AUSLEY & MCMULLEN

ATTORNEYS AND COUNSELORS AT LAW

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TALLAHASSEE, FLORIDA 32301
(850) 224-9115 FAX (850) 222-7560

April 1, 2002

HAND DELIVERED

Ms. Blanca S. Bayo, Director
Division of Commission Clerk
and Administrative Services
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

020000-PU

Re: Tampa Electric Company's Ten Year Site Plan

Dear Ms. Bayo:

Enclosed for filing on behalf of Tampa Electric Company are twenty-five (25) copies of the company's January 2002 to December 2011 Ten Year Site Plan.

Please acknowledge receipt and filing of the above by stamping the duplicate copy of this letter and returning same to this writer.

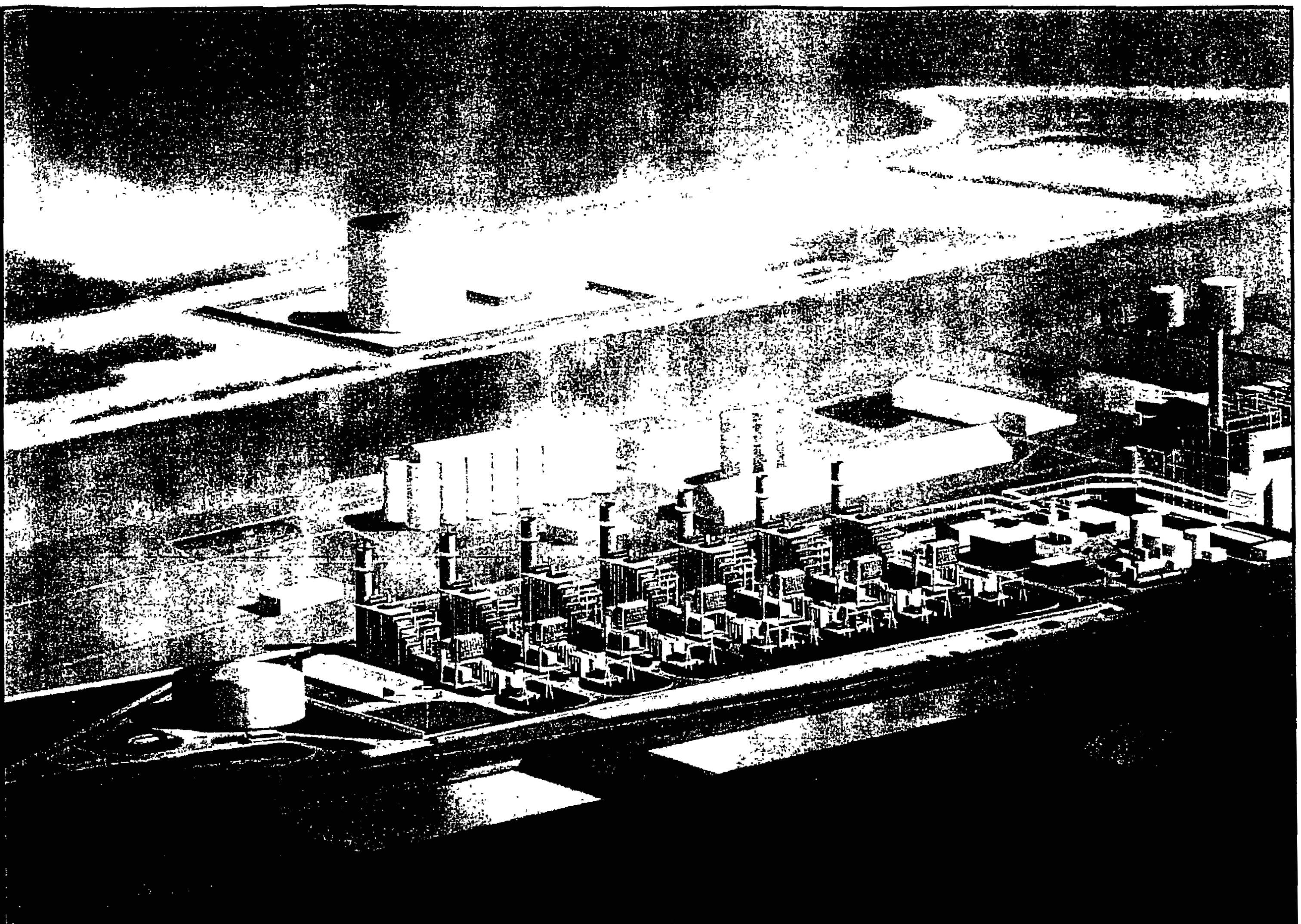
Thank you for your assistance in connection with this matter.

Sincerely,

James D. Beasley

JDB/pp
Enclosures

cc: Michael Haff (w/enc.)



TAMPA ELECTRIC

TEN-YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES

JANUARY 2002 TO DECEMBER 2011

TEN-YEAR SITE PLAN FOR ELECTRICAL GENERATING FACILITIES AND ASSOCIATED TRANSMISSION LINES

January 2002 to December 2011

TAMPA ELECTRIC COMPANY
Tampa, Florida

April 1, 2002

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CHAPTER IV

LIST OF FIGURES

TAMPA ELECTRIC COMPANY
CODE IDENTIFICATION SHEET

Unit Type:	CT	=	Combustion Turbine
	CC	=	Combined Cycle
	CG	=	Coal Gasifier
	D	=	Diesel
	FS	=	Fossil Steam
	HRSG	=	Heat Recovery Steam Generator
	IGCC	=	Integrated Gasification Combined Cycle
	ST	=	Steam Turbine
Unit Status:	P	=	Planned
	T	=	Regulatory Approval Received
	LTRS	=	Long Term Reserve Stand-by
	UC	=	Under Construction
Fuel Type:	BIT	=	Bituminous Coal
	C	=	Coal
	PC	=	Petroleum Coke
	HO	=	Heavy Oil (#6 Oil)
	LO	=	Light Oil (#2 Oil)
	NG	=	Natural Gas
	WH	=	Waste Heat
Environmental:	CL	=	Closed Loop Water Cooled
	CLT	=	Cooling Tower
	EP	=	Electrostatic Precipitator
	FQ	=	Fuel Quality
	LS	=	Low Sulfur
	FGD	=	Flue Gas Desulfurization
	OLS	=	Open Loop Cooling Water System
	OTS	=	Once-Through System
	NR	=	Not Required
Transportation:	PL	=	Pipeline
	TK	=	Truck
	RR	=	Railroad
	WA	=	Water
Other:	N	=	None

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CHAPTER I

DESCRIPTION OF EXISTING FACILITIES

Description of Electric Generating Facilities

Tampa Electric has seven generating plants consisting of fossil steam units, combustion turbine peaking units, diesel units and an integrated gasification combined cycle unit. The generating plants are Big Bend, Gannon, Hookers Point, Dinner Lake, Phillips, Partnership and Polk. Big Bend and Polk consist of both steam-generating units and combustion turbine units.

Tampa Electric currently has eleven coal fired units. The ten units at Big Bend and Gannon are fired with coal. Starting in 2003, Tampa Electric will increase the diversity of its generation mix by repowering Gannon Station. The station will be repowered with natural gas and renamed Bayside Power Station. Big Bend Station contains four pulverized coal fired steam units with desulfurization scrubbers. Polk Station is presently comprised of two generating units. Polk unit 1 is fired with synthetic gas produced from gasified coal and other carbonaceous fuels and is an integrated gasification combined cycle unit (IGCC). This technology integrates state-of-the-art environmental processes for creating a clean fuel gas from a variety of feedstocks with the efficiency benefits of combined cycle generation equipment. Polk unit 2 is a combustion turbine, fueled primarily with natural gas.

Generating units at Hookers Point and Phillips are residual oil fired plants. Dinner Lake is fueled by natural gas and residual oil. Both Hookers Point and Dinner Lake are currently on long-term reserve standby. The three combustion turbines at Big Bend Station use distillate oil. Total net system generation in 2001 was 16,146 GWh.

Schedule 1

Existing Generating Facilities
As of December 31, 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
								Alt	Commercial	Expected	Gen. Max.	Net Capability	
	Unit		Unit	Fuel		Fuel Transport		Fuel	In-Service	Retirement	Nameplate	Summer	Winter
Plant Name	No.	Location	Type	Pri	Alt	Pri	Alt	Days	Mo/Yr	Mo/Yr	KW	MW	MW
Big Bend		Hillsborough Co 14/31S/19E									1,998,000	1,851	1,909
	1		FS	C	N	WA	N	0	10/70	Unknown	445,500	416	426
	2		FS	C	N	WA	N	0	04/73	"	445,500	416	426
	3		FS	C	N	WA	N	0	05/76	"	445,500	433	433
	4		FS	C	N	WA	N	0	02/85	"	486,000	442	447
	CT 1		CT	LO	N	WA	TK	0	02/69	"	18,000	12	17
	CT 2&3		CT	LO	N	WA	TK	0	11/74	"	157,500	132	160
Dinner Lake (a)		Highland Co 12-055									12,650	11	11
	1		FS	NG	HO	PL	TK	2	12/66	01/01/03	12,650	11	11
Gannon		Hillsborough Co 4/30S/19E									1,301,880	1,120	1,150
	1		FS	C	N	WA	RR	0	09/57	12/31/04 (d)	125,000	114	114
	2		FS	C	N	WA	RR	0	11/58	12/31/04 (d)	125,000	98	98
	3		FS	C	N	WA	RR	0	10/60	12/31/04 (d)	179,520	145	155
	4		FS	C	N	WA	RR	0	11/63	12/31/04 (d)	187,500	159	159
	5		FS	C	N	WA	RR	0	11/65	05/01/03 (e)	239,360	232	232
	6		FS	C	N	WA	RR	0	10/67	05/01/04 (e)	445,500	372	392
Hookers Pt (c)		Hillsborough Co 19/29S/19E									232,600	157	157
	1		FS	HO	N	WA	N	0	07/48	01/01/03	33,000	20	20
	2		FS	HO	N	WA	N	0	06/50	01/01/03	34,500	20	20
	3		FS	HO	N	WA	N	0	08/50	01/01/03	34,500	20	20
	4		FS	HO	N	WA	N	0	10/53	01/01/03	49,000	30	30
	5		FS	HO	N	WA	N	0	05/55	01/01/03	81,600	67	67
Phillips		Highland Co 12-055									42,030	37	37
	1		D	HO	N	TK	N	0	06/83	Unknown	19,215	17	17
	2		D	HO	N	TK	N	0	06/83	Unknown	19,215	17	17
	3 (b)		HRSG	WH	N	N	N	0	06/83	Unknown	3,600	3	3
Polk		Polk Co. 2,3/32S/23E									521,299	410	430
	1		IGCC	C	LO	WA/TK	TK	0	09/96	Unknown	326,299	250	250
	2		CT	NG	LO	PL	TK	0	07/00	Unknown	195,000	160	180
Partnership Station		Hillsborough Co. W30/29/19									5,800	6	6
	1		D	NG	N	PL	N	0	04/01	Unknown	2,900	3	3
	2		D	NG	N	PL	N	0	04/01	Unknown	2,900	3	3
											TOTAL	3,592	3,700

Notes:
- (a) Unit placed on long-term reserve standby 03/01/94.
- (b) Unit on full forced outage with an undetermined return to service date.
- (c) Hooker's Pt. station limited to 90 MW of steam capacity, with a sixty day startup time for 2002 and unit 5 was placed on long term reserve standby 1/1/01. Capacity from Hookers Point station is not included in reserve margin calculations.
- (d) Stated retirement date for Gannon 1 through 4 are the dates that the units can no longer burn coal, but the units maybe repowered to burn natural gas.
- (e) Stated retirement date for Gannon 5 & 6 are the dates that the steam generators convert to Bayside 1 & 2.

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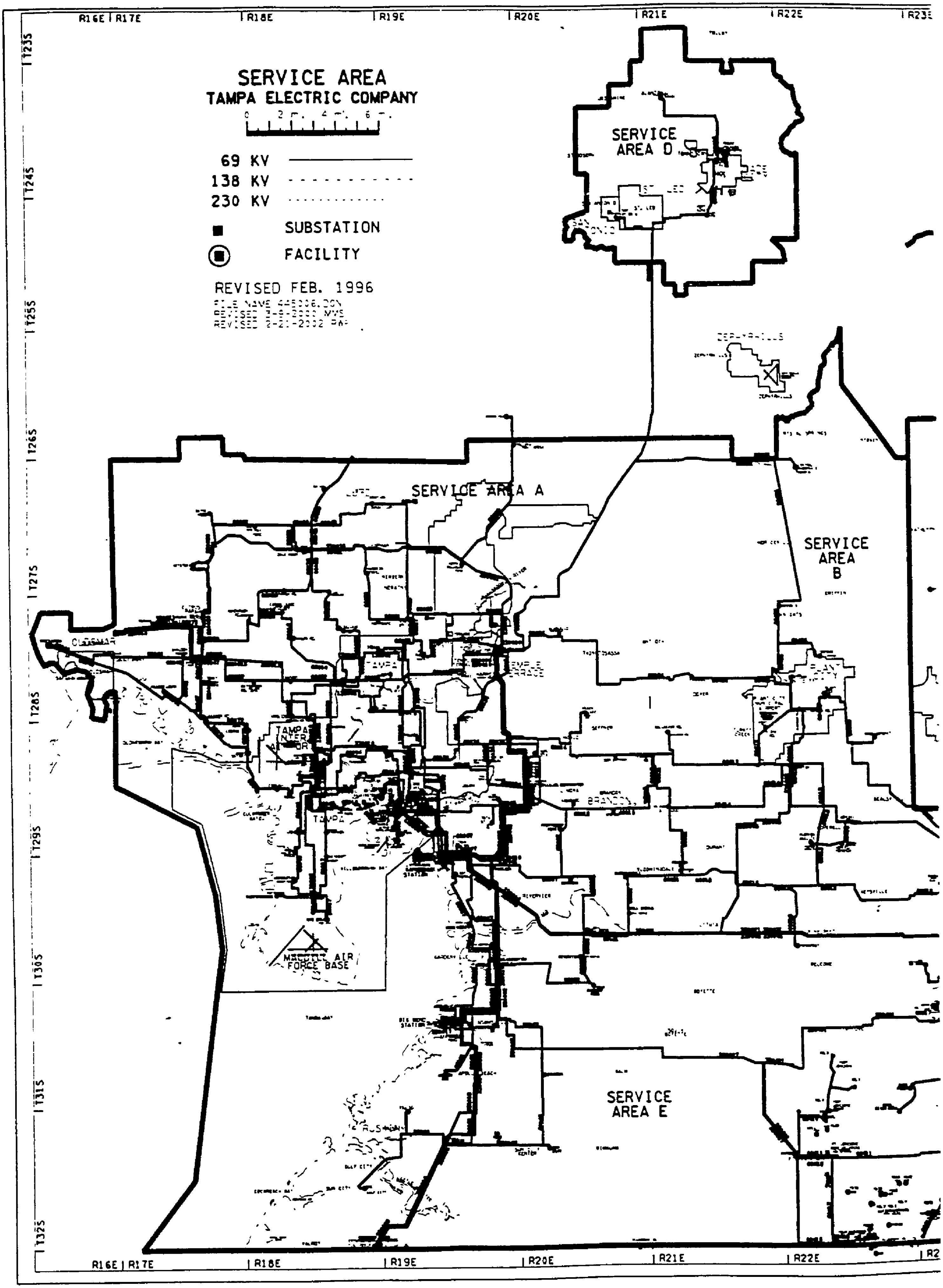
SERVICE AREA
TAMPA ELECTRIC COMPANY
69 KV
138 KV
230 KV
SUBSTATION
FACILITY
REVISED FEB. 1996
SERVICE AREA D
SERVICE AREA A
SERVICE AREA B
SERVICE AREA E
OLDSMAR
TAMPA
TEMPLE TERRACE
TAMPA INTERNATIONAL AIRPORT
MACDILL AIR FORCE BASE
BRANDON
RUSKIN
R16E
R17E
R18E
R19E
R20E
R21E
R22E
T23S
T24S
T25S
T26S
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T28S
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T30S
T31S
T32S

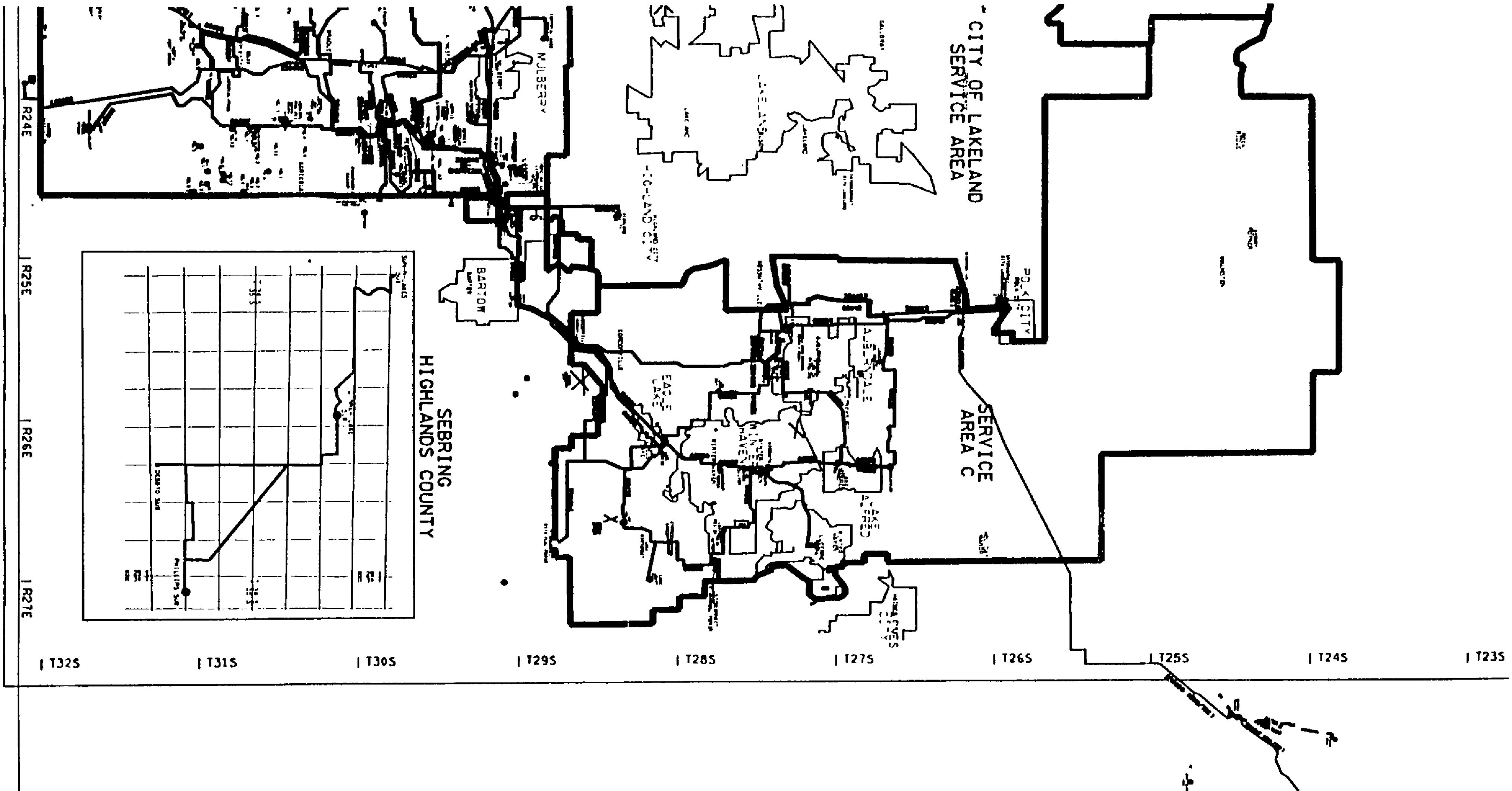

FIGURE I-1

TAMPA ELECTRIC RETAIL CUSTOMER SERVICE AREA

SOURCE: TAMPA ELECTRIC.

TAMPA ELECTRIC COMPANY

TEN YEAR SITE PLAN
FOR ELECTRICAL GENERATING FACILITIES
AND ASSOCIATED TRANSMISSION LINES

FILE NAME 445006.DGN
REVISED 3-9-2000 MMS
REVISED 2-21-2002 RMI

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CHAPTER II

FORECAST OF ELECTRIC POWER, DEMAND, AND ENERGY CONSUMPTION

Schedule 2.1:	History and Forecast of Energy Consumption and Number of Customers by Customer Class
Schedule 2.2:	History and Forecast of Energy Consumption and Number of Customers by Customer Class
Schedule 2.3:	History and Forecast of Energy Consumption and Number of Customers by Customer Class
Schedule 3.1:	History and Forecast of Summer Peak Demand
Schedule 3.2:	History and Forecast of Winter Peak Demand
Schedule 3.3:	History and Forecast of Annual Net Energy for Load
Schedule 4:	Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month
Schedule 5:	History and Forecast of Fuel Requirements
Schedule 6.1:	History and Forecast of Net Energy for Load by Fuel Source in GWH
Schedule 6.2:	History and Forecast of Net Energy for Load by Fuel Source as a Percentage

Schedule 2.1

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	Hillsborough County Population	Members Per Household	GWH	Customers*	Average KWH Consumption Per Customer	GWH	Customers*	Average KWH Consumption Per Customer
1992	853,990	2 5	5,560	412,970	13,463	4,333	51,727	83,767
1993	866,134	2.5	5,706	420,051	13,584	4,432	52,492	84,432
1994	879,069	2.5	5,947	427,594	13,908	4,583	53,482	85,692
1995	892,874	2.5	6,352	436,091	14,566	4,710	54,375	86,621
1996	910,855	2.5	6,607	445,664	14,825	4,815	55,479	86,790
1997	928,731	2.4	6,500	456,175	14,249	4,902	56,981	86,029
1998	942,322	2.4	7,050	466,189	15,123	5,173	58,542	88,364
1999	962,153	2.4	6,967	477,533	14,590	5,337	60,089	88,818
2000	1,006,400	2.6	7,369	491,925	14,980	5,541	61,902	89,514
2001	1,027,800	2.5	7,594	505,964	15,009	5,685	63,316	89,788
2002	1,043,300	2.5	8,000	517,149	15,469	5,973	64,337	92,839
2003	1,056,600	2.5	8,270	526,672	15,702	6,202	65,402	94,829
2004	1,070,100	2.5	8,544	535,848	15,945	6,422	66,293	96,873
2005	1,085,100	2.5	8,826	545,023	16,194	6,615	67,220	98,408
2006	1,101,000	2.5	9,108	554,349	16,430	6,800	68,501	99,269
2007	1,117,000	2.5	9,373	563,675	16,628	6,987	69,745	100,179
2008	1,132,500	2.5	9,657	573,001	16,853	7,193	70,991	101,323
2009	1,147,600	2.5	9,932	582,327	17,056	7,403	72,238	102,481
2010	1,163,000	2.5	10,215	591,652	17,265	7,613	73,486	103,598
2011	1,178,900	2.5	10,466	600,302	17,435	7,810	74,488	104,849

December 31, 2001 Status

* Average of end-of-month customers for the calendar year.

Schedule 2.2

History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	Industrial						
Year	GWH	Customers	Average KWH Consumption Per Customer	Railroads and Railways GWH	Street & Highway Lighting GWH	Other Sales to Public Authorities GWH	Total Sales to Ultimate Consumers GWH
1992	2,625	509	5,157,171	0	43	991	13,552
1993	2,236	509	4,392,927	0	45	1,028	13,447
1994	2,278	511	4,457,926	0	46	1,078	13,932
1995	2,362	491	4,810,591	0	51	1,125	14,600
1996	2,305	504	4,573,413	0	53	1,150	14,930
1997	2,465	629	3,918,919	0	53	1,170	15,090
1998	2,520	682	3,695,015	0	54	1,231	16,028
1999	2,223	740	3,004,054	0	52	1,226	15,805
2000	2,390	776	3,079,897	0	53	1,285	16,638
2001	2,329	851	2,736,780	0	54	1,314	16,976
2002	2,510	872	2,878,440	0	57	1,363	17,903
2003	2,257	914	2,469,365	0	59	1,392	18,180
2004	2,289	944	2,424,788	0	60	1,434	18,749
2005	2,318	974	2,379,877	0	62	1,471	19,292
2006	2,351	999	2,353,353	0	63	1,502	19,824
2007	2,411	1,024	2,354,492	0	65	1,529	20,365
2008	2,392	1,049	2,280,267	0	66	1,562	20,870
2009	2,423	1,074	2,256,052	0	67	1,590	21,415
2010	2,412	1,099	2,194,722	0	69	1,618	21,927
2011	2,441	1,124	2,171,708	0	70	1,643	22,430

December 31, 2001 Status.

- Average of end-of-month customers for the calendar year.

Schedule 2.3

History and Forecast of Energy Consumption and
Number of Customers by Customer Class

(1) Year	(2) Sales for Resale GWH	(3) Utility Use++ & Losses GWH	(4) Net Energy** for Load GWH	(5) Other Customers *	(6) Total Customers*
1992	214	671	14,437	3,790	468,996
1993	246	808	14,501	3,958	477,010
1994	163	636	14,731	4,111	485,698
1995	212	870	15,682	4,241	495,198
1996	399	760	16,089	4,391	506,038
1997	507	731	16,328	4,583	518,368
1998	431	783	17,242	4,839	530,252
1999	533	900	17,238	5,299	543,661
2000	763	972	18,373	5,497	560,101
2001	685	794	18,455	5,649	575,780
2002	705	945	19,553	5,815	588,173
2003	612	960	19,752	5,937	598,925
2004	410	989	20,148	6,068	609,153
2005	430	1,018	20,740	6,199	619,416
2006	431	1,046	21,301	6,332	630,181
2007	433	1,075	21,873	6,465	640,909
2008	434	1,101	22,405	6,598	651,639
2009	435	1,130	22,980	6,732	662,371
2010	436	1,157	23,520	6,865	673,102
2011	256	1,184	23,870	6,988	682,902

December 31, 2001 Status.

- * Average of end-of-month customers for the calendar year.
- ** Output to line including energy supplied by purchased cogeneration.
- ++ Utility Use and Losses include accrued sales.

Schedule 3.1

History and Forecast of Summer Peak Demand
Base Case

(1) Year	(2) Total +	(3) Wholesale++	(4) Retail +	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand	
1992	2,856	50	2,806	294	77	25	3	10	2,401	*
1993	2,951	60	2,891	273	91	28	6	11	2,492	*
1994	2,865	69	2,796	200	97	31	8	11	2,451	*
1995	3,028	81	2,947	170	98	34	8	13	2,624	
1996	3,146	92	3,054	234	98	41	18	16	2,647	
1997	3,167	106	3,061	225	89	45	17	15	2,677	*
1998	3,444	111	3,333	204	99	49	18	18	2,945	
1999	3,636	190	3,446	193	92	53	18	21	3,069	
2000	3,551	171	3,380	182	74	56	19	21	3,028	
2001	3,712	178	3,534	181	83	61	19	25	3,165	
2002	3,853	175	3,678	210	90	61	24	42	3,251	
2003	3,958	175	3,783	171	90	64	24	45	3,389	
2004	4,085	175	3,910	171	90	66	25	48	3,510	
2005	4,216	186	4,030	171	90	68	26	50	3,625	
2006	4,344	186	4,158	171	90	70	26	52	3,749	
2007	4,454	186	4,268	175	90	72	27	54	3,850	
2008	4,577	187	4,390	169	91	73	27	55	3,975	
2009	4,690	187	4,503	169	91	76	27	56	4,084	
2010	4,807	187	4,620	165	91	77	27	57	4,203	
2011	4,839	116	4,723	165	91	78	28	57	4,304	

December 31, 2001 Status

* Not coincident with system peak.
\+ Includes residential and commercial/industrial conservation.
++ Includes sales to FPC, Wauchula, FMPA, St. Cloud and Reedy Creek.
\# Commercial/Industrial Load Management includes Standby Generator.

Schedule 3.2

History and Forecast of Winter Peak Demand
Base Case

(1) Year	(2) Total +	(3) Wholesale ++	(4) Retail +	(5) Interruptible	(6) Residential Load Management	(7) Residential Conservation =	(8) Comm./Ind. Load Management #	(9) Comm./Ind. Conservation	(10) Net Firm Demand
1991/92	3,043	53	2,990	294	151	207	1	21	2,316
1992/93	3,130	63	3,067	281	168	221	4	23	2,370
1993/94	3,003	69	2,934	181	177	241	7	25	2,303
1994/95	3,539	74	3,465	240	227	270	8	25	2,695
1995/96	3,765	98	3,667	152	245	291	8	25	2,946
1996/97	3,577	109	3,468	228	153	325	18	25	2,719
1997/98	3,186	99	3,087	210	151	350	17	26	2,332
1998/99	3,953	131	3,822	152	250	385	17	28	2,990
1999/00	3,999	125	3,874	212	197	409	18	29	3,009
2000/01	4,390	136	4,254	191	184	422	19	31	3,407
2001/02	4,583	177	4,406	190	210	473	24	33	3,476
2002/03	4,710	178	4,532	157	211	500	24	34	3,606
2003/04	4,844	178	4,666	157	211	524	25	35	3,714
2004/05	5,006	189	4,817	156	212	545	25	36	3,843
2005/06	5,133	189	4,944	157	213	565	25	36	3,948
2006/07	5,290	190	5,100	161	213	585	26	37	4,078
2007/08	5,403	190	5,213	156	214	605	26	38	4,174
2008/09	5,558	190	5,368	156	214	624	27	38	4,309
2009/10	5,687	190	5,497	151	214	642	27	39	4,424
2010/11	5,807	191	5,616	151	215	659	27	39	4,525

December 31, 2001 Status

+ Includes cumulative conservation.
++ Includes sales to FPC, Wauchula, FMPA, St. Cloud and Reedy Creek.
# Commercial/Industrial Load Management includes Standby Generator.
= Residential conservation includes code changes.

Schedule 3.3

History and Forecast of Annual Net Energy for Load - GWH
Base Case

(1) Year	(2) Total	(3) Residential Conservation =	(4) Comm./Ind. Conservation	(5) Retail	(6) Wholesale +	(7) Utility Use & Losses	(8) Net Energy for Load	(9) Load Factor % **
1992	13,697	120	25	13,552	214	671	14,437	58 5
1993	13,603	127	30	13,446	246	808	14,500	57.0
1994	14,103	138	33	13,932	163	636	14,731	61.1
1995	14,798	158	40	14,600	212	870	15,682	55 2
1996	15,167	189	49	14,929	399	760	16,088	53.1
1997	15,354	210	54	15,090	507	731	16,328	57.8
1998	16,334	239	67	16,028	431	783	17,242	55.3
1999	16,162	281	76	15,805	533	900	17,238	60.3
2000	17,028	302	88	16,638	763	972	18,373	62.9
2001	17,388	316	96	16,976	684	794	18,455	51 6
2002	18,341	316	122	17,903	705	945	19,553	54.7
2003	18,641	333	128	18,180	613	960	19,752	54.0
2004	19,232	349	134	18,749	410	989	20,148	53 5
2005	19,792	361	139	19,292	430	1,018	20,740	53.5
2006	20,340	372	144	19,824	431	1,046	21,301	53.7
2007	20,896	383	148	20,365	433	1,075	21,873	53 5
2008	21,415	394	151	20,870	434	1,101	22,405	53 6
2009	21,973	404	154	21,415	435	1,130	22,980	53.6
2010	22,497	414	156	21,927	436	1,157	23,520	53 6
2011	23,010	423	157	22,430	256	1,184	23,870	53 3

December 31, 2001 Status

** Load Factor is the ratio of total system average load to peak demand.
\+ Includes sales to FPC, Wauchula, FMPA, St. Cloud and Reedy Creek.
= Residential conservation includes code changes.

Schedule 4

Previous Year and 2-Year Forecast of Peak Demand and Net Energy for Load by Month

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	2001 Actual		2002 Forecast		2003 Forecast	
Month	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH	Peak Demand MW	NEL GWH
January	3,937	1,647	4,077	1,492	4,176	1,507
February	3,003	1,260	3,564	1,332	3,648	1,345
March	2,670	1,374	3,221	1,465	3,288	1,463
April	3,051	1,429	3,039	1,448	3,117	1,464
May	3,431	1,639	3,418	1,731	3,496	1,751
June	3,600	1,744	3,750	1,847	3,849	1,868
July	3,479	1,720	3,709	1,947	3,814	1,972
August	3,626	1,874	3,723	1,964	3,825	1,989
September	3,430	1,638	3,576	1,840	3,674	1,863
October	3,167	1,519	3,306	1,620	3,391	1,638
November	2,571	1,283	3,155	1,400	3,237	1,408
December	2,647	1,328	3,425	1,467	3,515	1,484
TOTAL		**18,455**		**19,553**		**19,752**

December 31, 2001 Status

NOTE: Peak demand represents total retail and wholesale demand, excluding conservation impacts.

Schedule 5

History and Forecast of Fuel Requirements

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Fuel Requirements		Units	Actual 2000	Actual 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Nuclear		Trillion BTU	0	0	0	0	0	0	0	0	0	0	0	0
(2)	Coal		1000 Ton	7,327	6,962	7,051	6,811	5,972	5,084	5,258	5,288	5,288	5,315	5,317	5,331
(3)	Residual	Total	1000 BBL	505	144	196	117	78	140	140	146	149	159	154	161
(4)		Steam	1000 BBL	387	4	0	0	0	0	0	0	0	0	0	0
(5)		CC	1000 BBL	118	140	196	117	78	140	140	146	149	159	154	161
(6)		CT	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(7)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(8)	Distillate	Total	1000 BBL	499	408	507	189	176	309	321	392	472	566	568	685
(9)		Steam	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(10)		CC	1000 BBL	115	224	170	170	174	174	170	174	174	171	173	175
(11)		CT	1000 BBL	384	184	337	20	2	135	151	218	298	396	395	510
(12)		Diesel	1000 BBL	0	0	0	0	0	0	0	0	0	0	0	0
(13)	Natural Gas	Total	1000 MCF	1,592	3,349	7,728	25,552	51,311	63,245	64,047	64,621	68,334	69,546	73,655	74,580
(14)		Steam	1000 MCF	0	0	0	0	0	0	0	0	0	0	0	0
(15)		CC	1000 MCF	0	0	0	20,518	49,454	61,076	61,636	61,053	63,472	63,045	67,155	66,141
(16)		CT	1000 MCF	1,592	3,349	7,728	5,034	1,857	2,169	2,411	3,568	4,863	6,501	6,500	8,440
(17)	Other (Specify)														
(18)	Petroleum Coke		1000 Ton	224	327	528	585	593	575	578	595	587	580	585	598

Schedule 6.1

History and Forecast of Net Energy for Load by Fuel Source in GWH

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2000	Actual 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Annual Firm Interchange		GWh	459	203	600	679	417	755	765	737	846	880	862	848
(2)	Nuclear		GWh	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		GWh	16,051	14,623	14,376	13,796	12,053	10,410	10,774	10,805	10,853	10,906	10,897	10,900
(4)	Residual	Total	GWh	225	90	132	78	52	94	94	98	100	106	103	108
(5)		Steam	GWh	146	(2)	0	0	0	0	0	0	0	0	0	0
(6)		CC	GWh	79	92	132	78	52	94	94	98	100	106	103	108
(7)		CT	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	GWh	243	211	241	121	117	187	193	231	272	323	324	387
(10)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	GWh	80	141	114	114	117	117	114	117	117	115	116	117
(12)		CT	GWh	163	70	127	7	1	70	79	114	156	209	208	270
(13)		Diesel	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	GWh	136	311	758	3,436	7,257	8,949	9,055	9,082	9,547	9,639	10,234	10,278
(15)		Steam	GWh	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	GWh	0	0	0	2,950	7,077	8,741	8,822	8,743	9,085	9,020	9,616	9,477
(17)		CT	GWh	136	311	758	487	181	208	232	339	462	620	617	801
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		GWh	628	911	1,472	1,632	1,653	1,604	1,612	1,660	1,638	1,618	1,632	1,667
(20)	Net Interchange		GWh	236	1,669	1,500	(466)	(1,865)	(1,733)	(1,664)	(1,215)	(1,324)	(1,004)	(856)	(538)
(21)	Purchased Energy from Non-														
(22)	Utility Generators		GWh	394	439	473	475	463	474	474	474	474	510	323	220
(23)	Net Energy for Load*		GWh	18,372	18,455	19,553	19,750	20,148	20,739	21,301	21,871	22,406	22,979	23,520	23,870

* Values shown may be affected due to rounding.

Schedule 6.2

History and Forecast of Net Energy for Load by Fuel Source as Percentage

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
	Energy Sources		Units	Actual 2000	Actual 2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
(1)	Annual Firm Interchange		%	2	1	3	3	2	4	4	3	4	4	4	4
(2)	Nuclear		%	0	0	0	0	0	0	0	0	0	0	0	0
(3)	Coal		%	87	79	74	70	60	50	51	49	48	47	46	46
(4)	Residual	Total	%	1	0	1	0	0	0	0	0	0	0	0	0
(5)		Steam	%	1	(0)	0	0	0	0	0	0	0	0	0	0
(6)		CC	%	0	0	1	0	0	0	0	0	0	0	0	0
(7)		CT	%	0	0	0	0	0	0	0	0	0	0	0	0
(8)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(9)	Distillate	Total	%	1	1	1	1	1	1	1	1	1	1	1	2
(10)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(11)		CC	%	0	1	1	1	1	1	1	1	1	0	0	0
(12)		CT	%	1	0	1	0	0	0	0	1	1	1	1	1
(13)		Diesel	%	0	0	0	0	0	0	0	0	0	0	0	0
(14)	Natural Gas	Total	%	1	2	4	17	36	43	43	42	43	42	44	43
(15)		Steam	%	0	0	0	0	0	0	0	0	0	0	0	0
(16)		CC	%	0	0	0	15	35	42	41	40	41	39	41	40
(17)		CT	%	1	2	4	2	1	1	1	2	2	3	3	3
(18)	Other (Specify)														
(19)	Petroleum Coke Generation		%	3	5	8	8	8	8	8	8	7	7	7	7
(20)	Net Interchange		%	1	9	8	(2)	(9)	(8)	(8)	(6)	(6)	(4)	(4)	(2)
(21)	Purchased Energy from Non-														
(22)	Utility Generators		%	2	2	2	2	2	2	2	2	2	2	1	1
(23)	Net Energy for Load*		%	100	100	100	100	100	100	100	100	100	100	100	100

* Values shown may be affected due to rounding.

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CHAPTER III

FORECAST OF ELECTRIC POWER DEMAND

Tampa Electric Company Forecasting Methodology

The Customer, Demand and Energy Forecast is the foundation from which the integrated resource plan is developed. Recognizing its importance, Tampa Electric Company employs methodologies for carrying out this function. The primary objective in this procedure is to blend proven statistical techniques with practical forecasting experience to provide a projection, which represents the highest probability of occurrence.

This chapter is devoted to describing Tampa Electric Company's forecasting methods and the major assumptions utilized in developing the 2002-2011 forecast. The data provided in Chapter II outline the expected customer, demand, and energy values for the 2002-2011 time period.

Retail Load

The Tampa Electric Company retail demand and energy forecast is the result of five separate forecasting methods:

1. detailed end-use model (demand and energy);
2. multiregression model (demand and energy);
3. trend analysis (demand and energy);
4. phosphate analysis (demand and energy); and
5. conservation programs (demand and energy management).

The detailed end-use model, SHAPES, is the company's most sophisticated and primary forecasting model. The first three forecasting methods are blended together to develop a demand and energy projection, excluding phosphate load. Phosphate demand and energy is forecasted separately and then combined in the final forecast. Likewise, the effect of Tampa Electric Company's conservation, load management, and cogeneration programs is incorporated into the process by subtracting their expected reduction in demand and energy from the forecast.

1. Detailed End-Use Model

The SHAPES model was developed jointly by Tampa Electric Company, Tech Resources (formerly part of the Battelle Memorial Institute), and New Energy Associates and is the foundation of the demand and energy forecasting process. SHAPES projects annual energy consumption for the service area and load profiles by end-use for typical and extreme (peak) days.

The model consists of two parts: (1) a demand sections, and (2) an energy section. The demand section calculates hourly demands including peak demands based on temperature profiles for normal and extreme conditions. The energy section forecasts residential energy use by appliance, commercial consumption by employee, and energy used in the industrial and miscellaneous sectors.

SHAPES

The power model is comprised of four major sectors: (1) residential, (2) commercial, (3) industrial, and (4) miscellaneous (governmental, street lighting, and transmission and distribution line losses). This structure emphasizes the projection of hourly demand values by end-use based on month, day type, and temperature. Repeating these calculations for each hour of the day and for all consumption units yields the daily load curve of the system. The energy consumption for any period is calculated by summing demand in each hour in the period for all end-uses.

More specifically, the basic equation upon which the model is based is:

$$D_{ij} = \Sigma N_i * C_i * F_{ij}$$

where:

D_{ij} = Demand at hour j by end-use component i;

N_i = Number of use components of type i;

C_i = Connected load per use component i;

F_{ij} = Fraction of connected load of use component i which is operating at hour j.

In the residential sector, the energy-consuming units are the major household appliances. A list of the seventeen appliances treated explicitly in the model is provided in Table III-1. The appliance stock in a given year is influenced by the number of households, the mix of dwelling unit types, and family income. The latter two variables are used to derive saturation levels for each appliance which, combined with the number of households, results in the total number of units of a given appliance.

Looking at these two factors in more detail, data analysis indicates that saturation levels for certain appliances vary significantly according to housing type. To capture these differences, the occupied housing stock or number of households is partitioned into single family, multi-family, and mobile home categories. In addition, it was determined that certain appliance saturations are related to the individual household's income level. Those appliances having this characteristic included room air conditioners, electric clothes dryers, clothes washers, and dishwashers. Projections of housing mix and per capita income, therefore, were utilized in developing saturation rates for these appliance categories.

To capture the trend of including ranges, central air conditioning, electric water heating, electric space heating or electric heat pumps as standard items in new construction, penetration rates representing the percent of new housing with these features were used to project saturation levels for these appliances. Finally, certain appliances such as television sets and refrigerators have already achieved full saturation. Future saturation levels are similar to present rates except for quality shifts or intercategory adjustments from standard to frost-free refrigerators and black and white to color television.

The second major factor in the demand estimation equation is the connected load of the appliance, which was developed from company and industry studies. The last factor in the equation is the use factor or the probability of the appliance operating at a given time.

TABLE III-1. Appliances Treated Explicitly In End-Use Model

Electric Range
Refrigerator - Frost Free
Refrigerator - Standard
Freezer - Frost Free
Freezer - Standard
Dishwasher
Clothes Washer
Electric Dryer
Electric Water Heater
Microwave Oven
TV-Color
TV-Black and White
Lighting
Room Air Conditioner
Central Air Conditioner
Electric Space Heating
Electric Heat Pump
Miscellaneous

SOURCE: Tampa Electric Company

In the model, appliances can be separated into two groups: temperature insensitive and temperature sensitive. Those appliances which are temperature insensitive have use factors which vary by day type, month, and hour. Thus, the usage of these appliances is characterized by 1,152 use factors (12 months x 24 hours x 4 day types). These four-day types are Sunday, Monday, Tuesday-Friday, and Saturday. For temperature-sensitive appliances, which include air conditioners, electric space heaters, and electric heat pumps, the monthly use factors are replaced by a set of factors, which vary with respect to time and temperature. Therefore, the energy consumption of these appliances is a function of temperature, time, and day type. These temperature-related use factors are combined with monthly temperature probability matrices to calculate energy requirements over that period.

The model is capable of developing a residential as well as a system demand profile for each hour of each day type for all twelve months. In order to calculate peak demand, a temperature profile representing the expected hottest or coldest day must be input into the model. Supplying an average temperature for every hour can also develop an average day load profile for each month.

The commercial sector begins with the calculation of annual energy from energy intensiveness and employment. From the calculation of energy, commercial demand is determined by allocating annual consumption to the hours of the day through use factors. However, the commercial sector contains both temperature-sensitive and insensitive end-uses. The temperature-sensitive use patterns are a function of temperature and time. Therefore, peak demand is calculated, as in the residential sector, by specifying extreme temperatures to represent severe weather conditions.

The industrial class is disaggregated into four major groups representing different levels of energy intensiveness. These include Food Products (SIC 20); Tobacco, Printing, etc. (SIC 21, 23, 24, 25, 27, 37, 39); Fabricated Metals, etc. (SIC 26, 29, 30, 34, 35, 36, 38); and Basic Industries (SIC 32, 33). In each sector, annual energy consumption is computed by multiplying energy use per employee times projected employment. Monthly energy consumption is calculated by allocating the annual energy to the corresponding month using historic ratios of monthly-to-annual consumption. Once monthly energy is computed, it is further broken down by hour for each of the four-day types. That is, a use factor is applied which denotes the fraction of each month's energy that is consumed in a given hour. These use factors were developed from hourly billing data available for major industrial customers in each of the four categories.

The miscellaneous sector includes street lighting, sales to public authorities, and transmission and distribution line losses. For street lighting and public authorities, sales are expressed as a function of the number of residential customers, and demand is calculated using an allocation method similar to the industrial and commercial sectors.

The model also allows for price elasticity adjustments, which represent the change in electric consumption resulting from changes in the relative price of electricity. In order to capture the price effect, an adjustment factor is applied to the annual consumption. The adjustment factor for a given year is a time-dependent weighted average of short and long run elasticity. The general mathematical form of the consumption adjustment equation is as follows:

$C_n = C_0$ * (Price Elasticity Adjustment Factor)

where:

C_n = Consumption at the price level in year n, adjusted for price changes in years 0 to n.

C_0 = Consumption at the base year price level, that is, assuming no price changes.

The Adjustment Factor is given by the following:

Price Elasticity Adjustment Factor

$$\left(\frac{P_1}{P_0}\right)^{E_n} \cdots \left(\frac{P_i}{P_{i-1}}\right)^{E_{n-i+1}} \cdots \left(\frac{P_n}{P_{n-1}}\right)^{E_1}$$

where:

P_i = Price of electricity in period i (i = I to n).

E_i = Price elasticity coefficient expressed as a time-dependent weighted average of the short and long-run elasticity coefficients (i = 1 to n)

This relationship can be expressed as follows:

$$E_i = E_S + W_i(E_L - E_S)$$

where:

E_S = Short-run elasticity

E_L = Long-run elasticity

W_i = Weighting factor, $0 \le W_i \le 1$; $W_1 = 0$, $W_i = 1$ for $I \ge 12$.

The above relationship warrants two important observations. First, the price elasticity adjustment factor that is applied to a given year incorporates the effects of price changes not only for the given year but also for previous years. Second, the elasticity coefficient that is applied to a given year's price change increases numerically over time, gradually rising from the short-term elasticity value to the long-term. Therefore, each price increase or decrease has a lasting effect on future consumption patterns.

In the residential sector, each of the specific appliances was assigned a short-run and long-run elasticity. This was accomplished by partitioning the major appliances into three groups whose change in consumption due to price changes was considered to be either low, medium, or high Table III-2. In certain cases, these elasticities were assigned subjectively while in other cases they were based upon studies by National Economic Research Associates (NERA) and the Electric Power Research Institute (EPRI). In addition, the resulting coefficients have the mathematical property that their combined effect, which represents the average residential elasticity coefficient, closely approximates the results of NERA and EPRI research. Therefore, their cumulative effect is in accord with extensive statistical analysis. The elasticity factors used for the commercial and industrial categories were also developed from these studies.

TABLE III-2. Sensitivity of Consumption to Price

Appliances with Low Assumed Price Sensitivity:

Refrigerator	Frost Free Standard
Freezer	Frost Free Standard
TV	Color Black and White

Appliances with Medium Assumed Price Sensitivity:

Electric Range
Clothes Washer
Electric Water Heater
Microwave Oven
Lighting

Appliances with High Assumed Price Sensitivity:

Dishwasher
Electric Dryer
Room Air Conditioner
Central Air Conditioner
Electric Space Heating
Electric Heat Pump

SOURCE: Based on studies by National Economic Research Associates and the Electric Power Research Institute.

Another factor influencing residential energy consumption is the movement toward more energy-efficient appliances. The forces behind this development include market pressures for more energy-efficient technologies and the appliance efficiency standards enacted by the state and federal governments. The efficiency goals affect the usage associated with new additions to the appliance stock.

It should be noted that both price effects and efficiency improvements influence the base year appliance energy consumption. Thus, while some appliances are assumed to be rather price insensitive, their individual consumption levels decrease due to efficiency improvements.

2. Multiregression Demand and Energy Model

The retail multiregression forecasting model is a nine-equation model with two major sections. The energy section forecasts energy sales by the six major customer categories. The demand section forecasts peak load other than phosphate for both summer and winter. The regression technique is a more sophisticated approach than trend analysis as it attempts to examine those factors which influence load.

The selection of appropriate variables to include in the multiregression model equations is an extensive process that begins with the identification of variables that affect demand and energy. Those variables, which cannot be reasonably quantified or forecast, are dismissed from the process. Results from regressions using the remaining variables are evaluated to determine which variables perform best. As a result, the chosen equations are both statistically and theoretically appropriate.

The basic series that make up the regression method are supplied by Tampa Electric Company, the U.S. Bureau of Labor Statistics, the U.S. Bureau of Economic Analysis, the U.S. Geological Survey, the Federal Reserve Board, the National Oceanic and Atmospheric Administration, and the University of Florida's Bureau of Economic and Business Research. All projections of the independent variables in these equations are consistent with those used in the end-use model.

Demand Section

The demand section consists of three regression equations for load other than phosphate. One equation is for the base load, which by definition is that load on the system that is independent of temperature. The remaining two equations describe the summer peak temperature-sensitive demand and the winter peak temperature-sensitive demand. From regression analysis, the following relationships have been determined.

1.

Base Load = -219 + 4.536 * # Residential Customers -803.7 * $/kWh (lagged 1year)
(t = 91.86) (t = -1.4)

$\bar{R}$-Squared = .98 DW = 1.4

2.

Temperature Sensitive Demand (Summer) = (F°- 65) (17.32 + 0.123 * # A/Cs - 242.8 * $/kWh (lagged 2 periods))
(t = 50.7) (t = -6.9)

$\bar{R}$-Squared = .95 DW = 1.8

3.

Temperature Sensitive Demand (Winter) = (65 - F°) (-0.776 + 0.122 * # Electric Heaters)
(t = 24.14)

$\bar{R}$-Squared = .83 DW = 1.8

The Variables are defined as follows:

Base Load	The temperature-insensitive component of demand (MW).
Temperature-Sensitive Demand	The load component (MW) which is affected by heating or air conditioning on the system.
# Residential Customers	The average number of residential customers (in thousands).
$/kWh	Tampa Electric Company's average cost of electricity per kWh adjusted for inflation.
F° (Summer)	Average 24-hour temperature for the day of the system peak load.
F° (Winter)	Peak hour temperature at the time of the system peak load.

A/Cs — Number of residential air conditioners (in thousands) calculated by multiplying residential customers by cooling saturation levels.

Electric Heaters — Number of residential electric heaters (in thousands) calculated by multiplying residential customers by electric heating saturation levels.

Energy Section

The Energy Section of the retail multiregression model consists of five equations that estimate future energy by the major Customer classes (residential, commercial, industrial other than phosphate, sales to public authorities, and street and highway lighting.) These equations are listed below.

1.
Average Residential Usage = 73995.5 + 21.4 * Chg in Personal Inc. Per Capita (t = 0.7) - 756.3 * Cts/Kwh (t= -10.8) (lagged 1 year)
+ 2.3 * Heating Degree Days (t = 6.6) + 7222.1 * Htg/Cooling Saturation (t = 16.6)

(+ 1.0 *cooling degree day)
$\bar{R}$-Squared = .96 DW = 1.6

2.
Commercial Energy Sales = -1567.1 + 14.9 * Residential Customers (t = 131.1) - 88.0 * Cts/Kwh (lagged 1 yr) (t = -8.7)
+ 0.129 * Total Degree Days (t = 2.4)
$\bar{R}$-Squared = .99 DW = 1.0

3.
Other Industrial Energy Sales = 301.5 + 6.6 * Ind Prod Index (t = 17.7) - 125.7 * Trade Dummy Variable (t = -8.3)

$\bar{R}$-Squared = .92 DW = 1.6

4.
Sales to Public Authorities = 318.5 + 2.8 * Residential Customers (t = 28.9) - 60.7 * Chg in Cts/Kwh (t = -6.4)

$\bar{R}$-Squared = .99 DW = 1.3

5.
Street Lighting = - 24.2 + 0.097 * Population (t = 12.45) = .668 * AR (1) (t = 3.7)
$\bar{R}$-Squared = .99 DW = 1.7

The Variables are defined as follows:

Population	Hillsborough County Population (in thousands).
Residential Customers	Service Area Residential Customers (in thousands).
Chg in Personal Inc. Per Capita	Percent change in real personal income per capita in Hillsborough County.
Htg/Cooling Saturation	Weighted average of heating and cooling saturation rates.
Total Degree Days	Sum of heating and cooling degree days (billing cycle adjusted).
Ind Prod Index	Industrial Production Index (1992 = 100).
¢/kWh	Cost per kWh for a given customer class adjusted for inflation.
Chg in ¢/kWh	Percent change in cost per kWh for a given customer class adjusted for inflation.
Trade Dummy Variable	Dummy variable representing import substitution of local basic industries production.

3. Trend Analysis

The role of trend analysis in the Tampa Electric Company forecasting process has changed as the stability of fuel prices and supplies has decreased. The present economic and political environment throughout the world has contributed to changing energy consumption patterns resulting in a need for more sophisticated forecasting techniques. Trending provides a useful check for the more intricate methods used by the company in developing the Customer, Demand, and Energy Forecast.

The primary strength of trend analysis is simplicity. When applied to a series with stable growth patterns, this method is easy to use and is readily understood by those outside the forecasting process. The need for historical data is minimal, compared to other methods, and the need for external forecasts is alleviated as time is the only predictive variable. However, weaknesses are also a function of this simplicity. The use of time as the only explanatory variable limits the ability of the process to reflect changing economic conditions. Given the limitations of this technique, it can still be used to identify time trends, and it provides a familiarity with the data that aids in evaluating forecasts from other methods. Trend analysis is applied to several variables including:

1. population;
2. residential customers;
3. system peak demand;
4. residential energy sales;
5. commercial energy sales;
6. industrial energy sales;
7. street lighting energy sales;
8. sales to public authorities; and
9. average usage per customer.

The implementation of trend analysis involves establishing a mathematical relationship between the independent variable (time) and the dependent variable. A forecast can be constructed by entering a future year into the equation. Evaluating the data over different time periods allows one to identify changes in the trend over time. Once trend estimates for the various components are established, they can be combined to yield a total sales forecast.

4. Phosphate Demand and Energy Analysis

Because Tampa Electric Company's phosphate customers are relatively few in number, the company's Marketing and Sales Department has obtained detailed knowledge of industry developments including:

1. knowledge of expansion and close-out plans;
2. familiarity with historical and projected trends;
3. personal contact with industry personnel;
4. governmental legislation;
5. familiarity with worldwide demand for phosphate products;
6. knowledge of phosphate ore reserves; and
7. correlation between phosphate rock production and energy consumption.

This department's familiarity with industry dynamics and their close working relationship with phosphate company representatives forms the basis for a survey of the phosphate customers to determine their future energy and demand requirements. This survey is the foundation upon which the phosphate forecast is based. Further inputs are provided by the multiregression model's phosphate energy equation and discussions with industry experts.

5. Conservation, Load Management and Cogeneration Programs

Tampa Electric has developed conservation, load management and cogeneration programs to achieve five major objectives:

1. to defer capital expansion, particularly production plant construction;
2. to reduce marginal fuel cost by managing energy usage during higher fuel cost periods;
3. to give customers some ability to control their energy usage and decrease their energy costs; and
4. to pursue the cost-effective accomplishment of ten-year demand and energy goals established by the Florida Public Service Commission (FPSC) for the residential and commercial/industrial sectors.
5. To achieve the comprehensive energy policy objectives as required by the Florida Energy Efficiency Conservation Act as enacted in guiding conservation policy for utilities in Florida.

The company's current DSM plan contains a mix of proven, mature programs that focus on the market place demand for their specific offerings. The following is a list that briefly describes the company's programs:

1. <u>Heating and Cooling</u> - Encourages the installation of high-efficiency heating and cooling equipment in existing residential homes.

2. Load Management - Reduces weather-sensitive heating, cooling, water heating and pool pump loads through a radio signal control mechanism. residential, commercial and industrial programs are offered.

3. Energy Audits - The program is a "how to" information and analysis guide for customers. Five types of audits are available to Tampa Electric customers; three types are for residential class customers and two types for commercial/industrial customers.

4. Ceiling Insulation - An incentive program for existing residential structures which will help to supplement the cost of adding additional insulation.

5. Commercial Indoor Lighting - Encourages investment in more efficient lighting technologies within existing commercial facilities.

6. Standby Generator - A program designed to utilize the emergency generation capacity of commercial/industrial facilities in order to reduce weather sensitive peak demand.

7. Conservation Value - Encourages investments in measures that are not sanctioned by other commercial programs.

8. Duct Repair - An incentive program for existing homeowners which will help to supplement the cost of repairing leaky ductwork of central air–conditioning systems.

9. Cogeneration - A program whereby large industrial customers with waste heat or fuel resources may install electric generating equipment, meet their own electrical requirements and/or sell their surplus to the company.

10. Commercial Cooling - Encourages the installation of high efficiency direct expansion (DX) commercial cooling equipment.

11. Energy Plus Home - Encourages the construction of residential dwellings at efficiency levels greater than current Florida building code baseline practices.

The programs listed above were developed to meet the FPSC demand and energy goals established in Docket No. 991791-EG, approved on March 28, 2000. The 2000 and 2001 demand and energy savings achieved by conservation and load management programs are listed in Table III-3.

TABLE III-3

Comparison of Achieved MW and GWh Reductions With Florida Public Service Commission Goals

Residential

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2000	12.1	16.7	72.5%	4.3	5.8	74.1%	11.6	10.3	112.6%
2001	24.7	32.2	76.7%	9.2	11.1	82.9%	26.0	20.0	130.0%

Commercial/Industrial

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2000	1.8	1.5	120.0%	5.2	3.5	148.6%	19.0	12.9	147.3%
2001	3.7	3.0	123.3%	9.1	6.9	131.9%	27.3	25.7	106.2%

Combined Total

	Winter Peak MW Reduction			Summer Peak MW Reduction			GWh Energy Reduction		
Year	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance	Total Achieved	Commission Approved Goal	% Variance
2000	13.9	18.2	76.4%	9.5	9.3	102.2%	30.6	23.2	131.9%
2001	28.4	35.2	80.7%	18.3	18.0	101.7%	53.3	45.7	116.6%

To support the demand and energy savings filed as part of its plan, Tampa Electric Company developed its Monitoring and Evaluation (M&E) plan in response to requirements filed in Docket No. 941173-EG. The M&E plan was designed to effectively accomplish the required objective with prudent application of resources. Generally speaking, the M&E plan has as its focus two distinct areas: process evaluation and impact evaluation. Process evaluation examines how well a program has been implemented including the efficiency of delivery and customer satisfaction regarding the usefulness and quality of the services delivered. Impact evaluation is an evaluation of the change in demand and energy consumption achieved through program participation. The results of these evaluations give Tampa Electric Company insight into the direction that should be taken to refine delivery processes, program standards, and overall program cost-effectiveness.

Wholesale Load

Tampa Electric's firm long-term wholesale sales consist of sales contracts with the City of Wauchula, Florida Municipal Power Agency, through which it serves the requirements of the City of Fort Meade, Florida Power Corp., the City of St. Cloud, and the Reedy Creek Improvement District. Since Tampa Electric's sales to Wauchula and FMPA will vary over time based on the strength of their local economies, a multiple regression approach similar to that used for forecasting Tampa Electric's retail load has been utilized. For the remaining wholesale customers, future sales for a given year are based on the specific terms of their contracts with Tampa Electric.

Base Case Forecast Assumptions

Retail Load

1. Detailed End-Use Model

Numerous assumptions are inputs to the detailed end-use model of which the more significant ones are discussed below.

Population/Residential Customers

The residential customer forecast is the starting point from which the demand and energy projections are developed. The most important factor in the customer forecast is the service area population estimate. The population estimate is based on Hillsborough County projections supplied by the University of Florida's Bureau of Economic and Business Research (BEBR), which are in the form of high, medium, and low forecasts. For the 2002-2011 period, Hillsborough County population is expected to increase at a 1.3% average annual rate and residential customers and expected increase at a 1.7% average annual rate.

Commercial and Industrial Employment

Commercial and industrial employment assumptions are utilized in computing energy and demand in their respective sectors. Forecasts from outside consulting firms provide input into formulating these assumptions. For the 2002-2011 period, commercial employment is assumed to rise at a 2.1% average annual rate while industrial employment growth of 0.4% per year is expected.

Per Capita Income, Housing Mix, Appliance Saturations

The stock of appliances, which comprises the nucleus of SHAPES' residential sector, is determined by multiplying the number of households by the saturation rate for each appliance. The assumptions for real per capita income growth and housing mix are critical in computing these saturations since many of the appliances are influenced by income levels and the type of housing (single, multi-family, mobile home) in the service area. The housing mix and per capita income growth rates for the local area are based on forecasts from outside consulting services. For the 2002-2011 period, real per capita income is expected to increase at a 2.7% average annual rate.

Price Elasticity/Price of Electricity

Price elasticity measures the rate of change in the demand for a product, electricity in this case, that results from a change in its relative price. The expected elasticity effect can be quantified by multiplying this factor by the assumed change in the real price of electricity. During the 1970s, price elasticity played a major role in slowing demand and energy growth due to the sharp increase in the price of electricity resulting from an explosion in fuel costs. Since 1981, an easing in fuel price pressures has been an important factor in keeping electricity cost changes below the general pace of inflation. Over the next decade, this pattern is expected to continue, as the price of electricity should increase at a rate slower than other products and services.

Appliance Efficiency Standards

Another factor influencing residential energy consumption is the movement toward more efficient appliances. The forces behind this development include market pressures for more energy-saving devices and the appliance efficiency standards enacted by the state and federal governments. The efficiency goals affect the usage associated with new additions to the appliance stock.

Weather

Since weather is the most difficult input to project, historical data is the major determinant in developing temperature profiles. For example, monthly profiles used in calculating energy consumption are based on ten years of historical data. In addition, the temperature profiles used in projecting the winter and summer system peak are based on an examination of the minimum and maximum temperatures for the past forty years plus the temperatures on peak days for the past fifteen to twenty years.

2. Multiregression Demand and Energy Model

The multiregression model utilizes assumptions which are common to SHAPES. These assumptions include future inputs for population, residential customers, income, saturation levels for air conditioners/heaters, and the price of electricity. In all cases where the multiregression and SHAPES models use common input variables, the assumptions for these inputs are the same and result in forecasts, which are consistent and comparable.

High and Low Scenario Forecasts

The base case scenario is tested for sensitivity to varying economic conditions and customer growth rates. The high and low peak demand and energy scenarios represent alternatives to the company's base case outlook. The high scenario represents more optimistic economic conditions in the areas of customers, employment and income. The expected customer and economic growth rates in the high scenario are 0.5% greater than in the base case, while the low scenario represents a less optimistic scenario with 0.5% less expected growth.

History and Forecast of Energy Use

A history and forecast of energy consumption by customer classification are shown in Schedules 2.1 - 2.3.

Retail Energy

For 2002-2011, retail energy sales are projected to rise at a 3.0% annual rate. The major contributors to growth will continue to be the commercial, governmental, and residential categories. As a group, these three sectors will be increasing at a 2.9% annual rate.

In contrast, industrial sales are expected to remain flat over this period. Non-phosphate industrial consumption will register annual gains over the coming years. However, this will be more than offset by a drop in phosphate sales due market conditions and the southward migration of mining activity.

The combination of service area income growth and a declining real price of electricity has resulted in rising average residential usage in recent years. Over the 2002-2011 period, usage is anticipated to maintain this upward path based on expectations of continuing economic gains and a downward drift in the real price of electricity.

Wholesale Energy

Wholesale energy sales to FPC, Wauchula, FMPA, St. Cloud, and Reedy Creek of 705 GWh are expected in 2002, 613 GWh in 2003 and 410 GWh in 2004. Sales are expected to remain in the 256-436 GWh range for 2005-2011.

History and Forecast of Peak Loads

Historical and base, scenario forecasts of peak loads for the summer and winter seasons are presented in Schedules 3.1 and 3.2, respectively. For the 2002-2011 period, Tampa Electric's base case retail firm peak demand for the winter and summer are expected to advance at annual rates of 3.0% and 3.2%, respectively. In addition, historical and base scenario forecasts of NEL are listed in Schedule 3.3.

Monthly Forecast of Peak Loads for Years 1 and 2

A monthly forecast of retail peak loads (MW) and net energy for load (GWh) for years 1 and 2 of the forecast is provided in Schedule 4 along with actual for 2001.

CHAPTER IV

FORECAST OF FACILITIES REQUIREMENTS

The proposed generating facility additions and changes shown in Schedule 8 integrate demand side management programs and alternative generation technologies with traditional generating resources to provide economical, reliable service to Tampa Electric Company's customers. To achieve this objective, various energy resource plan alternatives comprised of a mixture of generating technologies, purchased power, and cost-effective demand side management programs are developed. These alternatives are analyzed with existing generating capabilities to develop a number of energy resource options, which meet Tampa Electric's future system demand and energy requirements. A detailed discussion of Tampa Electric Company's integrated resource planning process is included in Chapter V.

The results of the analysis provide Tampa Electric Company with a plan that is cost-effective while maintaining system reliability and balancing other engineering, business, and industry issues. The new capacity additions resulting from the analysis are shown in Schedule 8. Additional capacity is planned for 2002, based on an analysis of system reliability, the incorporation of the FPSC demand side management goals, projected system demand and energy requirements, purchased power, and the existing Tampa Electric generating system. To meet the expected system demand and energy requirements over the next ten years, combustion turbines are planned for service in 2005, 2007, 2008, 2009 and 2010. Tampa Electric will increase the diversity of its generation mix with the repowering of Gannon Station. The station will be repowered with natural gas and renamed Bayside Power Station. The repowering will consist of the addition of three CT's and three HRSG's to supply steam to unit 5 steam turbine and four CT's and four HRSG's to supply steam to unit 6 steam turbine. The repowered units will be named Bayside 1 and 2 and fueled with natural gas. The units are scheduled to come on-line in May 2003 and May 2004. In addition, Gannon units 1 through 4 will be retired from coal operation by December 31, 2004. Hookers Point Station has an assumed retirement date of January 1, 2003. Some of the assumptions and information that impact the plan are discussed in the following sections. Additional assumptions and information are discussed in Chapter V.

Cogeneration

Tampa Electric Company plans for 435 MW of cogeneration capacity operating in its service area in 2002. Self-service capacity of 234 MW (net) is used by cogenerators to serve internal load requirements, 62 MW are purchased by Tampa Electric on a firm contract basis, and 5 MW are purchased on a non-firm, as-available basis. The remaining 133 MW of cogeneration capacity is contracted to other utilities and exports out of Tampa Electric's system.

Fuel Requirements

A forecast of fuel requirements and energy sources is shown in Schedule 5, Schedule 6.1 and Schedule 6.2, respectively. At present, Tampa Electric Company plans to continue to use coal as the primary fuel for most of its generating requirements between 2002 and 2003. After 2003, Tampa Electric will increase the diversity of its fuel supply with the repowering of the coal fired Gannon units 5 and 6 to the natural gas fired Bayside 1 and 2 combined cycle units. Tampa Electric has entered into a firm transportation contract with the Florida Gas Transmission (FGT) company for delivery of natural gas to the new Bayside units. The implementation of repowering these units will reduce Tampa Electric's coal generation from 87% in 2000 to 50% in 2005.

Environmental Considerations

Emissions reductions made since 2000 are largely the result of a cooperative effort between the Florida Department of Environmental Protection (DEP) and Tampa Electric. The effort resulted in a comprehensive emissions reduction plan, which was finalized with the DEP on December 6, 1999. Approximately one year later, on December 29, 2000, Tampa Electric reached a similar agreement with the U.S. Environmental Protection Agency (EPA). The efforts to reduce emissions from our facilities began long before our recent settlement with the EPA. Since 1990, Tampa Electric has reduced annual sulfur dioxide (SO_2) and nitrogen oxides (NO_x) emissions from our facilities by 126,835 and 27,877 tons, respectively.

Reductions in SO_2 emissions were primarily accomplished through the installation of flue gas desulfurization (scrubber) systems on Big Bend Units 1-3. Big Bend Unit 4 was originally constructed with a scrubber. Currently, the scrubbers at Big Bend Station remove more than 95% of the SO_2 emissions from the flue gas streams. In addition, reductions in NO_x have been accomplished through combustion tuning and optimization projects at Big Bend and Gannon Stations.

Particulate matter (PM) is controlled at Big Bend and Gannon Stations through the use of electrostatic precipitators, which remove more than 99.9% of the PM generated during the combustion process.

Significant reductions in emissions outlined in the Tampa Electric's agreements with the DEP and EPA will result from the ongoing repowering of Gannon Station and the installation of additional NO_x emissions controls on all Big Bend Units. By 2010, these projects will result in the additional phased reduction of SO_2 by 47,110 tons per year, NO_x by 45,940 tons per year and PM by 2,000 tons per year. In total, Tampa Electric's emission reduction initiatives will result in the reduction in SO_2, NO_x and PM emissions by 89%, 90% and 42%, respectively, below 1990 levels. With these improvements in place, all of Tampa Electric's facilities will meet the same standards required of new power generating facilities and help to significantly enhance the quality of the air in our community.

Interchange Sales and Purchases

Tampa Electric's long-term interchange sales include Schedule D, Partial Requirements service agreements with Florida Power Corporation, Reedy Creek Improvement District, FMPA, as well as the cities of St. Cloud, and Wauchula.

Tampa Electric has a long-term purchase power contract for capacity and energy with Hardee Power Partners Limited (a TECO Power Services Corporation). The contract involves a shared-capacity agreement with Seminole Electric Cooperative, whereby Tampa Electric plans for the full net capability (359 MW winter and 296 MW summer) of the Hardee Power Station during those times when SEC plans for the full availability of Seminole units 1 and 2 and the SEC Crystal River unit 3 allocation, and reduced availability during times when Seminole units 1 and 2 are derated or unavailable due to planned maintenance. Tampa Electric also has an additional long-term purchase power contract with Hardee Power Partners Limited for 90 MW winter and 72 MW summer of firm non-shared capacity. The contract began in May 2000 and expires in 2012. A firm capacity sale from Tampa Electric's Big Bend Station unit 4 is made available, on a limited energy usage basis, to Hardee Power Partners Limited for resale to Seminole Electric Cooperative, which expires at the end of 2002.

Tampa Electric has a firm system power call option from Florida Power Corporation for 150 MW from January 1, 2002 running through January 31, 2003. In addition, Tampa Electric has a purchase power agreement with Ringhaver Equipment Co. Power Division for firm capacity of 50 MW for the summer and winter of 2002. Tampa Electric also had a purchase agreement for firm capacity with Okeelanta from January 1, 2002 through March 31, 2002 providing 40 MW. Tampa Electric had a unit contingent call option on capacity and energy from Aquila's interest in the Cane Island unit 3 for 50 MW that began January 1, 2002 through February 28, 2002 and May 1, 2002 through August 31, 2002. Tampa Electric also had a second contingent call option with Aquila for 10 MW for the month of January 2002.

Wholesale power sales and purchases are included in Schedules 3.1, 3.2, 3.3, 4, 5, 6.1, 7.1, and 7.2.

Schedule 7.1

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
							Reserve Margin Before Maintenance			Reserve Margin After Maintenance	
Year	Total Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	QF MW	Total Capacity Available MW	System Firm Summer Peak Demand MW	MW	% of Peak	Scheduled Maintenance MW	MW	% of Peak
2002	3,567	618	(147)	62	4,100	3,426	674	20%	0	674	20%
2003	4,058	368	0	62	4,488	3,564	924	26%	0	924	26%
2004	4,629	368	0	62	5,059	3,685	1,374	37%	0	1,374	37%
2005	4,273	368	0	62	4,703	3,810	893	23%	0	893	23%
2006	4,273	368	0	62	4,703	3,935	768	20%	0	768	20%
2007	4,433	368	0	62	4,863	4,037	826	20%	0	826	20%
2008	4,593	368	0	62	5,023	4,162	861	21%	0	861	21%
2009	4,753	368	0	62	5,183	4,271	912	21%	0	912	21%
2010	4,913	368	0	47	5,328	4,390	938	21%	0	938	21%
2011	4,913	368	0	21	5,302	4,420	882	20%	0	882	20%

NOTE:
1. Per FPSC ruling (Docket No. 981890-EU, Order No. PSC-99-2507-S-EU, Issued December 22,1999) 15% Reserve Margin to be increased to 20% starting summer 2004.
2. Capacity import for 2002 through 2011 includes firm purchase power agreement with Hardee Power Partners of 368 MW. Capacity imports for 2002 also include Aquila (50 MW), Florida Power Corp. (150 MW), and Ringhaver Equipment Co. (50 MW).
3. Capacity export includes 145 MW of Big Bend 4 which will be sold to Hardee Power Partners, on a limited basis, for use by Seminole Electric Cooperative.
4. The QF column accounts for cogeneration that will be purchased under firm contracts.
5. Gannon unit 5 will have a winter / summer rating of 218 MW after its April 2002 maintenance outage.

* Values may be affected due to rounding.

Schedule 7.2

Forecast of Capacity, Demand, and Scheduled Maintenance at Time of Winter Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
	Total Installed Capacity	Firm Capacity Import	Firm Capacity Export	QF	Total Capacity Available	System Firm Winter Peak Demand	Reserve Margin Before Maintenance		Scheduled Maintenance	Reserve Margin After Maintenance	
Year	MW	MW	MW	MW	MW	MW	MW	% of Peak	MW	MW	% of Peak
2001-02	3,529	749	(147)	62	4,193	3,654	539	15%	0	539	15%
2002-03	3,695	599	0	62	4,356	3,784	572	15%	0	572	15%
2003-04	4,274	449	0	62	4,785	3,892	893	23%	0	893	23%
2004-05	4,401	449	0	62	4,912	4,032	880	22%	0	880	22%
2005-06	4,581	449	0	62	5,092	4,137	955	23%	0	955	23%
2006-07	4,761	449	0	62	5,272	4,268	1,004	24%	0	1,004	24%
2007-08	4,761	449	0	62	5,272	4,364	908	21%	0	908	21%
2008-09	4,941	449	0	62	5,452	4,500	952	21%	0	952	21%
2009-10	5,121	449	0	47	5,617	4,615	1,002	22%	0	1,002	22%
2010-11	5,301	449	0	21	5,771	4,716	1,055	22%	0	1,055	22%

NOTE:
1. Per FPSC ruling (Docket No. 981890-EU, Order No. PSC-99-2507-S-EU, Issued December 22,1999) 15% Reserve Margin to be increased to 20% starting summer 2004.
2. Capacity import for 2002 through 2011 includes firm purchase power agreement with Hardee Power Partners of 449 MW. Capacity imports for 2002 also include Aquila (60 MW), Florida Power Corp. (150 MW), Ringhaver Equipment Co. (50 MW) and Okeelanta (40 MW). Capacity imports for 2003 also include Florida Power Corp. (150 MW).
3. Capacity export includes 145 MW of Big Bend 4 which will be sold to Hardee Power Partners, on a limited basis, for use by Seminole Electric Cooperative.
4. The QF column accounts for cogeneration that will be purchased under firm contracts.
5. Gannon unit 5 will have a winter / summer rating of 218 MW after its April 2002 maintenance outage.

* Values may be affected due to rounding.

Schedule 8

Planned and Prospective Generating Facility Additions

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
				Fuel		Fuel Trans.		Const.	Commercial	Expected	Gen. Max.	Net Capability		
Plant Name	Unit No.	Location	Unit Type	Primary	Alternate	Primary	Alternate	Start Mo/Yr	In-Service Mo/Yr	Retirement Mo/Yr	Nameplate kW	Summer MW	Winter MW	Status
Polk	3	Polk Co.	CT	NG	LO	PL	TK	3/01	5/02	unknown	unknown	160	180	UC
Bayside	1	Hills. Co.	CC	NG	N	PL	N	4/01	5/03	unknown	unknown	709	797	UC
Bayside	2	Hills. Co.	CC	NG	N	PL	N	4/02	5/04	unknown	unknown	943	1045	UC
Polk	4	Polk Co.	CT	NG	LO	PL	TK	3/04	5/05	unknown	unknown	160	180	P
Polk	5	Polk Co.	CT	NG	LO	PL	TK	11/05	1/07	unknown	unknown	160	180	P
Polk	6	Polk Co.	CT	NG	LO	PL	TK	3/07	5/08	unknown	unknown	160	180	P
Future Unit	1	unknown	CT	NG	LO	PL	TK	3/08	5/09	unknown	unknown	160	180	P
Future Unit	2	unknown	CT	NG	LO	PL	TK	3/09	5/10	unknown	unknown	160	180	P

Note: Gannon units 1, 2, 3, and 4 will be retired from coal operations by 12/31/2004, but may be repowered with natural gas. Gannon unit 5 steam turbine will be repowere with three combustion turbines and renamed Bayside unit 1. Gannon unit 6 steam turbines will be repowered with four combustion turbines and renamed Bayside unit 2.

SCHEDULE 9

(Page 1 of 8)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 3
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	MAR 2001
	B. COMMERCIAL IN-SERVICE DATE	MAY 2002
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOx BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	UNDER CONSTRUCTION
(10)	CERTIFICATION STATUS	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	Construction Permits Obtained
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2003)	8%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,600 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	299.86
	DIRECT CONSTRUCTION COST ($/kW)	286.24
	AFUDC AMOUNT ($/kW)	13.62
	ESCALATION ($/kW)	0.00
	FIXED O&M ($/kW – Yr)	2.04
	VARIABLE O&M ($/MWH)	5.00
	K FACTOR	1.7048

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

SCHEDULE 9

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	BAYSIDE UNIT 1
(2)	CAPACITY	
	A. SUMMER	709
	B. WINTER	797
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	APR 2001
	B. COMMERCIAL IN-SERVICE DATE	MAY 2003
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	NONE
(6)	AIR POLLUTION CONTROL STRATEGY	SCR, DLN BURNERS
(7)	COOLING METHOD	ONCE THROUGH
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 213 ACRES
(9)	CONSTRUCTION STATUS	UNDER CONSTRUCTION
(10)	CERTIFICATION STATUS	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	Construction Permits Obtained
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	3.9
	FORCED OUTAGE RATE (FOR)	5
	EQUIVALENT AVAILABILITY FACTOR (EAF)	91
	RESULTING CAPACITY FACTOR (2004)	55%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	7,034 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	475.06
	DIRECT CONSTRUCTION COST ($/kW)	429.00
	AFUDC AMOUNT ($/kW)	36.19
	ESCALATION ($/kW)	9.87
	FIXED O&M ($/kW – Yr)	4.13
	VARIABLE O&M ($/MWH)	2.89
	K FACTOR	1.7586

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL GANNON OR BAYSIDE SITE.

SCHEDULE 9

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	BAYSIDE UNIT 2
(2)	CAPACITY	
	A. SUMMER	943
	B. WINTER	1045
(3)	TECHNOLOGY TYPE	COMBINED CYCLE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	APR 2002
	B. COMMERCIAL IN-SERVICE DATE	MAY 2004
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	NONE
(6)	AIR POLLUTION CONTROL STRATEGY	SCR, DLN BURNERS
(7)	COOLING METHOD	ONCE THROUGH
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 213 ACRES
(9)	CONSTRUCTION STATUS	UNDER CONSTRUCTION
(10)	CERTIFICATION STATUS	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	Construction Permits Obtained
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	3.9
	FORCED OUTAGE RATE (FOR)	5
	EQUIVALENT AVAILABILITY FACTOR (EAF)	91
	RESULTING CAPACITY FACTOR (2005)	40%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	7,130 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	346.75
	DIRECT CONSTRUCTION COST ($/kW)	291.91
	AFUDC AMOUNT ($/kW)	41.26
	ESCALATION ($/kW)	13.58
	FIXED O&M ($/kW - Yr)	2.54
	VARIABLE O&M ($/MWH)	2.95
	K FACTOR	1.7586

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL GANNON OR BAYSIDE SITE.

SCHEDULE 9

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 4
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	MAR 2004
	B. COMMERCIAL IN-SERVICE DATE	MAY 2005
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NO_x BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2006)	7%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,600 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	317.99
	DIRECT CONSTRUCTION COST ($/kW)	286.24
	AFUDC AMOUNT ($/kW)	11.54
	ESCALATION ($/kW)	20.21
	FIXED O&M ($/kW - Yr)	2.18
	VARIABLE O&M ($/MWH)	5.35
	K FACTOR	1.7048

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

SCHEDULE 9

(Page 5 of 8)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 5
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START-DATE	NOV 2005
	B. COMMERCIAL IN-SERVICE DATE	JAN 2007
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NO_x BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2008)	6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,600 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	323.63
	DIRECT CONSTRUCTION COST ($/kW)	286.24
	AFUDC AMOUNT ($/kW)	2.93
	ESCALATION ($/kW)	34.46
	FIXED O&M ($/kW - Yr)	2.29
	VARIABLE O&M ($/MWH)	5.62
	K FACTOR	1.7048

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

SCHEDULE 9

(Page 6 of 8)

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	POLK UNIT 6
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	MAR 2007
	B. COMMERCIAL IN-SERVICE DATE	MAY 2008
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NO_x BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA [2]	APPROXIMATELY 4,347 ACRES
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	CERTIFIED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2009)	6%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,600 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	332.19
	DIRECT CONSTRUCTION COST ($/kW)	286.24
	AFUDC AMOUNT ($/kW)	4.11
	ESCALATION ($/kW)	41.84
	FIXED O&M ($/kW - Yr)	2.35
	VARIABLE O&M ($/MWH)	5.76
	K FACTOR	1.7048

[1] BASED ON IN-SERVICE YEAR.
[2] REPRESENTS TOTAL POLK SITE.

SCHEDULE 9

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE UNIT 1
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	MAR 2008
	B. COMMERCIAL IN-SERVICE DATE	MAY 2009
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NOx BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2010)	7%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,600 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	345.35
	DIRECT CONSTRUCTION COST ($/kW)	286.24
	AFUDC AMOUNT ($/kW)	9.72
	ESCALATION ($/kW)	49.39
	FIXED O&M ($/kW – Yr)	2.41
	VARIABLE O&M ($/MWH)	5.91
	K FACTOR	1.7048

1 BASED ON IN-SERVICE YEAR.

SCHEDULE 9

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES
UTILITY: TAMPA ELECTRIC COMPANY

(1)	PLANT NAME AND UNIT NUMBER	FUTURE UNIT 2
(2)	CAPACITY	
	A. SUMMER	160
	B. WINTER	180
(3)	TECHNOLOGY TYPE	COMBUSTION TURBINE
(4)	ANTICIPATED CONSTRUCTION TIMING	
	A. FIELD CONSTRUCTION START DATE	MAR 2009
	B. COMMERCIAL IN-SERVICE DATE	MAY 2010
(5)	FUEL	
	A. PRIMARY FUEL	NATURAL GAS
	B. ALTERNATE FUEL	DISTILLATE OIL
(6)	AIR POLLUTION CONTROL STRATEGY	DRY LOW NO_x BURNER
(7)	COOLING METHOD	N/A
(8)	TOTAL SITE AREA	UNDETERMINED
(9)	CONSTRUCTION STATUS	PROPOSED
(10)	CERTIFICATION STATUS	UNDETERMINED
(11)	STATUS WITH FEDERAL AGENCIES	N/A
(12)	PROJECTED UNIT PERFORMANCE DATA	
	PLANNED OUTAGE FACTOR (POF)	1.9
	FORCED OUTAGE RATE (FOR)	3.4
	EQUIVALENT AVAILABILITY FACTOR (EAF)	94
	RESULTING CAPACITY FACTOR (2011)	7%
	AVERAGE NET OPERATING HEAT RATE (ANOHR) [1]	10,600 Btu/kWh
(13)	PROJECTED UNIT FINANCIAL DATA	
	BOOK LIFE (YEARS)	30
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW)	348.77
	DIRECT CONSTRUCTION COST ($/kW)	286.24
	AFUDC AMOUNT ($/kW)	5.42
	ESCALATION ($/kW)	57.11
	FIXED O&M ($/kW – Yr)	2.47
	VARIABLE O&M ($/MWH)	6.06
	K FACTOR	1.7048

1 BASED ON IN-SERVICE YEAR.

Status Report and Specifications of Proposed Directly Associated Transmission Lines

Point of Origin and Termination	Number of Circuits	Right-of-Way	Circuit Length	Voltage	Anticipated In-Service Date	Anticipated Capital Investment	Substations	Participation with Other Utilities
Gannon/Juneau Conversion	1	Possible road ROW required	16.5 mi	230 kV	Summer 2003	$13.0 million	2 - 230/69 kV autos at Juneau	None
Juneau/ Ohio/Sheldon Loop	1	Possible road ROW required	4.0 mi	230 kV	Fall 2003	$3.5 million	No new substations	None
Bayside - Chapman	1	No new right of way required	23.0 mi	230 kV	Summer 2005	$13.8 million	No new substations	None
Davis - Dale Mabry	1	No new right of way required	13.3 mi	230 kV	Summer 2006	$11.0 million	No new substations	None
Lithia - Wheeler	1	No new right of way required	11.0 mi	230 kV	Summer 2008	$8.5 million	Wheeler 230/69 kV Substation	None
Lithia - Davis	1	No new right of way required	14.4 mi	230 kV	Summer 2008	$9.0 million	No new substations	None

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CHAPTER V

OTHER PLANNING ASSUMPTIONS AND INFORMATION

Transmission Constraints and Impacts

Based on an assessment of the Tampa Electric transmission system using year 2001 Florida Reliability Coordinating Council (FRCC) databank models, no transmission constraints, which violate the criteria stated in the Generation and Transmission Reliability Criteria section of this document, were identified.

Expansion Plan Economics and Fuel Forecast

The overall economics and cost-effectiveness of the plan were analyzed as stated in Tampa Electric's Integrated Resource Planning process, discussed in detail later in the chapter. As part of this process, Tampa Electric evaluated various planning and operating alternatives to current operations, with objectives ranging from meeting compliance requirements in the most cost-effective and reliable manner to maximizing operational flexibility and minimizing operational costs. Load forecasts used in the analysis are from the company's 2002 Fuel and Interchange Forecast.

The study was also updated from the most current planning assumptions including minimum reliability criteria of 15 percent firm reserve margin to 20 percent with a minimum 7 percent reserve margin from supply-side resources based on the stipulation between the FPSC and the three Peninsular Florida investor owned utilities. This was a result of Docket No. 981890-EU, Order No. PSC-99-2507-S-EU, approved in December 1999.

Early in the study process, many alternatives were screened on a qualitative and quantitative basis to determine those alternatives that were the most feasible options, overall. Those alternatives that failed to meet environmental acceptability, economics, technical feasibility, operational criteria, maintainability and reliability were eliminated. This phase of the study resulted in a set of feasible alternatives that were considered in the more detailed economic analysis.

Fuel commodity price for actual and forecasted data for the purpose of deriving base, high and low forecast pricing is done by careful analysis of historical, current and previous price forecasts obtained by various consultants and agencies. These sources include the Energy Information Administration, American Gas Association, Cambridge Energy Research Associates, Resource Data International, Coal Markets Weekly, Coal Daily, Energy Ventures Analysis, Inc., and coal, oil, natural gas, and propane pricing publications and periodicals which include: Coal Outlook, Inside FERC, Natural Gas Week, Platt's Oilgram, and the Oil and Gas Journal.

The high and low fuel price projections represent alternative forecasts to the company's base case outlook. The high and low price projection represents the effect of oil and natural gas prices escalating 10% above or below the base case and escalating at a slightly higher or lower escalation rate on a monthly basis for the year 2002. Annual high and low case price projections after 2002 are based on the company's internal general approach using information provided by consultants combined with internal fuel markets analysis.

Only base case forecasts are prepared for coal fuels because of the fuels relatively low price volatility. Base case analysis and forecasts include a large number of coal sources and diverse qualities. The individual price forecasts contained within the base forecast capture the market pressures and sensitivities that would otherwise be reflected in high and low case scenarios.

Generating Unit Performance Modeling

Tampa Electric Company models generating unit performance in the Generation and Fuel (GAF) module of STRATEGIST, a computer model developed by New Energy Associates. This module is a tool to evaluate long-range system operating costs associated with particular generation expansion plans. Generating units in the GAF are characterized by several different performance parameters. These parameters include capacity, heat rate, unit derations, planned maintenance weeks, and unplanned outage rates. The unit performance projections that are modeled are based on historical data trends, engineering judgement, time since last planned outage, and recent equipment performance. Planned outage projections are modeled two ways. The first five years of planned outages are based on a forecasted outage schedule, and the planned outages for the balance of the years are based on an average of the first five years.

The five-year outage schedule is based on unit-specific maintenance needs, material lead-time, labor availability, budget constraints, and the need to supply our customers with power in the most economical manner. Unplanned outage rate projections are based on an average of three years of historical data adjusted, if necessary, to account for current unit conditions.

Financial Assumptions

Tampa Electric makes numerous financial assumptions as part of the preparation for its Ten-Year Site Plan process. These assumptions are based on the current financial condition of the company, the market for securities, and the best available forecast of future conditions. The primary financial assumptions include the FPSC-approved Allowance for Funds Used During Construction (AFUDC) rate, capitalization ratios, financing cost rates, tax rates, and FPSC-approved depreciation rates.

- Per the Florida Administrative Code, an amount for AFUDC is recorded by the company during the construction phase of each capital project. This rate is set by the FPSC and represents the cost of money invested in the applicable project while it is under construction. This cost is capitalized, becomes part of the project investment, and is recovered over the life of the asset. The AFUDC rate assumed in the Ten-Year Site Plan represents the company's currently approved AFUDC rate.

- The capitalization ratios represent the percentages of incremental long-term capital that are expected to be issued to finance the capital projects identified in the Ten-Year Site Plan.

- The financing cost rates reflect the incremental cost of capital associated with each of the sources of long-term financing.

- Tax rates include federal income tax, state income tax, and miscellaneous taxes including property tax.

- Depreciation represents the annual cost to amortize the total original investment in a plant over its useful life less net salvage value. This provides for the recovery of plant investment. The assumed book life for each capital project within the Ten-Year Site Plan represents the average expected life for that type of investment.

Integrated Resource Planning Process

Tampa Electric Company's Integrated Resource Planning process was designed to evaluate demand side and supply side resources on a fair and consistent basis to satisfy future energy requirements in a cost-effective and reliable manner, while considering the interests of utility customers and shareholders.

The process incorporates a reliability analysis to determine timing of future needs, and an economic analysis to determine what resource alternatives best meet future system demand and energy requirements. Initially, a demand and energy forecast, which excludes incremental DSM programs, is developed. Then a supply plan based on the system requirements, which excludes incremental DSM, is developed. This interim supply plan becomes the basis for potential avoided unit(s) in a comprehensive cost-effective analysis of the DSM programs. Once the cost-effective DSM programs are determined, the system demand and energy requirements are revised to include the effects of these programs on reducing system peak and energy requirements. The process is repeated to incorporate the DSM programs and supply side resources. The same planning and business assumptions are used to develop numerous combinations of DSM and supply side resources that account for variances in both timing and type of resources added to the Tampa Electric Company system.

The cost-effectiveness of DSM programs is based on the following standard Commission tests: the Rate Impact Measure (RIM), the Total Resource Cost (TRC), and the Participants Tests. Using the Commission's standard cost-effectiveness methodology, each measure is evaluated based on different marketing and incentive assumptions. Utility plant avoidance assumptions for generation, transmission, and distribution are used in this analysis. All measures that pass the RIM, TRC, and Participants Tests in the DSM analysis are considered for utility program adoption. Each adopted measure is quantified into annual kW/kWh savings and is reflected in the demand and energy forecast. Measures with the highest RIM values are generally adopted first. Tampa Electric Company evaluates DSM measures using a spreadsheet that comports with Rule 25-17.008, F.A.C., and the Commission's prescribed cost-effectiveness methodology.

Generating resources to be considered are determined through an alternative technology screening analysis, which is designed to determine the economic viability of a wide range of generating technologies for the Tampa Electric Company service area. Geographic viability, weather conditions, public acceptance, economics, lead-time, environmental acceptability, safety, and proven demonstration and commercialization are used as criteria to screen the generating technologies to a manageable number.

The technologies, which pass the screening, are included in a supply side analysis, which examines various supply side alternatives for meeting future capacity requirements. These include modifying existing units by repowering or over-pressure operation and delayed retirements. Other supply resources such as constructing new unit additions, firm power purchases from other generating entities, joint ownership of generating capacity, and modifications of the transmission system to increase import capability are included in the analysis.

Tampa Electric Company uses the PROVIEW module of STRATEGIST, to evaluate the supply side resources. PROVIEW uses a dynamic programming approach to develop an estimate of the time and type of capacity additions, which would most economically meet the system demand and energy requirements. Dynamic programming compares all feasible combinations of generating unit additions, which satisfy the specified reliability criteria, and determines the schedule of additions, which have the lowest revenue requirements. The model uses production costing analysis and incremental capital and O&M expenses to project the revenue requirements used to rank each plan.

A detailed cost analysis for each of the top ranked resource plans are performed using the Capital Expenditure and Recovery module and the Generation and Fuel module of

A detailed cost analysis for each of the top ranked resource plans are performed using the Capital Expenditure and Recovery module and the Generation and Fuel module of STRATEGIST. The capital expenditures associated with each capacity addition are obtained based on the type of generating unit, fuel type, capital spending curve, and in-service year. The fixed charges resulting from the capital expenditures are expressed in present worth dollars for comparison. The fuel and the operating and maintenance costs associated with each scenario are projected based on economic dispatch of all the energy resources on our system. The projected operating expense, expressed in present worth dollars, is combined with the fixed charges to obtain the total present worth of revenue requirements for each alternative plan.

Strategic Concerns

Strategic concerns affect the type, capacity, and/or timing of future generation resource requirements. These concerns such as competitive pressures, environmental legislation, and plan acceptance are not easily quantified. These strategic concerns and economic analysis are combined to ensure that an economically viable expansion plan is selected which has the flexibility for the company to respond to future technological and economic changes.

The results of the Integrated Resource Planning process provide Tampa Electric Company with a plan that is cost-effective while maintaining flexibility and adaptability to a dynamic regulatory and competitive environment. The new capacity additions are shown in Schedule 8. To meet the expected system demand and energy requirements over the next ten years and cost-effectively maintain system reliability, combustion turbines are planned for May 2002, May 2005, January 2007, May 2008, May 2009 and May 2010. The Gannon repowering to Bayside is planned for May 2003 and May 2004. For the purposes of this study, Hookers Point Station is assumed to be retired in January of 2003. Tampa Electric's long-term purchased power contract, which began in the summer of 2000 for Hardee Power Partners Limited, has increased to 368 MW summer net capability and 449 MW winter net capability for the entire study period.

Generation and Transmission Reliability Criteria

Generation

As part of the stipulation reached in Docket No. 981890-EU, Generic Investigation into the Aggregate Electric Utility Reserve Margins Planned for Peninsular Florida, the minimum firm Reserve Margin adopted by Tampa Electric has been voluntarily adjusted from 15% to 20%. As part of the stipulation, Tampa Electric agreed to achieve the planned 20% reserve margin criterion over a transition period of four years. Thus, Tampa Electric will reach a planned reserve margin of 20% by the summer of 2004 (Order No. PSC-99-2507-S-EU). In addition, Tampa Electric has further adopted a 7% minimum summer supply-side reserve margin, which will be transitioned into the planning process by the summer of 2004.

Tampa Electric's approach to calculating percent reserves are consistent with that outlined in the settlement agreement incorporated. The calculation of the minimum 20% reserve margin employs an industry accepted method of using total available generating and firm purchased power capacity (capacity less planned maintenance and contracted unit sales) and subtracting the annual firm peak load, then dividing by the firm peak load, and multiplying by 100%. Since the reserve margin calculation assumes no forced outages, Tampa Electric includes the Hardee Power Station in its available capacity. Contractually, Hardee Power Station is planned to be available to Tampa Electric at the time of system peak. Also, the capacity dedicated to any firm unit or station power sales at the time of system peak is subtracted from Tampa Electric's available capacity.

Tampa Electric's summer supply-side reserve margin is calculated by dividing the difference of projected supply-side resources and projected total peak demand by the forecasted firm peak demand. The total peak demand includes the summer firm peak demand, and interruptible and load management loads.

Transmission

The following criteria are used as guidelines for proposing system expansion and/or improvement projects. A detailed engineering study including risk analysis must be performed prior to making a prudent decision to initiate a project.

Tampa Electric Company complies with the planning criteria contained in Section V of the FRCC System Planning Committee Handbook. In addition, Tampa Electric's specific criteria for normal system operation and single contingency operation are applied as follows:

Generation Dispatch Modeled

The generation dispatched in the planning models is dictated on an economic basis and is calculated by the Economic Dispatch (ECDI) function of the PSS/E loadflow software. The ECDI function schedules the unit dispatch so that the total generation cost required to meet the projected load is minimized. This is the generation scenario contained in the power flow cases submitted to fulfill the requirements of FERC Form 715 and the Florida Reliability Coordinating Council (FRCC).

Since unplanned and planned unit outages can result in a system dispatch that varies significantly from a base plan, bulk transmission planners also investigate several scenarios that may stress Tampa Electric's transmission system. These additional generation sensitivities are analyzed to ensure the integrity of the bulk transmission system under maximized bulk power flows.

Transmission System Planning Loading Limits Criteria

Tampa Electric follows the FRCC planning criteria as contained in Section V of the FRCC System Planning Committee Handbook. In addition to FRCC criteria, Tampa Electric utilizes company-specific planning criteria.

The following table summarizes the thresholds, which alert planners to problematic transmission lines and transformers.

Transmission System Loading Limits	
Transmission System Conditions	**Maximum Acceptable Loading Limit for Transformers and Transmission Lines**
All elements in service	100%
Single Contingency (pre-switching)	115%
Single Contingency (post-switching)	100%
Bus Outages (pre-switching)	115%
Bus Outages (post-switching)	100%

The transmission system is planned to allow voltage control on the 13.2 kV distribution buses between 1.023 and 1.043 per unit. For screening purposes, this criterion can be approximated by the following transmission system voltage limits.

Transmission System Voltage Limits			
Transmission System Conditions	**Industrial Substation Buses at point-of- service**	**69 kV Buses**	**138 kV and 230 kV Buses**
Single Contingency (pre-switching)	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 - 1.060 p.u.
Single Contingency (post-switching)	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 - 1.060 p.u.
Bus Outages	0.925 - 1.050 p.u.	0.925 - 1.050 p.u.	0.950 - 1.060 p.u.

Available Transmission Transfer Capability (ATC) Criteria

Tampa Electric Company complies with the FRCC ATC calculation methodology as well as the principles contained in the NERC ATC Definitions and Determinations document.

Transmission Planning Assessment Practices

Base Case Operating Conditions

The Transmission Planning department ensures that the Tampa Electric Company transmission system can support peak and off-peak system load levels without violation of the loading and voltage criteria stated in the Generation and Transmission Reliability Criteria section of this document.

Single Contingency Planning Criteria

The Tampa Electric Company transmission system is designed such that any single branch (transmission line or autotransformer) can be removed from service at any load level without violation the criteria stated in the Generation and Transmission Reliability Criteria section of this document.

Multiple Contingency Planning Criteria

Double contingencies involving two branches out of service simultaneously are analyzed at 70% of peak load level. The Tampa Electric Company transmission system is designed such that these double contingencies do not cause violation of FRCC criteria.

First Contingency Total Transfer Capability Considerations

The following First Contingency Total Transfer Capability (FCTTC) limits for Tampa Electric Company's multiple-circuit corridors must be observed:

Tie Line Corridor	FCTTC
Lake Tarpon - Sheldon Rd. 230 kV (FPC)	1,100 MVA
Big Bend - Manatee 230 kV (FPL)	1,550 MVA

Transmission Construction and Upgrade Plans

A detailed list of the construction projects can be found in Chapter IV, Schedule 10. This list represents the latest transmission expansion plan available. However, due to the timing of this document in relationship to our internal planning schedule, this plan may change in the near future.

Supply Side Resources Procurement Process

Tampa Electric Company will manage the procurement process in accordance with established policies and procedures. Prospective suppliers of supply side resources as well as suppliers of equipment and services will be identified using various data base resources and competitive bid evaluations, and will be used in developing award recommendations to management.

This process will allow for future supply side resources to be supplied from self-build, purchase power, or competitively bid third parties. Consistent with company practice, bidders will be encouraged to propose incentive arrangements that promote development and implementation of cost savings and process improvement recommendations. The procurement process will also demonstrate continued positive efforts by Tampa Electric to include minority, small, and women-owned businesses. Goals will be established and tracked to measure opportunities and awards realized by these firms.

DSM Energy Savings Durability

Tampa Electric Company identifies and verifies the durability of energy savings from its conservation and DSM programs by several methods. First, Tampa Electric Company has established a monitoring and evaluation process where historical analysis identifies the energy savings. These include:

(1) end-use sub-metering of survey samples to identify savings achieved in residential duct repair and commercial indoor lighting programs;

(2) periodic notch test, for residential load management (Prime Time) to confirm the accuracy of Tampa Electric Company's load reduction estimation formulas;

(3) billing analysis of program participants compared to control groups to minimize the impact of weather abnormalities; and

(4) in commercial programs such as Standby Generator and C/I Load Management, the reductions are verified through submetering of those loads under control to determine participant incentives relative to demand and energy savings.

Secondly, the programs are designed to promote the use of high-efficiency equipment having permanent installation characteristics. Where programs promote the installation of energy efficient measures or equipment (heat pumps, hard-wired lighting fixtures, ceiling insulation, air distribution system repairs), program standards require they be of a permanent nature. For example, the company's Commercial Indoor Lighting Program requires full-fixture replacement or hard- wiring of fixture replacements.

Smart Source – Tampa Electric's Green / Renewable Energy Program

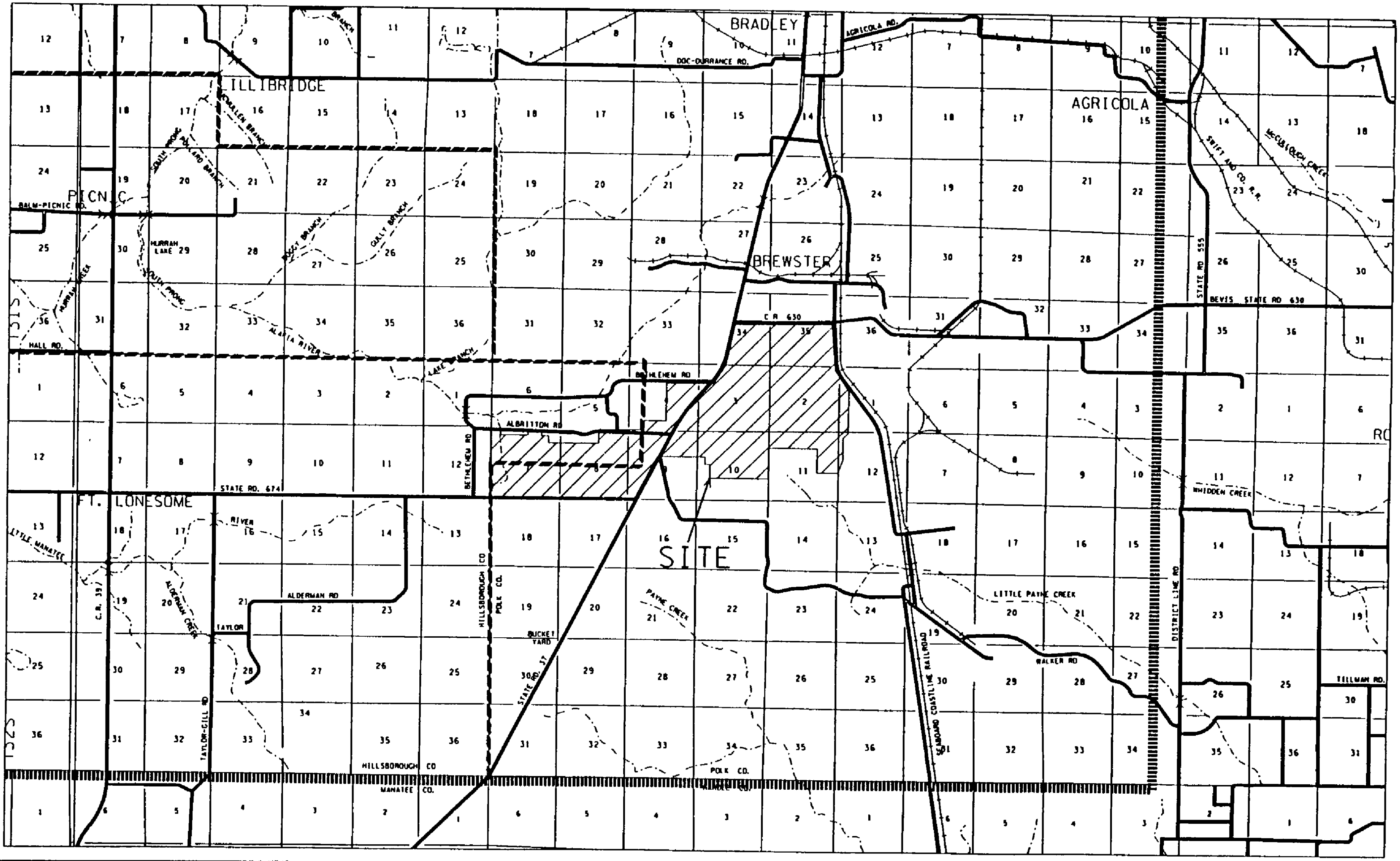
Smart Source generation mix consists of an 18kW photovoltaic array installed at the Museum of Science and Industry (MOSI), biomass (wood derived fuels) co-fired with coal in Gannon Unit Three's Cyclone unit and biomass which is gasified at Polk Power Station. The level of generation from biomass is contingent on the number of program subscribers and system operational needs.

CHAPTER VI

ENVIRONMENTAL AND LAND USE INFORMATION

The future generating capacity additions identified in Chapter IV will occur at the existing Gannon Station (to be renamed Bayside Power Station) and the existing Polk Power Station. The Gannon/Bayside Power Station site is located in Hillsborough County on Port Sutton Road (See Figure VI-2) and the Polk Power Station site is located in southwest Polk County close to the Hillsborough and Hardee County lines (See Figure VI-1). Both facilities are currently permitted as existing power plant sites. Additional land use requirements and/or alternative site locations are not currently under consideration.

FIGURE VI-1



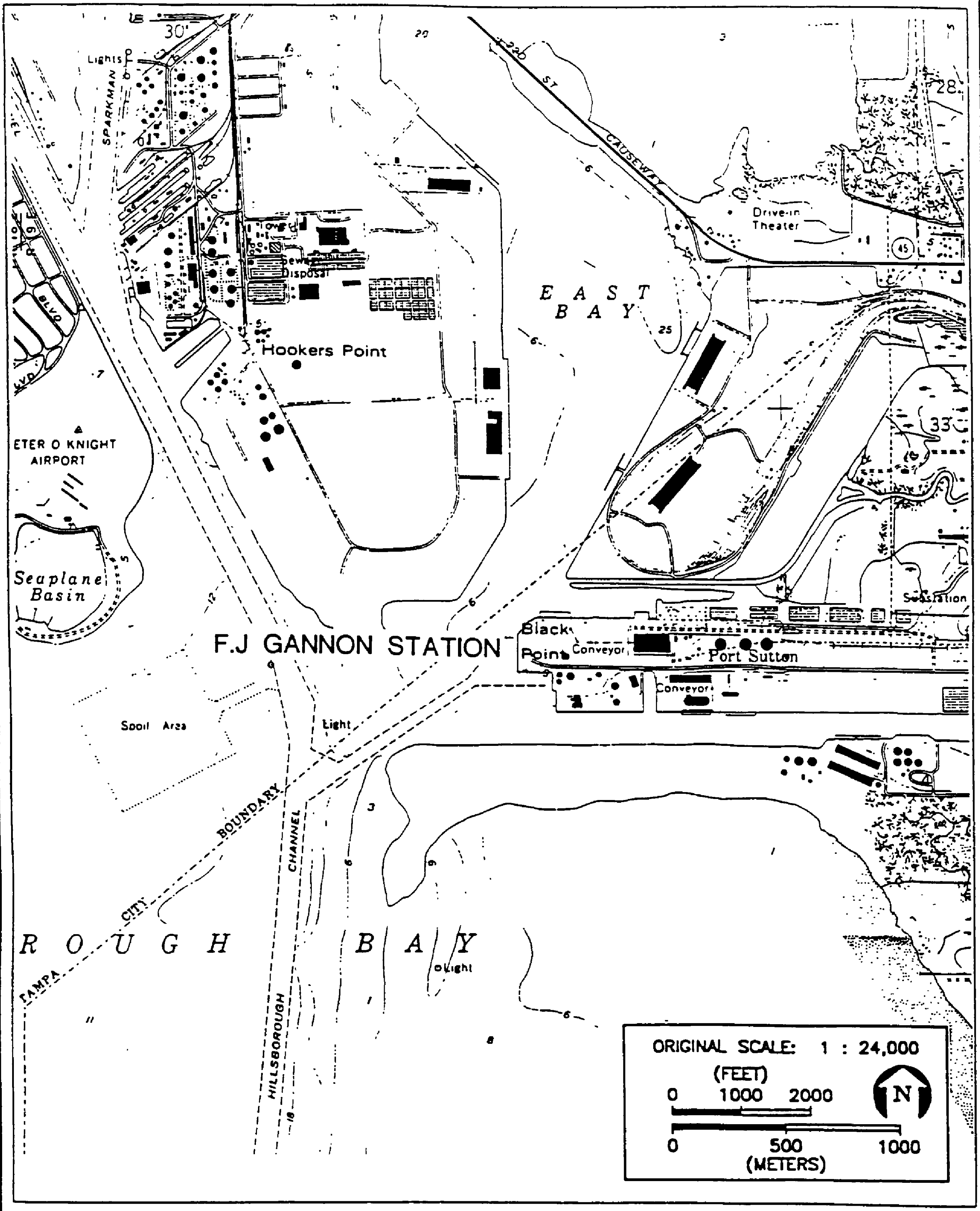
SITE LOCATION OF POLK POWER STATION

SOURCES: FDOT MAP, FLA, ECT

TAMPA ELECTRIC COMPANY

TEN-YEAR SITE PLAN
FOR ELECTRICAL GENERATING FACILITIES
AND ASSOCIATED TRANSMISSION LINES

FILE NAME 403020.DGN
REVISION 3/9/2000 MMS



F.J. GANNON STATION AREA MAP

Sources: USGS Quad, Tampa, FL 1981.

Figure VI-2

TAMPA ELECTRIC