONTRACTED CAPACITY ALLOCATED TO CERTAIN RESALE CUSTOMERS BY THE SOUTHEASTERN POWER ADMINISTRATION (SEPA), FIRM PURCHASES, AND ESTIMATED CONTRACTED DEMAND SIDE OPTIONS.

AVAILABILITY OF PURCHASED POWER

Gulf Power Company coordinates its planning and operation with the other operating companies of the Southern electric system: Alabama Power Company, Georgia Power Company, Mississippi Power Company, and Savannah Electric and Power Company. In any year an individual operating company may have a temporary surplus or deficit in generating capacity, depending on the relationship of its planned generating capacity to its load and reserve responsibility. Each company buys or sells its temporary deficit or surplus capacity from or to the pool. This is done through the mechanism of an Intercompany Interchange Contract among the companies, which is reviewed and updated annually.

OFF SYSTEM SALES

Unit Power Sales

Gulf Power Company, along with the other Southern operating companies, have negotiated the sales of capacity and energy to several utilities outside the Southern system. The term of the contracts started prior to 1994 and extends into 2010. Gulf's share of the capacity and energy sales varies from year to year and is reflected in the reserves on Forms 7A and 7B and the energy and fuel use on Forms 3A and 3B.

Long Term Sales

Contracts have also been finalized for the sale of non-firm capacity and energy through December of the year 1994. Reserves shown in this filing have not been reduced for this capacity; however, the energy sales have been reflected on Forms 3A and 3B.

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CHAPTER IV

SITE DESCRIPTION
AND
IMPACT ANALYSIS

Scholz Site

The Scholz site consists of 293 acres (total plant site) and is the location of the existing Scholz Electric Generating Facility. It is located south of the town of Sneads along the west side of the Apalachicola river. The site is accessable by railroad and river barge service.

Scholz has been chosen as the site for the installation of two 80 MW combustion turbines. The first will be in service in May of 1998 and the second in May of 1999. These two combustion turbines and associated transmission line are to be installed on existing cleared company property immediately adjacent to the existing Scholz plant. These units will be used during peak periods, and the impact of their operation on the surrounding area should be minimal.

Utility: Gulf Power Company

Status Report
Specifications of Proposed Generating Facilities

(1)	Plant Name & Unit	Scholz A
(2)	Status	This facility is planned but not authorized
(3)	Anticipated Construction Timing	In-Service May, 1998
(4)	Capacity	Summer 80.0 MW Winter 80.0 MW
(5)	Type	Combustion Turbine
(6)	Primary and Alternate Fuel	Primary - Natural Gas; Alternate - Light Oil (distillate)
(7)	Air Pollution Control Strategy	Steam Injection for NOx control
(8)	Cooling Method	NA
(9)	Total Site Area	293 acres (total plant site)
(10)	Anticipated Capital Investment	$ 31,483,324
(11)	Certification Status	Not applied
(12)	Status with Federal Agencies	Not applied

Utility: Gulf Power Company

Status Report
Specifications of Proposed Generating Facilities

(1)	Plant Name & Unit	Scholz B
(2)	Status	This facility is planned but not authorized
(3)	Anticipated Construction Timing	In-Service May, 1999
(4)	Capacity	Summer 80.0 MW Winter 80.0 MW
(5)	Type	Combustion Turbine
(6)	Primary and Alternate Fuel	Primary - Natural Gas; Alternate - Light Oil (distillate)
(7)	Air Pollution Control Strategy	Steam Injection for NOx control
(8)	Cooling Method	NA
(9)	Total Site Area	293 acres (total plant site)
(10)	Anticipated Capital Investment	$ 32,742,656
(11)	Certification Status	Not applied
(12)	Status with Federal Agencies	Not applied

Utility: Gulf Power Company

Status Report
Specifications of Proposed Generating Facilities

(1)	Plant Name & Unit	Intermediate Unit (25%)
(2)	Status	This facility is planned but not authorized
(3)	Anticipated Construction Timing	In-Service May, 2002
(4)	Capacity	Summer 158.0 MW Winter 158.0 MW
(5)	Type	Combined Cycle
(6)	Primary and Alternate Fuel	Primary - Natural Gas; Alternate - Light Oil (distillate)
(7)	Air Pollution Control Strategy	Steam Injection for NOx control for combustion turbine Selective Catalytic Reduction for heat recovery steam generator
(8)	Cooling Method	mechanical draft cooling tower
(9)	Total Site Area	Unknown
(10)	Anticipated Capital Investment	$ 95,322,092
(11)	Certification Status	Not applied
(12)	Status with Federal Agencies	Not applied

Utility: Gulf Power Company

Status Report and Specifications of Proposed
Directly-Associated Transmission Lines

(1)	Point of Origin and Termination	Scholz to Smith - Thomasville 230 KV loop
(2)	Number of Lines	2
(3)	Right-of-Way	Length: on company property Width:
(4)	Line Length	0.3 miles each
(5)	Voltage	230 KV
(6)	Anticipated Construction Timing	In-Service January, 1998
(7)	Anticipated Capital Investment	$ 209,733
(8)	Substations	None
(9)	Participation	None

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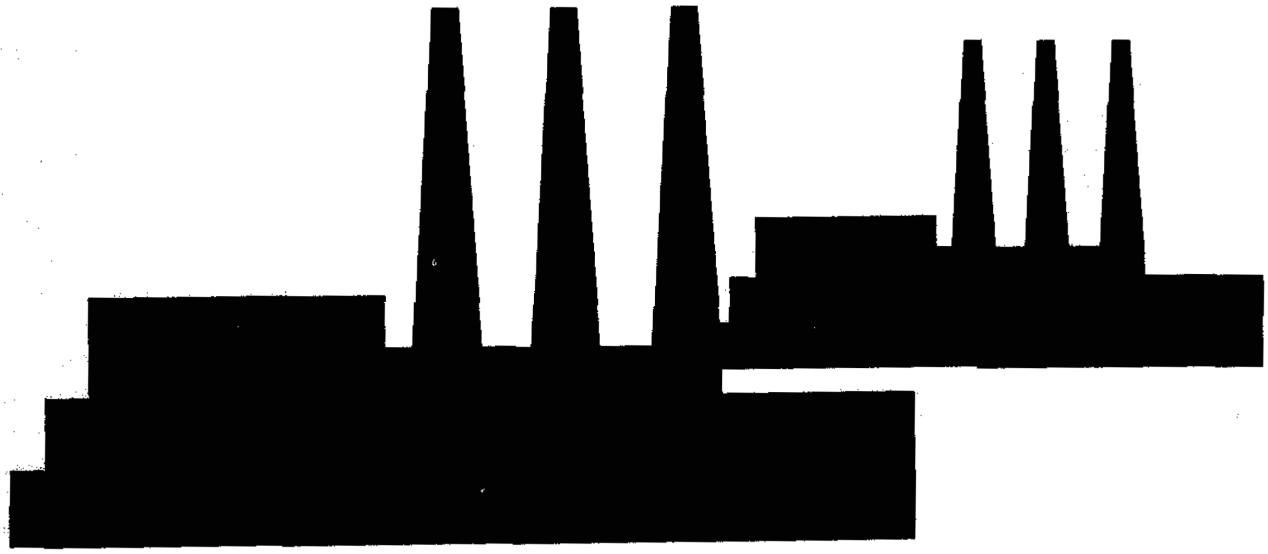
Gulf Power Company
Clean Air Act Compliance Plan



1994 Update

Gulf Power

the southern electric system

GULF POWER COMPANY

1994 UPDATE

CLEAN AIR ACT

COMPLIANCE PLAN

MARCH 1994

CLEAN AIR ACT
COMPLIANCE PLAN

1994 UPDATE

Gulf Power Company

March 1994

EXECUTIVE SUMMARY

Gulf Power Company is an operating subsidiary of The Southern Company. As a part of the Southern system, Gulf Power participates in an integrated power supply system with four other subsidiaries. The Southern system operates 90 fossil fueled generating units which are subject to the Clean Air Act legislation. The wide diversity of these units, i.e., fuel burn capability, emission allowances, proximity to low sulfur coal, etc. permit the development of a least cost system solution compared to a stand alone basis. Therefore, this plan is based on the Southern system compliance as allowed under the Federal Clean Air Act as amended in 1990. The strategy remains basically the same as the previous filing - a market strategy that takes advantage of the company's fuel switching options and minimizes the sulfur dioxide compliance costs in both Phase I and Phase II. Also the strategy minimizes nitrogen oxide control cost and provides the flexibility to make a number of decisions later when additional information is available on rulemakings, technologies, and the allowance market.

During Phase I, beginning in 1995, Gulf Power Company expects to meet the requirements of the act by switching units named in the legislation (i.e., Plant Crist Units 6 and 7) to lower sulfur coal. In addition, we will increase our compliance flexibility by adding seasonal natural gas firing capability. Through this action, our system will meet or exceed the new sulfur dioxide (SO_2) emission standards. Based on the projected operation of the named generating units, excess allowances will be created which will be banked for use during the second phase of compliance.

In addition to reducing SO_2 emissions, Gulf Power is installing low NO_x burners on the named units to comply with the requirements to reduce emissions of nitrogen oxides (NO_x). The continuous emissions monitors (CEMs) that are presently on all Gulf units are being upgraded to meet the new requirements. CEMs on Plant Crist Units 6 and 7 were installed to meet the November 1993 deadline.

In Phase II, beginning in the year 2000, Gulf Power and its affiliated companies plan to use SO_2 allowances banked in Phase I and either purchase additional allowances on the open market or comply internally depending on the price of SO_2 allowances. Internal compliance will involve additional fuel switching, seasonal natural gas burning and/or the installation of flue gas desulfurization (FGD) equipment (scrubbers) at various plants. Low-NOx burners will be installed or action taken as needed on the remainder of the system's fossil-fired plants to meet Phase II NOx requirements. This update represents no fundamental change in the Phase II strategy.

This updated compliance plan continues to maximize the Company's fuel switching options in Phase I, minimize the compliance cost in both Phase I and Phase II, and provides the flexibility to make a number of decisions later when better information is available on the regulations, control technology and the allowance market. Gulf Power and the Southern system will have the option in Phase II to either buy SO_2 allowances or comply through *internal means* depending on the value and availability of allowances on the market.

For Gulf Power, compliance with the 1990 Amendments to the Clean Air Act is projected to create a cumulative revenue requirement of $35 million (nominal values) for Phase I and $583 million (nominal values) for Phase II or $618 million (nominal values) for the 1993 through 2017 period. The net present value (1993 dollars) of the projected revenue requirement through 2017 is $176 million.

This plan is based on a Southern system solution which meets both the spirit and intent of the law, continues to protect the environment, and provides the greatest opportunity to minimize the financial impact on Gulf Power's customers.

The remainder of this document presents the basis for the compliance plan and provides background information on a number of associated issues.

CONTENTS

Page

1.0 INTRODUCTION

The 1990 Clean Air Act (CAA) Amendments have considerably increased the magnitude and complexity of clean air compliance for coal-fired electric utilities. Gulf Power Company, an operating subsidiary of The Southern Company, was involved in the amendments' development and recognized the necessity, even prior to the November 15, 1990, enactment for an integrated clean air compliance strategy. The principal requirements of the CAA that affect coal-fired generating plants are found in Title IV - Acid Deposition. However, the strategy development process also included consideration of other known requirements of the amendments and, to the extent possible, a review of potential future requirements.

A multi-disciplined project team and nearly a score of task forces reviewed the strategy against changes in a number of key drivers. These drivers included fuel prices, technology costs, expected allowance values, and regulatory developments. Even with these changes considered, The Southern Company compliance strategy remains basically the same - a market strategy that takes advantage of the company's fuel switching options and minimizes the sulfur dioxide compliance costs in both Phase I and Phase II. Also the strategy minimizes nitrogen oxide control cost and provides the flexibility to make a number of decisions later when additional information is available on rulemakings, technologies, and the allowance market.

Gulf Power Company's strategy achieves a major reduction in SO_2 emissions as illustrated by Table 1-1 and is projected to be the least cost plan. The table shows the plan reduction in total tons of SO_2 emitted by Gulf's plants from 1992 until the year 2017.

Commission Order

On September 20, 1993, the Florida Public Service Commission issued an order approving Gulf Power's Phase I Compliance Plan. The Commission's order also approved Gulf's Phase I plan regarding Continuous Emissions Monitors (CEMs) and standards regarding emissions of nitrogen oxides (NO_x).

The Commission's order identified four factors which were to be addressed in Gulf's future compliance plans:

1. Potential firm, seasonal, and take or pay natural gas options - This factor is addressed in the Natural Gas discussion in Section 7.0, Fuel.

2. Displacement of high SO_2 emitters with low emitters as provided by the Reduced Utilization provision of the Clean Air Act - This factor is addressed in Section 8.0, Other Issues, Reduced Utilization.

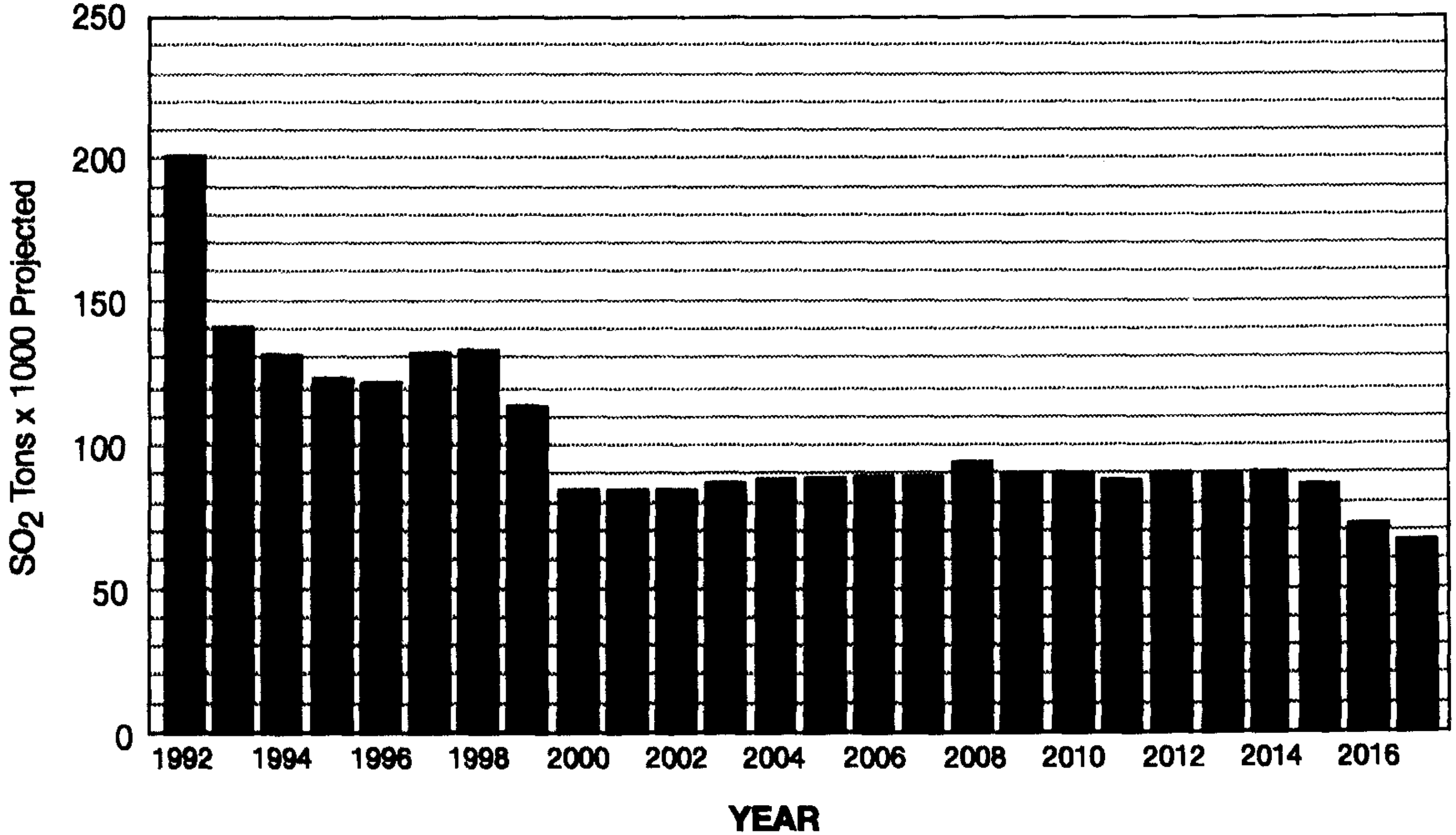
3. Pricing of allowances and Clean Air Act compliance costs for energy transactions and Intercompany Interchange Contract between affiliated companies - This factor is addressed in Section 8.0, Other Issues, Cost Allocation Among System Companies.

4. Use of long-term coal contracts over the entire planning horizon - This factor is addressed in Section 7.0, Fuel Related Modeling Issues.

TABLE 1-1

CLEAN AIR ACT COMPLIANCE STRATEGY

GULF POWER COMPANY SO_2 EMISSIONS



Actual 1992 - 1993

Projected 1994 - 2017

2.0 COMPLIANCE REQUIREMENTS

SO_2 Phase I

Beginning in 1995, the annual SO_2 emissions from the 28 Phase I units at Gulf Power Company and The Southern Company must not exceed the SO_2 allowances held in each of the unit accounts. The 28 units were named in the legislation and will be allocated SO_2 allowances by EPA based on the 1985-87 average operation and a 2.5 lbs/MBtu SO_2 emission rate.

The 28 Phase I units include:

Crist 6 & 7 (Gulf Power Company)
Gaston 1-4 (Alabama Power Company and Georgia Power Company)
Gaston 5 (Alabama Power Company)
Bowen 1-4 (Georgia Power Company)
Hammond 1-4 (Georgia Power Company)
McDonough 1 & 2 (Georgia Power Company)
Wansley 1 & 2 (Georgia Power Company)
Yates 1-7 (Georgia Power Company)
Watson 4 & 5 (Mississippi Power Company)

SO_2 Phase II

Beginning in 2000, the annual SO_2 emissions from all fossil-fired plants (over 25 MW) at Gulf Power Company and The Southern Company must not exceed the SO_2 allowances held in each of the unit accounts. The EPA allocation of allowances in Phase II is based on the 1985-87 average operation and a 1.2 lbs/MBtu SO_2 emission rate. Additional allowances in either phase can be obtained in a number of ways including purchase or by other exchange mechanisms.

Additional Gulf Power units affected during Phase II include:

Plant Crist 1, 2, 3, 4, & 5
Plant Smith 1 & 2
Plant Scholz 1 & 2
Plant Daniel 1 & 2
Plant Scherer 3

NO_X

By January 1, 1995, The Southern Company will be required to reduce on average NO_X emissions at all Phase I named units. The allowable emissions will be 0.45 lbs/MBtu for tangentially-fired boilers and 0.5 lbs/MBtu for wall-fired boilers. Approximately two-thirds of the coal-fired boilers in the Southern electric system are tangentially-fired. The remainder are wall-fired boilers.

Gulf Power Company's Crist 6 and 7 are wall-fired units and will have an allowable emission rate of 0.5 lbs/MBtu.

By January 1, 2000, the NO_X emissions on all Phase II coal-fired units (over 25MW) will have to be reduced on average to a level that EPA is required to establish by January 1, 1997. This allowable emission level for Phase II units could be below the Phase I allowable limits.

The Southern Company's initial compliance strategy (December 1990) called for the installation of low-NO_X burners at most of the Phase I and II units to comply with NO_X emission requirements under Title IV of the Act. The cost to install the burners was generally expected to be in the 15-40 $/kW range. Since this initial strategy, unit specific studies have identified a number of additional items that may be needed to insure the proper functioning of the low-NO_X burners. Gulf, in conjunction with the Southern Company, continues to reevaluate and update cost estimates in accord with the flexible strategy concept.

Because of these increased costs and due to the fact that NO_X emissions averaging will be allowed by plant, company, or system, The Southern Company task force continues to look at alternative NO_X technologies and strategies. The results of the task force study are included in Section 5.0 (NO_X Compliance Plan) and a summary of the alternatives considered are included under NO_X Compliance Alternatives located in the Appendix. The final EPA NO_X emission regulations under the Act were issued on March 1, 1994 and are currently under review.

Continuous Emission Monitoring Systems (CEMs)

The CAA Amendments require that continuous emissions monitors be installed by the Company, and certified on all Phase I units by November 15, 1993, and on all other units by January 1, 1995. Units below 25 MW and existing combustion turbines are not required to have CEMs under Title IV. The parameters to be monitored are opacity, NO_X, SO_2, CO_2, and volumetric flow.

Gulf Power has had effective continuous emission monitoring equipment in operation for over ten years. However, the existing monitors did not satisfy the requirements of the new CAA amendments. Gulf Power upgraded its CEMs system on Plant Crist Units 6 and 7 and completed certifications by November, 1993. Gulf Power will complete the installation of flow monitors and upgrade the CEM's on all other units this year. (See Section 9.0.)

The final EPA CEMs rules are more stringent than the existing state monitoring rules and compliance will be very difficult even with expected near term rule changes. The requirement to measure the flow rate of the flue gas has and will likely continue to present problems for some units due to existing duct arrangements. Also, the technology for making flow measurements is not completely proven at this time. A system team is in place to evaluate these problems.

Air Toxics

As previously stated in the initial plan, Title III of the Clean Air Act Amendments of 1990 requires a special 3-year study provision for hazardous air pollutant emissions from power plants. The legislation directs EPA to undertake a "study of the hazards of public health reasonably anticipated to occur as a result of emissions by electric steam generating units" of the 189 hazardous substances listed in the statute. EPA is to report the results of the study to Congress, including a description of alternative control strategies for those emissions which may warrant regulation.

In addition to the 3-year utility study, the Amendments also mandate:

a) A 4-year study by EPA of mercury emissions from power plants, municipal waste incinerators, and other sources, including area sources; the health and environmental effects of such emissions; and the control technologies available and their costs;

b) A 3-year study by the National Institute of Environmental Health Sciences of the mercury threshold level for adverse human health effects, including a threshold in the tissue of fish for consumption; and

c) A 3-year study by EPA of the health consequences of atmospheric deposition to the Great Lakes, Chesapeake Bay, and coastal waters. Accompanying this study is also a regulatory mandate for EPA to promulgate (by November 1995) emission control regulations "as may be appropriate and necessary."

EPA is combining the 3-year power plant study and the 4-year mercury study on power plants into a single study; this combined study is expected to be submitted to Congress in November 1995. Subsequently, in a time frame not specified, EPA is directed to consider the results of the study and regulate power plants if "such regulation is appropriate and necessary." If EPA decides that some regulation is appropriate, it is expected to initiate a rulemaking with proposed regulations in 1996 or 1997.

Other Title III provisions of importance address area source requirements, risk assessment methodology evaluations, and accidental release prevention plans.

The risk associated with air toxics regulation is the possibility that EPA may decide that regulation of air toxics emissions from power plants is warranted and that the resulting regulatory program promulgated by EPA will affect Gulf and Southern electric system plants. In such a case, affected sources could be required to use baghouse controls for control of particulate air toxics emissions and potentially some type of scrubber technology for removal of volatile substances.

Permitting

EPA will promulgate permitting regulations under both Title IV - Acid Deposition Control and Title V - Permits. The Phase I acid rain operating permits were issued by EPA in late 1993 and addressed the requirements to meet Title IV rules, including compliance monitoring and reporting requirements. The Phase II permits and the state operating permits, under Title V, will be issued by the states beginning in 1995. In addition to the acid rain related requirements, these permits will include:

1. Limits and conditions to assure compliance with all applicable EPA, state, and local clean air regulatory requirements. This will include existing rate or percentage limits and compliance monitoring requirements for sulfur dioxides, nitrogen oxides, particulates, and opacity;

2. Compliance plans and schedules for noncomplying sources, including sources in nonattainment areas such as Atlanta.

3. Inspection, entry, monitoring, compliance certification, recordkeeping and reporting requirements;

4. Provisions for revising, terminating, modifying, or reissuing the permits; and,

5. Provisions for the payment of annual fees to the states to operate the new permit program based on a minimum charge of $25/ton for each regulated pollutant (potentially everything listed in the Clean Air Act except carbon monoxide) with a limit of 4000 tons per pollutant for all stationary emission sources.

The permits will be renewed at least every five years and new requirements will be incorporated into the permits.

During the 1992 Florida legislative session, a bill was adopted authorizing the Florida Department of Environmental Regulation to implement the Clean Air Act Amendments of 1990. As part of the authorization, an emissions fee system was initiated in 1993 to supplement costs associated with implementation of the Act. The first year fees were set at $10 per ton of regulated emission as outlined in the air emissions permit with a

4000 ton cap per pollutant. The annual fee will be $10 per ton in 1994 and increase to a maximum of $25 per ton the following year. The total cost to Gulf of these fees were approximately $116,000 in 1993, are expected to be about the same in 1994, and are estimated to be about $340,000 in 1995 and beyond.

In addition, the Florida Department of Environmental Regulation has finalized regulations associated with Title V of the 1990 Clean Air Act Amendments. Under development and study at EPA are regulations and studies concerning air toxics emissions, ambient air quality standards, and compliance monitoring. These activities are expected to continue through 1995 and beyond.

3.0 ASSUMPTIONS FOR BASE STRATEGY DEVELOPMENT

Operational Assumptions

A. Compliance with Clean Air Act Amendments of 1990

Phase I - First Year:	1995
Base Rate:	2.5 lbs/MBtu (SO_2)
	0.45 lbs/MBtu (NO_x) Tangentially-fired boilers
	0.5 lbs/MBtu (NO_x) Dry Bottom, Wall-fired boilers
Affected Units:	Gulf: Crist 6-7
	Southern: Yates 1-7, Gaston 1-5, Bowen 1-4,
	Hammond 1-4, Watson 4-5
	McDonough 1-2, Wansley 1-2,

Phase II - First Year:	2000
Base Rate:	1.2 lbs/MBtu (SO_2)
	0.45 lbs/MBtu (NO_x) Tangentially-fired boilers
	0.5 lbs/MBtu (NO_x) Dry Bottom, Wall-fired boilers
Affected units:	All fossil steam plants above 25 MW

B. Quantity of lower sulfur coal required by the Southern system will not affect market prices.

C. Projected energy sales to UPS (Unit Power Sales) customers included in generated energy. UPS customers are Florida Power and Light Company, Jacksonville Electric Authority, and the City of Tallahassee.

D. Reflects recent sale of Scherer 4 to Florida Power and Light Company and Jacksonville Electric Authority.

E. Marginal cost dispatch modified to include an emissions cost equal to the expected value of allowances. The expected value of allowances used in the analysis are listed in the Appendix.

F. SO_2 emissions surrender rate for underutilization in Phase I assumed to be 0.91 lbs/MBtu. Underutilization is a Phase I issue only if Phase I affected units operate, in aggregate, at annual MBtu levels less than the total of the 1985-1987 baselines.

G. Seasonal gas options assume natural gas is burned for the months of April through October.

H. Scherer Units 3 and 4 and Miller Unit 3 are assumed to burn Powder River Basin coal throughout the study period. Plant Daniel is assumed to burn Powder River Basin coal during the non-summer months and high Btu Western coal during the summer months throughout the study period.

I. All existing coal contracts are modeled, including Gulf's Peabody contract. All coal purchases above the existing contracted amounts are assumed to be purchased from the spot market. Section 7 contains a detailed discussion of the fuel inputs to the model.

J. Load and energy forecasts are consistent with Gulf's 1994 Ten Year Site Plan filing.

Financial Assumptions

A. Revenue requirements due to Clean Air compliance have been calculated based on comparing the revenue requirements of a "compliance" case versus a case without compliance costs. The resulting incremental revenue requirements are calculated assuming full cost recovery. The cost of equity is assumed to be 13.5% for all years.

B. The capital structure moves from the current allocation projected through 1998 to a 45% debt / 5% preferred stock / 50% common stock structure by 2002 and remains at that level through 2017.

C. The book life of all clean air related equipment is 15 years. The tax life is determined as follows:

   1. For expenditures on plant placed in service prior to 1976:

      75% of this property would qualify for five year straight line amortization. However, Section 291 of the Internal Revenue Code (IRC) limits rapid amortization to 80% of the tax-base allowable (i.e. the 75%) in Section 169. This combination allows for a total of 60% of the tax-base to qualify for five year straight line amortization (i.e. 75% * 80%). The remaining 40% of the tax-base would be depreciated using 20 year modified ACRS tax life using 150% declining balance methodology.

   2. For expenditures on plant placed in service in 1976 or later:

      20-year tax life using 150% declining balance methodology.

D. In the Base Strategy, all SO_2 allowances are purchased from the allowance market at the assumed market value (Section 4.0 - Allowance Trading). This includes purchases among the system companies to meet their compliance requirements. In the Internal Case, considering that the SO_2 allowance market is *not* used, the appropriate value used for transferring allowances among system companies for compliance requirements is the system incremental cost of compliance. No off-system allowance sales are assumed.

E. The timing of Phase I construction costs is estimated to coincide with scheduled maintenance. This results in some projects being completed prior to the Phase I compliance date of January 1, 1995. All construction is assumed to be closed to plant at the completion of the project, and costs are included in rate base at that time. Therefore, there are some cost impacts reflected in years prior to the beginning of Phase I and Phase II.

4.0 SO_2 COMPLIANCE PLAN

Overview

Gulf Power Company's plan for meeting SO_2 compliance requirements is as follows:

Phase I - Gulf Power Company

Plant Crist Units 6 and 7 will be switched to lower sulfur coal. Unit modifications, including new precipitator construction at Crist Unit 6, will be completed in order to burn coal with less than 1.5% sulfur at 12,000 Btu/lb. All SO_2 allowances that will be created by Units 6 and 7 emitting less than 2.5 lbs SO_2/MBtu will be banked for future compliance.

If natural gas is available, at prices competitive with coal and in volumes sufficient to power Plant Crist Units 6 or 7, gas will be burned, which would result in lower average emission levels.

Phase II - Gulf Power Company

All Gulf Power units will be switched to lower sulfur coals and/or sufficient allowances that will be purchased to bring them into compliance with the Act. Plant Crist Units 4 and 5, Plant Smith Units 1 and 2, and Plant Scholz Units 1 and 2 are expected to be capable of burning low sulfur coal with only minor modifications.

The cost of low sulfur coal and the scrubber alternative will be compared to the allowance purchase alternative on a continuing basis. Gulf will purchase allowances to achieve compliance as necessary from the Southern system or the open market.

The Gulf/Southern system strategy will be routinely reviewed. As changes occur in the allowance market, cost of fuel, and cost of scrubbing, the strategy will be updated.

Development of Alternative Compliance Plans

The Southern Company has developed three compliance plan cases based on various scenarios associated with the ability to utilize the allowance market. These three cases are listed below. All three approaches yield the same Phase I compliance plan for Gulf Power.

- Base Strategy
- Internal Case
- Company-by-Company Case

Side by side comparisons of these alternative strategies are shown in Table 4-1 on page 4-9. In the previous filing, a fourth case, Phase I Scrubber Case, was included; this case is no longer considered since scrubbing in Phase I was determined not to be a least cost option in the 1993 Gulf Power Clean Air Act Compliance filing. The use of scrubbers as a Phase II compliance option continues to be evaluated.

Base Strategy

This strategy considers the benefit of additional compliance in Phase I for use in Phase II and takes advantage of the Company's and the System's low cost compliance opportunities in Phase I. The additional allowances are banked by the company and system and used for compliance in the initial years of Phase II. A decision can be made in 1995 or 1996 to buy allowances for Phase II at an expected cost below system compliance costs or to comply internally.

Table 4-2 on page 4-10 shows how Gulf accumulates an allowance bank through 1999 and then uses that bank through 2003 to comply. After 2003, the system must purchase allowances to comply as shown on the Table 4-3 on page 4-11 Gulf Power must purchase allowances beginning in the year 2003 (see Table 4-2 on page 4-10).

- This is expected to be the least-cost compliance plan and is the plan that Gulf has adopted.
- Even though Gulf's plan is to buy allowances, we will monitor the allowance market and based on its performance, either buy or sell allowances. This strategy provides the flexibility to make the best decision.

Internal Case

This variation of the Base Strategy provides an alternative to purchasing allowances in Phase II for system compliance by relying on internal compliance utilizing scrubbers. Tables 4-4 and 4-5 on pages 4-12 and 4-13 show how Gulf Power Company and The Southern Company accumulate allowance banks through 1999 and use these banks potentially with some scrubbing to maintain system compliance without having to purchase allowances. Under this strategy (Table 4-4 for the Internal Case is similar to Table 4-2 for the Base Strategy because Gulf will not scrub any of its units) the additional allowances required by Gulf Power, beginning in year 2005, will be provided from the banks of affiliated companies. Gulf Power Company units are more costly to scrub than other system units, therefore, Gulf Power continues only to fuel switch in this Case.

Company by Company Case

A company by company least cost compliance plan forces each operating company to comply alone, without purchasing allowances either from the market (Base Strategy) or from the banks of affiliated companies (Internal Case). Gulf Power's Company by Company Case is shown on Table 4-6 on page 4-14.

SO_2 Compliance Alternatives for Each Generating Unit

Analysis was performed to evaluate the compliance plan alternatives available to each generating plant. This analysis was conducted using the Utility Planning Model (UPM). Each alternative for each unit (i.e., scrubbing, fuel-switching, etc.) was modeled and the removal cost ($/ton removed) was calculated by dividing the cost of the option by the associated reduction in SO_2.

The compliance alternatives were then ranked (for the Southern electric system) according to this removal cost and the most cost effective options were selected as part of the compliance strategy. Once an option was selected, however, the incremental cost of the other options had to be recalculated since the effectiveness of each option is dependent upon actions already taken. This methodology provides for the least-cost strategy for emissions reduction for the system by considering capital costs, fuel costs, O&M costs and the actions previously selected within the overall strategy.

The analysis was directed and reviewed by a multi-disciplined project team with representatives from each operating company. The analysis was approved by an Executive Project Board consisting of representatives from Gulf and each of the operating companies.

The following compliance alternatives were considered for each generating unit in developing the compliance plan:

A. Fuel Switching

The availability and delivered cost of lower sulfur coal was projected for comparison purposes. Also considered was the cost of retrofits i.e., boiler modifications, flue gas conditioning (FGC), electrostatic precipitator modifications, etc. which would be required to burn the lower sulfur coal. Fuel switching to lower sulfur coal at affected plants was chosen as the most economical method for reducing emissions to comply with the Clean Air Act. Fuel switching also provides flexibility to respond to future strategy changes.

B. Purchase of Allowances

The purchase of allowances provides the key to a flexible compliance strategy. For Southern, the projected price and, subsequently, the market price of allowances will guide the evolving strategy, particularly for Phase II. A high market price of allowances will drive the system to choose other alternative compliance methods, i.e., FGD or additional fuel switching. A low price will increase the role that allowance purchases play in the strategy.

While the uncertainty associated with the development of the market has been reduced basic uncertainties associated with any market remain. These uncertainties are related to the available volumes and prices of the allowances and depend on technological advances, regulatory treatment, state environmental regulations, etc. These remaining uncertainties make it difficult to predict the number of allowances which may be required by Southern.

C. Demand Side Options

Gulf Power has established a track record as a market leader in the development and implementation of successful demand side programs. With the nationally acclaimed Good Cents Home program serving as the core of these efforts, Gulf has achieved a level of annual energy savings equivalent to approximately 439 million kwh.

In a statewide study of demand side potential being conducted by Synergic Resources Corporation for the Florida Energy Office, an assessment of both demand and energy savings was made. Table 4-7 on page 4-15, which was taken from a draft version of the final report on this assessment, highlights the effectiveness of Gulf Power's energy conservation efforts. Gulf's energy savings, expressed as a percentage of sales, are substantially higher than for any of the other utilities in the comparison, most of which were included due to their reputations as leaders in implementation of demand side measures.

Over the next 20 years, demand side savings, attributable to existing programs, are estimated to grow to an annual level of approximately 1 billion kwh, as depicted in Table 4-8 on page 4-16. In addition, the Company is investigating the potential associated with additional measures and new technologies, such as advanced energy management with variable pricing, thermal storage, heat pipes and high efficiency lighting.

D. Conversion to Natural Gas

Conversion to natural gas and/or co-firing were analyzed. These options offer potentially significant operational and environmental advantages in cost efficiency. They might also present operational constraints, given the design of the boilers.

The uncertain cost of natural gas and seasonal gas transportation constraints have reduced this alternative to an option that can be employed only if gas supply and year round transportation are available at a cost competitive with other alternatives. An option to year-round firing of natural gas is seasonal firing during the summer months (April-October) which is the off-peak season both for gas supply and transportation. In order to implement this option Gulf has maintained the capability of burning natural gas at Plant Crist.

Based on current and forcasted prices, which are much higher than low sulfur coal, natural gas is not currently an economic alternative. If gas becomes available at competitive prices, the burning of gas will facilitate the reduction of annual SO_2 emission levels. This alternative remains under consideration with the flexible strategy concept.

E. Co-Firing With Natural Gas

With respect to the co-firing of natural gas with coal to lower emission rates, the problems identified include uncertain cost of gas, boiler firing problems, and gas transportation constraints during certain times of the year and at certain locations on the gas pipeline networks.

Based on current and forecasted prices and the operational uncertainties associated with cofiring natural gas in a boiler designed to burn coal; co-firing is not currently an economic alternative. This alternative remains under consideration with the flexible strategy concept.

F. Installation of Flue Gas Desulfurization Equipment (FGD) or Scrubbers.

Engineering estimates were made of the cost to install and operate FGD systems at each plant. The cost of FGD was then compared to other alternatives. FGD was found to be uneconomical as compared to other options for reducing SO_2 emissions, primarily due to high capital cost.

G. Various Combinations.

The primary strategy is to switch to lower sulfur coal to build allowances in Phase I for use in Phase II. However, some combination of burning natural gas, purchasing allowances, cost effective demand side options, and purchasing clean power will probably contribute to system compliance. The flexibility of the Southern system strategy will allow Gulf to take advantage of any combination of alternatives that develop.

__Allowance Trading__

Under the Clean Air Act Amendments, SO_2 emissions are regulated based on tonnage emission limits. The tonnage limits are implemented through an SO_2 allowance program. Under this program The Southern Company will receive a fixed number of SO_2 allowances per year. Each allowance is an authorization to emit one ton of SO_2 during or after the year in which the allowance is issued. To comply with the law, the company must have one allowance for each ton of SO_2 that is emitted during a calendar year.

Although emission limits are defined for and allowances are allocated to specific units, there are two features of the allowance program that are intended to help reduce the costs of compliance with the legislation. These features are allowance banking and allowance transfers between and among units. Allowance banking means any unused allowances may be carried over for use in subsequent years. Allowance transfers provide the opportunity to reduce the overall cost of controls. Units that can be "overcontrolled" at a relatively low cost will not require their entire allowance allocation and the excess allowances may be transferred to a unit with higher control costs instead of taking compliance actions at the higher cost unit.

Allowance transfers are not limited to intra-company or intra-system transfers. Transfers may also take place between non-affiliated companies and even non-utilities may be able to participate in allowance transfers. The intent of the legislation is to create a free and open market for SO_2 allowances.

In response to concerns that utilities would not actively participate in allowance trading either because of their own conservatism or that of the public service commissions, the Clean Air Act Amendments established a requirement that a portion of the allocated allowances be withheld from utilities. The primary use of the withheld allowances will be to create an annual allowance auction, to be administered, under the authority of EPA. In addition to the auction the withheld allowances are also intended to supply the fixed price reserve. This reserve is intended as a supplier of last resort for IPPs unable to obtain allowances from any source, including the annual auction. Proceeds from the sale of withheld allowances are to be paid out, in full, to the original allowance holders in proportion to their contribution to the auction and fixed price reserve. Any unsold allowances will eventually be returned to the original holders in proportion to their contribution.

Gulf participated in the 1993 auction by bidding on its withheld allowances. Gulf was successful in securing its withheld allowances near the average auction price, which was below market price. For the upcoming 1994 auction, Gulf's participation will again be to bid on its withheld allowances.

The potential of the allowance market should not be underestimated. The purchase and sale of allowances will provide substantial opportunities to minimize the impact of the legislation on the customers and stockholders of the Company. In order to adequately reflect this potential it is important to incorporate allowance markets and values into the analysis used in compliance planning.

It is useful to think of the SO_2 allowances created by the Clean Air Act Amendments of 1990 as a new input required to produce electricity. For each ton of SO_2 emitted in generating power a utility must possess an allowance. In this respect an allowance can be viewed just like coal or any other required input. The basic difference is that most utilities receive an annual allocation of allowances. Since the allowances are marketable, the utility must decide whether the allowances are more valuable if they are used directly by the utility or if they are to be sold to some other party. In addition, the utility may also choose to buy additional allowances if desired. One implication with marketable allowances is that compliance planning becomes part of the normal activities of the utility, just as fuel purchases are. Given the marketability of allowances, an estimate of their market value is necessary for planning the least cost method of providing customer service.

The legislative and technical details of the allowance system have not changed since the passage of the amendments. However, the expected value of allowances has dropped sharply from the values that were put forward during the debate over the amendments and immediately upon passage. This decrease in the expected value of allowances reflects an industry that is becoming better informed on the available compliance options, the role of allowance banking, and the potential value of allowance transactions in reducing compliance costs.

The current allowance value forecast continues to support the existing compliance strategy. In developing the current forecast of allowance values, The Southern Company participated in a study by ICF Resources, Inc. This study was directed at examining in detail the potential market for allowances under a number of scenarios. In addition, the study explicitly modeled the allowance banking provisions to provide an indication of their impact on the potential market. The ICF study does not predict the year by year prices that may evolve as the allowance market develops. The goal of the ICF effort was to provide an estimate of the basic underlying value of allowances, i.e., their long run equilibrium value.

Based on the results of the ICF study, and other less detailed public information that indicated lower allowance values, as well as published survey results indicating falling expectations, a price forecast for allowance values to be used in evaluating compliance options was developed. (See Appendix.)

TABLE 4-1

Gulf Power Company
Summary of Alternative Compliance Plans
Unit Specific Actions

Plant	Years	Base	Internal	Company By Company
Crist 6	1995-1999	1% Coal	1% Coal	1% Coal
	2000-2017	1% Coal	0.7% Coal	0.7% Coal
Crist 7	1995-1999	1% Coal	1% Coal	1% Coal
	2000-2017	1% Coal	0.7% Coal	0.7% Coal
Scherer 3 (1, 2)	2000-2017	-	-	-
Crist 4	2000-2017	1% Coal	0.7% Coal	Scrub
Crist 5	2000-2017	1% Coal	0.7% Coal	Scrub
Scholz 1	2000-2017	1% Coal	0.7% Coal	0.7% Coal
Scholz 2	2000-2017	1% Coal	0.7% Coal	0.7% Coal
Daniel 1 (1, 2)	2000-2017	-	-	-
Daniel 2 (1, 2)	2000-2017	-	-	-
Smith 1	2000-2017	1% Coal	0.7% Coal	0.7% Coal
Smith 2	2000-2017	1% Coal	0.7% Coal	0.7% Coal

(1) These NSPS (New Source Performance Standards) units are already in compliance.

(2) Gulf Power Company's share of the unit.

TABLE 4-2

BASE STRATEGY SO_2 EMISSIONS AND ALLOWANCES IMPACT ON GULF POWER COMPANY

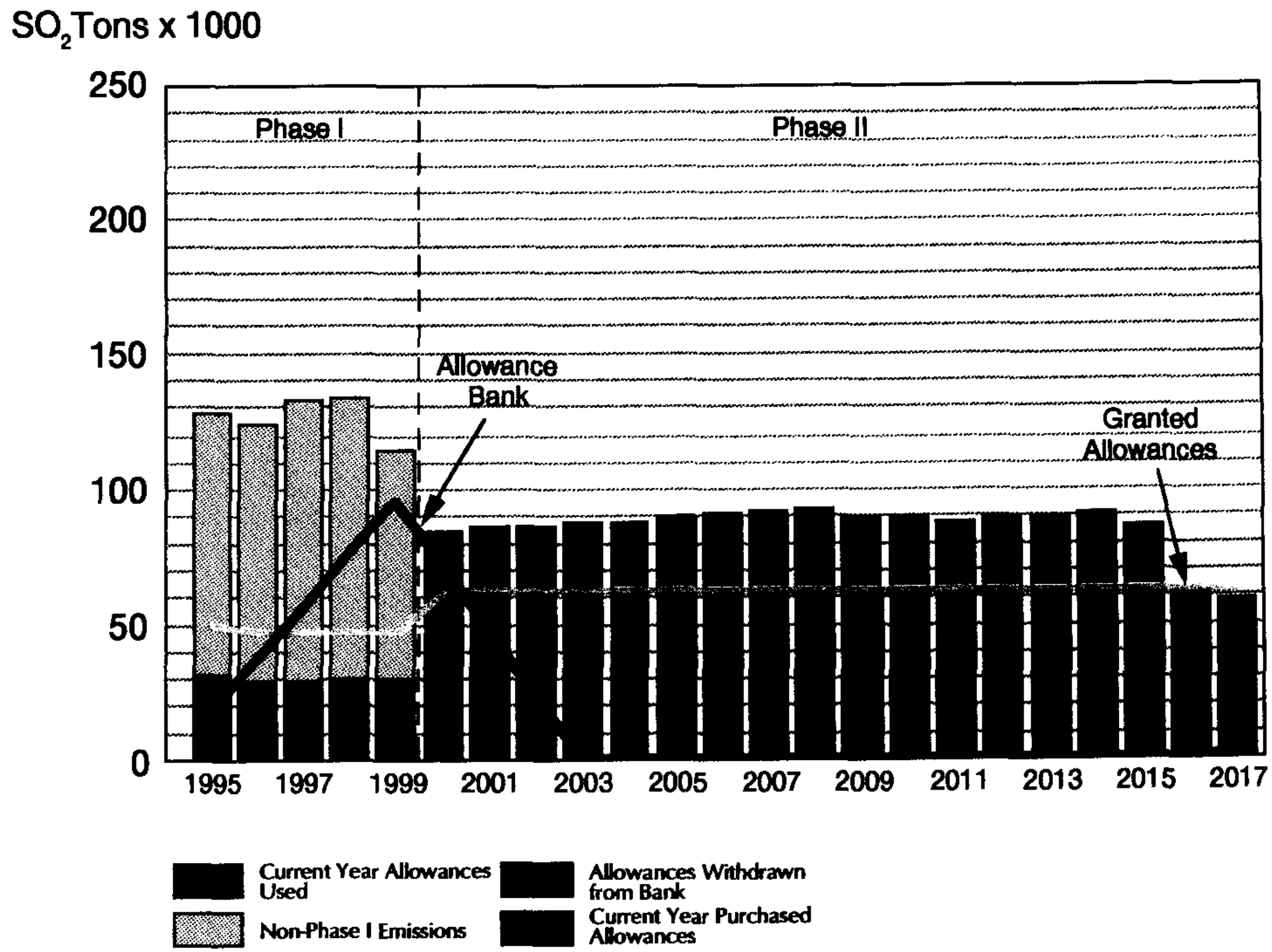


TABLE 4-3

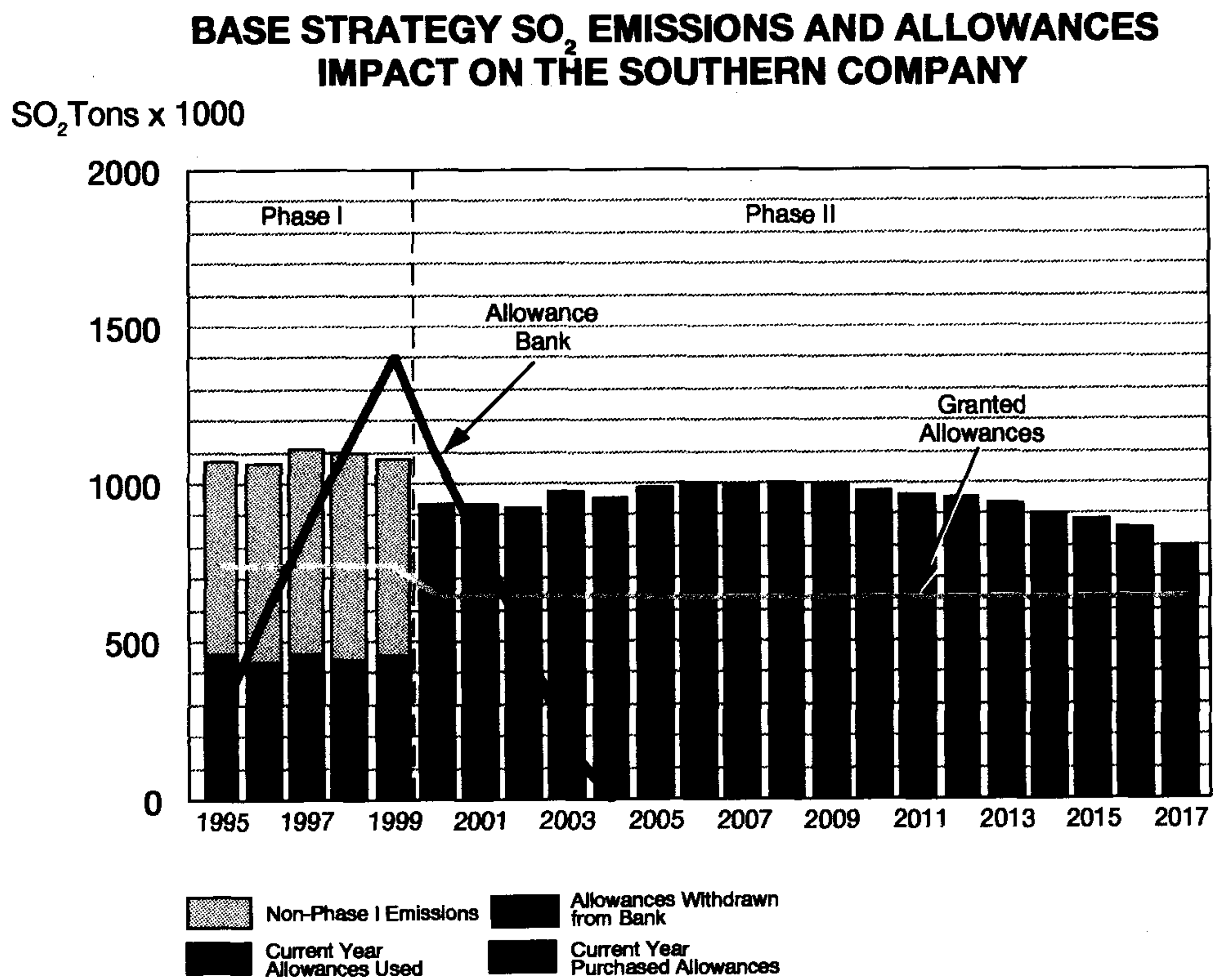

BASE STRATEGY SO_2 EMISSIONS AND ALLOWANCES
IMPACT ON THE SOUTHERN COMPANY
SO_2 Tons x 1000
2000
1500
1000
500
0
Phase I
Phase II
Allowance Bank
Granted Allowances
1995
1997
1999
2001
2003
2005
2007
2009
2011
2013
2015
2017
Non-Phase I Emissions
Allowances Withdrawn from Bank
Current Year Allowances Used
Current Year Purchased Allowances

TABLE 4-4

INTERNAL CASE SO_2 EMISSIONS AND ALLOWANCES IMPACT ON GULF POWER COMPANY

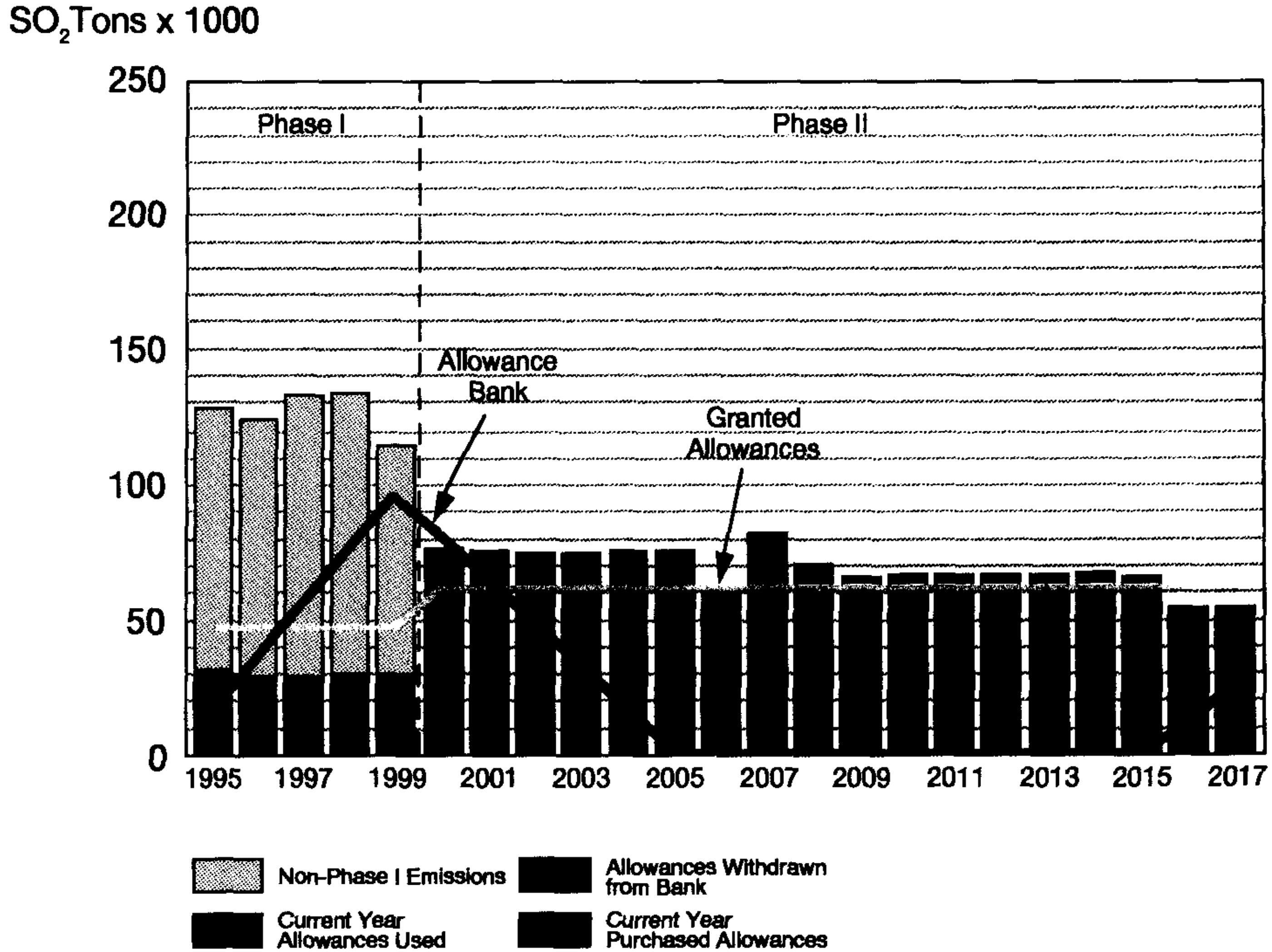


TABLE 4-5

INTERNAL CASE SO_2 EMISSIONS AND ALLOWANCES IMPACT ON THE SOUTHERN COMPANY

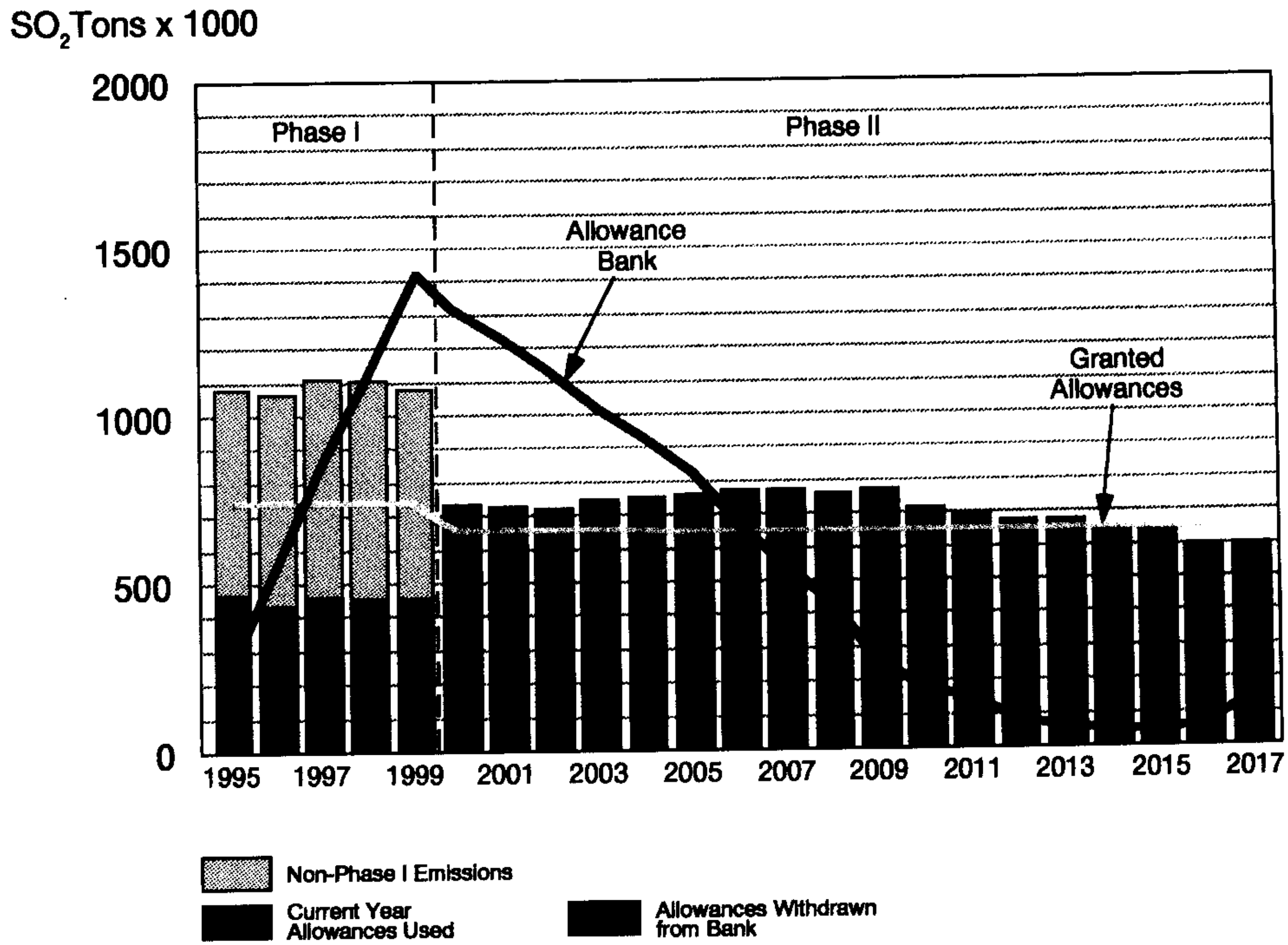


TABLE 4-6

COMPANY-BY-COMPANY CASE SO_2 EMISSIONS AND ALLOWANCES IMPACT ON GULF POWER COMPANY

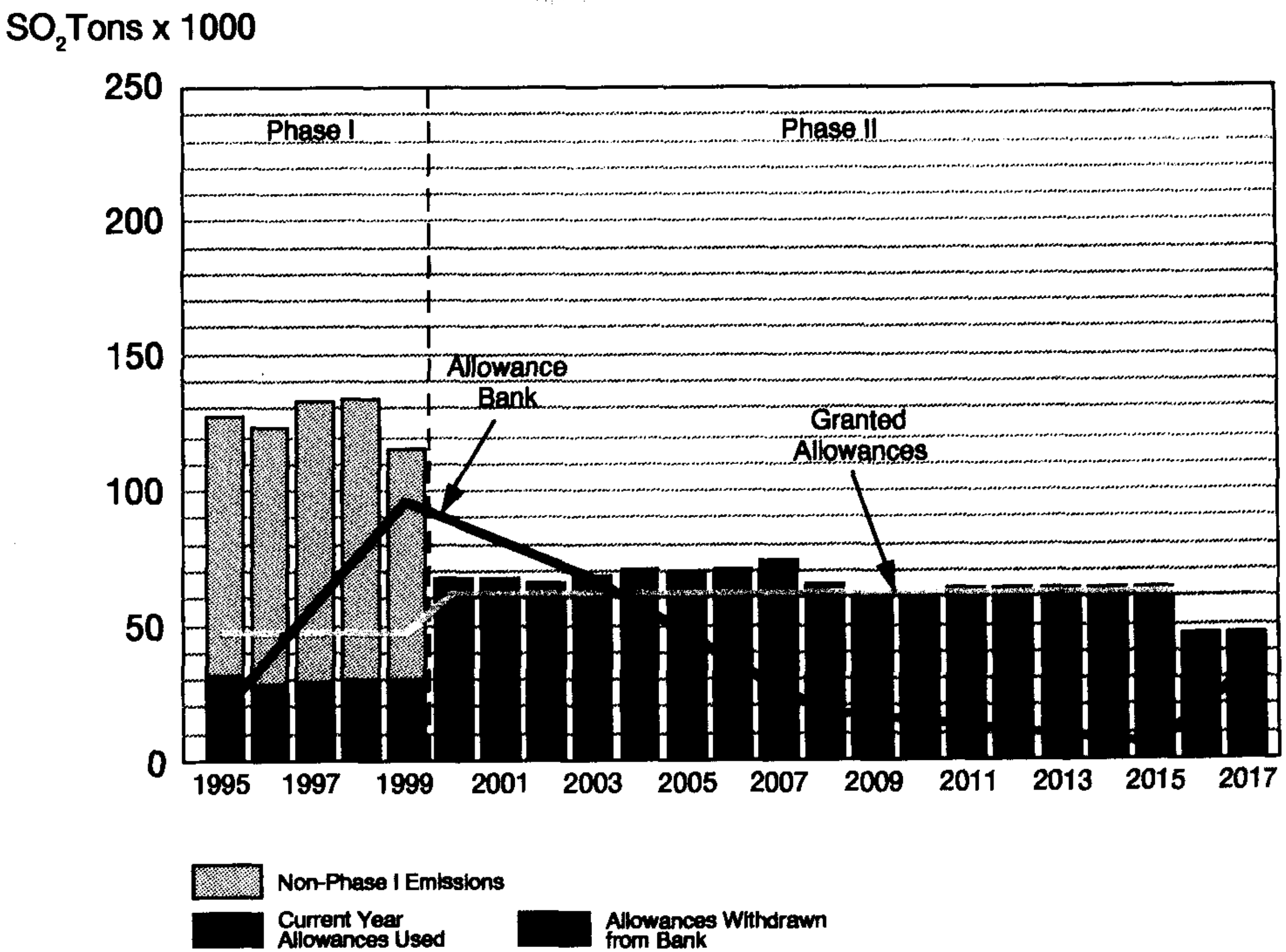


TABLE 4-7

REVIEW OF UTILITY DSM ACTIVITIES

UTILITY		First Year Programs were Offered	Number of Programs Offered (1991) Conservation	Load Mgmt	Int/TOU	1991 Program Expenditures (000's)	1991 Expenditures as % of Electric Revenues	1992 Program Expenditures (000's)	Peak Reduction (1991) (MW)* Conserv.	Load Mgmt	Int/TOU	% of capacity	Energy Conserved (1991) (GWh)*	% of Sales	Rate (Avg. cents/kWh)	Notes
FLORIDA UTILITIES																
FLORIDA	Residential	1978	7	1	0	$72,000	1.4%	$106,600	763	272	97	6.8%	1552	2.3%	7.6	K
POWER & LIGHT	Comm/Ind		2	2	1	total	program			total	program		865	1.3%	avg.	
FLORIDA POWER	Residential	1981	5	1	0	$57,184	3.3%	$74,125	106	P 696	P 196	15.8%	408.4	1.6%	7.3	KW
CORPORATION	Comm/Ind		7	1	1	$1,462	0.1%	$2,945		total	program		total		6.2	
GULF POWER	Residential	1976	2	1	1	$1,196	0.2%	$1,123	176			8.1%	381	4.8%	6.7	K
COMPANY	Comm/Ind		2	1	1	$892	0.2%	$1,203		total	program		total		5.1	
TAMPA ELEC-	Residential	1981	5	1	0	$12,621	1.3%	$13,490	217	139	240	18.9%	157	1.2%	7.9	KW
TRIC COMPANY	Comm/Ind		3	2	1	$258	0.0%	$710		total	program		total		6.9	
ORLANDO UTS	Residential		5	0	0	$597	0.2%	$586	9	0	0	1.2%	63	1.8%	7.5	
COMMISSION	Comm/Ind		2	0	0	$72	0.0%	$81	4	0	0	0.5%	total		7.0	
CITY OF	Residential	1983	5	0	0	$1,862	1.3%	$2,283	Y 2	0	0	0.0%	Y 16	0.0%	7.8	FK
TALLAHASSEE	Comm/Ind		2	0	0	total	program			total	program		total		7.4	
NON-FLORIDA UTILITIES																
DUKE	Residential	1991	6	3	0	$48,062	1.3%	$34,102	10	407	0	2.6%	(30)	negl.	7.1	N
POWER	Comm/Ind		0	0	2	total	program	$28,417	0	0	595	3.6%	0	0.0%	n/a	
GEORGIA	Residential	1977	4	0	1	$0	0.0%	$0				0.0%	59	0.1%	7.5	AB
POWER	Comm/Ind	1991	7	0	2	$0	0.0%	$12			284	1.8%	0	0.0%	5.0	
N.E. ELEC	Residential	1979	9	1	0	$20,237	1.0%	$29,409	17	3	0	0.3%	87	0.4%	9.6	C
SYSTEM	Comm/Ind		4	1	3	$49,267	2.4%	$53,222	108	3	54	2.9%	435	2.0%	8.5	
NORTHEAST	Residential	1987	14	1	0	$15,382	0.6%	$20,625	105	2	0	1.4%	288	1.0%	10.5	DW
UTILITIES	Comm/Ind	1986	12	0	2	$66,044	2.4%	$51,427	124	0	25	2.0%	662	2.2%	8.8	
PACIFIC	Residential		18	0	2	$74,681	1.0%	$90,206	Y 26	0	0	0.2%	M 1,630	2.2%	10.4	DJL
GAS & ELEC	Comm/Ind		11	2	1	$70,732	1.0%	$112,460	Y 93	Y 10	P 544	4.3%	M 2,175	2.9%	8.6	
SEATTLE	Residential	1977	5	N/A	N/A	$7,565	2.7%	N/A	14	N/A	N/A	0.7%	119	1.4%	3.4	EGH
CITY LIGHT	Comm/Ind	1979	7	N/A	N/A	$2,891	1.0%	N/A	11	N/A	N/A	0.6%	90	1.1%	3.2	
S. CALIFORNIA	Residential	1972	5	1	0	$42,807	0.6%	$52,931	Y 19	Y 237	0	1.3%	M 263	0.4%	10.3	D
EDISON	Comm/Ind	1972	4	2	4	$64,637	0.9%	$87,919	Y 124	Y 39	1088	6.2%	M 2,120	3.0%	avg.	
WEPCO	Residential	1981	4	0	2	$40,267	3.1%	N/A	218	40	32	5.1%	853	3.5%	6.8	K
	Comm/Ind	1987	7	1	2	total	program	N/A		total	program		total		4.7	

*Peak Reduction and Power Conserved are annual figures based on all measures installed to date (unless indicated otherwise)

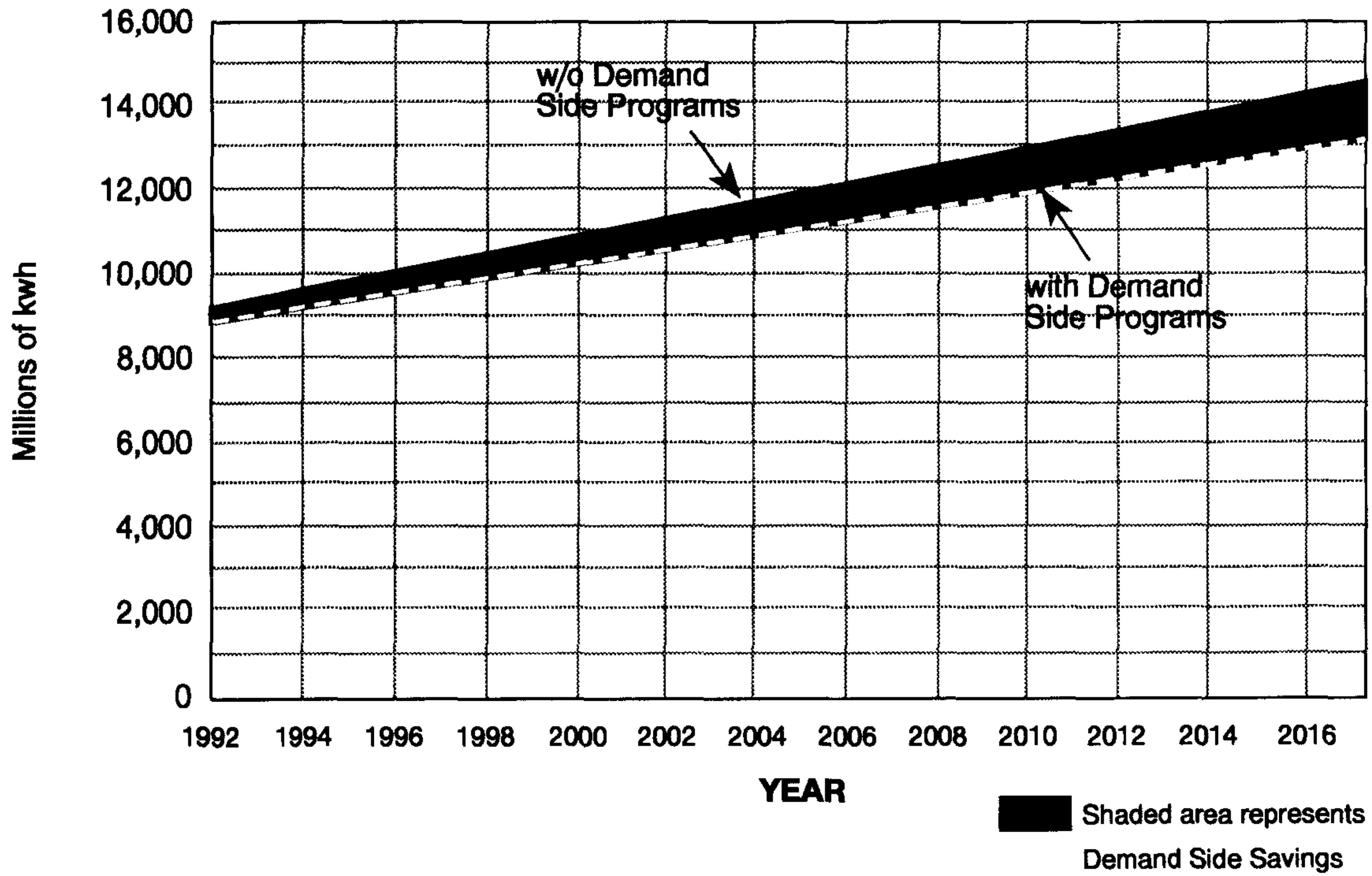
NOTES

A – Number of 1992 programs
B – Georgia Power is in planning stages for implementation of programs in 1992 & 1993
1993 expenditures = $10.7 million residential, $25.6 million C/I. 133 GWh expected savings (29–R;104–C/I)
C – $ Figures from 1990 NEESPLAN. Actual spending for all programs in 1991 was $95 million. '92 budget is $100 million
D – Expenditure figures include planning, evaluation, GA and supplies apportioned between Residential and C/I
E – All data for Seattle is 1990 Data
F – Expenditure figures do not include all administrative costs; total expenditures somewhat higher
G – MWh savings data unavailable for EnergySmart Design Program and Lighting Design Lab
H – % load reduction taken as % of peak, not capacity
J – % of capacity figured excluding 7762 MW of purchased capacity
K – Reduction figures taken from DOE/EIA –861 filing
L – Rate data based on 1990 annual report
M – Savings are for all utility programs/efforts from 1977–1994 including projected savings.
N – Revenue figure used to estimate percentage is estimated
P – Potential Interruptible/TOU capability (not all utilized during 1991)
W – Winter peaking utility; load reduction shown for winter
Y – One year savings only – previous installations not counted

TABLE 4-8

GULF POWER COMPANY

FORECAST ENERGY SUPPLY



5.0 NO_X COMPLIANCE PLAN

Overview

Gulf Power Company's plan for meeting NO_X compliance requirements is as follows:

Gulf Power Company has installed low-NO_X burners in Crist Unit 7 and is currently installing low-NO_X burners in Crist Unit 6 during Spring 1994. The construction cost for these burners is approximately 18 million dollars. Currently, the Crist Unit 7 burners are being tested and optimized. After installation of the Crist Unit 6 burners and testing of both units is completed, should these burners not meet the expected reduction, overfire air equipment will be considered as part of the vendor guarantee. If these units do not meet the compliance limit, then, Gulf Power will evaluate system NO_X emissions averaging, an application for an alternative emissions limit, and other technologies to meet the compliance limit. The burners will include gas nozzles to provide Gulf Power with the option to burn natural gas at Crist 6 and 7.

Additional Comments

Boiler performance tests will be performed on all Phase I and Phase II units to determine the current NO_X emissions rate and representative baseline boiler performance data for each unit. The boiler performance test results data for each unit will be reviewed and analyzed against similar data for other units in The Southern Company to determine the optimum method of NO_X control to meet the requirements of the applicable federal, state and local legislation. If changes in the current boiler operating procedures at one or more of these units appears to be reasonable and will achieve adequate reductions to meet the required NO_X emissions, it will be evaluated as a compliance strategy along with the other NO_X reduction alternatives. Current emission limits and operations for each unit will also be reviewed to determine if certain units would be suitable for averaging techniques involving other NO_X reduction alternatives such as low-NO_X burners, selective non-catalytic reduction and selective catalytic reduction.

Strategy Development

The strategy for Phase I NO_X compliance includes low-NO_X burners at Crist Unit 6 and Unit 7. An analysis was performed to determine the need for additional NO_X emissions controls for these units. Based on the current NO_X rate projections for these units, additional technologies are not required to reduce NO_X emissions below the legislated rate of 0.50 lb/MBtu. If after testing, these units do not meet the emission limits, the installation of overfired air will be considered. The technologies that were evaluated were based on economics and engineering feasibility. Descriptions of these technologies are listed in the Appendix.

Table 5-1 on Page 5-3 shows the data used in the analysis. Only data for those additional controls that were considered applicable or were not screened out are shown on this table.

TABLE 5-1

UNIT	OPTION TITLE	CAPITAL (M$)	O&M (M$)	TOTAL (M$)	NO_x REDUCTION (%)	NO_x RATE (#/MBTU)	REMOVAL COST ($/TON)	CUSTOMER COST ($/KWH)
CRIST 6	BASE	0.0	0.0	0.0	0.0	0.49		
CRIST 6	LNB+OFA	2.2	0.0	2.2	7.0	0.46	1,168	0.0002
CRIST 6	LNB+SCR	46.6	31.5	78.0	80.0	0.10	3,128	0.0064
CRIST 7	BASE	0.0	0.0	0.0	0.0	0.48		
CRIST 7	LNB+OFA	3.3	0.0	3.3	7.0	0.44	1,027	0.0002
CRIST 7	LNB+SCR	66.4	42.8	109.3	80.0	0.09	3,098	0.0063

NOTES:
1. ALL DOLLARS ARE 1993 PRESENT VALUED MILLIONS OF DOLLARS (REVENUE REQUIREMENTS FOR CAPITAL COSTS ARE INCLUDED).
2. THE BASE OPTION ASSUMES LOW NO_x BURNERS INSTALLED.
3. VARIABLE O&M COSTS FOR SCR ARE INCLUDED WITH FIXED O&M.
4. NO_x RATES ARE FROM SHORT TERM TEST RESULTS AND REFLECT NO_x VERSUS CAPACITY.
5. THE NO_x REDUCTION VALUES USED IN THIS ANALYSIS ARE BASED UPON TEST RESULTS FROM THE LOW NO_x BURNERS INSTALLED AT GEORGIA POWER'S PLANT HAMMOND. THESE REDUCTION VALUES ARE CONSISTENT WITH THE VALUES MODELED FOR OTHER SYSTEM UNITS. THE VENDOR GUARANTEES, FOR LOW NO_x BURNERS WERE NOT FACTORED INTO THIS ANALYSIS.
6. ANNUAL TONS OF REDUCED NO_x AND GENERATION ARE AN AVERAGE OVER THE STUDY PERIOD OF 1995-2013.
7. LNB - LOW NO_x BURNERS
   OFA - SEPARATED OVERFIRED AIR
   SCR - SELECTIVE CATALYTIC REDUCTION

6.0 FINANCIAL AND REGULATORY

Objectives

An appropriate and affordable strategy to comply with the Clean Air Act amendments should meet the following financial and regulatory objectives:

1. Provide the lowest overall cost among achievable alternatives;

2. Hold annual customer rate increases to minimum levels which will not cause significant demand pattern shifts; and

3. Provide for reasonable annual financing requirements over the period of time such that the credit quality of the system companies can be maintained.

The criteria for evaluating the least cost alternative used in the compliance strategy development project is Net Present Value (NPV) of Revenue Requirements. Under the assumptions used in the analysis, the strategy resulting in the lowest NPV of Revenue Requirements represents the least cost to the customer.

Sources of Clean Air Compliance Costs

Costs associated with Clean Air Compliance result from the following areas:

- capital costs (Depreciation, Return on Equity requirements, and Income taxes);

- production costs (fuel prices used in the strategy, costs associated with any dispatch differences and non-fuel production costs associated with Clean Air Compliance equipment, for example, increased production costs required to run scrubbers);

- emission allowances costs (the number of allowances bought or sold times the appropriate value); and

- governmental fees and permits.

Capital costs are further broken into three areas:

1. SO_2-related (Electrostatic precipitator modifications, Flue Gas Conditioning equipment to allow burning of low sulfur coal, and scrubber installation);

2. NO_x-related (low-NO_x burner equipment and upgrades to equipment impacted by the low-NO_x burner equipment); and

3. Continuous Emission Monitoring (CEM) equipment.

Strategy Alternatives

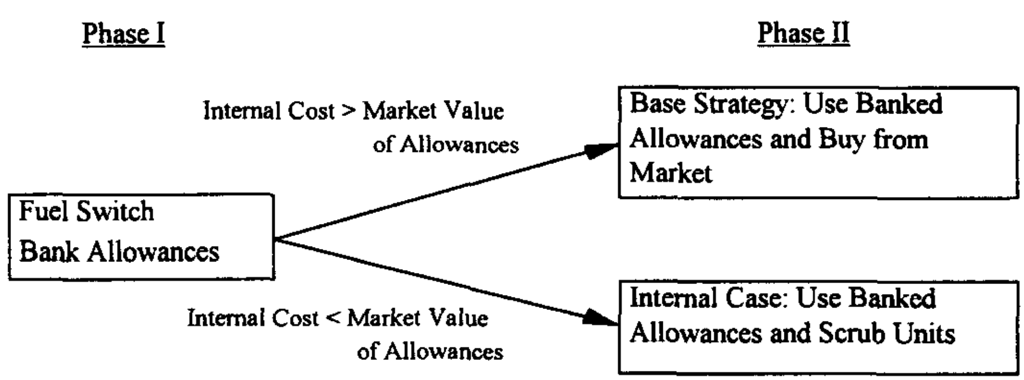
Three strategies for achieving a least cost compliance plan have been analyzed. Two of the strategies use a system strategy approach to compliance. This assumes that a compliance strategy based on system compliance (this states that the whole system - adding all companies' emissions together - must be in compliance) results in the least cost compliance versus a company-by-company compliance strategy. These three methods of system compliance were analyzed (Table 6-1 on page 6-5):

The **Base Strategy** (Market Strategy) - This assumes that the allowance market exists and works efficiently. Buying allowances from the market is a prudent and effective method for attaining compliance. In selecting the actions to take for compliance, the system will compare the costs of complying itself (i.e. take actions on its own plants) versus buying allowances. It will, therefore, choose each compliance action on this internal cost versus allowance comparison. This will result in choosing all internal options up to the allowance cost at which point it will buy allowances from the allowance market for additional compliance requirements.

The **Internal Case** - This case assumes that the internal approach is always the least-cost decision in comparing the costs of complying internally versus buying allowances from the market. This condition could result from: (1) the market not working efficiently so that a consistent, reliable supply of allowances can not be expected; or (2) there are constraints regulatory and otherwise imposed on the system to prevent it from buying allowances for compliance.

The following chart illustrates this decision path.

FIGURE 6-1
COMPLIANCE PLAN DECISION PATH



The **Company by Company Case** - Another alternative has been considered in this analysis. This strategy assumes that compliance must be achieved on a company-by-company or stand alone basis. This approach could be required by a state regulatory environment that will not let emission allowances be traded among operating companies or not let companies share costs associated with a system-based compliance plan strategy. Under these circumstances, each company must comply with the Clean Air Act standards on its own. This strategy also assumes that all internal actions for compliance are more economical than buying allowances, similar to the Internal Case.

Construction Cost Estimates

Cost estimates for NO_X controls, Electrostatic Precipitator upgrades, Flue Gas Conditioning and Continuous Emission Monitoring equipment for Phase I units were developed by the Compliance Organization and the Power Generation Services area of each Operating Company. The estimates are based on plant site inspections, test projects and estimates from vendors. The cost relationships from the Phase I estimates are used on comparable units affected in Phase II to develop Phase II estimates (see Table 6-2, page 6-6 for detail on Phase I and Table 6-3, page 6-7 for by-phase construction estimates for each strategy). Scrubber costs were based on a site-specific estimate for each plant.

Cost allocation is reflected in the exchange of allowances between companies which either serves to increase or reduce a company's revenue requirements.

These cost estimates are expected to change as a result of further reviews by Gulf Power Company and The Southern Company and as more information is provided by tests sites and vendor proposals.

Components of Clean Air Related Revenue Requirements

As mentioned earlier, the revenue requirements associated with Clean Air compliance are grouped by production costs, capital costs and allowance costs. Clean air revenue requirements are defined as all costs associated with implementing a compliance strategy. This can be calculated by modeling the Southern system under a compliance strategy and comparing this to a case reflecting no compliance costs. This reference case assumes that the Southern system operates under all pre-1990 Clean Air Act (CAA) rules and regulations and based its planning decisions accordingly (e.g., fuel selection based solely on the lowest cost fuel that meets prior sulfur content limitations; no compliance-related construction, such as NO_X controls, CEMs, or plant modifications, to burn low-sulfur coal). The difference between these two cases is the change in revenue requirements due to the compliance strategy implementation. Table 6-4 and Table 6-5 provide an overview of revenue requirements. Over time, production costs will increase relative to the capital costs as the Clean Air compliance related plant is depreciated (Table 6-5 on pages 6-9 and 6-10).

Financial Impacts

The impact of Clean Air compliance can be measured by determining the average annual increase in revenue requirements including Clean Air costs, on a percentage basis, compared to revenue requirements without Clean Air costs. This helps to describe how much more an average customer will have to pay in an average year solely due to costs related to Clean Air Compliance.

For purposes of this analysis, it is assumed that cost recovery (as reflected in revenue requirements) begins when the construction projects are completed. However, the Environmental Cost Recovery Clause allows Gulf Power to recover revenue requirements associated with Construction Work in Progress - Non-Interest Bearing during construction.

The Base Strategy also has a lower Net Present Value (NPV) of revenue requirements (through the year 2017) than the Internal Case and the Company by Company Case ($176 million for the Base Strategy vs. $184 million for the Internal Case and $189 million for the Company by Company Case). Therefore, the Base Strategy, having the lowest NPV revenue requirements, represents the least cost strategy among the alternatives studied.

Risks

These strategies have certain inherent risks associated with them. Some of these are outlined below:

For purposes of this analysis, revenue requirement impacts due to Clean Air compliance assume that full cost recovery of all compliance-related costs is realized.

Future environmental legislation could reduce the value of a compliance strategy for meeting new requirements. For example, Global Climate Change related requirements could make an SO_2 related strategy counterproductive for meeting CO_2 standards. Or, if controlling Air Toxins becomes an integral part of future clean air standards, the costs for compliance could increase significantly, such as requiring the scrubbing of virtually all of Southern's fossil-fired generation.

If a technology-based strategy is selected (i.e., one that relies on scrubbing or Low-NO_X Burners), the supply of the necessary equipment from the manufacturer may be constrained if the demand is high. The result could be either the inability to acquire equipment in a timely manner or the costs could escalate dramatically due to the high demand.

If the allowance market is to be used, it is in the best interest of Gulf/Southern to ensure that it does function well, and the system should take steps to aid in the market's evolution.

TABLE 6-1

Gulf Power Company
Clean Air Compliance Plan

Construction Cost Estimates
($ millions)

	1991-1995 Phase I	1996-2000 Phase II	Total
BASE STRATEGY			
Gulf Power Company	41	36	77
Southern Company	327	452	779
INTERNAL CASE			
Gulf Power Company	41	36	77
Southern Company	327	766	1,093
COMPANY BY COMPANY CASE			
Gulf Power Company	41	92	133
Southern Company	327	1,049	1,376

TABLE 6-2

Clean Air Compliance Plan Estimated Construction Expenditures For Phase I
($ thousands)

	1991(1)	1992(1)	1993	1994	1995	Total
Gulf Power Company						
SO_2	0	2,106	3,605	11,200	0	16,911
NO_x (2)	0	2,644	5,801	8,312	1,745	18,502
CEM	0	1,707	1,594	2,188	0	5,489
TOTAL	0	6,457	11,000	21,700	1,745	40,902
Southern Company						
SO_2	0	9,157	20,470	30,257	2,480	62,364
NO_x	3,969	29,606	90,707	97,050	13,484	234,816
CEM	0	5,803	14,657	9,088	35	29,583
TOTAL	3,969	44,566	125,834	136,395	15,999	326,763

Construction expenditures do not reflect cost allocation among system companies.
Total may not add due to rounding.

(1) Actual
(2) NO_x expenditures shown here represent the cost of low-NO_x burners, overfire air, and impacted systems.

TABLE 6-3

Clean Air Compliance Plan Estimated Construction Expenditures
($ millions)

		Phase II			Total		
	Phase I	Base	Internal	Co by Co	Base	Internal	Co by Co
Gulf Power Company							
SO_2	17	0	0	0	17	17	17
NO_X (1)	19	36	36	36	55	55	55
CEM	5	0	0	0	5	5	5
Scrub	0	0	0	56	0	0	56
TOTAL	41	36	36	92	77	77	133
Southern Company							
SO_2	62	39	45	45	101	107	107
NO_X	235	413	413	413	648	648	648
CEM	30	0	0	0	30	30	30
Scrub	0	0	308	591	0	308	591
TOTAL	327	452	766	1,049	779	1,093	1,376

(1) NO_X expenditures shown here represent the cost of low-NO_X burners, overfire air and impacted systems.

TABLE 6-4

Clean Air Compliance Plan
Comparison of Strategies
Projections

		Base Strategy	Internal Case	Company by Company Case
CUMULATIVE REVENUE REQUIREMENTS 1993-2017 ($ MILLIONS) (NOMINAL VALUES)				
Gulf Power Company	Total	618	656	598
NPV REVENUE REQUIREMENTS (1993 MILLIONS $)				
Gulf Power Company	Total	176	184	189
NPV REVENUE REQUIREMENTS AS A % OF BASE CASE (NO CLEAN AIR ACT) (1993 $)				
Gulf Power Company	Total	2.8%	2.9%	3.0%

TABLE 6-5

Gulf Power Company
Clean Air Compliance Plan
Components of Revenue Requirements
Projections

(Million Nominal $)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
Base Strategy													
Fuel & O&M	0	1	0	1	1	1	1	5	6	6	7	8	9
Capital	0	3	5	5	5	7	9	12	13	12	12	11	11
Allowances	0	0	0	(1)	(1)	(1)	(1)	(2)	(4)	(3)	2	9	10
Total	0	4	5	5	5	7	9	15	15	15	21	28	30
Internal Case													
Fuel & O&M	0	1	0	1	1	1	1	7	9	9	11	12	14
Capital	0	3	5	5	5	7	10	12	13	13	12	12	11
Allowances	0	0	0	(1)	(1)	(1)	(1)	(2)	(2)	(2)	(4)	(4)	1
Total	0	4	5	5	5	7	10	17	20	20	19	20	26
Company by Company Case													
Fuel & O&M	0	1	0	1	1	1	1	10	11	12	13	15	16
Capital	0	3	5	5	5	7	10	24	26	24	23	21	20
Allowances	0	0	0	(1)	(1)	(1)	(1)	(4)	(4)	(4)	(5)	(6)	(6)
Total	0	4	5	5	5	7	10	30	33	32	31	30	30

TABLE 6-5 (continued)

Gulf Power Company
Clean Air Compliance Plan
Components of Revenue Requirements
Projections

(Million Nominal $)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Base Strategy													
Fuel & O&M	11	13	24	25	27	26	28	29	30	28	17	15	319
Capital	10	10	9	8	6	6	5	5	4	3	2	2	175
Allowances	12	13	15	16	14	12	12	11	11	9	(4)	(5)	124
Total	33	36	48	49	47	44	45	45	45	40	15	12	618
Internal Case													
Fuel & O&M	16	18	36	38	39	39	42	43	45	44	26	24	477
Capital	11	10	10	9	7	7	6	6	5	4	3	3	189
Allowances	9	11	4	2	0	(2)	(1)	(1)	0	(2)	(7)	(6)	(10)
Total	36	39	50	49	46	44	47	48	50	46	22	21	656
Company by Company Case													
Fuel & O&M	19	21	31	32	33	32	34	36	36	40	21	24	441
Capital	19	18	17	15	14	13	12	11	10	4	3	3	312
Allowances	(7)	(8)	(8)	(7)	(14)	(15)	(14)	(13)	(12)	(10)	(8)	(6)	(155)
Total	31	31	40	40	33	30	32	34	34	34	16	21	598

7.0 FUEL

Historically, coal for Gulf Power Company's plants have predominately come from the Illinois Basin coal source region (Southern Illinois and Indiana and Western Kentucky). In considering other options for coal for Phase I (Plant Crist) and Phase II (all Gulf units) compliance, Gulf Power Company (and The Southern Company) "offer" coal, in the computer model, from several regions, and with various sulfur levels, to each plant.

The prices of the different types of fuel, primarily coal and natural gas, (i.e. Btu and sulfur content) over time are based on projections from the Southern Electric System Fossil Fuel Price Forecast, which is reviewed and revised annually. The coal price forecast starts with a current market FOB mine price and escalates that price over time based on assumptions about future supply and demand factors for each source regions. There may be as many as three coal coal price forecasts for a source region based on the sulfur content of the fuel. Current and projected transportation rates to each Southern Company plant are then added to the FOB mine prices to arrive at a delivered prices of coal to be offered in the compliance strategy model. Transportation rates are escalated based on assumptions about future supply and demand factors affecting each transportation mode. For Gulf Power Company's coastal plants, barge rates are used to bring coals to Plants Crist and Smith, while rail rates are used for Plant Scholz.

The model then chooses the most economic compliance option by combining the delivered price of the various fuel types with capital and operating expenditures necessary to burn that fuel. For example, as previously discussed, switching Gulf Power Company's plants to a lower sulfur coal will require capital expenditures for upgrades to particulate collection devices.

FUEL OPTIONS

Fuel options considered for Gulf Power Company are Illinois Basin coals (the traditional source region), Central Appalachian coals, Alabama coals, Powder River Basin coals, foreign coals, and natural gas.

The following paragraphs will briefly describe the characteristics and assumptions related to the coal options considered.

Illinois Basin Coals

The 1993 fuel price forecast modeled three coals from the Illinois Basin. A 1.5% sulfur coal (medium sulfur) with 12,000 Btu/lb, a 2.8% sulfur coal (high sulfur) with 11,600 Btu/lb and a 3.0% sulfur coal (high sulfur) with 10,800 Btu/lb.

Central Appalachian Coals

Coals from the Central Appalachian source region (primarily Eastern Kentucky, Southern West Virginia, and Western Virginia) typically have lower sulfur levels than coals from the Illinois Basin, ranging from 1.5% sulfur down to 0.7% sulfur levels. The 1993 fuel price forecast priced Central Appalachian coals from three sulfur ranges - 1.5%, 1.0%, and 0.7% (NSPS). Due to the logistics of getting this coal "on the water" and then coupled with the longer barge haul to move these coals to the Gulf Coast, they are generally more expensive, on a delivered basis, than the Illinois Basin coals for Gulf Power Company, but again have a much lower sulfur content. These competing factors are considered in the model.

Alabama Coals

The 1993 fuel price forecast priced Alabama barge coals to Plant Crist. These coals, which can have sulfur contents of less than 1.5%, were more expensive, on a delivered basis, at all sulfur levels, than either Central Appalachian or Illinois Basin coals due to the more expensive mining conditions in this source region.

Powder River Basin Coals

Another compliance option is the use of very low sulfur coal from the Powder River Basin (Wyoming and Montana). This coal is very low in sulfur (0.4%), and very inexpensive on an FOB mine basis, but also has a relatively low Btu content. The 1993 fuel price forecast priced three Powder River Basin coals with Btu contents of 8,400 Btu/lb, 8,800 Btu/lb, and 9,200 Btu/lb. The low Btu content, along with other chemical characteristics, makes it of limited applicability in The Southern Company. Powder River Basin coal has been test burned in units at our newer, "NSPS" plants, Daniel in Mississippi, Miller in Alabama, and Scherer in Georgia. Currently, because of the original boiler designs, major retrofits, and perhaps derates, would be required to burn Powder River Basin coals in other Southern plants, it is only offered as a compliance option in the model to the aforementioned NSPS plants.

Natural Gas

The concept of "seasonal firing", or burning 100% gas in selected boilers for the months of April through October, and then switching back to 100% coal, was considered as a compliance option. This scenario may have applicability at Plant Crist, because of its proximity to the natural gas fields and major pipelines. However, at this time, gas prices have not been quoted at a level, on a long-term basis, that would make this an economic option for Gulf Power Company. Gulf Power Company and the Southern Company will continue to talk to natural gas suppliers, and if this option becomes attractive, it will be implemented. Meanwhile, as noted above, Gulf Power Company intends to install low-NO_x burners that will enable Plant Crist to burn gas on a seasonal basis should this become the economic choice.

Foreign Coal

Another assumption embedded within the price forecast in the compliance simulation model is one regarding South American (Colombia and Venezuela) or South African coals. The basic premise here is that foreign producers will "meet" or just beat the delivered price of domestic low sulfur coal at our coastal plants. This type coal was a prime candidate to replace the Daniel contracts in 1987, but negotiations failed to produce a long term supply agreement. During 1993, a substantial amount of the Venezuelan and Colombian coal have been tested at Plants Crist and Smith.

Previously, the European market was considered the primary market for this coal with the U.S. being viewed as a "swing" market for any excess production. We will continue to monitor this source region and maintain contacts with these suppliers to see if and when we should modify the above price assumption.

If Plant Crist moves away from the Illinois source region due to Clean Air Compliance, then the delivered price of foreign coal begins to compare more favorably with the cost of lower sulfur domestic coal for fuel switching. Additional risk factors associated with ocean freight and political stability of governments as they relate to enforceable contracts then must be considered with the long term purchase of foreign coals.

FUEL RELATED MODELING INPUTS

The Utility Planning Model (UPM) is capable of including two fuel inputs for each generating unit. These two fuel inputs allow the user to model both existing fuel contracts as well as a spot fuel for each unit. The section below describes how these fuel inputs are used in the development of the Clean Air Compliance Strategy.

Existing Fuel Contracts

Existing fuel contracts, such as the Peabody coal contract, are input as the primary fuel source for the generating units which will burn coal from these contracts. The Fuels Department at Southern Company Services provides the input concerning existing contracts for each generating unit. This input includes the tonnage to each unit on an annual basis, the sulfur content, the heat content, and price of the existing contracted coal.

In the UPM all coal from existing contracts is assumed to be burned before other purchases are made. The UPM will warn the user if a unit is not burning at least all of the contracted coal in a particular year based upon fuel inventory limits that are provided by the Fuels Department.

During the development of the Clean Air Compliance Strategy the existing contracted coals are considered as fixed inputs. Any coal that is necessary above the currently contracted amount is considered to be purchased through the secondary fuel source (spot coal).

Spot Coal Purchases

In the UPM after a generating unit consumes all of the coal available in that year from its primary fuel source (existing contracts) it begins to burn coal from its secondary source. In the development of the Clean Air Strategy the secondary fuel source for each unit is spot coal.

The Fossil Fuel Price Forecast (See Appendix) contains price projections for each of the coals available to the generating units. This forecast information is used as input into the UPM for all secondary fuel sources.

Since existing contracts are fixed, fuel switching from a high sulfur coal to a low sulfur coal only affects fuel purchases that are necessary above the amount of coal supplied under existing contracts. In order to determine the worth of changing from a higher sulfur coal to a lower sulfur coal at a plant two UPM runs are made. The first run is made with a higher sulfur coal as the secondary source. Another run is made with the lower sulfur coal as the secondary source. The output of these two runs is compared to determine if switching to the lower sulfur coal is a economic option. This technique allows many fuel switching options to be analyzed for each generating plant in order to determine the least cost fuel options for each plant.

Future Fuel Contracts

Future coal contracts are not modeled in the UPM during the process of evaluating each compliance option due to modeling and time constraints. Future fuel contract estimates are not included with the existing contract data because the type of coal to be contracted in the future is not known at the beginning of the strategy process. Future fuel contract estimates are not included with the spot fuel data because the UPM uses the spot fuel data to determine the dispatch price of each unit. Including future contracts with the spot fuel data would incorrectly alter the dispatch of the generating units. This modeling technique does not change the company's fuel contracting policy but only provides a method by which many fuel options can be evaluated in an acceptable amount of time.

In order to determine the effect of not modeling future contracts in the strategy development process a UPM run was made based upon the fuel choices in the Base Strategy including future contract assumptions for Gulf Power. Gulf's current contract with Peabody coal does not expire until the end of the year 2007. This contract fulfills Gulf's need for contracted coal until its expiration therefore future contract assumptions do not affect Gulf Power until the year 2008. Beginning in 2008 the Fuels Department supplied assumptions concerning future coal contracts for the Gulf Power units. The results from the UPM run with future contract assumptions and the run without future contract assumptions were compared. Gulf Power net present value revenue requirements over the study period increased by only 0.5% when future contracts were included in the analysis.

8.0 OTHER ISSUES

Cost Allocation Among System Companies

The Clean Air Act Amendments of 1990 permit utility systems to create system-wide "bubbles" in which coordinated efforts between affiliated companies can produce the most cost-effective compliance plan for the entire system. Inherent in this approach is that one affiliate company can over-comply (as far as the compliance requirements of its owned plants) so that the excess emission allowances can be used for compliance at another system company, with the result that compliance costs for both companies are less than if each company complied on its own. To successfully implement this strategy, a method must be identified that:

1. fully compensates the over-complied company so that its ratepayers pay no more than if it complied on its own;

2. allows the under-complied company to realize the savings of participating in a system strategy; and

3. will pass all regulatory review so that all costs are recovered and the intended savings are realized.

The Southern Company is studying different approaches that will equitably share the costs of a system-wide compliance strategy.

Additionally, Gulf Power, as part of the integrated Southern electric system, participates in a system-wide economic dispatch of its generating units. This economic dispatch results in the minimization of variable costs of the dispatchable resources, primarily steam generating units. As generation is produced from Clean Air Act-affected units, another cost of generation is introduced, namely the consumption of emission allowances. At the start of the Clean Air Act compliance date (1995), the economic dispatch will include the cost of consuming emission allowances as it determines the least cost method of dispatching units to serve load. Further, as energy is exchanged between companies as a result of the system-wide dispatch, the costs of the emission allowances consumed will be passed through the intercompany billing to compensate any company selling energy for the emission allowances consumed in the transaction.

The development of a methodology for transferring allowances between affiliates within The Southern Company raises the issue of what price to use in conjunction with these transfers.

Wording was included in the Clean Air Act Amendments to refute any authority the Public Utility Holding Company Act (PUHCA) of 1935 would have over the price at which allowances may be traded among pool members. Allowances are exempt from the rules and regulations under PUHCA and from the jurisdiction of the SEC. This means that allowances are then subject to Section 205 of the Federal Power act which requires that the charge for these allowances be "just and reasonable". Under the Base Strategy, allowances are traded between companies based on our latest projection of the market value of allowances. In the Internal Case, where The Southern Company complies on its own as a system (ignoring the market), the system incremental cost is used as an appropriate value for allowance trading.

<u>Potential For New Short-Term Ambient Air Quality Standard for SO_2</u>

On April 22, 1988, EPA published its proposal to reaffirm the existing ambient air quality standards for SO_2. In the same notice EPA requested comments on the need for a new ambient standard for one-hour average SO_2 concentrations at a level of 0.4 ppm. Any stringent one-hour average standard in the range of 0.2 to 0.5 ppm could force SO_2 emission reductions at a majority of Southern Company coal-fired power plants; beyond that required under the Clean Air Act. Unlike emission reductions under the new acid rain legislation, the new emission limitations would be source-specific -- the requirements could not be met by emission reductions at other facilities.

EPA is currently evaluating exposure assessment results for a 0.75 ppm five-minute average standard (roughly equivalent to a one-hour average standard of 0.375 ppm) with either 1 or 5 exceedences allowed per year. Preliminary analyses indicate that such a standard would be quite disruptive of the allowance trading program.

It is not clear when EPA will issue its final decision on its proposed reaffirmation of existing standards; however, EPA will likely have to re-propose if it decides to pursue establishment of a new one-hour average standard. A new ambient air quality standard of SO_2 could have a broad range of consequences on the allowable emission rates of Southern electric system plants and on any Clean Air Act Compliance Strategy. The extent of those consequences are a function of the level and the form of such a standard and cannot be reliably predicted at this time. Necessary adjustment to the Clean Air Act Compliance Strategy will be made as soon as developments narrow the range of expectations.

<u>Effect of WEPCo Decision on Clean Air Compliance</u>

The WEPCo issue refers to EPA's determination of the applicability of the New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) regulations under the Clean Air Act (CAA) to certain maintenance and renovation activities at Wisconsin Electric Power Company's (WEPCo's) Port Washington plant in 1988. EPA determined that the activities WEPCo proposed to undertake constituted "modifications" or "major modifications" within the context of the NSPS and PSD rules, respectively. This decision meant that they would have to undergo a PSD review, which could result in even more stringent emission control requirements.

On July 21, 1992, EPA issued a final rule on the WEPCo issue. The rule relieves many uncertainties associated with plant retrofit projects which the electric utility industry may undertake, either for compliance with the 1990 Amendments to the Clean Air Act (CAA) or for maintenance. Absent this rule, these projects risked triggering the stringent control requirements applied to new sources.

Basically, the WEPCo rule exempts "pollution control projects" from new source review; "pollution control projects" include installation of scrubbers, low NO_x burners, precipitators, or anything necessary to switch to a less polluting fuel.

Of course, the plant must still meet all applicable State Implementation Plan limits, permit conditions, and National Ambient Air Quality Standards. The permitting authority may require modeling to ensure that all applicable requirements continue to be met.

Although final WEPCo rules have been issued, petitions for review have been filed. The outcome of this litigation could affect compliance plans being made by the electric utility industry.

Reduced Utilization

Beginning in 1995, emissions cost will become part of the economic dispatch algorithm. Because SO_2 allowances are assumed to have value, the opportunity cost associated with consuming them will be factored in as part of the dispatch decision. This means that "cleaner" units will tend to operate more in the future. NO_x regulations may place additional constraints on how we operate specific units as well. The ability to average NO_x emissions will impact plant operations.

The Reduced Utilization provision of the Clean Air Act has implications for Phase I compliance. This provision states that all Phase I affected units, in aggregate, must meet their 1985-1987 level of burn. The intent of this provision was to prevent utilities from shifting to unaffected units during Phase I as a means of compliance. The current EPA regulations contain alternatives to "forcing" these units to meet this constraint. Under the "Compensating Generation" concept, allowances can be surrendered at the end of each year to compensate for the amount of reduced utilization.

In this year's compliance strategy, the Compensating Generation concept was utilized and the surrender of Phase I allowances was factored in as part of this compliance cost. Preliminary results indicate that the Southern system could have reduced utilization in 1995 and 1996 prior to the use of compensating generation. With the availability of compensating generation candidates, such as Crist 4 & 5, Gulf's exposure to the surrender of allowances is minimized.

Compliance Reserves

The Clean Air Act imposes extremely harsh penalties for non-compliance. Consequently, it is imperative that adequate margin be designed into the compliance strategy to ensure compliance under possible scenarios such as higher than forecasted energy demand and/or unanticipated outage of controlled and/or non-emitting base load generation resources.

The reserve margin would not be the only resource available to cover unforeseen scenarios such as those above. Operational flexibility is an option in that higher utilization of low-emitting generation resources out of economic dispatch is available. This option will have a higher cost to the system than purchasing allowances since the emissions dispatch would already have the value of allowances factored into the dispatch costs of the curtailed higher-emitting sources.

In Phase I, an adequate margin for compliance is available for all years in the form of the allowance bank built for use in Phase II. A Phase II system allowance reserve margin will be provided by purchasing additional allowances, which would then remain in the bank throughout Phase II.

Future Technology Improvements

The proposed Phase I compliance strategy of fuel switching to a lower sulfur coal provides Gulf/The Southern Company with a valuable asset: time. This time will be well utilized to learn from the various system Department Of Energy (DOE) demonstration projects for scrubbers and Low-NO_X burners during Phase I and to allow for the expected improvements and cost reductions in available compliance technology as well as the potential for new technology development.

Combustion Turbines

Existing simple cycle combustion turbines (CTs) are not affected by the legislation, however, any combustion turbines placed in service after November 15, 1990 are impacted.

(1) CEMs will be needed by January 1, 1995.

(2) Allowances will be needed by January 1, 2000, if the CTs are burning No. 2 oil.

(3) Emission permit fees are expected to be at least $25 per ton of regulated pollutants annually.

9.0 COMPLIANCE AND INSTALLATION DATES

Clean Air Act Compliance

Bill Signed into Law	November 15, 1990
Phase I	
Phase I and II Allowance Rules (EPA)	Due - May 15, 1992 Final Rules - January 11, 1993
Phase I NO_x Reduction Rules (EPA)	Due - May 15, 1992 Final Rules - March 1, 1994
CEM Requirements (EPA)	Due - May 15, 1992 Final Rules - January 11, 1993
Phase I SO_2 Compliance Plan and Permit Applications to EPA	February 15, 1993
Phase I SO_2 Permit Approved by EPA	September 10, 1993
Phase I NO_x Compliance Plan	Due to EPA approximately May 15, 1994
Phase I NO_x Compliance Plan Approval Expected (1)	November 15, 1994
CEMs Certified - Phase I units Phase II units	November 15, 1993 (1) January 1, 1995
Phase I Compliance - SO_2 and NO_x	January 1, 1995
NO_x System Averaging Plan Due	January 1, 1995
Phase II	
Phase II Allowances Issued (EPA)	December 31, 1992
Phase II SO_2 Compliance Plan and Permit Applications to State	January 1, 1996
Phase II NO_x Reduction Rules (EPA)	January 1, 1997
Phase II SO_2 Permit Approval by States	December 31, 1997

Clean Air Act Compliance Installation Dates

Phase II NO_x Compliance Plan and Permit Applications to State	January 1, 1998
Phase II NO_x Permit Approval by States	July 1, 1998 (1)
Phase II Compliance - SO_2 and NO_x	January 1, 2000
Precipitator Modification & Gas Conditioning Bids	Beginning November 1991
Precipitator Modification & Gas Conditioning Engineering	January, 1992 - December, 1993
Precipitator Modification & Gas Conditioning Installation	May, 1992 - December, 1994
CEM Bids	December, 1991
CEM Delivery	April, 1992 - May, 1994
CEM Installation	June, 1992 - July, 1994
Low-NO_x Burner Bids	Beginning June, 1992
Low-NO_x Burner Vendor Fabrication (20 Months)	Beginning September, 1992 - August, 1994
Low-NO_x Burner Installation	By January 1, 1995
Low-NO_x Burner Installation(Phase II)	By January 1, 2000

(1) Assumes six months for states to issue permits, could be longer

APPENDIX

CLEAN AIR COMPLIANCE TECHNOLOGY DESCRIPTIONS

Flue Gas Desulfurization (FGD)

Flue gas desulfurization (often referred to as scrubbers) is used to remove sulfur oxides, predominately SO_2, which are formed from the combustion of sulfur in the fuel. The amount of SO_2 produced is directly proportional to the sulfur content of the fuel and coal firing rate (lb/hr). Generically, the preferred FGD technology for The Southern Company is wet limestone utilizing forced oxidation. This selection provides the following advantages:

- Wet FGD provides fuel flexibility because of its ability to obtain high removal rates of SO_2 over a relatively large range of coal sulfur contents.

- Limestone is a plentiful resource in the southeastern United States which is economically obtainable at all potentially effected plant sites.

- The gypsum byproduct which is produced is a physically stable, chemically inert, environmentally benign waste product which can be disposed of on site or sold commercially if a gypsum market were to develop.

Sulfur oxides are removed by contacting flue gas with an alkaline limestone solution. The limestone is received by rail, truck or barge and is conveyed to a storage pile. From the storage pile, the limestone is transferred to a day bin which feeds a wet ball mill and classifier system. The classification loop ensures the proper size distribution of the limestone particles which is critical to the process. The solids slurry from the ball mill/classification loop is further diluted and stored in a limestone slurry tank prior to transfer to the scrubber vessel.

Flue gas enters the scrubber vessel where the SO_2 is absorbed by the alkaline limestone slurry. The slurry then enters an agitated reaction tank which is large enough to provide adequate time for crystallization of the calcium salts. Air is blown into the reaction tank to fully oxidize the slurry to at least 95% gypsum. A bleed stream from the reaction tank is pumped to the waste processing area for disposal via gypsum stacking or dewatering and landfill. The water removed from the by-product is returned to the scrubber vessel and re-used.

The cleaned flue gas, now saturated, enters a mist eliminator to remove any entrained droplets before exiting to the stack. To prevent corrosion downstream of the FGD equipment, most U.S. utilities use corrosion resistant materials while most European and Japanese use flue gas reheat.

Continuous Emission Monitor (CEM) Systems

The term CEM describes a variety of techniques and instrumentation used to measure air pollution emissions from power plants on a continuous basis. In general, CEM systems are complex devices which include physical and chemical analytical instruments and data recording systems. The typical CEM system employed on the Southern electric system would be used to measure and record levels of opacity, flue gas flow, concentrations of SO_2, NO_x and diluent gases (either oxygen (O_2) or carbon dioxide (CO_2)) in the exhaust gases exiting the stack.

Although various types of sample acquisition, handling, and analysis techniques are employed, commercially available CEM systems can be categorized as in-situ, dilution or extractive. In-situ and extractive are the most common types used in the utility industry. Extractive systems remove a gas sample from the exhaust which must be cleaned and dried before being introduced into the gas analyzers. A sample conditioning system is typically provided for this purpose and removes particulate matter and moisture prior to actual measurement of the gaseous species. In-situ gas monitoring systems are designed to measure gas concentrations directly in the stack or duct without having to extract samples for external analysis. This results in a wet-basis measurement versus a dry-basis measurement for the extractive systems. The results of either method are corrected to a benchmark scale (by measurement of the diluent gases) for compliance reporting.

CEM systems are complex, analytical systems that are expected to operate in hostile environments typical of power plants. Experience has shown that CEM systems demand a high level of maintenance and must receive priority attention, preferably from a dedicated, well-trained staff. All CEM systems placed on the Southern electric system for purposes of compliance monitoring must pass an established performance specification and test procedures for initial EPA certification. Additional information concerning CEM systems can be found in EPRI manual CS-3723.

Electrostatic Precipitators (ESP)

One option of compliance with sulfur dioxide emissions is fuel switching to a lower sulfur coal. While burning low sulfur coal improves the sulfur emissions positively, it may adversely effect the particulate emissions due to increasing the ash resistivity making the ash more difficult to collect in an electrostatic precipitator.

Electrostatic precipitators collect ash by passing an electric current through the flue gas stream. The current passes from high voltage discharge electrodes to the collecting plates of the precipitator. This flow of current creates electrical forces which cause the ash to accumulate on the collection plates. When fly ash resistivity is high, the flow of current cannot pass through the collected ash, resulting in a high voltage across the fly ash layer and hence, a significant reduction in precipitator efficiency. While the majority of ESPs in the Southern electric system are marginally sized to burn low sulfur coal, there are some remedial actions which can minimize the impact of burning low sulfur coals.

Precipitator modifications in the form of equipment repairs/upgrades will undoubtedly be a part of a fuel switch strategy within the Southern electric system. These upgrades will examine each plant's current precipitator capabilities and recommend changes which may include internal straightening or replacement of collection plates, replacement or repair of electrodes, improved rappers for more efficient ash removal from plates, evaluations of existing T-R sets, internal flow modifications, review of hot to cold side conversions, and installation of state-of-the-art controls. Additionally, installation of SO3 flue gas conditioning systems to enhance the ESP performance may be a viable option to allow low sulfur coal to be burned.

Flue Gas Conditioning

Flue gas conditioning systems create SO_3 which, when injected into the ductwork ahead of the ESP, reduces the ash resistivity, and allows higher precipitator efficiency. Flue gas conditioning systems produce SO_2 by catalytically converting sulfur dioxide (SO_2) which is generated by burning sulfur. Sulfur is normally delivered to the site in a molten state and stored in a heated storage tank. The molten sulfur is pumped into the burner/converter while ambient air is heated and blown into the burner for sulfur ignition. The SO_2 produced is oxidized over a catalyst to SO_3 which is uniformly injected into the ductwork through a distribution piping system and a series of injection probes.

Baghouse or Fabric Filter

Baghouses are used as an alternate to electrostatic precipitators to remove fly ash and particulates from combustion gases. The typical baghouse is fabricated into multiple modules located on either side of inlet and outlet manifolds. Flue gas enters through the inlet manifold and is directed to individual modules. Each module contains a number of fabric bags which are typically supported on a rigid wire frame or with support rings to prevent the bag from collapsing. Depending on the cleaning mechanism of the particular baghouse, gas flow can be from outside the bag flowing toward the inside of the bag or from inside the bag outward. Regardless of the direction of flow, the ash collects on the bag surface and forms a "filter cake". The performance of the baghouse increases with the formation of the filter cake, but at the expense of increased draft loss.

The control system automatically begins the cleaning sequence on a timed interval or when the build-up of particulates on the bags causes the pressure difference to reach a preset level. Each module is capable of being isolated from the remaining modules by dampers located in the inlet and outlet headers. The three most widely used methods of cleaning bags are the pulse-jet, mechanical shaking, and reverse flow. Each method forces the particulates off the bag in the opposite direction of normal gas flow. Once all of the bags in a module are cleaned, the module is returned to service while a new module is isolated for cleaning.

Particulate removal efficiency is a strong function of the fabric used in the baghouse. Typical materials include polypropylene, fiberglass, Teflon, acrylic, polyester, and Nomex. Individual bag lengths can be varied to match the desired air/cloth ratio and removal efficiencies.

NO_X Compliance Alternatives

Low-NO_X Burners (LNB)

The primary combustion NO_X control technology being considered for the units in The Southern Company is current low-NO_X burner technology for wall-fired units and tangentially-fired units.

NO_X formation in coal combustion comes from the nitrogen in the coal and the thermal fixation of nitrogen with oxygen found in the air required for the combustion process. Low-NO_X burners produce a fuel-rich combustion that reduces the NO_X formation from the nitrogen in the coal during the primary stage of combustion. By means of secondary air control dampers or vanes, the low-NO_X burners gradually combine the secondary air with the fuel at a lower temperature during the secondary stage of the combustion process to further reduce the NO_X formation.

Overfire Air (w/Low-NO_X Burners) (LNB + OFA)

Overfire air systems are installed with low-NO_X burners on tangentially-fired units and wall-fired units to achieve greater NO_X reduction than with low-NO_X burners only. Overfire air systems are more likely to be installed with low-NO_X burners on tangentially fired units because of technical differences between these boiler types. Ducting for the overfire air system injects some of the combustion air above the primary combustion zone. The use of overfire air offers the potential for greater NO_X reduction by allowing staged combustion in the primary combustion zone. Secondary combustion of the fuel occurs in the cooler zones of the furnace above the burners with the overfire air. The net effect of this combustion process is a lower NO_X emission rate from the unit. However, an over fire air system may not be feasible to retrofit to some boilers due to furnace geometry, potential for tube wastage and excessive slagging, unacceptable increases in unburned carbon, and excessive levels of carbon monoxide.

Selective Non-Catalytic Reduction (SNCR)

SNCR is based on injection of ammonia or urea (a liquid compound which thermally degrades to ammonia) directly into the boiler at a flue gas temperature that allows spontaneous reaction of the ammonia with NO_X to form nitrogen and water. The injection point is typically near the top of the furnace to achieve the correct temperature window between 1600°F and 2100°F for the reaction to proceed. In order to achieve NO_x removals over the operating range of the boiler, multiple injection points are required to track the temperature window as it moves in the boiler. Suitable injection points must be located between existing heat transfer surfaces to provide correct residence time and allow adequate blending of reagent with NO_x. Existing boiler penetrations may be used, if available, to reduce the need for water wall modifications.

Application of SNCR to The Southern Company boilers would generally target smaller units (below 250 MW) with low-capacity factor and relatively short remaining life (up to 10 years). Estimates have identified several older units which have relatively high burner retrofit costs because of auxiliary systems that must be upgraded. SNCR could play a role in providing NO_x reduction as opposed to installing burners for this group of units. SNCR may also play a role in additional NO_x removal, which may be required for ozone nonattainment areas, (i.e., Atlanta).

Selective Catalytic Reduction (SCR)

SCR involves the injection of ammonia into the flue gas stream. The ammonia reacts in the presence of a catalyst to reduce NO_x to nitrogen and water. SCR accomplishes the same reaction as selective non-catalytic reduction (SNCR), but, because it occurs at a lower temperature, a catalyst is required to promote the reaction.

Although there are several configurations for SCR, it is anticipated that a high-dust arrangement will be used for Southern Company applications. The high-dust arrangement locates the SCR reactor downstream of the economizer outlet and upstream of the air preheater. This arrangement takes advantage of the fact that the boiler exit gas temperature is typically in the SCR operating temperature window of 600°F to 750°F.

SCR can achieve NO_x reductions as high as 90 to 95 percent, although most systems typically operate at 80 to 85 percent NO_x reduction to reduce the potential of excess ammonia slip. The key to successful SCR operation is to maintain catalyst selectivity. Side reactions such as oxidation of SO_2 to SO_3, formation of ammonium bisulfate, and oxidation of ammonia to form NO_x detract from the system's performance.

Anhydrous or aqueous ammonia is vaporized and blended with a carrier gas (typically air or steam) and is injected in proportion to the flue gas NO_x concentration upstream of the SCR reactor. A series of individually controlled injection pipes ensures the ammonia distribution matches the NO_x distribution across the duct cross-sectional area.

One of the most important variables for SCR performance is space velocity or the volume of flue gas treated with respect to the volume of catalyst present. Low space velocities indicate a long residence time, which implies high NO_x conversion. High space velocity implies greater throughput of flue gas or, more appropriately, a lesser amount of catalyst required for a given NO_X reduction. Sensitivity analysis for different catalyst life will be included in the evaluation of SCR for The Southern Company. SCR is the subject of a Gulf Clean Coal Technology (CCT) project at Gulf Power's Plant Crist.

Natural Gas/Seasonal Firing (GAS-SEA)

Natural gas is the cleanest burning fossil fuel. The concept of seasonal firing is being considered for NO_X control strategy. The concept of seasonal firing is burning 100-percent gas in selected boilers for the months of April through October and then switching back to 100 percent coal firing for the months of November through March. The most appropriate application of seasonal firing or co-firing could be at the coastal plants, more specifically Plant Crist and Mississippi Power Company's Plant Watson, due to their proximity to major natural gas pipeline systems and their current use of gas. The current and forecasted price of natural gas keeps this option from being economically feasible.

Burners Out of Service (BOOS)

An effect similar to over fired air (OFA) can be created by taking the top burners out of service (BOOS) in a boiler, and thus reducing the level of NO_X. Although BOOS may provide a non-capital cost NO_X reduction alternative, it does not provide enough NO_X reduction for Crist Units 6 and 7 to meet compliance. Along with not providing adequate NO_X reduction, capacity may not be obtainable with BOOS.

The advantage of BOOS is low cost. New equipment is not required since it is a mode of operation. It generally gives good NO_X reduction for the smaller units but mixed NO_X reduction for the larger units.

One major disadvantage is the loss of capacity due to a mill being out of service. The capacity loss could be 20 percent or more with a small unit. Units with marginal mill capacity or high mill maintenance will not be able to obtain maximum benefits from BOOS. Other problems such as increased loss on ignition (LOI) normally associated with overfire air systems also exist. For the larger units, BOOS generally does not provide enough NO_X reduction to meet CAA requirements. Off-set air is required for tube wall protection when using low-NO_X firing systems. BOOS does not provide this off-set air.

BOOS testing is being done in the Southern electric system. BOOS is not recommended for the large base load units due to the mixed NO_X reduction and the potential for water wall damage. BOOS is seasonally possible for the small low capacity units. NO_X reduction does not occur 100 percent of the time, but loss of generating capacity during the high-load periods could be avoided and compliance can frequently be realized through the use of averaging.

Other Options

Listed below are additional options for NO_x control which were screened out. These options will be re-evaluated in future strategy updates:

Repowering
Retirement
Coal Switching
Reburning of natural gas
Modifications to Economic Dispatch
Combined SO_2/NO_x Reduction

EQUIVALENT ALLOWANCE VALUES

Gulf Power Company has several different SO_2 compliance options available for most of the generating facilities affected by the CAA Amendments. These options include switching to lower sulfur coal or natural gas, purchasing allowances, and installing scrubbers. The large number of generating facilities in the Southern electric system along with the various options available to each unit created a need for a ranking tool to aid in the screening of the numerous compliance options. Expressing all decisions in terms of the equivalent allowance value (EAV) was employed for this purpose. The EAV expresses the value of each compliance option in terms of \$/ton of SO_2 removed.

The EAV is computed in three steps. Table A-1 illustrates the EAV calculation. In step 1, the cost of the compliance option is calculated as the net present value (NPV) X (in 1995 dollars) of the incremental revenue requirements due to implementing the compliance option. For example, switching to lower sulfur coals at a particular plant would likely result in an increase in fuel costs and possibly additional capital and O&M costs. Changes in system dispatch and any other change in system costs resulting from the fuel switch would also be captured as part of the cost of this option.

In step 2, the benefit of the compliance option is calculated as the NPV Y (in 1995 dollars) of the resulting system emissions reductions priced at the projected market value of allowances. The 1995 starting point for the allowance value forecast is identified as Z, and is expressed in dollars per ton. If the benefit Y determined in step 2 is higher (or lower) than the cost X calculated in step 1, then the option is expected to be less (or more) expensive than the projected value of allowances.

In step 3, the EAV is calculated by multiplying Z (the 1995 starting point of the original allowance value forecast) times the ratio of X (the costs calculated in step 1) and Y (the benefits calculated in step 2) and is expressed in dollars per ton of SO_2 removed.

Table A-2 provides a list of the Equivalent Allowance Values for each of the Gulf Power Company compliance options. The EAVs in Table A-2 are the result of the initial individual compliance option simulations as described in Section 4. Tables A-3 through A-5 provide a list of the final EAVs for each Gulf Power Company option that was chosen for the Base Strategy, Internal Case , and the Company by Company Case.

TABLE A-1

EXAMPLE EQUIVALENT ALLOWANCE VALUE (EAV) CALCULATION

(All values used in this example are fictitious and are for illustrative purposes only.)

	STEP #1			STEP #2			
	SYSTEM INCREASED COSTS ($)			SYSTEM REDUCED EMISSIONS BENEFITS			
	FUEL & O&M	CAPITAL	TOTAL $ 000	TONS SO_2	$/TON SO_2		TOTAL $ 000
1995	1,405	4,467	5,872	8,773	300	(Z)	2,632
1996	1,534	4,274	5,808	12,391	310		3,841
1997	1,901	4,087	5,988	10,974	320		3,512
1998	2,267	3,906	6,173	11,320	330		3,736
1999	2,492	3,731	6,223	11,502	340		3,911
2000	2,056	3,561	5,617	16,384	350		5,734
2001	3,111	3,396	6,507	16,062	360		5,782
2002	3,377	3,234	6,611	15,816	370		5,852
2003	3,644	3,072	6,716	16,191	380		6,153
2004	4,709	2,910	7,619	16,510	390		6,439
2005	5,258	2,748	8,006	17,940	400		7,176
2006	5,852	2,586	8,438	14,292	410		5,860
2007	7,205	2,423	9,628	15,719	420		6,602
2008	9,030	2,261	11,291	13,789	430		5,929
2009	14,379	2,099	16,478	63,991	440		28,156
2010	21,925	1,937	23,862	76,628	450		34,483
2011	20,901	1,775	22,676	72,404	460		33,306
2012	24,190	1,613	25,803	76,387	470		35,902
2013	22,937	1,451	24,388	79,625	480		38,220
2014	25,266	1,303	26,569	79,774	490		39,089
2015	27,139	1,183	28,322	76,271	500		38,136
2016	28,402	991	29,393	77,645	510		39,599

PRESENT VALUE (1995 $000) 91,292 (X) PRESENT VALUE (1995 $000) 92,880 (Y)

STEP #3 EQUIVALENT ALLOWANCE VALUE (EAV) = X/Y times Z.

EQUIVALENT ALLOWANCE VALUE (EAV) 295 $/Ton SO_2

TABLE A-2
INDIVIDUAL SIMULATION OF COMPLIANCE OPTIONS

Plant	Compliance Option	Equivalent Allowance Value ($/Ton SO2 Removed)
Crist	Fuel Switch to 1.5% Coal in 1995	48
	Fuel Switch to 1.5% Coal in 2000	48
	Fuel Switch to 1% Coal in 1995	139
	Fuel Switch to 1% Coal in 2000	136
	Fuel Switch to 0.7% Coal in 1995	224
	Fuel Switch to 0.7% Coal in 2000	229
	Fuel Switch to 0.5% Coal in 1995	299
	Fuel Switch to 0.5% Coal in 2000	297
	Scrub 3% Coal in 2000	347
	Scrub 1.5% Coal in 2000	441
	Scrub 3% Coal at Units 4-5 in 2000	464
	Scrub 1.5% Coal at Units 4-5 in 2000	523
	Scrub 3% Coal at Units 6-7 in 2000	381
	Scrub 1.5% Coal at Units 6-7 in 2000	473
	Natural Gas at Units 6-7 in 1995	1,046
	Natural Gas at Units 6-7 in 2000	1,176
	Seasonal Natural Gas at Units 6-7 in 1995	926
	Seasonal Natural Gas at Units 6-7 in 2000	1,024
Scholz	Fuel Switch to 1.5% Coal in 2000	60
	Fuel Switch to 1% Coal in 2000	110
	Fuel Switch to 0.7% Coal in 2000	193
Smith	Fuel Switch to 1.5% Coal in 2000	39
	Fuel Switch to 1% Coal in 2000	142
	Fuel Switch to 0.7% Coal in 2000	227
	Fuel Switch to 0.5% Coal in 2000	320
	Scrub 3% Coal in 2000	279
	Scrub 1.5% Coal in 2000	435

TABLE A-3
FINAL STACKING OF COMPLIANCE OPTIONS
BASE STRATEGY

Plant	Compliance Option	Equivalent Allowance Value ($/Ton SO2 Removed)
Crist	Fuel Switch to 1.5% Coal in 1995	41
Crist	Fuel Switch to 1% Coal in 1995	133
Scholz	Fuel Switch to 1.5% Coal in 2000	46
Scholz	Fuel Switch to 1% Coal in 2000	106
Scholz	Fuel Switch to 0.7% Coal in 2000	*
Smith	Fuel Switch to 1.5% Coal in 2000	41
Smith	Fuel Switch to 1% Coal in 2000	137

* Fuel Switching to 0.7% Coal at Plant Scholz was favorable in the individual simulations but proved to be uneconomic after other lower cost options were implemented and therefore was not included in the final Base Strategy.

TABLE A-4
FINAL STACKING OF COMPLIANCE OPTIONS
INTERNAL CASE

Plant	Compliance Option	Equivalent Allowance Value ($/Ton SO2 Removed)
Crist	Fuel Switch to 1.5% Coal in 1995	41
Crist	Fuel Switch to 1% Coal in 1995	133
Crist	Fuel Switch to 0.7% Coal in 2000	235
Scholz	Fuel Switch to 1.5% Coal in 2000	46
Scholz	Fuel Switch to 1% Coal in 2000	106
Scholz	Fuel Switch to 0.7% Coal in 2000	231
Smith	Fuel Switch to 1.5% Coal in 2000	41
Smith	Fuel Switch to 1% Coal in 2000	137
Smith	Fuel Switch to 0.7% Coal in 2000	227

TABLE A-5
FINAL STACKING OF COMPLIANCE OPTIONS
COMPANY BY COMPANY CASE

Plant	Compliance Option	Equivalent Allowance Value ($/Ton SO2 Removed)
Crist	Fuel Switch to 1.5% Coal in 1995	41
Crist	Fuel Switch to 1% Coal in 1995	133
Crist	Fuel Switch to 0.7% Coal in 2000	235
Crist	Scrub 3% Coal at Units 4-5 in 2000	465
Scholz	Fuel Switch to 1.5% Coal in 2000	46
Scholz	Fuel Switch to 1% Coal in 2000	106
Scholz	Fuel Switch to 0.7% Coal in 2000	231
Smith	Fuel Switch to 1.5% Coal in 2000	41
Smith	Fuel Switch to 1% Coal in 2000	137
Smith	Fuel Switch to 0.7% Coal in 2000	227

FLUE GAS DESULFURIZATION (SCRUBBER) CAPITAL COST ESTIMATES
(1993 Dollars)

Unit Name	Fuel	Capital Cost w/o AFUDC ($ 000)	$/KW	Fixed O&M ($ 000)	Variable O&M $/Ton SO2 Removed
Crist 4-5	3% Coal	51.1	292	618.8	22.40
Crist 4-5	1.5% Coal	51.1	292	618.8	23.70
Crist 6-7	3% Coal	177.9	210	4,928.7	22.38
Crist 6-7	1.5% Coal	177.9	210	4,928.7	23.49
Crist 4-7	3% Coal	204.2	200	5,547.5	22.38
Crist 4-7	1.5% Coal	204.2	200	5,547.5	22.49
Smith	3% Coal	88.5	250	3,295.2	31.48
Smith	1.5% Coal	88.5	250	3,295.2	40.55

Notes: (1) Scrubber analysis included no cost for capacity replacement; scrubber was assumed to be off-line during summer peak hours.

(2) Scrubber characteristics include efficiency of 95%, dispatch capacity reduction of 1.8%, and heat rate increase of 4.5%.

(3) All costs are based on whole unit ratings

(4) The Crist 4-7 capital cost does not equal the sum of Crist 4-5 and Crist 6-7 due to common facilities and site preparation costs which have been included in both the 4-5 and 6-7 estimates

PROJECTED MARKET VALUE OF ALLOWANCES
($ per Ton of SO2)

Year	1993 Forecast
1995	195
1996	212
1997	230
1998	251
1999	274
2000	299
2001	327
2002	357
2003	391
2004	428
2005	469
2006	515
2007	565
2008	620
2009	680
2010	745
2011	704
2012	665
2013	628
2014	593
2015	560
2016	529
2017	500

1993 FUEL PRICE FORECAST

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

CENTRAL APPALACHIA - NSPS COAL DELIVERED TO PLANT CRIST
0.7% SULFUR 12500 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	7.00		29.25	31.30	0.00	7.85	0.00	7.85			37.10	39.15	1.4840	1.5659
1994	2.516	1.0252	7.00	-2.000	29.49	31.55		7.89		7.89			37.38	39.44	1.4951	1.5776
1995	2.613	1.0519	7.00	-2.000	29.76	31.84		7.93		7.93			37.69	39.77	1.5076	1.5910
1996	2.469	1.0779	7.00	-2.000	29.99	32.09		7.96		7.96			37.95	40.05	1.5182	1.6021
1997	2.560	1.1055	7.00	-2.000	30.25	32.37		8.00		8.00			38.25	40.37	1.5302	1.6149
1998	2.790	1.1364	7.00	-2.000	30.56	32.70		8.06		8.06			38.62	40.76	1.5449	1.6305
1999	2.929	1.1696	7.00	-2.000	31.32	33.51		8.13		8.13			39.45	41.65	1.5781	1.6658
2000	3.053	1.2054	7.00	-2.000	32.13	34.38		8.21		8.21			40.34	42.59	1.6138	1.7037
2001	3.165	1.2435	6.00	-1.000	33.28	35.28		8.39		8.39			41.67	43.67	1.6668	1.7467
2002	3.133	1.2825	5.00	-1.000	34.47	36.19		8.57		8.57			43.04	44.76	1.7214	1.7904
2003	3.228	1.3239	4.00	-1.000	35.74	37.17		8.75		8.75			44.49	45.92	1.7798	1.8369
2004	3.311	1.3677	4.00	-1.000	37.08	38.56		8.95		8.95			46.03	47.52	1.8413	1.9007
2005	3.442	1.4148	4.00	-1.000	38.53	40.07		9.17		9.17			47.70	49.24	1.9080	1.9696
2006	3.500	1.4643	4.00	-1.000	40.06	41.66		9.39		9.39			49.45	51.06	1.9782	2.0423
2007	3.492	1.5154	4.00	-1.000	41.66	43.33		9.63		9.63			51.29	52.95	2.0514	2.1181
2008	3.482	1.5682	4.00	-1.000	43.33	45.06		9.86		9.86			53.19	54.92	2.1276	2.1970
2009	3.468	1.6226	4.00	-1.000	45.06	46.86		10.10		10.10			55.16	56.96	2.2064	2.2785
2010	3.452	1.6786	4.00	-1.000	46.87	48.74		10.35		10.35			57.22	59.09	2.2886	2.3636
2011	3.482	1.7370	4.00	-1.000	48.77	50.72		10.60		10.60			59.37	61.32	2.3747	2.4528
2012	3.411	1.7963	4.00	-1.000	50.73	52.76		10.85		10.85			61.58	63.61	2.4632	2.5444
2013	3.434	1.8580	4.00	-1.000	52.31	54.40		11.11		11.11			63.42	65.51	2.5368	2.6205
2014	3.451	1.9221	4.00	-1.000	53.95	56.11		11.38		11.38			65.33	67.49	2.6132	2.6995
2015	3.463	1.9886	4.00	-1.000	55.65	57.88		11.66		11.66			67.31	69.53	2.6922	2.7813
2016	3.510	2.0584	4.00	-1.000	57.44	59.74		11.94		11.94			69.38	71.68	2.7754	2.8673
2017	3.470	2.1299	4.00	-1.000	59.27	61.64		12.23		12.23			71.50	73.88	2.8602	2.9550
2018	3.470	2.2038	4.00	-1.000	61.16	63.61		12.53		12.53			73.69	76.14	2.9477	3.0456

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

CENTRAL APPALACHIA - LOW SULFUR COAL DELIVERED TO PLANT CRIST
1.0% SULFUR 12000 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	7.00		25.75	27.55	0.00	7.85	0.00	7.85			33.60	35.40	1.4000	1.4751
1994	2.516	1.0252	7.00	-2.000	25.96	27.78		7.89		7.89			33.85	35.66	1.4103	1.4860
1995	2.613	1.0519	7.00	-2.000	26.18	28.01		7.93		7.93			34.11	35.94	1.4213	1.4976
1996	2.469	1.0779	7.00	-2.000	26.38	28.23		7.96		7.96			34.34	36.19	1.4310	1.5079
1997	2.560	1.1055	7.00	-2.000	26.60	28.46		8.00		8.00			34.60	36.47	1.4419	1.5194
1998	2.790	1.1364	7.00	-2.000	27.10	29.00		8.06		8.06			35.16	37.06	1.4651	1.5442
1999	2.929	1.1696	7.00	-2.000	27.64	29.57		8.13		8.13			35.77	37.71	1.4906	1.5712
2000	3.053	1.2054	7.00	-2.000	28.34	30.32		8.21		8.21			36.55	38.54	1.5231	1.6058
2001	3.165	1.2435	6.00	-1.000	29.09	30.84		8.39		8.39			37.48	39.22	1.5616	1.6344
2002	3.133	1.2825	5.00	-1.000	29.85	31.34		8.57		8.57			38.42	39.91	1.6007	1.6628
2003	3.228	1.3239	4.00	-1.000	30.92	32.16		8.75		8.75			39.67	40.91	1.6531	1.7046
2004	3.311	1.3677	4.00	-1.000	32.05	33.33		8.95		8.95			41.00	42.29	1.7085	1.7619
2005	3.442	1.4148	4.00	-1.000	33.28	34.61		9.17		9.17			42.45	43.78	1.7687	1.8242
2006	3.500	1.4643	4.00	-1.000	34.57	35.95		9.39		9.39			43.96	45.35	1.8319	1.8895
2007	3.492	1.5154	4.00	-1.000	35.92	37.36		9.63		9.63			45.55	46.98	1.8977	1.9576
2008	3.482	1.5682	4.00	-1.000	37.33	38.82		9.86		9.86			47.19	48.68	1.9663	2.0285
2009	3.468	1.6226	4.00	-1.000	38.80	40.35		10.10		10.10			48.90	50.45	2.0375	2.1022
2010	3.452	1.6786	4.00	-1.000	40.32	41.93		10.35		10.35			50.67	52.28	2.1111	2.1783
2011	3.482	1.7370	4.00	-1.000	41.93	43.61		10.60		10.60			52.53	54.21	2.1887	2.2586
2012	3.411	1.7963	4.00	-1.000	43.58	45.32		10.85		10.85			54.43	56.17	2.2679	2.3406
2013	3.434	1.8580	4.00	-1.000	44.92	46.72		11.11		11.11			56.03	57.83	2.3346	2.4095
2014	3.451	1.9221	4.00	-1.000	46.30	48.15		11.38		11.38			57.68	59.53	2.4033	2.4805
2015	3.463	1.9886	4.00	-1.000	47.74	49.65		11.66		11.66			59.40	61.31	2.4748	2.5544
2016	3.510	2.0584	4.00	-1.000	49.25	51.22		11.94		11.94			61.19	63.16	2.5498	2.6318
2017	3.470	2.1299	4.00	-1.000	50.79	52.82		12.23		12.23			63.02	65.06	2.6260	2.7107
2018	3.470	2.2038	4.00	-1.000	52.39	54.49		12.53		12.53			64.92	67.02	2.7051	2.7924

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

CENTRAL APPALACHIA - MEDIUM SULFUR COAL DELIVERED TO PLANT CRIST
1.5% SULFUR 12000 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	7.00		25.75	27.55	0.00	7.85	0.00	7.85			33.60	35.40	1.4000	1.4751
1994	2.516	1.0252	7.00	-2.000	25.74	27.54		7.89		7.89			33.63	35.43	1.4011	1.4762
1995	2.613	1.0519	7.00	-2.000	25.75	27.55		7.93		7.93			33.68	35.48	1.4034	1.4785
1996	2.469	1.0779	7.00	-2.000	25.73	27.53		7.96		7.96			33.69	35.50	1.4039	1.4790
1997	2.560	1.1055	7.00	-2.000	25.73	27.53		8.00		8.00			33.73	35.54	1.4056	1.4807
1998	2.790	1.1364	7.00	-2.000	25.78	27.58		8.06		8.06			33.84	35.65	1.4101	1.4853
1999	2.929	1.1696	7.00	-2.000	25.85	27.66		8.13		8.13			33.98	35.79	1.4160	1.4914
2000	3.053	1.2054	7.00	-2.000	26.28	28.12		8.21		8.21			34.49	36.33	1.4373	1.5139
2001	3.165	1.2435	6.00	-1.000	26.74	28.34		8.39		8.39			35.13	36.73	1.4637	1.5306
2002	3.133	1.2825	5.00	-1.000	27.20	28.56		8.57		8.57			35.77	37.13	1.4902	1.5469
2003	3.228	1.3239	4.00	-1.000	28.16	29.29		8.75		8.75			36.91	38.04	1.5381	1.5850
2004	3.311	1.3677	4.00	-1.000	29.17	30.34		8.95		8.95			38.12	39.29	1.5885	1.6371
2005	3.442	1.4148	4.00	-1.000	30.27	31.48		9.17		9.17			39.44	40.65	1.6433	1.6937
2006	3.500	1.4643	4.00	-1.000	31.42	32.68		9.39		9.39			40.81	42.07	1.7006	1.7530
2007	3.492	1.5154	4.00	-1.000	32.63	33.94		9.63		9.63			42.26	43.56	1.7607	1.8150
2008	3.482	1.5682	4.00	-1.000	33.89	35.25		9.86		9.86			43.75	45.11	1.8230	1.8795
2009	3.468	1.6226	4.00	-1.000	35.20	36.61		10.10		10.10			45.30	46.71	1.8875	1.9462
2010	3.452	1.6786	4.00	-1.000	36.57	38.03		10.35		10.35			46.92	48.38	1.9548	2.0158
2011	3.482	1.7370	4.00	-1.000	38.00	39.52		10.60		10.60			48.60	50.12	2.0249	2.0883
2012	3.411	1.7963	4.00	-1.000	39.48	41.06		10.85		10.85			50.33	51.91	2.0971	2.1629
2013	3.434	1.8580	4.00	-1.000	40.68	42.31		11.11		11.11			51.79	53.42	2.1580	2.2258
2014	3.451	1.9221	4.00	-1.000	41.92	43.60		11.38		11.38			53.30	54.98	2.2208	2.2907
2015	3.463	1.9886	4.00	-1.000	43.20	44.93		11.66		11.66			54.86	56.58	2.2857	2.3577
2016	3.510	2.0584	4.00	-1.000	44.55	46.33		11.94		11.94			56.49	58.28	2.3539	2.4282
2017	3.470	2.1299	4.00	-1.000	45.93	47.77		12.23		12.23			58.16	60.00	2.4235	2.5001
2018	3.470	2.2038	4.00	-1.000	47.36	49.25		12.53		12.53			59.89	61.79	2.4955	2.5745

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ILLINOIS BASIN – MEDIUM SULFUR COAL DELIVERED TO PLANT CRIST
1.5% SULFUR 12000 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	2.00		26.00	26.52	0.00	5.53	0.00	5.53			31.53	32.05	1.3138	1.3354
1994	2.516	1.0252	2.00	-2.000	26.65	27.18		5.56		5.56			32.21	32.74	1.3419	1.3641
1995	2.613	1.0519	2.00	-2.000	27.35	27.90		5.59		5.59			32.94	33.48	1.3724	1.3952
1996	2.469	1.0779	2.00	-2.000	28.03	28.59		5.61		5.61			33.64	34.20	1.4017	1.4250
1997	2.560	1.1055	2.00	-2.000	28.74	29.31		5.64		5.64			34.38	34.95	1.4325	1.4564
1998	2.790	1.1364	2.00	-2.000	29.55	30.14		5.68		5.68			35.23	35.82	1.4679	1.4926
1999	2.929	1.1696	2.00	-2.000	30.41	31.02		5.73		5.73			36.14	36.75	1.5058	1.5312
2000	3.053	1.2054	2.00	-2.000	31.34	31.97		5.79		5.79			37.13	37.75	1.5469	1.5731
2001	3.165	1.2435	2.00	-1.000	32.01	32.65		5.91		5.91			37.92	38.56	1.5800	1.6067
2002	3.133	1.2825	2.00	-1.000	32.68	33.33		6.03		6.03			38.71	39.37	1.6131	1.6403
2003	3.228	1.3239	2.00	-1.000	33.40	34.07		6.17		6.17			39.57	40.23	1.6486	1.6764
2004	3.311	1.3677	2.00	-1.000	34.16	34.84		6.31		6.31			40.47	41.15	1.6861	1.7146
2005	3.442	1.4148	2.00	-1.000	34.98	35.68		6.46		6.46			41.44	42.14	1.7266	1.7558
2006	3.500	1.4643	2.00	-1.000	35.84	36.56		6.62		6.62			42.46	43.18	1.7691	1.7990
2007	3.492	1.5154	2.00	-1.000	36.72	37.45		6.78		6.78			43.50	44.24	1.8125	1.8431
2008	3.482	1.5682	2.00	-1.000	37.62	38.37		6.95		6.95			44.57	45.32	1.8570	1.8883
2009	3.468	1.6226	2.00	-1.000	38.93	39.71		7.12		7.12			46.05	46.82	1.9186	1.9510
2010	3.452	1.6786	2.00	-1.000	40.27	41.08		7.29		7.29			47.56	48.36	1.9816	2.0151
2011	3.482	1.7370	2.00	-1.000	41.67	42.50		7.47		7.47			49.14	49.97	2.0473	2.0821
2012	3.411	1.7963	2.00	-1.000	43.10	43.96		7.64		7.64			50.74	51.61	2.1143	2.1502
2013	3.434	1.8580	2.00	-1.000	44.58	45.47		7.83		7.83			52.41	53.30	2.1836	2.2208
2014	3.451	1.9221	2.00	-1.000	46.11	47.03		8.02		8.02			54.13	55.05	2.2553	2.2937
2015	3.463	1.9886	2.00	-1.000	47.71	48.66		8.21		8.21			55.92	56.88	2.3300	2.3698
2016	3.510	2.0584	2.00	-1.000	49.38	50.37		8.41		8.41			57.79	58.78	2.4081	2.4492
2017	3.470	2.1299	2.00	-1.000	51.10	52.12		8.62		8.62			59.72	60.74	2.4883	2.5309
2018	3.470	2.2038	2.00	-1.000	52.87	53.93		8.83		8.83			61.70	62.76	2.5708	2.6148

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ILLINOIS BASIN - HIGH SULFUR, HIGH BTU COAL DELIVERED TO PLANT CRIST
2.8% SULFUR 11600 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	2.00		24.00	24.48	0.00	6.15	0.00	6.15			30.15	30.63	1.2996	1.3203
1994	2.516	1.0252	2.00	-2.000	24.36	24.85		6.18		6.18			30.54	31.03	1.3163	1.3373
1995	2.613	1.0519	2.00	-2.000	24.74	25.23		6.21		6.21			30.95	31.45	1.3342	1.3555
1996	2.469	1.0779	2.00	-2.000	24.85	25.35		6.24		6.24			31.09	31.59	1.3401	1.3615
1997	2.560	1.1055	2.00	-2.000	24.97	25.47		6.27		6.27			31.24	31.74	1.3466	1.3681
1998	2.790	1.1364	2.00	-2.000	25.16	25.66		6.32		6.32			31.48	31.98	1.3568	1.3785
1999	2.929	1.1696	2.00	-2.000	25.38	25.89		6.37		6.37			31.75	32.26	1.3686	1.3905
2000	3.053	1.2054	2.00	-2.000	25.63	26.14		6.44		6.44			32.07	32.58	1.3821	1.4042
2001	3.165	1.2435	2.00	-1.000	26.18	26.70		6.57		6.57			32.75	33.28	1.4118	1.4343
2002	3.133	1.2825	2.00	-1.000	26.73	27.26		6.71		6.71			33.44	33.98	1.4414	1.4645
2003	3.228	1.3239	2.00	-1.000	27.31	27.86		6.86		6.86			34.17	34.71	1.4728	1.4963
2004	3.311	1.3677	2.00	-1.000	27.93	28.49		7.01		7.01			34.94	35.50	1.5062	1.5303
2005	3.442	1.4148	2.00	-1.000	28.61	29.18		7.18		7.18			35.79	36.37	1.5428	1.5675
2006	3.500	1.4643	2.00	-1.000	29.31	29.90		7.36		7.36			36.67	37.26	1.5806	1.6059
2007	3.492	1.5154	2.00	-1.000	30.03	30.63		7.54		7.54			37.57	38.17	1.6194	1.6453
2008	3.482	1.5682	2.00	-1.000	30.77	31.39		7.73		7.73			38.50	39.11	1.6593	1.6858
2009	3.468	1.6226	2.00	-1.000	31.83	32.47		7.91		7.91			39.74	40.38	1.7131	1.7405
2010	3.452	1.6786	2.00	-1.000	32.93	33.59		8.10		8.10			41.03	41.69	1.7687	1.7971
2011	3.482	1.7370	2.00	-1.000	34.08	34.76		8.30		8.30			42.38	43.06	1.8269	1.8562
2012	3.411	1.7963	2.00	-1.000	35.24	35.94		8.50		8.50			43.74	44.45	1.8854	1.9158
2013	3.434	1.8580	2.00	-1.000	36.45	37.18		8.70		8.70			45.15	45.88	1.9463	1.9777
2014	3.451	1.9221	2.00	-1.000	37.71	38.46		8.92		8.92			46.63	47.38	2.0097	2.0422
2015	3.463	1.9886	2.00	-1.000	39.02	39.80		9.13		9.13			48.15	48.93	2.0755	2.1091
2016	3.510	2.0584	2.00	-1.000	40.39	41.20		9.36		9.36			49.75	50.56	2.1443	2.1791
2017	3.470	2.1299	2.00	-1.000	41.79	42.63		9.59		9.59			51.38	52.21	2.2145	2.2505
2018	3.470	2.2038	2.00	-1.000	43.24	44.10		9.82		9.82			53.06	53.92	2.2870	2.3243

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ILLINOIS BASIN - HIGH SULFUR, LOW BTU COAL DELIVERED TO PLANT CRIST
3.0% SULFUR 10800 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	2.00		19.00	19.38	0.00	6.15	0.00	6.15			25.15	25.53	1.1644	1.1819
1994	2.516	1.0252	2.00	-2.000	18.89	19.27		6.18		6.18			25.07	25.45	1.1606	1.1781
1995	2.613	1.0519	2.00	-2.000	18.81	19.19		6.21		6.21			25.02	25.40	1.1585	1.1759
1996	2.469	1.0779	2.00	-2.000	18.69	19.06		6.24		6.24			24.93	25.30	1.1541	1.1714
1997	2.560	1.1055	2.00	-2.000	18.60	18.97		6.27		6.27			24.87	25.24	1.1514	1.1687
1998	2.790	1.1364	2.00	-2.000	18.54	18.91		6.32		6.32			24.86	25.23	1.1508	1.1680
1999	2.929	1.1696	2.00	-2.000	18.70	19.07		6.37		6.37			25.07	25.45	1.1607	1.1781
2000	3.053	1.2054	2.00	-2.000	18.89	19.27		6.44		6.44			25.33	25.70	1.1725	1.1900
2001	3.165	1.2435	2.00	-1.000	19.29	19.68		6.57		6.57			25.86	26.25	1.1973	1.2152
2002	3.133	1.2825	2.00	-1.000	19.70	20.09		6.71		6.71			26.41	26.80	1.2227	1.2410
2003	3.228	1.3239	2.00	-1.000	20.13	20.53		6.86		6.86			26.99	27.39	1.2494	1.2681
2004	3.311	1.3677	2.00	-1.000	20.59	21.00		7.01		7.01			27.60	28.02	1.2780	1.2970
2005	3.442	1.4148	2.00	-1.000	21.08	21.50		7.18		7.18			28.26	28.68	1.3085	1.3280
2006	3.500	1.4643	2.00	-1.000	21.60	22.03		7.36		7.36			28.96	29.39	1.3408	1.3608
2007	3.492	1.5154	2.00	-1.000	22.13	22.57		7.54		7.54			29.67	30.11	1.3737	1.3942
2008	3.482	1.5682	2.00	-1.000	22.67	23.12		7.73		7.73			30.40	30.85	1.4072	1.4282
2009	3.468	1.6226	2.00	-1.000	23.46	23.93		7.91		7.91			31.37	31.84	1.4525	1.4742
2010	3.452	1.6786	2.00	-1.000	24.27	24.76		8.10		8.10			32.37	32.86	1.4988	1.5213
2011	3.482	1.7370	2.00	-1.000	25.12	25.62		8.30		8.30			33.42	33.93	1.5474	1.5706
2012	3.411	1.7963	2.00	-1.000	25.97	26.49		8.50		8.50			34.47	34.99	1.5959	1.6199
2013	3.434	1.8580	2.00	-1.000	26.86	27.40		8.70		8.70			35.56	36.10	1.6465	1.6714
2014	3.451	1.9221	2.00	-1.000	27.79	28.35		8.92		8.92			36.71	37.26	1.6993	1.7250
2015	3.463	1.9886	2.00	-1.000	28.75	29.33		9.13		9.13			37.88	38.46	1.7538	1.7804
2016	3.510	2.0584	2.00	-1.000	29.76	30.36		9.36		9.36			39.12	39.71	1.8110	1.8386
2017	3.470	2.1299	2.00	-1.000	30.80	31.42		9.59		9.59			40.39	41.00	1.8697	1.8982
2018	3.470	2.2038	2.00	-1.000	31.86	32.50		9.82		9.82			41.68	42.32	1.9296	1.9591

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ALABAMA - NSPS COAL DELIVERED TO PLANT CRIST
0.7% SULFUR 12000 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	2.00		38.00	38.76	0.00	5.13	0.00	5.13			43.13	43.89	1.7971	1.8288
1994	2.516	1.0252	2.00	-2.000	38.37	39.14		5.15		5.15			43.52	44.29	1.8135	1.8455
1995	2.613	1.0519	2.00	-2.000	38.78	39.56		5.18		5.18			43.96	44.74	1.8318	1.8641
1996	2.469	1.0779	2.00	-2.000	39.15	39.93		5.20		5.20			44.35	45.14	1.8481	1.8807
1997	2.560	1.1055	2.00	-2.000	39.55	40.34		5.23		5.23			44.78	45.57	1.8659	1.8988
1998	2.790	1.1364	2.00	-2.000	40.04	40.84		5.27		5.27			45.31	46.11	1.8879	1.9213
1999	2.929	1.1696	2.00	-2.000	40.59	41.40		5.32		5.32			45.91	46.72	1.9127	1.9465
2000	3.053	1.2054	2.00	-2.000	41.83	42.67		5.37		5.37			47.20	48.03	1.9666	2.0014
2001	3.165	1.2435	2.00	-2.000	43.16	44.02		5.43		5.43			48.59	49.45	2.0245	2.0604
2002	3.133	1.2825	2.00	-2.000	44.51	45.40		5.49		5.49			50.00	50.89	2.0831	2.1202
2003	3.228	1.3239	2.00	-2.000	45.95	46.87		5.55		5.55			51.50	52.42	2.1458	2.1841
2004	3.311	1.3677	2.00	-2.000	47.47	48.42		5.62		5.62			53.09	54.04	2.2120	2.2516
2005	3.442	1.4148	2.00	-2.000	49.10	50.08		5.70		5.70			54.80	55.78	2.2831	2.3241
2006	3.500	1.4643	2.00	-2.000	50.82	51.84		5.78		5.78			56.60	57.61	2.3582	2.4005
2007	3.492	1.5154	2.00	-2.000	52.59	53.64		5.86		5.86			58.45	59.50	2.4354	2.4792
2008	3.482	1.5682	2.00	-2.000	54.42	55.51		5.94		5.94			60.36	61.45	2.5151	2.5604
2009	3.468	1.6226	2.00	-2.000	56.31	57.44		6.02		6.02			62.33	63.46	2.5973	2.6442
2010	3.452	1.6786	2.00	-2.000	58.26	59.43		6.11		6.11			64.37	65.53	2.6820	2.7306
2011	3.482	1.7370	2.00	-2.000	60.28	61.49		6.19		6.19			66.47	67.68	2.7698	2.8200
2012	3.411	1.7963	2.00	-2.000	62.34	63.59		6.28		6.28			68.62	69.86	2.8591	2.9110
2013	3.434	1.8580	2.00	-2.000	64.48	65.77		6.36		6.36			70.84	72.13	2.9518	3.0055
2014	3.451	1.9221	2.00	-2.000	66.71	68.04		6.45		6.45			73.16	74.50	3.0484	3.1040
2015	3.463	1.9886	2.00	-2.000	69.02	70.40		6.54		6.54			75.56	76.94	3.1484	3.2059
2016	3.510	2.0584	2.00	-2.000	71.44	72.87		6.64		6.64			78.08	79.50	3.2531	3.3127
2017	3.470	2.1299	2.00	-2.000	73.92	75.40		6.73		6.73			80.65	82.13	3.3603	3.4219
2018	3.470	2.2038	2.00	-2.000	76.48	78.01		6.82		6.82			83.30	84.83	3.4709	3.5347

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ALABAMA – LOW SULFUR COAL DELIVERED TO PLANT CRIST
1.0% SULFUR 12000 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	2.00		32.30	32.95	0.00	5.13	0.00	5.13			37.43	38.08	1.5596	1.5865
1994	2.516	1.0252	2.00	-2.000	32.53	33.18		5.15		5.15			37.68	38.33	1.5702	1.5973
1995	2.613	1.0519	2.00	-2.000	32.80	33.46		5.18		5.18			37.98	38.64	1.5826	1.6099
1996	2.469	1.0779	2.00	-2.000	33.02	33.68		5.20		5.20			38.22	38.88	1.5927	1.6202
1997	2.560	1.1055	2.00	-2.000	33.27	33.94		5.23		5.23			38.50	39.17	1.6042	1.6319
1998	2.790	1.1364	2.00	-2.000	33.60	34.27		5.27		5.27			38.87	39.54	1.6196	1.6476
1999	2.929	1.1696	2.00	-2.000	33.98	34.66		5.32		5.32			39.30	39.97	1.6373	1.6656
2000	3.053	1.2054	2.00	-2.000	34.35	35.04		5.37		5.37			39.72	40.41	1.6549	1.6835
2001	3.165	1.2435	2.00	-2.000	35.44	36.15		5.43		5.43			40.87	41.58	1.7028	1.7323
2002	3.133	1.2825	2.00	-2.000	36.55	37.28		5.49		5.49			42.04	42.77	1.7515	1.7819
2003	3.228	1.3239	2.00	-2.000	37.73	38.48		5.55		5.55			43.28	44.03	1.8033	1.8347
2004	3.311	1.3677	2.00	-2.000	38.98	39.76		5.62		5.62			44.60	45.38	1.8583	1.8907
2005	3.442	1.4148	2.00	-2.000	40.32	41.13		5.70		5.70			46.02	46.82	1.9173	1.9509
2006	3.500	1.4643	2.00	-2.000	41.73	42.56		5.78		5.78			47.51	48.34	1.9794	2.0142
2007	3.492	1.5154	2.00	-2.000	43.19	44.05		5.86		5.86			49.05	49.91	2.0437	2.0797
2008	3.482	1.5682	2.00	-2.000	44.69	45.58		5.94		5.94			50.63	51.53	2.1097	2.1469
2009	3.468	1.6226	2.00	-2.000	46.24	47.16		6.02		6.02			52.26	53.19	2.1777	2.2162
2010	3.452	1.6786	2.00	-2.000	47.84	48.80		6.11		6.11			53.95	54.90	2.2478	2.2877
2011	3.482	1.7370	2.00	-2.000	49.51	50.50		6.19		6.19			55.70	56.69	2.3210	2.3623
2012	3.411	1.7963	2.00	-2.000	51.19	52.21		6.28		6.28			57.47	58.49	2.3945	2.4371
2013	3.434	1.8580	2.00	-2.000	52.95	54.01		6.36		6.36			59.31	60.37	2.4714	2.5155
2014	3.451	1.9221	2.00	-2.000	54.78	55.88		6.45		6.45			61.23	62.33	2.5513	2.5969
2015	3.463	1.9886	2.00	-2.000	56.68	57.81		6.54		6.54			63.22	64.35	2.6342	2.6814
2016	3.510	2.0584	2.00	-2.000	58.67	59.84		6.64		6.64			65.31	66.48	2.7211	2.7699
2017	3.470	2.1299	2.00	-2.000	60.70	61.91		6.73		6.73			67.43	68.64	2.8095	2.8601
2018	3.470	2.2038	2.00	-2.000	62.81	64.07		6.82		6.82			69.63	70.89	2.9013	2.9537

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ALABAMA – MEDIUM SULFUR COAL DELIVERED TO PLANT CRIST

2.0% SULFUR 11800 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	4.00		30.00	31.20	0.00	5.13	0.00	5.13			35.13	36.33	1.4886	1.5394
1994	2.516	1.0252	4.00	−2.000	30.29	31.50		5.15		5.15			35.44	36.66	1.5019	1.5532
1995	2.613	1.0519	4.00	−2.000	30.62	31.84		5.18		5.18			35.80	37.03	1.5171	1.5690
1996	2.469	1.0779	4.00	−2.000	30.90	32.14		5.20		5.20			36.10	37.34	1.5299	1.5822
1997	2.560	1.1055	4.00	−2.000	31.22	32.47		5.23		5.23			36.45	37.70	1.5445	1.5974
1998	2.790	1.1364	4.00	−2.000	31.61	32.87		5.27		5.27			36.88	38.14	1.5627	1.6163
1999	2.929	1.1696	4.00	−2.000	32.05	33.33		5.32		5.32			37.37	38.65	1.5833	1.6376
2000	3.053	1.2054	4.00	−2.000	32.53	33.83		5.37		5.37			37.90	39.20	1.6058	1.6610
2001	3.165	1.2435	4.00	−2.000	33.56	34.90		5.43		5.43			38.99	40.33	1.6520	1.7089
2002	3.133	1.2825	4.00	−2.000	34.61	35.99		5.49		5.49			40.10	41.48	1.6990	1.7576
2003	3.228	1.3239	4.00	−2.000	35.73	37.16		5.55		5.55			41.28	42.71	1.7491	1.8097
2004	3.311	1.3677	4.00	−2.000	36.91	38.39		5.62		5.62			42.53	44.00	1.8020	1.8646
2005	3.442	1.4148	4.00	−2.000	38.18	39.71		5.70		5.70			43.88	45.40	1.8591	1.9238
2006	3.500	1.4643	4.00	−2.000	39.52	41.10		5.78		5.78			45.30	46.88	1.9194	1.9863
2007	3.492	1.5154	4.00	−2.000	40.90	42.54		5.86		5.86			46.76	48.39	1.9813	2.0506
2008	3.482	1.5682	4.00	−2.000	42.32	44.01		5.94		5.94			48.26	49.95	2.0450	2.1167
2009	3.468	1.6226	4.00	−2.000	43.79	45.54		6.02		6.02			49.81	51.57	2.1108	2.1850
2010	3.452	1.6786	4.00	−2.000	45.30	47.11		6.11		6.11			51.41	53.22	2.1783	2.2551
2011	3.482	1.7370	4.00	−2.000	46.88	48.76		6.19		6.19			53.07	54.95	2.2489	2.3284
2012	3.411	1.7963	4.00	−2.000	48.48	50.42		6.28		6.28			54.76	56.70	2.3202	2.4024
2013	3.434	1.8580	4.00	−2.000	50.14	52.15		6.36		6.36			56.50	58.51	2.3942	2.4792
2014	3.451	1.9221	4.00	−2.000	51.87	53.94		6.45		6.45			58.32	60.40	2.4712	2.5591
2015	3.463	1.9886	4.00	−2.000	53.67	55.82		6.54		6.54			60.21	62.36	2.5513	2.6423
2016	3.510	2.0584	4.00	−2.000	55.55	57.77		6.64		6.64			62.19	64.41	2.6350	2.7291
2017	3.470	2.1299	4.00	−2.000	57.48	59.78		6.73		6.73			64.21	66.51	2.7207	2.8181
2018	3.470	2.2038	4.00	−2.000	59.48	61.86		6.82		6.82			66.30	68.68	2.8094	2.9102

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

WESTERN - COMPLIANCE COAL DELIVERED TO PLANT CRIST
0.5% SULFUR 11800 BTU/LB

	GDP IPD		CONT			$ / TON							
	ANN	CUM	PREM	REAL % INC		F.O.B.	TRANSPORTATION				0.00		$ / MMBTU
YEAR	%	FACT	%	W RAIL	BARGE	LD PT	W RAIL	BARGE	TL FEE	TOTAL	% TAX	DELIVERED	DELIVERED
1993		1.0000	0			14.25	15.50	6.45	0.00	21.95		36.20	1.5339
1994	2.516	1.0252	0	-1.000	-2.000	14.46	15.73	6.48		22.21		36.67	1.5539
1995	2.613	1.0519	0	-1.000	-2.000	14.69	15.98	6.52		22.50		37.19	1.5757
1996	2.469	1.0779	0	-1.000	-2.000	15.05	16.21	6.54		22.76		37.81	1.6019
1997	2.560	1.1055	0	-1.000	-2.000	15.44	16.46	6.58		23.04		38.48	1.6304
1998	2.790	1.1364	0	-1.000	-2.000	15.87	16.75	6.63		23.38		39.25	1.6629
1999	2.929	1.1696	0	-1.000	-2.000	16.34	17.07	6.68		23.75		40.09	1.6988
2000	3.053	1.2054	0	-1.000	-2.000	16.83	17.41	6.75		24.16		40.99	1.7370
2001	3.165	1.2435	0	0.000	-1.000	17.37	17.96	6.89		24.86		42.23	1.7893
2002	3.133	1.2825	0	0.000	-1.000	17.91	18.53	7.04		25.57		43.48	1.8422
2003	3.228	1.3239	0	0.000	-1.000	18.49	19.13	7.19		26.32		44.81	1.8987
2004	3.311	1.3677	0	0.000	-1.000	19.29	19.76	7.36		27.12		46.41	1.9663
2005	3.442	1.4148	0	0.000	-1.000	20.16	20.44	7.53		27.97		48.13	2.0395
2006	3.500	1.4643	0	0.000	-1.000	21.07	21.15	7.72		28.87		49.94	2.1163
2007	3.492	1.5154	0	0.000	-1.000	22.02	21.89	7.91		29.80		51.82	2.1959
2008	3.482	1.5682	0	0.000	-1.000	23.02	22.66	8.10		30.76		53.78	2.2787
2009	3.468	1.6226	0	0.000	-1.000	24.06	23.44	8.30		31.74		55.80	2.3644
2010	3.452	1.6786	0	0.000	-1.000	25.13	24.25	8.50		32.75		57.88	2.4526
2011	3.482	1.7370	0	0.000	-1.000	26.27	25.09	8.71		33.80		60.07	2.5455
2012	3.411	1.7963	0	0.000	-1.000	27.44	25.95	8.92		34.87		62.31	2.6401
2013	3.434	1.8580	0	0.000	-1.000	28.38	26.84	9.13		35.97		64.35	2.7267
2014	3.451	1.9221	0	0.000	-1.000	29.36	27.77	9.35		37.12		66.48	2.8169
2015	3.463	1.9886	0	0.000	-1.000	30.38	28.73	9.58		38.31		68.69	2.9105
2016	3.510	2.0584	0	0.000	-1.000	31.44	29.74	9.81		39.55		70.99	3.0081
2017	3.470	2.1299	0	0.000	-1.000	32.53	30.77	10.05		40.82		73.35	3.1082
2018	3.470	2.2038	0	0.000	-1.000	33.66	31.84	10.30		42.14		75.80	3.2117

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

CENTRAL APPALACHIA - NSPS COAL DELIVERED TO PLANT SCHOLZ (CSX)
0.7% SULFUR 12500 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	7.00		24.50	26.22	21.07	0.00	0.00	21.07			45.57	47.29	1.8228	1.8914
1994	2.516	1.0252	7.00	-2.000	24.74	26.47	21.17			21.17			45.91	47.64	1.8363	1.9056
1995	2.613	1.0519	7.00	-2.000	25.01	26.76	21.29			21.29			46.30	48.05	1.8519	1.9219
1996	2.469	1.0779	7.00	-2.000	25.24	27.01	21.38			21.38			46.62	48.38	1.8646	1.9353
1997	2.560	1.1055	7.00	-2.000	25.50	27.29	21.48			21.48			46.98	48.77	1.8794	1.9508
1998	2.790	1.1364	7.00	-2.000	25.81	27.62	21.64			21.64			47.45	49.26	1.8981	1.9704
1999	2.929	1.1696	7.00	-2.000	26.57	28.43	21.83			21.83			48.40	50.26	1.9360	2.0104
2000	3.053	1.2054	7.00	-2.000	27.38	29.30	22.05			22.05			49.43	51.34	1.9771	2.0538
2001	3.165	1.2435	6.00	-1.000	28.53	30.24	22.52			22.52			51.05	52.76	2.0419	2.1104
2002	3.133	1.2825	5.00	-1.000	29.72	31.21	22.99			22.99			52.71	54.20	2.1084	2.1679
2003	3.228	1.3239	4.00	-1.000	30.99	32.23	23.50			23.50			54.49	55.73	2.1794	2.2290
2004	3.311	1.3677	4.00	-1.000	32.33	33.62	24.03			24.03			56.36	57.65	2.2544	2.3062
2005	3.442	1.4148	4.00	-1.000	33.78	35.13	24.61			24.61			58.39	59.74	2.3356	2.3896
2006	3.500	1.4643	4.00	-1.000	35.31	36.72	25.22			25.22			60.53	61.94	2.4211	2.4776
2007	3.492	1.5154	4.00	-1.000	36.91	38.39	25.84			25.84			62.75	64.22	2.5098	2.5689
2008	3.482	1.5682	4.00	-1.000	38.58	40.12	26.47			26.47			65.05	66.59	2.6019	2.6637
2009	3.468	1.6226	4.00	-1.000	40.31	41.92	27.11			27.11			67.42	69.03	2.6969	2.7614
2010	3.452	1.6786	4.00	-1.000	42.12	43.80	27.77			27.77			69.89	71.57	2.7955	2.8629
2011	3.482	1.7370	4.00	-1.000	44.02	45.78	28.45			28.45			72.47	74.23	2.8987	2.9691
2012	3.411	1.7963	4.00	-1.000	45.98	47.82	29.12			29.12			75.10	76.94	3.0041	3.0777
2013	3.434	1.8580	4.00	-1.000	47.56	49.46	29.82			29.82			77.38	79.28	3.0953	3.1714
2014	3.451	1.9221	4.00	-1.000	49.20	51.17	30.54			30.54			79.74	81.71	3.1897	3.2684
2015	3.463	1.9886	4.00	-1.000	50.90	52.94	31.28			31.28			82.18	84.22	3.2874	3.3688
2016	3.510	2.0584	4.00	-1.000	52.69	54.80	32.06			32.06			84.75	86.86	3.3900	3.4743
2017	3.470	2.1299	4.00	-1.000	54.52	56.70	32.84			32.84			87.36	89.54	3.4944	3.5816
2018	3.470	2.2038	4.00	-1.000	56.41	58.67	33.64			33.64			90.05	92.31	3.6020	3.6922

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

CENTRAL APPALACHIA - LOW SULFUR COAL DELIVERED TO PLANT SCHOLZ (CSX)
1.0% SULFUR 12000 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	7.00		21.00	22.47	21.07	0.00	0.00	21.07			42.07	43.54	1.7529	1.8142
1994	2.516	1.0252	7.00	-2.000	21.21	22.69	21.17			21.17			42.38	43.86	1.7658	1.8276
1995	2.613	1.0519	7.00	-2.000	21.43	22.93	21.29			21.29			42.72	44.22	1.7799	1.8424
1996	2.469	1.0779	7.00	-2.000	21.63	23.14	21.38			21.38			43.01	44.52	1.7919	1.8550
1997	2.560	1.1055	7.00	-2.000	21.85	23.38	21.48			21.48			43.33	44.86	1.8056	1.8694
1998	2.790	1.1364	7.00	-2.000	22.35	23.91	21.64			21.64			43.99	45.56	1.8330	1.8982
1999	2.929	1.1696	7.00	-2.000	22.89	24.49	21.83			21.83			44.72	46.32	1.8634	1.9301
2000	3.053	1.2054	7.00	-2.000	23.59	25.24	22.05			22.05			45.64	47.29	1.9016	1.9704
2001	3.165	1.2435	6.00	-1.000	24.34	25.80	22.52			22.52			46.86	48.32	1.9524	2.0133
2002	3.133	1.2825	5.00	-1.000	25.10	26.36	22.99			22.99			48.09	49.35	2.0038	2.0561
2003	3.228	1.3239	4.00	-1.000	26.17	27.22	23.50			23.50			49.67	50.71	2.0694	2.1130
2004	3.311	1.3677	4.00	-1.000	27.30	28.39	24.03			24.03			51.33	52.42	2.1388	2.1843
2005	3.442	1.4148	4.00	-1.000	28.53	29.67	24.61			24.61			53.14	54.28	2.2142	2.2617
2006	3.500	1.4643	4.00	-1.000	29.82	31.01	25.22			25.22			55.04	56.23	2.2932	2.3429
2007	3.492	1.5154	4.00	-1.000	31.17	32.42	25.84			25.84			57.01	58.25	2.3753	2.4272
2008	3.482	1.5682	4.00	-1.000	32.58	33.88	26.47			26.47			59.05	60.35	2.4603	2.5146
2009	3.468	1.6226	4.00	-1.000	34.05	35.41	27.11			27.11			61.16	62.52	2.5484	2.6052
2010	3.452	1.6786	4.00	-1.000	35.57	36.99	27.77			27.77			63.34	64.76	2.6391	2.6984
2011	3.482	1.7370	4.00	-1.000	37.18	38.67	28.45			28.45			65.63	67.11	2.7345	2.7964
2012	3.411	1.7963	4.00	-1.000	38.83	40.38	29.12			29.12			67.95	69.51	2.8314	2.8961
2013	3.434	1.8580	4.00	-1.000	40.17	41.78	29.82			29.82			69.99	71.60	2.9163	2.9833
2014	3.451	1.9221	4.00	-1.000	41.55	43.21	30.54			30.54			72.09	73.75	3.0039	3.0731
2015	3.463	1.9886	4.00	-1.000	42.99	44.71	31.28			31.28			74.27	75.99	3.0948	3.1664
2016	3.510	2.0584	4.00	-1.000	44.50	46.28	32.06			32.06			76.56	78.34	3.1900	3.2641
2017	3.470	2.1299	4.00	-1.000	46.04	47.88	32.84			32.84			78.88	80.72	3.2867	3.3634
2018	3.470	2.2038	4.00	-1.000	47.64	49.55	33.64			33.64			81.28	83.18	3.3866	3.4660

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

CENTRAL APPALACHIA – MEDIUM SULFUR COAL DELIVERED TO PLANT SCHOLZ (CSX)

1.5% SULFUR 12000 BTU/LB

YEAR	GDP IPD ANN %	GDP IPD CUM FACT	CONT PREM %	REAL % INC TRAN	$/TON F.O.B. LD PT SPOT	$/TON F.O.B. LD PT CONT	$/TON TRANSPORTATION RAIL	$/TON TRANSPORTATION BARGE	$/TON TRANSPORTATION TL FEE	$/TON TRANSPORTATION TOTAL	$/TON % TAX = 0.00 SPOT	$/TON % TAX = 0.00 CONT	$/TON DELIVERED SPOT	$/TON DELIVERED CONT	$/MMBTU DELIVERED SPOT	$/MMBTU DELIVERED CONT
1993		1.0000	7.00		21.00	22.47	21.07	0.00	0.00	21.07			42.07	43.54	1.7529	1.8142
1994	2.516	1.0252	7.00	−2.000	20.99	22.46	21.17			21.17			42.16	43.63	1.7566	1.8178
1995	2.613	1.0519	7.00	−2.000	21.00	22.47	21.29			21.29			42.29	43.76	1.7620	1.8232
1996	2.469	1.0779	7.00	−2.000	20.98	22.45	21.38			21.38			42.36	43.82	1.7648	1.8260
1997	2.560	1.1055	7.00	−2.000	20.98	22.45	21.48			21.48			42.46	43.93	1.7694	1.8306
1998	2.790	1.1364	7.00	−2.000	21.03	22.50	21.64			21.64			42.67	44.14	1.7780	1.8394
1999	2.929	1.1696	7.00	−2.000	21.10	22.58	21.83			21.83			42.93	44.41	1.7888	1.8503
2000	3.053	1.2054	7.00	−2.000	21.53	23.04	22.05			22.05			43.58	45.08	1.8157	1.8785
2001	3.165	1.2435	6.00	−1.000	21.99	23.31	22.52			22.52			44.51	45.83	1.8545	1.9095
2002	3.133	1.2825	5.00	−1.000	22.45	23.57	22.99			22.99			45.44	46.56	1.8934	1.9402
2003	3.228	1.3239	4.00	−1.000	23.41	24.35	23.50			23.50			46.91	47.84	1.9544	1.9934
2004	3.311	1.3677	4.00	−1.000	24.42	25.40	24.03			24.03			48.45	49.43	2.0188	2.0595
2005	3.442	1.4148	4.00	−1.000	25.52	26.54	24.61			24.61			50.13	51.15	2.0887	2.1313
2006	3.500	1.4643	4.00	−1.000	26.67	27.74	25.22			25.22			51.89	52.95	2.1619	2.2064
2007	3.492	1.5154	4.00	−1.000	27.88	29.00	25.84			25.84			53.72	54.83	2.2382	2.2846
2008	3.482	1.5682	4.00	−1.000	29.14	30.31	26.47			26.47			55.61	56.77	2.3170	2.3656
2009	3.468	1.6226	4.00	−1.000	30.45	31.67	27.11			27.11			57.56	58.78	2.3984	2.4492
2010	3.452	1.6786	4.00	−1.000	31.82	33.09	27.77			27.77			59.59	60.86	2.4828	2.5359
2011	3.482	1.7370	4.00	−1.000	33.25	34.58	28.45			28.45			61.70	63.03	2.5707	2.6261
2012	3.411	1.7963	4.00	−1.000	34.73	36.12	29.12			29.12			63.85	65.24	2.6606	2.7184
2013	3.434	1.8580	4.00	−1.000	35.93	37.37	29.82			29.82			65.75	67.19	2.7397	2.7996
2014	3.451	1.9221	4.00	−1.000	37.17	38.66	30.54			30.54			67.71	69.20	2.8214	2.8833
2015	3.463	1.9886	4.00	−1.000	38.45	39.99	31.28			31.28			69.73	71.27	2.9056	2.9697
2016	3.510	2.0584	4.00	−1.000	39.80	41.39	32.06			32.06			71.86	73.45	2.9941	3.0605
2017	3.470	2.1299	4.00	−1.000	41.18	42.83	32.84			32.84			74.02	75.67	3.0842	3.1528
2018	3.470	2.2038	4.00	−1.000	42.61	44.31	33.64			33.64			76.25	77.95	3.1771	3.2481

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ILLINOIS BASIN - MEDIUM SULFUR COAL DELIVERED TO PLANT SCHOLZ
1.5% SULFUR 12000 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	2.00		26.00	26.52	13.11	0.00	0.00	13.11			39.11	39.63	1.6296	1.6513
1994	2.516	1.0252	2.00	-2.000	26.65	27.18	13.17			13.17			39.82	40.35	1.6592	1.6814
1995	2.613	1.0519	2.00	-2.000	27.35	27.90	13.24			13.24			40.59	41.14	1.6915	1.7142
1996	2.469	1.0779	2.00	-2.000	28.03	28.59	13.30			13.30			41.33	41.89	1.7221	1.7455
1997	2.560	1.1055	2.00	-2.000	28.74	29.31	13.37			13.37			42.11	42.68	1.7545	1.7785
1998	2.790	1.1364	2.00	-2.000	29.55	30.14	13.47			13.47			43.02	43.61	1.7923	1.8170
1999	2.929	1.1696	2.00	-2.000	30.41	31.02	13.58			13.58			43.99	44.60	1.8331	1.8584
2000	3.053	1.2054	2.00	-2.000	31.34	31.97	13.72			13.72			45.06	45.69	1.8774	1.9035
2001	3.165	1.2435	2.00	-1.000	32.01	32.65	14.01			14.01			46.02	46.66	1.9175	1.9442
2002	3.133	1.2825	2.00	-1.000	32.68	33.33	14.31			14.31			46.99	47.64	1.9577	1.9850
2003	3.228	1.3239	2.00	-1.000	33.40	34.07	14.62			14.62			48.02	48.69	2.0008	2.0286
2004	3.311	1.3677	2.00	-1.000	34.16	34.84	14.95			14.95			49.11	49.80	2.0464	2.0748
2005	3.442	1.4148	2.00	-1.000	34.98	35.68	15.31			15.31			50.29	50.99	2.0955	2.1247
2006	3.500	1.4643	2.00	-1.000	35.84	36.56	15.69			15.69			51.53	52.25	2.1471	2.1769
2007	3.492	1.5154	2.00	-1.000	36.72	37.45	16.08			16.08			52.80	53.53	2.1998	2.2304
2008	3.482	1.5682	2.00	-1.000	37.62	38.37	16.47			16.47			54.09	54.84	2.2537	2.2851
2009	3.468	1.6226	2.00	-1.000	38.93	39.71	16.87			16.87			55.80	56.58	2.3250	2.3574
2010	3.452	1.6786	2.00	-1.000	40.27	41.08	17.28			17.28			57.55	58.35	2.3978	2.4314
2011	3.482	1.7370	2.00	-1.000	41.67	42.50	17.70			17.70			59.37	60.20	2.4738	2.5085
2012	3.411	1.7963	2.00	-1.000	43.10	43.96	18.12			18.12			61.22	62.08	2.5509	2.5868
2013	3.434	1.8580	2.00	-1.000	44.58	45.47	18.56			18.56			63.14	64.03	2.6307	2.6678
2014	3.451	1.9221	2.00	-1.000	46.11	47.03	19.00			19.00			65.11	66.04	2.7131	2.7515
2015	3.463	1.9886	2.00	-1.000	47.71	48.66	19.47			19.47			67.18	68.13	2.7990	2.8387
2016	3.510	2.0584	2.00	-1.000	49.38	50.37	19.95			19.95			69.33	70.32	2.8886	2.9298
2017	3.470	2.1299	2.00	-1.000	51.10	52.12	20.43			20.43			71.53	72.56	2.9806	3.0231
2018	3.470	2.2038	2.00	-1.000	52.87	53.93	20.93			20.93			73.80	74.86	3.0750	3.1191

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ILLINOIS BASIN - HIGH SULFUR, HIGH BTU COAL DELIVERED TO PLANT SCHOLZ
2.8% SULFUR 11600 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	2.00		24.00	24.48	13.11	0.00	0.00	13.11			37.11	37.59	1.5996	1.6203
1994	2.516	1.0252	2.00	-2.000	24.36	24.85	13.17			13.17			37.53	38.02	1.6177	1.6387
1995	2.613	1.0519	2.00	-2.000	24.74	25.23	13.24			13.24			37.98	38.48	1.6373	1.6586
1996	2.469	1.0779	2.00	-2.000	24.85	25.35	13.30			13.30			38.15	38.65	1.6444	1.6658
1997	2.560	1.1055	2.00	-2.000	24.97	25.47	13.37			13.37			38.34	38.84	1.6525	1.6740
1998	2.790	1.1364	2.00	-2.000	25.16	25.66	13.47			13.47			38.63	39.13	1.6649	1.6866
1999	2.929	1.1696	2.00	-2.000	25.38	25.89	13.58			13.58			38.96	39.47	1.6795	1.7013
2000	3.053	1.2054	2.00	-2.000	25.63	26.14	13.72			13.72			39.35	39.86	1.6960	1.7181
2001	3.165	1.2435	2.00	-1.000	26.18	26.70	14.01			14.01			40.19	40.71	1.7324	1.7549
2002	3.133	1.2825	2.00	-1.000	26.73	27.26	14.31			14.31			41.04	41.57	1.7688	1.7918
2003	3.228	1.3239	2.00	-1.000	27.31	27.86	14.62			14.62			41.93	42.48	1.8073	1.8308
2004	3.311	1.3677	2.00	-1.000	27.93	28.49	14.95			14.95			42.88	43.44	1.8484	1.8725
2005	3.442	1.4148	2.00	-1.000	28.61	29.18	15.31			15.31			43.92	44.49	1.8932	1.9179
2006	3.500	1.4643	2.00	-1.000	29.31	29.90	15.69			15.69			45.00	45.59	1.9397	1.9649
2007	3.492	1.5154	2.00	-1.000	30.03	30.63	16.08			16.08			46.11	46.71	1.9873	2.0132
2008	3.482	1.5682	2.00	-1.000	30.77	31.39	16.47			16.47			47.24	47.85	2.0362	2.0627
2009	3.468	1.6226	2.00	-1.000	31.83	32.47	16.87			16.87			48.70	49.34	2.0991	2.1266
2010	3.452	1.6786	2.00	-1.000	32.93	33.59	17.28			17.28			50.21	50.87	2.1641	2.1925
2011	3.482	1.7370	2.00	-1.000	34.08	34.76	17.70			17.70			51.78	52.46	2.2319	2.2613
2012	3.411	1.7963	2.00	-1.000	35.24	35.94	18.12			18.12			53.36	54.07	2.3000	2.3304
2013	3.434	1.8580	2.00	-1.000	36.45	37.18	18.56			18.56			55.01	55.73	2.3709	2.4024
2014	3.451	1.9221	2.00	-1.000	37.71	38.46	19.00			19.00			56.71	57.47	2.4446	2.4771
2015	3.463	1.9886	2.00	-1.000	39.02	39.80	19.47			19.47			58.49	59.27	2.5209	2.5546
2016	3.510	2.0584	2.00	-1.000	40.39	41.20	19.95			19.95			60.34	61.15	2.6008	2.6356
2017	3.470	2.1299	2.00	-1.000	41.79	42.63	20.43			20.43			62.22	63.06	2.6820	2.7181
2018	3.470	2.2038	2.00	-1.000	43.24	44.10	20.93			20.93			64.17	65.04	2.7660	2.8033

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ILLINOIS BASIN – HIGH SULFUR, LOW BTU COAL DELIVERED TO PLANT SCHOLZ
3.0% SULFUR 10800 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	2.00		19.00	19.38	13.11	0.00	0.00	13.11			32.11	32.49	1.4866	1.5042
1994	2.516	1.0252	2.00	−2.000	18.89	19.27	13.17			13.17			32.06	32.44	1.4843	1.5018
1995	2.613	1.0519	2.00	−2.000	18.81	19.19	13.24			13.24			32.05	32.43	1.4840	1.5014
1996	2.469	1.0779	2.00	−2.000	18.69	19.06	13.30			13.30			31.99	32.36	1.4810	1.4983
1997	2.560	1.1055	2.00	−2.000	18.60	18.97	13.37			13.37			31.97	32.34	1.4800	1.4972
1998	2.790	1.1364	2.00	−2.000	18.54	18.91	13.47			13.47			32.01	32.38	1.4818	1.4989
1999	2.929	1.1696	2.00	−2.000	18.70	19.07	13.58			13.58			32.28	32.66	1.4946	1.5119
2000	3.053	1.2054	2.00	−2.000	18.89	19.27	13.72			13.72			32.61	32.99	1.5096	1.5271
2001	3.165	1.2435	2.00	−1.000	19.29	19.68	14.01			14.01			33.30	33.69	1.5417	1.5596
2002	3.133	1.2825	2.00	−1.000	19.70	20.09	14.31			14.31			34.01	34.40	1.5743	1.5926
2003	3.228	1.3239	2.00	−1.000	20.13	20.53	14.62			14.62			34.75	35.15	1.6088	1.6274
2004	3.311	1.3677	2.00	−1.000	20.59	21.00	14.95			14.95			35.54	35.95	1.6455	1.6646
2005	3.442	1.4148	2.00	−1.000	21.08	21.50	15.31			15.31			36.39	36.81	1.6848	1.7044
2006	3.500	1.4643	2.00	−1.000	21.60	22.03	15.69			15.69			37.29	37.72	1.7264	1.7464
2007	3.492	1.5154	2.00	−1.000	22.13	22.57	16.08			16.08			38.21	38.65	1.7688	1.7893
2008	3.482	1.5682	2.00	−1.000	22.67	23.12	16.47			16.47			39.14	39.59	1.8120	1.8330
2009	3.468	1.6226	2.00	−1.000	23.46	23.93	16.87			16.87			40.33	40.80	1.8671	1.8888
2010	3.452	1.6786	2.00	−1.000	24.27	24.76	17.28			17.28			41.55	42.03	1.9235	1.9460
2011	3.482	1.7370	2.00	−1.000	25.12	25.62	17.70			17.70			42.82	43.32	1.9824	2.0057
2012	3.411	1.7963	2.00	−1.000	25.97	26.49	18.12			18.12			44.09	44.61	2.0412	2.0653
2013	3.434	1.8580	2.00	−1.000	26.86	27.40	18.56			18.56			45.42	45.95	2.1026	2.1275
2014	3.451	1.9221	2.00	−1.000	27.79	28.35	19.00			19.00			46.79	47.35	2.1664	2.1921
2015	3.463	1.9886	2.00	−1.000	28.75	29.33	19.47			19.47			48.22	48.79	2.2322	2.2588
2016	3.510	2.0584	2.00	−1.000	29.76	30.36	19.95			19.95			49.71	50.30	2.3013	2.3288
2017	3.470	2.1299	2.00	−1.000	30.80	31.42	20.43			20.43			51.23	51.85	2.3719	2.4004
2018	3.470	2.2038	2.00	−1.000	31.86	32.50	20.93			20.93			52.79	53.43	2.4440	2.4735

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ALABAMA - NSPS COAL DELIVERED TO PLANT SCHOLZ
0.7% SULFUR 12000 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX =	0.00	DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	2.00		38.00	38.76	11.31	0.00	0.00	11.31			49.31	50.07	2.0546	2.0863
1994	2.516	1.0252	2.00	-2.000	38.37	39.14	11.36			11.36			49.73	50.50	2.0722	2.1042
1995	2.613	1.0519	2.00	-2.000	38.78	39.56	11.43			11.43			50.21	50.98	2.0919	2.1242
1996	2.469	1.0779	2.00	-2.000	39.15	39.93	11.47			11.47			50.62	51.41	2.1093	2.1420
1997	2.560	1.1055	2.00	-2.000	39.55	40.34	11.53			11.53			51.08	51.87	2.1284	2.1614
1998	2.790	1.1364	2.00	-2.000	40.04	40.84	11.62			11.62			51.66	52.46	2.1524	2.1858
1999	2.929	1.1696	2.00	-2.000	40.59	41.40	11.72			11.72			52.31	53.12	2.1795	2.2133
2000	3.053	1.2054	2.00	-2.000	41.83	42.67	11.83			11.83			53.66	54.50	2.2360	2.2709
2001	3.165	1.2435	2.00	-1.000	43.16	44.02	12.09			12.09			55.25	56.11	2.3020	2.3379
2002	3.133	1.2825	2.00	-1.000	44.51	45.40	12.34			12.34			56.85	57.74	2.3688	2.4059
2003	3.228	1.3239	2.00	-1.000	45.95	46.87	12.61			12.61			58.56	59.48	2.4401	2.4784
2004	3.311	1.3677	2.00	-1.000	47.47	48.42	12.90			12.90			60.37	61.32	2.5154	2.5550
2005	3.442	1.4148	2.00	-1.000	49.10	50.08	13.21			13.21			62.31	63.29	2.5963	2.6372
2006	3.500	1.4643	2.00	-1.000	50.82	51.84	13.54			13.54			64.36	65.37	2.6815	2.7238
2007	3.492	1.5154	2.00	-1.000	52.59	53.64	13.87			13.87			66.46	67.51	2.7691	2.8129
2008	3.482	1.5682	2.00	-1.000	54.42	55.51	14.21			14.21			68.63	69.72	2.8595	2.9048
2009	3.468	1.6226	2.00	-1.000	56.31	57.44	14.55			14.55			70.86	71.99	2.9526	2.9996
2010	3.452	1.6786	2.00	-1.000	58.26	59.43	14.91			14.91			73.17	74.33	3.0486	3.0971
2011	3.482	1.7370	2.00	-1.000	60.28	61.49	15.27			15.27			75.55	76.76	3.1479	3.1981
2012	3.411	1.7963	2.00	-1.000	62.34	63.59	15.63			15.63			77.97	79.22	3.2489	3.3008
2013	3.434	1.8580	2.00	-1.000	64.48	65.77	16.01			16.01			80.49	81.78	3.3537	3.4074
2014	3.451	1.9221	2.00	-1.000	66.71	68.04	16.39			16.39			83.10	84.44	3.4627	3.5183
2015	3.463	1.9886	2.00	-1.000	69.02	70.40	16.79			16.79			85.81	87.19	3.5755	3.6331
2016	3.510	2.0584	2.00	-1.000	71.44	72.87	17.21			17.21			88.65	90.08	3.6937	3.7532
2017	3.470	2.1299	2.00	-1.000	73.92	75.40	17.63			17.63			91.55	93.03	3.8145	3.8761
2018	3.470	2.2038	2.00	-1.000	76.48	78.01	18.06			18.06			94.54	96.07	3.9390	4.0028

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ALABAMA - LOW SULFUR COAL DELIVERED TO PLANT SCHOLZ
1.0% SULFUR 12000 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	2.00		32.30	32.95	11.31	0.00	0.00	11.31			43.61	44.26	1.8171	1.8440
1994	2.516	1.0252	2.00	-2.000	32.53	33.18	11.36			11.36			43.89	44.54	1.8289	1.8560
1995	2.613	1.0519	2.00	-2.000	32.80	33.46	11.43			11.43			44.23	44.88	1.8428	1.8701
1996	2.469	1.0779	2.00	-2.000	33.02	33.68	11.47			11.47			44.49	45.15	1.8539	1.8814
1997	2.560	1.1055	2.00	-2.000	33.27	33.94	11.53			11.53			44.80	45.47	1.8668	1.8945
1998	2.790	1.1364	2.00	-2.000	33.60	34.27	11.62			11.62			45.22	45.89	1.8841	1.9121
1999	2.929	1.1696	2.00	-2.000	33.98	34.66	11.72			11.72			45.70	46.38	1.9041	1.9324
2000	3.053	1.2054	2.00	-2.000	34.35	35.04	11.83			11.83			46.18	46.87	1.9244	1.9530
2001	3.165	1.2435	2.00	-1.000	35.44	36.15	12.09			12.09			47.53	48.24	1.9803	2.0098
2002	3.133	1.2825	2.00	-1.000	36.55	37.28	12.34			12.34			48.89	49.62	2.0371	2.0676
2003	3.228	1.3239	2.00	-1.000	37.73	38.48	12.61			12.61			50.34	51.10	2.0976	2.1290
2004	3.311	1.3677	2.00	-1.000	38.98	39.76	12.90			12.90			51.88	52.66	2.1616	2.1941
2005	3.442	1.4148	2.00	-1.000	40.32	41.13	13.21			13.21			53.53	54.34	2.2304	2.2640
2006	3.500	1.4643	2.00	-1.000	41.73	42.56	13.54			13.54			55.27	56.10	2.3027	2.3375
2007	3.492	1.5154	2.00	-1.000	43.19	44.05	13.87			13.87			57.06	57.92	2.3774	2.4134
2008	3.482	1.5682	2.00	-1.000	44.69	45.58	14.21			14.21			58.90	59.79	2.4541	2.4913
2009	3.468	1.6226	2.00	-1.000	46.24	47.16	14.55			14.55			60.79	61.72	2.5331	2.5716
2010	3.452	1.6786	2.00	-1.000	47.84	48.80	14.91			14.91			62.75	63.70	2.6144	2.6543
2011	3.482	1.7370	2.00	-1.000	49.51	50.50	15.27			15.27			64.78	65.77	2.6992	2.7404
2012	3.411	1.7963	2.00	-1.000	51.19	52.21	15.63			15.63			66.82	67.85	2.7843	2.8269
2013	3.434	1.8580	2.00	-1.000	52.95	54.01	16.01			16.01			68.96	70.02	2.8733	2.9174
2014	3.451	1.9221	2.00	-1.000	54.78	55.88	16.39			16.39			71.17	72.27	2.9656	3.0113
2015	3.463	1.9886	2.00	-1.000	56.68	57.81	16.79			16.79			73.47	74.61	3.0614	3.1086
2016	3.510	2.0584	2.00	-1.000	58.67	59.84	17.21			17.21			75.88	77.05	3.1616	3.2105
2017	3.470	2.1299	2.00	-1.000	60.70	61.91	17.63			17.63			78.33	79.54	3.2637	3.3142
2018	3.470	2.2038	2.00	-1.000	62.81	64.07	18.06			18.06			80.87	82.12	3.3695	3.4218

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ALABAMA - MEDIUM SULFUR COAL DELIVERED TO PLANT SCHOLZ
2.0% SULFUR 11800 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX =	0.00	DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	4.00		30.00	31.20	11.31	0.00	0.00	11.31			41.31	42.51	1.7504	1.8013
1994	2.516	1.0252	4.00	-2.000	30.29	31.50	11.36			11.36			41.65	42.86	1.7649	1.8163
1995	2.613	1.0519	4.00	-2.000	30.62	31.84	11.43			11.43			42.05	43.27	1.7816	1.8335
1996	2.469	1.0779	4.00	-2.000	30.90	32.14	11.47			11.47			42.37	43.61	1.7955	1.8479
1997	2.560	1.1055	4.00	-2.000	31.22	32.47	11.53			11.53			42.75	44.00	1.8116	1.8645
1998	2.790	1.1364	4.00	-2.000	31.61	32.87	11.62			11.62			43.23	44.49	1.8317	1.8852
1999	2.929	1.1696	4.00	-2.000	32.05	33.33	11.72			11.72			43.77	45.05	1.8546	1.9089
2000	3.053	1.2054	4.00	-2.000	32.53	33.83	11.83			11.83			44.36	45.67	1.8799	1.9350
2001	3.165	1.2435	4.00	-1.000	33.56	34.90	12.09			12.09			45.65	46.99	1.9342	1.9911
2002	3.133	1.2825	4.00	-1.000	34.61	35.99	12.34			12.34			46.95	48.34	1.9895	2.0481
2003	3.228	1.3239	4.00	-1.000	35.73	37.16	12.61			12.61			48.34	49.77	2.0484	2.1090
2004	3.311	1.3677	4.00	-1.000	36.91	38.39	12.90			12.90			49.81	51.29	2.1106	2.1731
2005	3.442	1.4148	4.00	-1.000	38.18	39.71	13.21			13.21			51.39	52.92	2.1775	2.2423
2006	3.500	1.4643	4.00	-1.000	39.52	41.10	13.54			13.54			53.06	54.64	2.2481	2.3151
2007	3.492	1.5154	4.00	-1.000	40.90	42.54	13.87			13.87			54.77	56.40	2.3207	2.3900
2008	3.482	1.5682	4.00	-1.000	42.32	44.01	14.21			14.21			56.53	58.22	2.3952	2.4670
2009	3.468	1.6226	4.00	-1.000	43.79	45.54	14.55			14.55			58.34	60.10	2.4722	2.5464
2010	3.452	1.6786	4.00	-1.000	45.30	47.11	14.91			14.91			60.21	62.02	2.5511	2.6278
2011	3.482	1.7370	4.00	-1.000	46.88	48.76	15.27			15.27			62.15	64.03	2.6335	2.7129
2012	3.411	1.7963	4.00	-1.000	48.48	50.42	15.63			15.63			64.11	66.05	2.7167	2.7988
2013	3.434	1.8580	4.00	-1.000	50.14	52.15	16.01			16.01			66.15	68.15	2.8029	2.8879
2014	3.451	1.9221	4.00	-1.000	51.87	53.94	16.39			16.39			68.26	70.34	2.8926	2.9805
2015	3.463	1.9886	4.00	-1.000	53.67	55.82	16.79			16.79			70.46	72.61	2.9857	3.0767
2016	3.510	2.0584	4.00	-1.000	55.55	57.77	17.21			17.21			72.76	74.98	3.0830	3.1771
2017	3.470	2.1299	4.00	-1.000	57.48	59.78	17.63			17.63			75.11	77.41	3.1825	3.2800
2018	3.470	2.2038	4.00	-1.000	59.48	61.86	18.06			18.06			77.54	79.92	3.2855	3.3863

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

CENTRAL APPALACHIA - NSPS COAL DELIVERED TO PLANT SMITH
0.7% SULFUR 12500 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	7.00		29.25	31.30	0.00	8.45	0.00	8.45			37.70	39.75	1.5080	1.5899
1994	2.516	1.0252	7.00	-2.000	29.49	31.55		8.49		8.49			37.98	40.04	1.5192	1.6017
1995	2.613	1.0519	7.00	-2.000	29.76	31.84		8.54		8.54			38.30	40.38	1.5319	1.6152
1996	2.469	1.0779	7.00	-2.000	29.99	32.09		8.57		8.57			38.56	40.66	1.5425	1.6265
1997	2.560	1.1055	7.00	-2.000	30.25	32.37		8.62		8.62			38.87	40.98	1.5547	1.6394
1998	2.790	1.1364	7.00	-2.000	30.56	32.70		8.68		8.68			39.24	41.38	1.5696	1.6552
1999	2.929	1.1696	7.00	-2.000	31.32	33.51		8.76		8.76			40.08	42.27	1.6030	1.6907
2000	3.053	1.2054	7.00	-2.000	32.13	34.38		8.84		8.84			40.97	43.22	1.6389	1.7288
2001	3.165	1.2435	6.00	-1.000	33.28	35.28		9.03		9.03			42.31	44.31	1.6924	1.7723
2002	3.133	1.2825	5.00	-1.000	34.47	36.19		9.22		9.22			43.69	45.41	1.7476	1.8166
2003	3.228	1.3239	4.00	-1.000	35.74	37.17		9.42		9.42			45.16	46.59	1.8065	1.8637
2004	3.311	1.3677	4.00	-1.000	37.08	38.56		9.64		9.64			46.72	48.20	1.8687	1.9280
2005	3.442	1.4148	4.00	-1.000	38.53	40.07		9.87		9.87			48.40	49.94	1.9360	1.9976
2006	3.500	1.4643	4.00	-1.000	40.06	41.66		10.11		10.11			50.17	51.78	2.0069	2.0710
2007	3.492	1.5154	4.00	-1.000	41.66	43.33		10.36		10.36			52.02	53.69	2.0809	2.1475
2008	3.482	1.5682	4.00	-1.000	43.33	45.06		10.61		10.61			53.94	55.68	2.1578	2.2271
2009	3.468	1.6226	4.00	-1.000	45.06	46.86		10.87		10.87			55.93	57.74	2.2373	2.3094
2010	3.452	1.6786	4.00	-1.000	46.87	48.74		11.14		11.14			58.01	59.88	2.3202	2.3952
2011	3.482	1.7370	4.00	-1.000	48.77	50.72		11.41		11.41			60.18	62.13	2.4071	2.4852
2012	3.411	1.7963	4.00	-1.000	50.73	52.76		11.68		11.68			62.41	64.44	2.4964	2.5776
2013	3.434	1.8580	4.00	-1.000	52.31	54.40		11.96		11.96			64.27	66.36	2.5708	2.6545
2014	3.451	1.9221	4.00	-1.000	53.95	56.11		12.25		12.25			66.20	68.36	2.6480	2.7343
2015	3.463	1.9886	4.00	-1.000	55.65	57.88		12.55		12.55			68.20	70.42	2.7279	2.8169
2016	3.510	2.0584	4.00	-1.000	57.44	59.74		12.86		12.86			70.30	72.59	2.8119	2.9038
2017	3.470	2.1299	4.00	-1.000	59.27	61.64		13.17		13.17			72.44	74.81	2.8976	2.9924
2018	3.470	2.2038	4.00	-1.000	61.16	63.61		13.49		13.49			74.65	77.10	2.9860	3.0839

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

CENTRAL APPALACHIA - LOW SULFUR COAL DELIVERED TO PLANT SMITH
1.0% SULFUR 12000 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	7.00		25.75	27.55	0.00	8.45	0.00	8.45			34.20	36.00	1.4250	1.5001
1994	2.516	1.0252	7.00	-2.000	25.96	27.78		8.49		8.49			34.45	36.27	1.4354	1.5111
1995	2.613	1.0519	7.00	-2.000	26.18	28.01		8.54		8.54			34.72	36.55	1.4465	1.5229
1996	2.469	1.0779	7.00	-2.000	26.38	28.23		8.57		8.57			34.95	36.80	1.4564	1.5333
1997	2.560	1.1055	7.00	-2.000	26.60	28.46		8.62		8.62			35.22	37.08	1.4673	1.5449
1998	2.790	1.1364	7.00	-2.000	27.10	29.00		8.68		8.68			35.78	37.68	1.4908	1.5699
1999	2.929	1.1696	7.00	-2.000	27.64	29.57		8.76		8.76			36.40	38.33	1.5165	1.5971
2000	3.053	1.2054	7.00	-2.000	28.34	30.32		8.84		8.84			37.18	39.17	1.5493	1.6319
2001	3.165	1.2435	6.00	-1.000	29.09	30.84		9.03		9.03			38.12	39.87	1.5884	1.6611
2002	3.133	1.2825	5.00	-1.000	29.85	31.34		9.22		9.22			39.07	40.56	1.6279	1.6901
2003	3.228	1.3239	4.00	-1.000	30.92	32.16		9.42		9.42			40.34	41.58	1.6810	1.7325
2004	3.311	1.3677	4.00	-1.000	32.05	33.33		9.64		9.64			41.69	42.97	1.7370	1.7904
2005	3.442	1.4148	4.00	-1.000	33.28	34.61		9.87		9.87			43.15	44.48	1.7979	1.8534
2006	3.500	1.4643	4.00	-1.000	34.57	35.95		10.11		10.11			44.68	46.07	1.8618	1.9194
2007	3.492	1.5154	4.00	-1.000	35.92	37.36		10.36		10.36			46.28	47.72	1.9284	1.9883
2008	3.482	1.5682	4.00	-1.000	37.33	38.82		10.61		10.61			47.94	49.44	1.9977	2.0599
2009	3.468	1.6226	4.00	-1.000	38.80	40.35		10.87		10.87			49.67	51.23	2.0697	2.1344
2010	3.452	1.6786	4.00	-1.000	40.32	41.93		11.14		11.14			51.46	53.07	2.1440	2.2112
2011	3.482	1.7370	4.00	-1.000	41.93	43.61		11.41		11.41			53.34	55.02	2.2224	2.2923
2012	3.411	1.7963	4.00	-1.000	43.58	45.32		11.68		11.68			55.26	57.00	2.3025	2.3751
2013	3.434	1.8580	4.00	-1.000	44.92	46.72		11.96		11.96			56.88	58.68	2.3700	2.4449
2014	3.451	1.9221	4.00	-1.000	46.30	48.15		12.25		12.25			58.55	60.40	2.4395	2.5167
2015	3.463	1.9886	4.00	-1.000	47.74	49.65		12.55		12.55			60.29	62.20	2.5119	2.5915
2016	3.510	2.0584	4.00	-1.000	49.25	51.22		12.86		12.86			62.11	64.08	2.5878	2.6699
2017	3.470	2.1299	4.00	-1.000	50.79	52.82		13.17		13.17			63.96	65.99	2.6650	2.7497
2018	3.470	2.2038	4.00	-1.000	52.39	54.49		13.49		13.49			65.88	67.98	2.7450	2.8324

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

CENTRAL APPALACHIA – MEDIUM SULFUR COAL DELIVERED TO PLANT SMITH
1.5% SULFUR 12000 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	7.00		25.75	27.55	0.00	8.45	0.00	8.45			34.20	36.00	1.4250	1.5001
1994	2.516	1.0252	7.00	−2.000	25.74	27.54		8.49		8.49			34.23	36.03	1.4262	1.5013
1995	2.613	1.0519	7.00	−2.000	25.75	27.55		8.54		8.54			34.29	36.09	1.4286	1.5037
1996	2.469	1.0779	7.00	−2.000	25.73	27.53		8.57		8.57			34.30	36.10	1.4293	1.5043
1997	2.560	1.1055	7.00	−2.000	25.73	27.53		8.62		8.62			34.35	36.15	1.4311	1.5061
1998	2.790	1.1364	7.00	−2.000	25.78	27.58		8.68		8.68			34.46	36.26	1.4358	1.5110
1999	2.929	1.1696	7.00	−2.000	25.85	27.66		8.76		8.76			34.61	36.41	1.4419	1.5173
2000	3.053	1.2054	7.00	−2.000	26.28	28.12		8.84		8.84			35.12	36.96	1.4634	1.5401
2001	3.165	1.2435	6.00	−1.000	26.74	28.34		9.03		9.03			35.77	37.38	1.4904	1.5573
2002	3.133	1.2825	5.00	−1.000	27.20	28.56		9.22		9.22			36.42	37.78	1.5175	1.5742
2003	3.228	1.3239	4.00	−1.000	28.16	29.29		9.42		9.42			37.58	38.71	1.5660	1.6129
2004	3.311	1.3677	4.00	−1.000	29.17	30.34		9.64		9.64			38.81	39.97	1.6170	1.6656
2005	3.442	1.4148	4.00	−1.000	30.27	31.48		9.87		9.87			40.14	41.35	1.6725	1.7229
2006	3.500	1.4643	4.00	−1.000	31.42	32.68		10.11		10.11			41.53	42.79	1.7305	1.7829
2007	3.492	1.5154	4.00	−1.000	32.63	33.94		10.36		10.36			42.99	44.30	1.7913	1.8457
2008	3.482	1.5682	4.00	−1.000	33.89	35.25		10.61		10.61			44.50	45.86	1.8544	1.9109
2009	3.468	1.6226	4.00	−1.000	35.20	36.61		10.87		10.87			46.07	47.48	1.9197	1.9784
2010	3.452	1.6786	4.00	−1.000	36.57	38.03		11.14		11.14			47.71	49.17	1.9878	2.0487
2011	3.482	1.7370	4.00	−1.000	38.00	39.52		11.41		11.41			49.41	50.93	2.0587	2.1220
2012	3.411	1.7963	4.00	−1.000	39.48	41.06		11.68		11.68			51.16	52.74	2.1317	2.1975
2013	3.434	1.8580	4.00	−1.000	40.68	42.31		11.96		11.96			52.64	54.27	2.1933	2.2611
2014	3.451	1.9221	4.00	−1.000	41.92	43.60		12.25		12.25			54.17	55.85	2.2570	2.3269
2015	3.463	1.9886	4.00	−1.000	43.20	44.93		12.55		12.55			55.75	57.47	2.3228	2.3948
2016	3.510	2.0584	4.00	−1.000	44.55	46.33		12.86		12.86			57.41	59.19	2.3920	2.4662
2017	3.470	2.1299	4.00	−1.000	45.93	47.77		13.17		13.17			59.10	60.94	2.4625	2.5391
2018	3.470	2.2038	4.00	−1.000	47.36	49.25		13.49		13.49			60.85	62.75	2.5355	2.6144

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ILLINOIS BASIN – MEDIUM SULFUR COAL DELIVERED TO PLANT SMITH
1.5% SULFUR 12000 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	2.00		26.00	26.52	0.00	6.19	0.00	6.19			32.19	32.71	1.3412	1.3629
1994	2.516	1.0252	2.00	-2.000	26.65	27.18		6.22		6.22			32.87	33.40	1.3695	1.3917
1995	2.613	1.0519	2.00	-2.000	27.35	27.90		6.25		6.25			33.60	34.15	1.4002	1.4229
1996	2.469	1.0779	2.00	-2.000	28.03	28.59		6.28		6.28			34.31	34.87	1.4296	1.4529
1997	2.560	1.1055	2.00	-2.000	28.74	29.31		6.31		6.31			35.05	35.63	1.4605	1.4844
1998	2.790	1.1364	2.00	-2.000	29.55	30.14		6.36		6.36			35.91	36.50	1.4962	1.5208
1999	2.929	1.1696	2.00	-2.000	30.41	31.02		6.41		6.41			36.82	37.43	1.5343	1.5597
2000	3.053	1.2054	2.00	-2.000	31.34	31.97		6.48		6.48			37.82	38.44	1.5757	1.6018
2001	3.165	1.2435	2.00	-1.000	32.01	32.65		6.62		6.62			38.63	39.27	1.6094	1.6361
2002	3.133	1.2825	2.00	-1.000	32.68	33.33		6.75		6.75			39.43	40.09	1.6431	1.6703
2003	3.228	1.3239	2.00	-1.000	33.40	34.07		6.90		6.90			40.30	40.97	1.6793	1.7071
2004	3.311	1.3677	2.00	-1.000	34.16	34.84		7.06		7.06			41.22	41.90	1.7175	1.7460
2005	3.442	1.4148	2.00	-1.000	34.98	35.68		7.23		7.23			42.21	42.91	1.7587	1.7879
2006	3.500	1.4643	2.00	-1.000	35.84	36.56		7.41		7.41			43.25	43.96	1.8020	1.8319
2007	3.492	1.5154	2.00	-1.000	36.72	37.45		7.59		7.59			44.31	45.04	1.8463	1.8769
2008	3.482	1.5682	2.00	-1.000	37.62	38.37		7.78		7.78			45.40	46.15	1.8915	1.9228
2009	3.468	1.6226	2.00	-1.000	38.93	39.71		7.97		7.97			46.90	47.67	1.9540	1.9864
2010	3.452	1.6786	2.00	-1.000	40.27	41.08		8.16		8.16			48.43	49.23	2.0178	2.0514
2011	3.482	1.7370	2.00	-1.000	41.67	42.50		8.36		8.36			50.03	50.86	2.0845	2.1192
2012	3.411	1.7963	2.00	-1.000	43.10	43.96		8.56		8.56			51.66	52.52	2.1523	2.1882
2013	3.434	1.8580	2.00	-1.000	44.58	45.47		8.76		8.76			53.34	54.23	2.2226	2.2597
2014	3.451	1.9221	2.00	-1.000	46.11	47.03		8.97		8.97			55.08	56.01	2.2951	2.3335
2015	3.463	1.9886	2.00	-1.000	47.71	48.66		9.19		9.19			56.90	57.86	2.3709	2.4106
2016	3.510	2.0584	2.00	-1.000	49.38	50.37		9.42		9.42			58.80	59.79	2.4499	2.4911
2017	3.470	2.1299	2.00	-1.000	51.10	52.12		9.65		9.65			60.75	61.77	2.5312	2.5737
2018	3.470	2.2038	2.00	-1.000	52.87	53.93		9.88		9.88			62.75	63.81	2.6147	2.6588

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ILLINOIS BASIN – HIGH SULFUR, HIGH BTU COAL DELIVERED TO PLANT SMITH
2.8% SULFUR 11600 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	2.00		24.00	24.48	0.00	6.85	0.00	6.85			30.85	31.33	1.3297	1.3504
1994	2.516	1.0252	2.00	−2.000	24.36	24.85		6.88		6.88			31.24	31.73	1.3466	1.3676
1995	2.613	1.0519	2.00	−2.000	24.74	25.23		6.92		6.92			31.66	32.16	1.3647	1.3860
1996	2.469	1.0779	2.00	−2.000	24.85	25.35		6.95		6.95			31.80	32.30	1.3707	1.3921
1997	2.560	1.1055	2.00	−2.000	24.97	25.47		6.98		6.98			31.95	32.45	1.3774	1.3989
1998	2.790	1.1364	2.00	−2.000	25.16	25.66		7.04		7.04			32.20	32.70	1.3878	1.4095
1999	2.929	1.1696	2.00	−2.000	25.38	25.89		7.10		7.10			32.48	32.99	1.3999	1.4218
2000	3.053	1.2054	2.00	−2.000	25.63	26.14		7.17		7.17			32.80	33.31	1.4137	1.4358
2001	3.165	1.2435	2.00	−1.000	26.18	26.70		7.32		7.32			33.50	34.02	1.4440	1.4666
2002	3.133	1.2825	2.00	−1.000	26.73	27.26		7.47		7.47			34.20	34.74	1.4743	1.4974
2003	3.228	1.3239	2.00	−1.000	27.31	27.86		7.64		7.64			34.95	35.49	1.5064	1.5300
2004	3.311	1.3677	2.00	−1.000	27.93	28.49		7.81		7.81			35.74	36.30	1.5406	1.5647
2005	3.442	1.4148	2.00	−1.000	28.61	29.18		8.00		8.00			36.61	37.18	1.5781	1.6027
2006	3.500	1.4643	2.00	−1.000	29.31	29.90		8.20		8.20			37.51	38.09	1.6167	1.6420
2007	3.492	1.5154	2.00	−1.000	30.03	30.63		8.40		8.40			38.43	39.03	1.6564	1.6823
2008	3.482	1.5682	2.00	−1.000	30.77	31.39		8.61		8.61			39.38	39.99	1.6972	1.7237
2009	3.468	1.6226	2.00	−1.000	31.83	32.47		8.81		8.81			40.64	41.28	1.7519	1.7794
2010	3.452	1.6786	2.00	−1.000	32.93	33.59		9.03		9.03			41.96	42.62	1.8085	1.8369
2011	3.482	1.7370	2.00	−1.000	34.08	34.76		9.25		9.25			43.33	44.01	1.8676	1.8970
2012	3.411	1.7963	2.00	−1.000	35.24	35.94		9.47		9.47			44.71	45.41	1.9271	1.9575
2013	3.434	1.8580	2.00	−1.000	36.45	37.18		9.70		9.70			46.15	46.87	1.9890	2.0204
2014	3.451	1.9221	2.00	−1.000	37.71	38.46		9.93		9.93			47.64	48.39	2.0534	2.0859
2015	3.463	1.9886	2.00	−1.000	39.02	39.80		10.17		10.17			49.19	49.97	2.1203	2.1539
2016	3.510	2.0584	2.00	−1.000	40.39	41.20		10.42		10.42			50.81	51.62	2.1902	2.2250
2017	3.470	2.1299	2.00	−1.000	41.79	42.63		10.68		10.68			52.47	53.30	2.2615	2.2975
2018	3.470	2.2038	2.00	−1.000	43.24	44.10		10.94		10.94			54.18	55.04	2.3352	2.3725

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ILLINOIS BASIN - HIGH SULFUR, LOW BTU COAL DELIVERED TO PLANT SMITH
3.0% SULFUR 10800 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	2.00		19.00	19.38	0.00	6.85	0.00	6.85			25.85	26.23	1.1968	1.2144
1994	2.516	1.0252	2.00	-2.000	18.89	19.27		6.88		6.88			25.77	26.15	1.1931	1.2106
1995	2.613	1.0519	2.00	-2.000	18.81	19.19		6.92		6.92			25.73	26.11	1.1912	1.2086
1996	2.469	1.0779	2.00	-2.000	18.69	19.06		6.95		6.95			25.64	26.01	1.1870	1.2043
1997	2.560	1.1055	2.00	-2.000	18.60	18.97		6.98		6.98			25.58	25.96	1.1845	1.2017
1998	2.790	1.1364	2.00	-2.000	18.54	18.91		7.04		7.04			25.58	25.95	1.1841	1.2012
1999	2.929	1.1696	2.00	-2.000	18.70	19.07		7.10		7.10			25.80	26.17	1.1943	1.2116
2000	3.053	1.2054	2.00	-2.000	18.89	19.27		7.17		7.17			26.06	26.44	1.2064	1.2239
2001	3.165	1.2435	2.00	-1.000	19.29	19.68		7.32		7.32			26.61	27.00	1.2320	1.2498
2002	3.133	1.2825	2.00	-1.000	19.70	20.09		7.47		7.47			27.17	27.57	1.2581	1.2763
2003	3.228	1.3239	2.00	-1.000	20.13	20.53		7.64		7.64			27.77	28.17	1.2856	1.3042
2004	3.311	1.3677	2.00	-1.000	20.59	21.00		7.81		7.81			28.40	28.81	1.3149	1.3340
2005	3.442	1.4148	2.00	-1.000	21.08	21.50		8.00		8.00			29.08	29.50	1.3463	1.3659
2006	3.500	1.4643	2.00	-1.000	21.60	22.03		8.20		8.20			29.80	30.23	1.3795	1.3995
2007	3.492	1.5154	2.00	-1.000	22.13	22.57		8.40		8.40			30.53	30.97	1.4134	1.4339
2008	3.482	1.5682	2.00	-1.000	22.67	23.12		8.61		8.61			31.28	31.73	1.4479	1.4689
2009	3.468	1.6226	2.00	-1.000	23.46	23.93		8.81		8.81			32.27	32.74	1.4942	1.5159
2010	3.452	1.6786	2.00	-1.000	24.27	24.76		9.03		9.03			33.30	33.78	1.5416	1.5640
2011	3.482	1.7370	2.00	-1.000	25.12	25.62		9.25		9.25			34.37	34.87	1.5911	1.6144
2012	3.411	1.7963	2.00	-1.000	25.97	26.49		9.47		9.47			35.44	35.96	1.6407	1.6647
2013	3.434	1.8580	2.00	-1.000	26.86	27.40		9.70		9.70			36.56	37.09	1.6924	1.7173
2014	3.451	1.9221	2.00	-1.000	27.79	28.35		9.93		9.93			37.72	38.28	1.7463	1.7720
2015	3.463	1.9886	2.00	-1.000	28.75	29.33		10.17		10.17			38.92	39.50	1.8019	1.8285
2016	3.510	2.0584	2.00	-1.000	29.76	30.36		10.42		10.42			40.18	40.78	1.8603	1.8879
2017	3.470	2.1299	2.00	-1.000	30.80	31.42		10.68		10.68			41.48	42.09	1.9202	1.9487
2018	3.470	2.2038	2.00	-1.000	31.86	32.50		10.94		10.94			42.80	43.43	1.9813	2.0108

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ALABAMA – NSPS COAL DELIVERED TO PLANT SMITH
0.7% SULFUR 12000 BTU/LB

	GDP IPD		CONT	REAL	$/TON										$/MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	2.00		38.00	38.76	0.00	6.19	0.00	6.19			44.19	44.95	1.8412	1.8729
1994	2.516	1.0252	2.00	-2.000	38.37	39.14		6.22		6.22			44.59	45.36	1.8579	1.8898
1995	2.613	1.0519	2.00	-2.000	38.78	39.56		6.25		6.25			45.03	45.81	1.8764	1.9087
1996	2.469	1.0779	2.00	-2.000	39.15	39.93		6.28		6.28			45.43	46.21	1.8929	1.9255
1997	2.560	1.1055	2.00	-2.000	39.55	40.34		6.31		6.31			45.86	46.65	1.9109	1.9439
1998	2.790	1.1364	2.00	-2.000	40.04	40.84		6.36		6.36			46.40	47.20	1.9333	1.9666
1999	2.929	1.1696	2.00	-2.000	40.59	41.40		6.41		6.41			47.00	47.82	1.9585	1.9923
2000	3.053	1.2054	2.00	-2.000	41.83	42.67		6.48		6.48			48.31	49.14	2.0128	2.0477
2001	3.165	1.2435	2.00	-2.000	43.16	44.02		6.55		6.55			49.71	50.57	2.0712	2.1072
2002	3.133	1.2825	2.00	-2.000	44.51	45.40		6.62		6.62			51.13	52.02	2.1304	2.1675
2003	3.228	1.3239	2.00	-2.000	45.95	46.87		6.70		6.70			52.65	53.56	2.1936	2.2319
2004	3.311	1.3677	2.00	-2.000	47.47	48.42		6.78		6.78			54.25	55.20	2.2604	2.2999
2005	3.442	1.4148	2.00	-2.000	49.10	50.08		6.87		6.87			55.97	56.95	2.3322	2.3731
2006	3.500	1.4643	2.00	-2.000	50.82	51.84		6.97		6.97			57.79	58.81	2.4079	2.4503
2007	3.492	1.5154	2.00	-2.000	52.59	53.64		7.07		7.07			59.66	60.71	2.4858	2.5296
2008	3.482	1.5682	2.00	-2.000	54.42	55.51		7.17		7.17			61.59	62.68	2.5662	2.6116
2009	3.468	1.6226	2.00	-2.000	56.31	57.44		7.27		7.27			63.58	64.71	2.6492	2.6961
2010	3.452	1.6786	2.00	-2.000	58.26	59.43		7.37		7.37			65.63	66.80	2.7346	2.7831
2011	3.482	1.7370	2.00	-2.000	60.28	61.49		7.47		7.47			67.75	68.96	2.8231	2.8733
2012	3.411	1.7963	2.00	-2.000	62.34	63.59		7.57		7.57			69.91	71.16	2.9131	2.9651
2013	3.434	1.8580	2.00	-2.000	64.48	65.77		7.68		7.68			72.16	73.45	3.0066	3.0603
2014	3.451	1.9221	2.00	-2.000	66.71	68.04		7.78		7.78			74.49	75.83	3.1039	3.1595
2015	3.463	1.9886	2.00	-2.000	69.02	70.40		7.89		7.89			76.91	78.29	3.2047	3.2622
2016	3.510	2.0584	2.00	-2.000	71.44	72.87		8.01		8.01			79.45	80.88	3.3103	3.3698
2017	3.470	2.1299	2.00	-2.000	73.92	75.40		8.12		8.12			82.04	83.52	3.4183	3.4799
2018	3.470	2.2038	2.00	-2.000	76.48	78.01		8.23		8.23			84.71	86.24	3.5297	3.5934

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ALABAMA - LOW SULFUR COAL DELIVERED TO PLANT SMITH
1.0% SULFUR 12000 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	2.00		32.30	32.95	0.00	6.19	0.00	6.19			38.49	39.14	1.6037	1.6307
1994	2.516	1.0252	2.00	-2.000	32.53	33.18		6.22		6.22			38.75	39.40	1.6145	1.6416
1995	2.613	1.0519	2.00	-2.000	32.80	33.46		6.25		6.25			39.05	39.71	1.6272	1.6546
1996	2.469	1.0779	2.00	-2.000	33.02	33.68		6.28		6.28			39.30	39.96	1.6375	1.6650
1997	2.560	1.1055	2.00	-2.000	33.27	33.94		6.31		6.31			39.58	40.25	1.6492	1.6770
1998	2.790	1.1364	2.00	-2.000	33.60	34.27		6.36		6.36			39.96	40.63	1.6649	1.6929
1999	2.929	1.1696	2.00	-2.000	33.98	34.66		6.41		6.41			40.39	41.07	1.6831	1.7114
2000	3.053	1.2054	2.00	-2.000	34.35	35.04		6.48		6.48			40.83	41.51	1.7011	1.7298
2001	3.165	1.2435	2.00	-2.000	35.44	36.15		6.55		6.55			41.99	42.70	1.7495	1.7791
2002	3.133	1.2825	2.00	-2.000	36.55	37.28		6.62		6.62			43.17	43.90	1.7987	1.8292
2003	3.228	1.3239	2.00	-2.000	37.73	38.48		6.70		6.70			44.43	45.18	1.8511	1.8825
2004	3.311	1.3677	2.00	-2.000	38.98	39.76		6.78		6.78			45.76	46.54	1.9066	1.9391
2005	3.442	1.4148	2.00	-2.000	40.32	41.13		6.87		6.87			47.19	48.00	1.9663	1.9999
2006	3.500	1.4643	2.00	-2.000	41.73	42.56		6.97		6.97			48.70	49.53	2.0292	2.0640
2007	3.492	1.5154	2.00	-2.000	43.19	44.05		7.07		7.07			50.26	51.12	2.0941	2.1301
2008	3.482	1.5682	2.00	-2.000	44.69	45.58		7.17		7.17			51.86	52.75	2.1608	2.1980
2009	3.468	1.6226	2.00	-2.000	46.24	47.16		7.27		7.27			53.51	54.43	2.2296	2.2681
2010	3.452	1.6786	2.00	-2.000	47.84	48.80		7.37		7.37			55.21	56.17	2.3004	2.3403
2011	3.482	1.7370	2.00	-2.000	49.51	50.50		7.47		7.47			56.98	57.97	2.3743	2.4156
2012	3.411	1.7963	2.00	-2.000	51.19	52.21		7.57		7.57			58.76	59.79	2.4485	2.4912
2013	3.434	1.8580	2.00	-2.000	52.95	54.01		7.68		7.68			60.63	61.69	2.5262	2.5703
2014	3.451	1.9221	2.00	-2.000	54.78	55.88		7.78		7.78			62.56	63.66	2.6068	2.6525
2015	3.463	1.9886	2.00	-2.000	56.68	57.81		7.89		7.89			64.57	65.71	2.6905	2.7378
2016	3.510	2.0584	2.00	-2.000	58.67	59.84		8.01		8.01			66.68	67.85	2.7782	2.8271
2017	3.470	2.1299	2.00	-2.000	60.70	61.91		8.12		8.12			68.82	70.03	2.8674	2.9180
2018	3.470	2.2038	2.00	-2.000	62.81	64.07		8.23		8.23			71.04	72.30	2.9601	3.0124

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

ALABAMA – MEDIUM SULFUR COAL DELIVERED TO PLANT SMITH
2.0% SULFUR 11800 BTU/LB

	GDP IPD		CONT	REAL	$ / TON										$ / MMBTU	
	ANN	CUM	PREM	% INC	F.O.B. LD PT		TRANSPORTATION				% TAX = 0.00		DELIVERED		DELIVERED	
YEAR	%	FACT	%	TRAN	SPOT	CONT	RAIL	BARGE	TL FEE	TOTAL	SPOT	CONT	SPOT	CONT	SPOT	CONT
1993		1.0000	4.00		30.00	31.20	0.00	6.19	0.00	6.19			36.19	37.39	1.5335	1.5843
1994	2.516	1.0252	4.00	−2.000	30.29	31.50		6.22		6.22			36.51	37.72	1.5470	1.5983
1995	2.613	1.0519	4.00	−2.000	30.62	31.84		6.25		6.25			36.87	38.10	1.5624	1.6143
1996	2.469	1.0779	4.00	−2.000	30.90	32.14		6.28		6.28			37.18	38.42	1.5754	1.6278
1997	2.560	1.1055	4.00	−2.000	31.22	32.47		6.31		6.31			37.53	38.78	1.5903	1.6432
1998	2.790	1.1364	4.00	−2.000	31.61	32.87		6.36		6.36			37.97	39.23	1.6088	1.6624
1999	2.929	1.1696	4.00	−2.000	32.05	33.33		6.41		6.41			38.46	39.75	1.6298	1.6841
2000	3.053	1.2054	4.00	−2.000	32.53	33.83		6.48		6.48			39.01	40.31	1.6528	1.7080
2001	3.165	1.2435	4.00	−2.000	33.56	34.90		6.55		6.55			40.11	41.45	1.6995	1.7564
2002	3.133	1.2825	4.00	−2.000	34.61	35.99		6.62		6.62			41.23	42.61	1.7470	1.8056
2003	3.228	1.3239	4.00	−2.000	35.73	37.16		6.70		6.70			42.43	43.85	1.7977	1.8583
2004	3.311	1.3677	4.00	−2.000	36.91	38.39		6.78		6.78			43.69	45.17	1.8512	1.9138
2005	3.442	1.4148	4.00	−2.000	38.18	39.71		6.87		6.87			45.05	46.58	1.9090	1.9737
2006	3.500	1.4643	4.00	−2.000	39.52	41.10		6.97		6.97			46.49	48.07	1.9699	2.0369
2007	3.492	1.5154	4.00	−2.000	40.90	42.54		7.07		7.07			47.97	49.61	2.0326	2.1019
2008	3.482	1.5682	4.00	−2.000	42.32	44.01		7.17		7.17			49.49	51.18	2.0970	2.1687
2009	3.468	1.6226	4.00	−2.000	43.79	45.54		7.27		7.27			51.06	52.81	2.1635	2.2378
2010	3.452	1.6786	4.00	−2.000	45.30	47.11		7.37		7.37			52.67	54.48	2.2318	2.3086
2011	3.482	1.7370	4.00	−2.000	46.88	48.76		7.47		7.47			54.35	56.23	2.3031	2.3826
2012	3.411	1.7963	4.00	−2.000	48.48	50.42		7.57		7.57			56.05	57.99	2.3752	2.4574
2013	3.434	1.8580	4.00	−2.000	50.14	52.15		7.68		7.68			57.82	59.82	2.4499	2.5349
2014	3.451	1.9221	4.00	−2.000	51.87	53.94		7.78		7.78			59.65	61.73	2.5277	2.6156
2015	3.463	1.9886	4.00	−2.000	53.67	55.82		7.89		7.89			61.56	63.71	2.6086	2.6996
2016	3.510	2.0584	4.00	−2.000	55.55	57.77		8.01		8.01			63.56	65.78	2.6931	2.7872
2017	3.470	2.1299	4.00	−2.000	57.48	59.78		8.12		8.12			65.60	67.90	2.7796	2.8770
2018	3.470	2.2038	4.00	−2.000	59.48	61.86		8.23		8.23			67.71	70.09	2.8692	2.9700

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL COAL PRICES
FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

WESTERN - COMPLIANCE COAL DELIVERED TO PLANT SMITH
0.5% SULFUR 11800 BTU/LB

	GDP IPD		CONT			$ / TON							
	ANN	CUM	PREM	REAL % INC		F.O.B.	TRANSPORTATION				0.00		$ / MMBTU
YEAR	%	FACT	%	W RAIL	BARGE	LD PT	W RAIL	BARGE	TL FEE	TOTAL	% TAX	DELIVERED	DELIVERED
1993		1.0000	0			14.25	15.50	7.30	0.00	22.80		37.05	1.5699
1994	2.516	1.0252	0	-1.000	-2.000	14.46	15.73	7.33		23.07		37.53	1.5900
1995	2.613	1.0519	0	-1.000	-2.000	14.69	15.98	7.38		23.36		38.05	1.6121
1996	2.469	1.0779	0	-1.000	-2.000	15.05	16.21	7.41		23.62		38.67	1.6385
1997	2.560	1.1055	0	-1.000	-2.000	15.44	16.46	7.44		23.90		39.34	1.6671
1998	2.790	1.1364	0	-1.000	-2.000	15.87	16.75	7.50		24.25		40.12	1.6999
1999	2.929	1.1696	0	-1.000	-2.000	16.34	17.07	7.56		24.63		40.97	1.7361
2000	3.053	1.2054	0	-1.000	-2.000	16.83	17.41	7.64		25.05		41.88	1.7747
2001	3.165	1.2435	0	0.000	-1.000	17.37	17.96	7.80		25.77		43.14	1.8278
2002	3.133	1.2825	0	0.000	-1.000	17.91	18.53	7.97		26.49		44.40	1.8815
2003	3.228	1.3239	0	0.000	-1.000	18.49	19.13	8.14		27.27		45.76	1.9388
2004	3.311	1.3677	0	0.000	-1.000	19.29	19.76	8.33		28.09		47.38	2.0074
2005	3.442	1.4148	0	0.000	-1.000	20.16	20.44	8.53		28.97		49.13	2.0816
2006	3.500	1.4643	0	0.000	-1.000	21.07	21.15	8.74		29.89		50.96	2.1594
2007	3.492	1.5154	0	0.000	-1.000	22.02	21.89	8.95		30.84		52.86	2.2400
2008	3.482	1.5682	0	0.000	-1.000	23.02	22.66	9.17		31.83		54.85	2.3240
2009	3.468	1.6226	0	0.000	-1.000	24.06	23.44	9.39		32.83		56.89	2.4108
2010	3.452	1.6786	0	0.000	-1.000	25.13	24.25	9.62		33.87		59.00	2.5000
2011	3.482	1.7370	0	0.000	-1.000	26.27	25.09	9.86		34.95		61.22	2.5941
2012	3.411	1.7963	0	0.000	-1.000	27.44	25.95	10.09		36.04		63.48	2.6899
2013	3.434	1.8580	0	0.000	-1.000	28.38	26.84	10.33		37.17		65.55	2.7777
2014	3.451	1.9221	0	0.000	-1.000	29.36	27.77	10.58		38.35		67.71	2.8691
2015	3.463	1.9886	0	0.000	-1.000	30.38	28.73	10.84		39.57		69.95	2.9639
2016	3.510	2.0584	0	0.000	-1.000	31.44	29.74	11.11		40.85		72.29	3.0629
2017	3.470	2.1299	0	0.000	-1.000	32.53	30.77	11.38		42.15		74.68	3.1643
2018	3.470	2.2038	0	0.000	-1.000	33.66	31.84	11.65		43.49		77.15	3.2692

SOUTHERN ELECTRIC SYSTEM PROJECTION OF GENERIC NOMINAL NATURAL GAS PRICES FOR USE IN THE 1994 FUEL BUDGET AND OTHER LONG-TERM STUDIES

GULF POWER COMPANY – DELIVERED TO PLANT CRIST

	GDP IPD				NOMINAL CENTS / MMBTU – 1000 BTU / MCF								
	ANN	CUM	REAL % INC		F.O.B. LA PIPE		TRANSPORTATION		% TAX = 0.00		DELIVERED		
YEAR	%	FACT	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	SUMMER	WINTER	AVERAGE
1993		1.0000			190.00	240.00	26.60	27.75			216.60	267.75	237.91
1994	2.516	1.0252	0.000	−0.500	194.78	244.81	27.27	28.45			222.05	273.26	243.39
1995	2.613	1.0519	0.000	−0.500	199.87	249.95	27.98	29.19			227.85	279.14	249.22
1996	2.469	1.0779	0.000	−0.500	204.80	254.84	28.67	29.91			233.47	284.75	254.84
1997	2.560	1.1055	0.000	−0.500	210.05	260.06	29.41	30.68			239.46	290.74	260.82
1998	2.790	1.1364	0.000	−0.500	215.91	265.98	30.23	31.53			246.14	297.51	267.54
1999	2.929	1.1696	0.000	−0.500	222.23	272.40	31.11	32.46			253.34	304.86	274.81
2000	3.053	1.2054	0.000	−0.500	229.02	279.31	32.06	33.45			261.08	312.76	282.61
2001	3.165	1.2435	6.153	5.043	250.80	302.68	33.08	34.51			283.88	337.19	306.09
2002	3.133	1.2825	9.906	8.208	284.28	337.79	34.11	35.59			318.39	373.38	341.30
2003	3.228	1.3239	6.866	5.779	313.61	368.84	35.21	36.74			348.82	405.58	372.47
2004	3.311	1.3677	6.425	5.463	344.81	401.87	36.38	37.95			381.19	439.82	405.62
2005	3.442	1.4148	4.907	4.210	374.18	433.20	37.63	39.26			411.81	472.46	437.08
2006	3.500	1.4643	2.159	1.865	395.63	456.72	38.95	40.63			434.58	497.35	460.74
2007	3.492	1.5154	1.758	1.523	416.65	479.87	40.31	42.05			456.96	521.92	484.03
2008	3.482	1.5682	1.386	1.203	437.13	502.56	41.71	43.52			478.84	546.08	506.86
2009	3.468	1.6226	1.363	1.186	458.46	526.15	43.16	45.03			501.62	571.18	530.60
2010	3.452	1.6786	1.012	0.882	479.08	549.11	44.65	46.58			523.73	595.69	553.71
2011	3.482	1.7370	0.999	0.871	500.72	573.18	46.20	48.20			546.92	621.38	577.95
2012	3.411	1.7963	0.989	0.864	522.91	597.85	47.78	49.85			570.69	647.70	602.78
2013	3.434	1.8580	0.982	0.859	546.18	623.70	49.42	51.56			595.60	675.26	628.79
2014	3.451	1.9221	0.646	0.566	568.69	648.87	51.13	53.34			619.82	702.21	654.15
2015	3.463	1.9886	0.321	0.281	590.27	673.23	52.90	55.18			643.17	728.41	678.69
2016	3.510	2.0584	0.320	0.281	612.94	698.82	54.75	57.12			667.69	755.94	704.46
2017	3.470	2.1299	0.319	0.280	636.23	725.09	56.65	59.10			692.88	784.19	730.93
2018	3.470	2.2038	0.319	0.320	660.41	752.35	58.62	61.15			719.03	813.50	758.39

NOTE: SUMMER MONTHS EQUAL MARCH – SEPTEMBER.
WINTER MONTHS EQUAL OCTOBER – FEBRUARY.