BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for Determination of Need of Hines Unit 2 Power Plant	)))	Docket No.: 001064-EI Submitted for Filing: October 18, 2000

FLORIDA POWER CORPORATION'S THIRD REQUEST FOR CONFIDENTIAL CLASSIFICATION

Florida Power Corporation ("FPC" or the "Company"), pursuant to Section 366.093, Fla. Stats., and Rule 25-22.006, F.A.C., requests confidential classification of certain documents provided the Staff in response to Staff's Request for Documents to FPC. Those documents are identified by bates numbers FPC001-019, FPC032, FPC040, FPC148-149, FPC154-155, FPC173-177, FPC178-210, FPC212-233, FPC234, FPC235-251, and FPC296-299. These documents have been provided by FPC to Staff in FPC's response to Staff's Request for Documents and they are being filed under seal with the Florida Public Service Commission ("PSC" or the "Commission") because they contain proprietary, confidential business information which has not been made public.

Introduction

FPC's confidential documents fall into one of four categories: confidential bidder information (bates numbers FPC-001-019, FPC212, FPC234, and FPC235-251), third party proprietary information (bates numbers FPC040, FPC148-149, FPC154-155, and FPC173-177), proprietary contract information (bates numbers FPC032, FPC178-210, and FPC213-233), and confidential management information (FPC296-299). We will address each category in turn.

The Confidentiality of the Bids

In its RFP, the Company provided for the confidentiality of the bids it received in response to its RFP (along with any other information provided by the bidders during the course of the Company's evaluation of their proposals). Two bidders submitted proposals for FPC's consideration. Both bidders requested confidential treatment for the terms of their proposals. As a result, the Company has treated the bidders' proposals as private, confidential information and the Company has not disclosed them to the public.

The documents bearing bates numbers FPC-001-019, FPC212, FPC234, and FPC235-251 contain information provided by the bidders in response to FPC's RFP that the bidders designated as confidential. Accordingly, FPC has treated the information as confidential, has restricted access to the information within the Company to those who needed the information to perform their responsibilities for the Company, and has not made the information public. (Aff. of Michael D. Rib, pp. 2-3).

The Company requested confidential classification of the bids and bidder information identified in FPC's evaluation of the bids in its request for confidential classification filed with the Commission on August 7, 2000. On October 16, 2000, an Order was entered granting FPC's request for confidential classification with respect to the bidders' information and FPC's evaluation of the bids. The documents identified by bates number in the preceding paragraph contain the same information and, for the same reasons provided in its earlier request for confidential classification, the supporting affidavit of Michael D. Rib, and now the Order granting that earlier request, as well as the affidavit of Michael D. Rib in support of FPC's Third Request for Confidential Classification filed herewith, FPC requests confidential classification for these documents.

Third Party Proprietary Information

The documents bearing bates numbers FPC040, FPC148-149, and FPC154-155 contain sensitive, proprietary information provided to FPC by FPC's equipment supplier and potential gas transportation suppliers for the Hines 2 power unit. The documents with bates numbers FPC173-177 contains proprietary modeling formats belonging to one of FPC's system model providers. In both cases, the information is not public and FPC, pursuant to its understanding with the providers of this information, has treated and continues to treat the information as confidential. FPC requests confidential classification for the documents bearing bates numbers FPC040, FPC148-149, FPC154-155 and FPC173-177 because they contain confidential, sensitive proprietary business information belonging to third parties who provided the documents or information to FPC with the express understanding that it would be kept confidential.

Subsection 366.093(1) provides that "any records received by the Commission which are shown and found by the Commission to be proprietary confidential business information shall be kept confidential and shall be exempt from [the Public Records Act]." Proprietary confidential business information means information that is (i) intended to be and is treated as private, confidential information by the Company, (ii) because disclosure of the information would cause harm, (iii) either to the Company's ratepayers or the Company's business operations, and (iv) the information has not been voluntarily disclosed to the public. § 366.093(3), Fla.Stats.

Public disclosure of this proprietary third party information would harm the Company and its ratepayers. This information, or information like it, is frequently obtained or used during the course of the Company's operations and it is necessary to the efficient and effective operation of the Company's system. (Id., ¶ 9). Public disclosure of the information could undermine the ability of the Company to obtain the information in the future or cause the suppliers to impose even more restrictive terms on the receipt and use of such information. (Id.). Such disclosure might subject the Company to claims by the third party providers as well. (Id.). In either event, the Company and its ratepayers will suffer.

For these reasons, access within the Company to such information is restricted to those employees who need the information to perform their responsibilities for the Company. At no time is the information provided to the public. Accordingly, FPC requests confidential classification for the documents bearing bates numbers FPC040, FPC148-149, FPC154-155 and FPC173-177.

Proprietary Contract Information

The documents bearing bates numbers FPC178-210 contain the confidential, proprietary contract data between FPC and its equipment supplier for the Hines 2 power plant. The documents with bates numbers FPC032 and FPC213-233 are detailed financial pro formas containing information that embodies confidential, proprietary contract and variable operation and maintenance information provided to FPC by FPC's equipment supplier. Both sets of documents contain confidential, proprietary information.

As noted above, Section 366.093, Fla. Stats., provides that proprietary, confidential business information is (i) intended to be and is treated as private, confidential information by the Company, (ii) because disclosure of the information would cause harm, (iii) either to the Company's ratepayers or the Company's business operations, and (iv) the information has not been voluntarily disclosed to the public. § 366.093(3), Fla.Stats. More to the point, contract or bid information the "disclosure of which would impair the efforts of the public utility or its affiliates to contract for goods or services on favorable terms" is specifically defined as proprietary confidential business information. § 366.093(3)(d), Fla.Stats.

The contract and technical terms between FPC and its equipment suppliers fit this statutory definition of proprietary confidential business information. Accordingly, FPC's documents containing the information, directly or indirectly, are entitled to protection under Section 366.093 and Rule 25-22.006, F.A.C.

The very purpose of FPC's negotiations with its equipment suppliers is to obtain potentially favorable contract terms for FPC and its ratepayers. FPC endeavors at all times to negotiate contract terms that will offer lower cost resources or provide more economic value to FPC and its ratepayers. In order to negotiate and obtain such favorable terms, however, FPC must be able to assure potential suppliers that the terms of their negotiations and contracts will be kept confidential.

Without the assurance of confidentiality for the negotiations and the terms of contracts with suppliers, the utility's "efforts ... to contract for goods or services on favorable terms" will be impaired. §366.093, Fla.Stats. Indeed, if such proprietary contract information is not kept confidential, and potential suppliers know that the negotiations and terms of their contracts or bids are subject to public disclosure, they will be less willing to make concessions on price, delivery, and other contract terms. (Aff. of Michael D. Rib, ¶ 13). Rather than make such concessions known to their competitors or other potential customers, thus impairing their ability to compete or negotiate more favorable terms in the future with other customers, they will refuse to negotiate with the Company on such terms at all. (Id.). Or, suppliers who otherwise would have submitted bids to, or entered into negotiations with, the Company might decide not to do so, if there is no assurance that their proposals would be protected from disclosure. (Id.). In either event, the Company will be able to obtain equipment or services only upon less favorable terms than it otherwise would have if the parties were assured that the terms of their negotiations or contract proposals would remain confidential.

For all these reasons, FPC has treated and continues to treat this information as confidential, especially its proprietary contract information. (Id. ¶ 12). Access to the information is restricted within FPC to those employees who need the information to perform their duties and responsibilities with the Company. At no time has such proprietary contract information ever been made public. (Id.).

Accordingly, for each of the foregoing reasons, FPC requests confidential classification for the documents bearing bates numbers FPC032, FPC178-210, and FPC213-233 that were produced by FPC in response to Staff's Request for Documents to FPC.

Confidential Management Information

The documents bearing bates numbers FPC296-299 contain confidential, sensitive management information with respect to the proprietary contract information mentioned above and the internal financial assessment of the Hines 2 power plant. This is confidential, proprietary business information.

The public disclosure of such information will harm FPC and its ratepayers. (Id. ¶ 13). Such disclosure will undermine the ability of the Company to make such decisions in the future on behalf of the Company and its ratepayers. No Company would document such proprietary business and financial information for its management if it will be forced to make such information public. (Id.).

The Company certainly treats such information confidentially. Very few employees were involved in the preparation of the document for management, access was restricted to management until a decision was made, and it was not disseminated within the Company after that decision was made. (Id. ¶ 12). It has never been made public. (Id.).

For these reasons, FPC requests confidential classification for the documents bearing bates numbers FPC296-299 that were produced by FPC in response to Staff's Request for Documents to FPC.

Conclusion

Attachment A hereto contains a justification matrix supporting FPC's third request for confidential classification of the confidential documents provided the Staff in response to Staff's Request for Documents to FPC. The confidential information is identified by document, page, and/or line, where appropriate (for example, in place of certain documents in FPC's response to Staff's Request for Documents to FPC, which would contain nothing but blank pages if the proprietary, confidential business information was redacted, FPC has included a single page for the confidential classification). FPC respectfully requests that certain documents provided by FPC in response to Staff's Request for Documents to FPC identified by bates number in this request for confidential classification, which contain confidential, proprietary information, be classified as confidential for the reasons set forth above.

Respectfully submitted this 18th day of October, 2000.

Gary L. Sasso
J. Michael Walls
Jill H. Bowman
Carlton Fields
P. O. Box 2861
St. Petersburg, Florida 33731-2861
Telephone: (727) 821-7000
Facsimile: (727) 822-3768

and

Robert A. Glenn
Director, Regulatory Counsel Group
Florida Power Corporation
P.O. Box 2861
St. Petersburg, FL 33731
Telephone: (727) 820-5184
Facsimile: (727) 820-5519

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT a true and correct copy of the foregoing has been furnished by Federal Express to Deborah Hart, Esq., as counsel for the Public Service Commission, and by U.S. Mail to all other interested parties of record as listed below on this 17th of October, 2000.

Attorney

PARTIES OF RECORD:

Deborah Hart, Esq.
Division of Legal Services
Florida Public Service Commission
Gunter Building
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Buck Oven
Siting Coordination Office
Department of Environmental Protection
2600 Blairstone Road
Tallahassee, FL 32301

Myron Rollins
Black & Veatch
P.O. Box 8405
Kansas City, MO 64114

Paul Darst
Strategic Planning
Department of Community Affairs
2740 Centerview Drive
Tallahassee, FL 32399-2100

ATTACHMENT A		
DOCUMENT	**PAGE/LINE**	**JUSTIFICATION**
FPC's Response to Staff's Request for Documents to FPC, bates numbers FPC001-019, FPC212, FPC234, and FPC235-251	All	§366.093(3)(d). This is information concerning the bids in response to the Request for Proposals ("RFP"), the disclosure of which would impair the utility's efforts to contract for such services on favorable terms.
FPC's Response to Staff's Request for Documents to FPC, bates numbers FPC040, FPC148-149, FPC154-155, and FPC173-177	All	§366.093. This is third party proprietary information, the disclosure of which would impair the utility's efforts to efficiently and effectively operate its system.
FPC's Response to Staff's Request for Documents to FPC	All.	§366.093(3)(d). This is information concerning the contract terms and negotiations with FPC's suppliers, the disclosure of which would impair the utility's efforts to contract for equipment or services on favorable terms.
FPC's Response to Staff's Request for Documents to FPC	All.	§366.093. This is proprietary, confidential business information involving FPC's management decisions, the disclosure of which would restrict or preclude full and open discussions and thus result in harm to the utility and its ratepayers.

BATES NOS. FPC 001 – FPC 019
CONFIDENTIAL
PURSUANT TO FLORIDA
POWER CORPORATION'S
REQUST FOR CONFIDENTIAL
CLASSIFICATION FILED
AUGUST 7, 2000

RESERVE MARGINS

	WINTER RM%			SUMMER RM%			
YEAR	1999 TYSP	2000 TYSP	'00 - '99 CHANGE	YEAR	1999 TYSP	2000 TYSP	'00 - '99 CHANGE
1999 / 00	16	-		2000	18	19	1
2000 / 01	17	16	-1	2001	17	18	1
2001 / 02	18	20	2	2002	19	23	4
2002 / 03	24	22	-2	2003	25	26	1
2003 / 04	20	25	5	2004	21	29	8
2004 / 05	22	23	1	2005	23	26	3
2005 / 06	19	25	6	2006	19	27	8
2006 / 07	23	21	-2	2007	22	23	1
2007 / 08	20	24	4	2008	18	26	8
2008 / 09	17	20	3	2009		21	
2009 / 10		22					

Note: Reserve margin criteria increased from 15% in 1999 to 20% in 2000.

PLANNED ADDITIONS

	1999 TYSP		2000 TYSP		
ADDITION	(MW)	IN-SERVICE	(MW)	IN-SERVICE	COMMENTS
HEC#1	505	4/99	0		Included in existing system
System upgrades	91		58		CR upgrades / CT Fogging
System changes	0		35		Rating changes
IC #12-14	297	12/00	282	12/00	
HEC#2	567	11/04	567	11/03	1 year acceleration
HEC#3	567	11/06	567	11/05	1 year acceleration
HEC#4			567	11/07	new unit
HEC#5			567	11/09	new unit
TOTAL NEW	2,027		2,643		
SR STEAM	-147	12/01	-146	12/03	Delayed 2 yrs
HIGGINS P1-4	-148	12/03	-134	12/05	Delayed 2 yrs
RIO PINAR	-18	12/03	-16	12/05	Delayed 2 yrs
AP P1-2	-64	12/04	-64	12/06	Delayed 2 yrs
TURNER P1-2	-36	12/04	-32	12/06	Delayed 2 yrs
TOTAL RETIRE	-413		-392		
NET PLANNED	1,614		2,251		

Note: Retirement plan in 2000 does not match dismantlement plan.

DEMAND & ENERGY												
	1999 TYSP				2000 TYSP				2000 TYSP LESS 1999 TYSP (DELTA)			
YEAR	WHOLE SALE (MW)	LOAD MGT (MW)	FIRM LOAD (MW)	NET ENERGY (GWh)	WHOLE SALE (MW)	LOAD MGT (MW)	FIRM LOAD (MW)	NET ENERGY (GWh)	WHOLE SALE (MW)	LOAD MGT (MW)	FIRM LOAD (MW)	NET ENERGY (GWh)
1999 / 00	1,575	865	8,221	39,228	1,647	849	8,259	40,846	72	-16	38	1,618
2000 / 01	1,668	859	8,459	40,367	1,731	809	8,528	41,927	63	-50	69	1,560
2001 / 02	1,266	790	8,271	39,525	1,274	744	8,282	41,330	8	-46	11	1,805
2002 / 03	720	743	7,913	40,048	928	701	8,120	42,221	208	-42	207	2,173
2003 / 04	666	713	8,020	40,967	877	673	8,230	43,268	211	-40	210	2,301
2004 / 05	728	690	8,232	41,911	890	652	8,394	44,215	162	-38	162	2,304
2005 / 06	806	670	8,455	42,856	968	635	8,609	45,214	162	-35	154	2,358
2006 / 07	883	652	8,677	43,789	1,046	619	8,820	46,180	163	-33	143	2,391
2007 / 08	963	637	8,900	44,714	1,129	605	9,029	47,066	166	-32	129	2,352
2008 / 09	1,046	623	9,125		1,210	592	9,233	47,945	164	-31	108	
2009 / 10					1,291	580	9,440					

FLORIDA POWER CORPORATION

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

(1)	PLANT NAME AND UNIT NUMBER:	INTERCESSION CITY P12 - 14	
(2)	CAPACITY		
	a. SUMMER:	240 MW	
	b. WINTER:	282 MW	
(3)	TECHNOLOGY TYPE:	COMBUSTION TURBINE	
(4)	ANTICIPATED CONSTRUCTION TIMING		
	a. FIELD CONSTRUCTION START-DATE:	3/1999	
	b. COMMERCIAL IN-SERVICE DATE:	12/2000 (EXPECTED)	
(5)	FUEL		
	a. PRIMARY FUEL:	NATURAL GAS	
	b. ALTERNATE FUEL:	DISTILLATE OIL	
(6)	AIR POLLUTION CONTROL STRATEGY:	DRY LOW NOx COMBUSTION (NATURAL GAS) WATER INJECTION (DISTILLATE OIL)	
(7)	COOLING METHOD:	AIR	
(8)	TOTAL SITE AREA:	165 ACRES	
(9)	CONSTRUCTION STATUS:	UNDER CONSTRUCTION	
(10)	CERTIFICATION STATUS:	SITE PERMITTED	
(11)	STATUS WITH FEDERAL AGENCIES:	SITE PERMITTED	
(12)	PROJECTED UNIT PERFORMANCE DATA		
	PLANNED OUTAGE FACTOR (POF):	2.88 %	
	FORCED OUTAGE FACTOR (FOF):	3.00 %	
	EQUIVALENT AVAILABILITY FACTOR (EAF):	91.00 %	
	ASSUMED CAPACITY FACTOR (%):	15.00 %	
	AVERAGE NET OPERATING HEAT RATE (ANOHR):	13,272 BTU/KWH	
(13)	PROJECTED UNIT FINANCIAL DATA		Reference
	BOOK LIFE (YEARS):	25	Only
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW):	308.51	87,000
	DIRECT CONSTRUCTION COST ($/kW):	281.21	79,300
	AFUDC AMOUNT ($/kW):	27.30	7,700
	ESCALATION ($/kW):	0.00	0
	FIXED O & M ($/kW-Yr):	1.40	395
	VARIABLE O & M ($/MWH):	4.35	
	K FACTOR:	NO CALCULATION	

FLORIDA POWER CORPORATION

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

(1)	PLANT NAME AND UNIT NUMBER:	HINES ENERGY COMPLEX UNIT #2	
(2)	CAPACITY		
	a. SUMMER:	495 MW	
	b. WINTER:	567 MW	
(3)	TECHNOLOGY TYPE:	COMBINED CYCLE	
(4)	ANTICIPATED CONSTRUCTION TIMING		
	a. FIELD CONSTRUCTION START-DATE:	8/2000	
	b. COMMERCIAL IN-SERVICE DATE:	11/2003 (EXPECTED)	
(5)	FUEL		
	a. PRIMARY FUEL:	NATURAL GAS	
	b. ALTERNATE FUEL:	DISTILLATE OIL	
(6)	AIR POLLUTION CONTROL STRATEGY:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION	
(7)	COOLING METHOD:	COOLING PONDS	
(8)	TOTAL SITE AREA:	8,200 ACRES	
(9)	CONSTRUCTION STATUS:	PLANNED	
(10)	CERTIFICATION STATUS:	SITE PERMITTED	
(11)	STATUS WITH FEDERAL AGENCIES:	SITE PERMITTED	
(12)	PROJECTED UNIT PERFORMANCE DATA		
	PLANNED OUTAGE FACTOR (POF):	4.41 %	
	FORCED OUTAGE FACTOR (FOF):	3.70 %	
	EQUIVALENT AVAILABILITY FACTOR (EAF):	91.00 %	
	ASSUMED CAPACITY FACTOR (%):	70.00 %	
	AVERAGE NET OPERATING HEAT RATE (ANOHR):	7,306 BTU/KWH	
(13)	PROJECTED UNIT FINANCIAL DATA		Reference
	BOOK LIFE (YEARS):	25	Only
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW):	345.95	196,154
	DIRECT CONSTRUCTION COST ($/kW):	292.00	165,564
	AFUDC AMOUNT ($/kW):	37.88	21,478
	ESCALATION ($/kW):	16.07	9,112
	FIXED O & M ($/kW-Yr):	2.50	1,418
	VARIABLE O & M ($/MWH):	2.10	
	K FACTOR:	NO CALCULATION	

FLORIDA POWER CORPORATION

SCHEDULE 9

STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

(1)	PLANT NAME AND UNIT NUMBER:	HINES ENERGY COMPLEX UNIT #3	
(2)	CAPACITY		
	a. SUMMER:	495 MW	
	b. WINTER:	567 MW	
(3)	TECHNOLOGY TYPE:	COMBINED CYCLE	
(4)	ANTICIPATED CONSTRUCTION TIMING		
	a. FIELD CONSTRUCTION START-DATE:	8/2002	
	b. COMMERCIAL IN-SERVICE DATE:	11/2005 (EXPECTED)	
(5)	FUEL		
	a. PRIMARY FUEL:	NATURAL GAS	
	b. ALTERNATE FUEL:	DISTILLATE OIL	
(6)	AIR POLLUTION CONTROL STRATEGY:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION	
(7)	COOLING METHOD:	COOLING PONDS	
(8)	TOTAL SITE AREA:	8,200 ACRES	
(9)	CONSTRUCTION STATUS:	PLANNED	
(10)	CERTIFICATION STATUS:	SITE PERMITTED	
(11)	STATUS WITH FEDERAL AGENCIES:	SITE PERMITTED	
(12)	PROJECTED UNIT PERFORMANCE DATA		
	PLANNED OUTAGE FACTOR (POF):	4.41 %	
	FORCED OUTAGE FACTOR (FOF):	3.70 %	
	EQUIVALENT AVAILABILITY FACTOR (EAF):	91.00 %	
	ASSUMED CAPACITY FACTOR (%):	70.00 %	
	AVERAGE NET OPERATING HEAT RATE (ANOHR):	7,306 BTU/KWH	
			Reference Only
(13)	PROJECTED UNIT FINANCIAL DATA		
	BOOK LIFE (YEARS):	25	
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW):	408.61	231,682
	DIRECT CONSTRUCTION COST ($/kW):	329.00	186,543
	AFUDC AMOUNT ($/kW):	44.74	25,368
	ESCALATION ($/kW):	34.87	19,771
	FIXED O & M ($/kW-Yr):	2.50	1,418
	VARIABLE O & M ($/MWH):	2.10	
	K FACTOR:	NO CALCULATION	

FLORIDA POWER CORPORATION

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

(1)	PLANT NAME AND UNIT NUMBER:	HINES ENERGY COMPLEX UNIT #4	
(2)	CAPACITY		
	a. SUMMER:	495 MW	
	b. WINTER:	567 MW	
(3)	TECHNOLOGY TYPE:	COMBINED CYCLE	
(4)	ANTICIPATED CONSTRUCTION TIMING		
	a. FIELD CONSTRUCTION START-DATE:	8/2004	
	b. COMMERCIAL IN-SERVICE DATE:	11/2007 (EXPECTED)	
(5)	FUEL		
	a. PRIMARY FUEL:	NATURAL GAS	
	b. ALTERNATE FUEL:	DISTILLATE OIL	
(6)	AIR POLLUTION CONTROL STRATEGY:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION	
(7)	COOLING METHOD:	COOLING PONDS	
(8)	TOTAL SITE AREA:	8,200 ACRES	
(9)	CONSTRUCTION STATUS:	PLANNED	
(10)	CERTIFICATION STATUS:	SITE PERMITTED	
(11)	STATUS WITH FEDERAL AGENCIES:	SITE PERMITTED	
(12)	PROJECTED UNIT PERFORMANCE DATA		
	PLANNED OUTAGE FACTOR (POF):	4.41 %	
	FORCED OUTAGE FACTOR (FOF):	3.70 %	
	EQUIVALENT AVAILABILITY FACTOR (EAF):	91.00 %	
	ASSUMED CAPACITY FACTOR (%):	70.00 %	
	AVERAGE NET OPERATING HEAT RATE (ANOHR):	7,306 BTU/KWH	
(13)	PROJECTED UNIT FINANCIAL DATA		Reference Only
	BOOK LIFE (YEARS):	25	
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW):	429.30	243,413
	DIRECT CONSTRUCTION COST ($/kW):	329.00	186,543
	AFUDC AMOUNT ($/kW):	47.00	26,649
	ESCALATION ($/kW):	53.30	30,221
	FIXED O & M ($/kW-Yr):	2.50	1,418
	VARIABLE O & M ($/MWH):	2.10	
	K FACTOR:	NO CALCULATION	

FLORIDA POWER CORPORATION

SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES

(1)	PLANT NAME AND UNIT NUMBER:	HINES ENERGY COMPLEX UNIT #5	
(2)	CAPACITY		
	a. SUMMER:	495 MW	
	b. WINTER:	567 MW	
(3)	TECHNOLOGY TYPE:	COMBINED CYCLE	
(4)	ANTICIPATED CONSTRUCTION TIMING		
	a. FIELD CONSTRUCTION START-DATE:	8/2006	
	b. COMMERCIAL IN-SERVICE DATE:	11/2009 (EXPECTED)	
(5)	FUEL		
	a. PRIMARY FUEL:	NATURAL GAS	
	b. ALTERNATE FUEL:	DISTILLATE OIL	
(6)	AIR POLLUTION CONTROL STRATEGY:	DRY LOW NOx COMBUSTION with SELECTIVE CATALYTIC REDUCTION	
(7)	COOLING METHOD:	COOLING PONDS	
(8)	TOTAL SITE AREA:	8,200 ACRES	
(9)	CONSTRUCTION STATUS:	PLANNED	
(10)	CERTIFICATION STATUS:	SITE PERMITTED	
(11)	STATUS WITH FEDERAL AGENCIES:	SITE PERMITTED	
(12)	PROJECTED UNIT PERFORMANCE DATA		
	PLANNED OUTAGE FACTOR (POF):	4.41 %	
	FORCED OUTAGE FACTOR (FOF):	3.70 %	
	EQUIVALENT AVAILABILITY FACTOR (EAF):	91.00 %	
	ASSUMED CAPACITY FACTOR (%):	70.00 %	
	AVERAGE NET OPERATING HEAT RATE (ANOHR):	7,306 BTU/KWH	
(13)	PROJECTED UNIT FINANCIAL DATA		Reference Only
	BOOK LIFE (YEARS):	25	
	TOTAL INSTALLED COST (IN-SERVICE YEAR $/kW):	451.03	255,734
	DIRECT CONSTRUCTION COST ($/kW):	329.00	186,543
	AFUDC AMOUNT ($/kW):	49.38	27,998
	ESCALATION ($/kW):	72.65	41,193
	FIXED O & M ($/kW-Yr):	2.50	1,418
	VARIABLE O & M ($/MWH):	2.10	
	K FACTOR:	NO CALCULATION	

2000 Ten-Year Site Plan
2000 Dollars

Confidential

Plant name / Option name		Repower Higgins Steam	Repower Bartow	Retire Bartow Steam	NET Bartow at CC MW	Hines F Type	Hines F Type Market	Hines G Type	Hines IGCC	Hines Pulv. Coal	Hines FL. BED	Inter. City CT gas ("EA")	FPC System CT gas ("F")
Study		2000 TYSP	2000 TYSP	2000 TYSP	2000 TYSP	2000 TYSP	2000 TYSP	2000 TYSP	2000 TYSP	2000 TYSP	2000 TYSP	2000 TYSP	2000 TYSP
alternative number		SRS	RBART	BART	net	HF	HFM	HG	HIGCC	HPC	HFB	CTEA	CTF
SUGGESTED alternative number		RHS	BAR3/2	XBAR	net BAR3/2	CCH2	CCM	CCG	IGCC	PVC	FLB	3CTEA	CTF
Generation and Fuel													
New winter maximum capacity	MW	380	561	225	561	567	567	365	577	800	500	282	178
New summer maximum capacity	MW	353	516	220	516	495	495	323	494	780	500	249	151
New minimum capacity	MW	189	269		269	289	289	190	288	400	250	141	89
Number of Units in capacity ratings		1 site	1 of 2	Unit 3 or 1&2		1	1	1	1	1	2	3	1
Avaialable Capacity		380	1122	450	672	no limit	no limit	no limit	no limit	no limit	no limit	no limit	no limit
Full load net heat rate (x000)	(btu/kwh)	8.060	7.045			6.800	6.800	6.787	8.555	9.874	10.300	11.814	10.614
Minimum load net heat rate (x000)	(btu/kwh)	8.855	8.315			7.850	7.850	7.535	9.867	10.704	11.000	15.621	13.972
Mature forced outage rate	%	5.0	5.0			3.7	3.7	3.7	8.0	7.0	7.0	3.0	3.0
Maintenance requirement	(wks/yr)	3.0	3.0			2.3	2.3	2.3	4.0	5.0	4.0	1.5	1.5
Primary fuel type	fuel name	Firm Gas	Firm Gas			Firm Gas	Firm Gas	Firm Gas	HS coal	HS coal	HS coal	IT Gas	IT Gas
Secondary fuel type	fuel name	IT Gas	IT Gas			IT Gas	IT Gas	IT Gas	HS coal	HS coal	HS coal	Dist. Oil	Dist. Oil
Incremental Fixed O&M rate	($/kw/yr)	5.9	2.72	14.4	existing O&M	2.5	2.5	2.4	33.4	22.0	20.3	1.4	2.9
Incremental Fixed O&M rate	($000/yr)	2,220	1,525	3,247	0	1,402	1,402	865	19,260	17,634	10,146	407	519
* Fixed gas demand cost	($/kw/yr)	32	32	0	32	32	32	32	0	n/a	n/a	n/a	n/a
* Fixed gas demand cost	($000/yr)	12,144	17,952	0	17,952	18,144	18,144	11,680	0	n/a	n/a	n/a	n/a
* Fixed gas quantity	(mmbtu/day)	43,505	64,312		64,312	65,000	65,000	41,843					
Variable O&M cost	($/mwh)	2.02	2.19	2.41	1.34	2.10	2.10	1.96	0.72	1.28	4.59	4.35	3.77
Variable O&M Capacity Factor (check)	(CF%)	0.60	0.70	0.50	0.70	0.70	0.70	0.70	0.65	0.85	0.85	0.15	0.15
Variable O&M cost (check)	($000/yr)	3,884	7,220	2,304	3,193	6,842	6,842	4,128	2,875	7,513	17,103	1,516	815
Capital Expenditure & Recovery													
Design construction duration	years	3	3			3	3	3	4	4	4	2	2
Generation Costs	($1000)	173,040	194,155			165,830	186,430	160,680	718,940	707,610	491,310	80,000	44,808
Construction expenditure (1st year)	%	20	20			15	15	15	20	20	10	30	30
Construction expenditure (2nd year)	%	50	50			60	60	60	20	25	20	70	70
Construction expenditure (3rd year)	%	30	30			25	25	25	30	35	40		
Construction expenditure (4th year)	%								30	20	30		
Base cost w/o AFUDC	($/kw) WTR	456	346			292	329	440	1,246	885	983	284	252
Base cost w/o AFUDC	($/kw) NOM.	473	361			312	351	467	1,343	896	983	301	272
Base Incremental cost w/o AFUDC	($/kw) WTR				578								
Additional Information													
Comments							begin 3/2004	begin 1/2005					begin 1/2002
Comments		1 unit	2 units		2 units	1 unit	3 units	2 units	1 unit	1 unit	1 unit	3 units	1 unit
High Capital Sensitivity													
High Generation Costs	($1000)	191,506	210,831			182,413	233,038	176,645	745,308	778,680	527,875	100,000	56,011
High cost w/o AFUDC	($/kw) WTR	505	376			322	411	484	1,292	973	1,056	355	315
Low Capital Sensitivity													
Low Generation Costs	($1000)	157,578	159,653			157,539	177,109	155,015	579,684	638,600	437,750	76,000	42,568
Low cost w/o AFUDC	($/kw) WTR	415	285			278	312	425	1,005	798	876	270	239

Proposed Heat Rate Curves - Hines 2 Half Unit

W S

Input-Output Curves

CC:	205.18	204.72
CL:	4.6924	4.6808
CI:	0.004414	0.004327

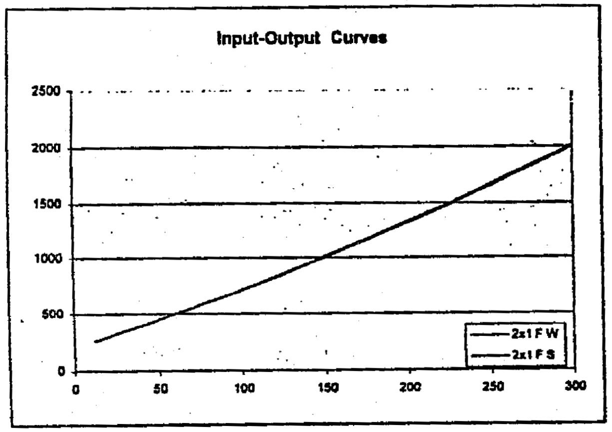
HtRt Pen Fact	1	1
	2x1 F W	2x1 F S
13	265	264
25	325	324
38	387	386
50	451	450
63	516	514
75	582	580
88	650	647
100	719	716
113	789	786
125	861	857
138	934	930
150	1008	1004
163	1084	1080
175	1162	1156
188	1240	1234
200	1320	1314
213	1402	1395
225	1484	1477
238	1569	1560
250	1654	1645
263	1741	1732
275	1829	1819
288	1919	1908
300	2010	1998

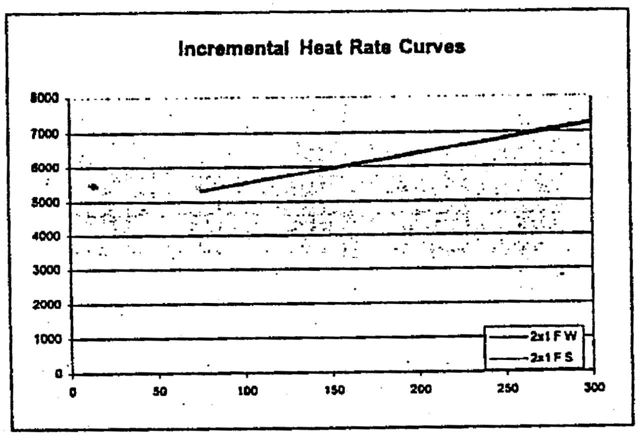
Incremental Heat Rate Curves

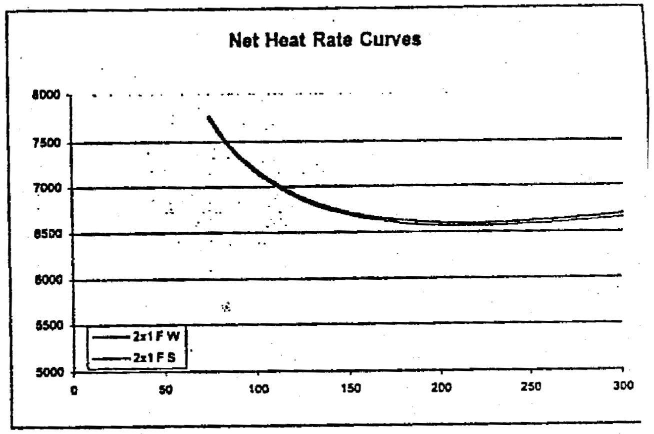
	2x1 F W	2x1 F S
75	5299	5276
88	5410	5384
100	5520	5492
113	5630	5600
125	5741	5708
138	5851	5817
150	5961	5925
163	6072	6033
175	6182	6141
188	6292	6249
200	6403	6358
213	6513	6466
225	6624	6574
238	6734	6682
250	6844	6790
263	6955	6898
275	7065	7007
288	7175	7115
300	7286	7223

Net Heat Rate Curves

	2x1 F W	2x1 F S
75	7759	7735
88	7424	7399
100	7186	7161
113	7013	6987
125	6886	6859
138	6792	6765
150	6722	6695
163	6672	6644
175	6637	6608
188	6614	6584
200	6601	6570
213	6596	6564
225	6597	6564
238	6605	6570
250	6617	6581
263	6633	6597
275	6652	6615
288	6675	6637
300	6701	6661







Peakers Example at $100 million

Revenue requirement - based on Corporate WACC

($000s)

2030 End of Plant Life

	2001	2002	2003	2004	2005	2006	2007	2008
Rate Base (year end)								
Gross Electric Plant	$100,000	$ 100,000	$100,000	$100,000	$100,000	$100,000	$100,000	$ 100,000
Less ADIT	(643)	(3,022)	(5,034)	(6,718)	(8,105)	(9,222)	(10,212)	(11,202)
Less accumulated depreciation	(3,333)	(6,667)	(10,000)	(13,333)	(16,667)	(20,000)	(23,333)	(26,667)
Equals total rate base	96,024	90,311	84,966	79,949	75,228	70,778	66,455	62,131
Interest Expense	3,220	3,061	2,879	2,709	2,549	2,398	2,254	2,112
Net Income	6,469	6,149	5,784	5,442	5,121	4,818	4,529	4,243
Income Taxes	4,062	3,862	3,632	3,418	3,216	3,026	2,844	2,665
Revenue Requirement on Rate Base	13,751	13,071	12,296	11,569	10,886	10,242	9,627	9,020
Depreciation Expense	3,333	3,333	3,333	3,333	3,333	3,333	3,333	3,333
Property Taxes	2,060	2,069	2,047	2,024	1,997	1,968	1,937	1,903
Depreciation and Property Tax Expense	5,393	5,402	5,380	5,357	5,330	5,301	5,270	5,236
Fixed Cost Revenue Requirements	$ 19,144	$ 18,474	$ 17,676	$ 16,926	$ 16,216	$ 15,544	$ 14,897	$ 14,257

ATWACC	8.62%
NPV of Revenue Requirements	142,792
Total Initial Cost	100,000
NPV of Rev. Req. / Initial Cost - or - "K Factor"	1.428

Inputs	2001	2002	2003	2004	2005	2006	2007	2008
Capitalization								
Equity	55.0%	55.0%	55.0%	55.0%	55.0%	55.0%	55.0%	55.0%
Debt	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%	45.0%
	100%	100%	100%	100%	100%	100%	100%	100%
Cost Capital								
Equity	12.0%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%	12.00%
Debt	7.3%	7.30%	7.30%	7.30%	7.30%	7.30%	7.30%	7.30%
WEIGHTED COST OF CAPITAL								
Equity	6.60%	6.60%	6.60%	6.60%	6.60%	6.60%	6.60%	6.60%
Debt	3.29%	3.29%	3.29%	3.29%	3.29%	3.29%	3.29%	3.29%
Pre-tax Debt, After-tax Equity WACC	9.89%	9.89%	9.89%	9.89%	9.89%	9.89%	9.89%	9.89%

Property Taxes			2001	2002	2003	2004	2005	2006	2007	2008
Property tax millage rate (Max @ 30 mils) - Osceola County	2.50%	escalation	$ 20.60	$ 21.40	$ 21.94	$ 22.48	$ 23.05	$ 23.62	$ 24.21	$ 24.82

VALUE DEFERRAL CALCULATIONS USING PSC METHODOLOGY - DOCKET 891049-EU, ORDER 23623

DESCRIPTION OF STUDY:
1991 Pulverized Coal @SITE FPC
REFERENCE DESIGN

FILE: VAL_DEF
REV: 09/16/91
DISK: GEB9005

CAPACITY PAYMENTS BASED ON INPUT ASSUMPTIONS & ENTRY VARIABLES

ENTRY VARIABLES:

		DESCRIPTION
	2003	Base year of study
K =	1.35880567	K Factor(Mid year)- P.V. of carry'g chrg's for $1 in rate base for econ. life of plant.
	$372.1	$/KW - Total cost, direct + AFUDC, in 1/2003 $.
On =	$4.33	$/KW/Yr - Fixed O&M costs in 1/2003 $.
	1.20	$/MWH - Variable O&M costs in 1/2003 $.
ip =	3.30%	Annual escalation rate of plant costs.
io =	3.30%	Annual esclation rate for O & M costs.
r =	9.00%	Util. discount rate
L =	25	Years - Economic life of plant.
n =	2003	Inservice year of deferred unit
cf =	65.0%	Capacity factor of avoided unit
C =	1.0	Risk factor assigned to plant.
	1.00	Factor to be used for O & M
	25	Number of years for Value deferral calc.

CALCULATED VALUES BASED ON INPUTS

(1+ip)/(1+r) =	0.947706	
((1+ip)/(1+r))^L =	0.261123	
1-(1+ip)/(1+r) =	0.052294	
1-((1+ip)/(1+r))^L =	0.738877	
In =	$372.13	$/kw -Installed costs of the plant in in-service year 2003 $.
On =	$4.40	$/KW/Yr - Midyear Fix O&M cost 20
	$1.22	$/MWH - Midyear Var. O&M cost 20
VACm =	$3.93	$/kw/mo - Value of avoiding plant
	$47.13	for one month in 2003. (capital costs and fixed O&M)
PV of CC =	$463.90	P.V. of the carry costs of plant in 2003 $.
PV of OM =	$147.08	P.V. of O&M in 2003 $.

OUTPUTS CALCULATED FOR 25 YEARS OF AVOIDANCE: COG-2_103

	1	2	3	4	5	6	7	8	9	10	11	12
			<-VALUE of DEF PAYMENTS->			<-------- EARLY CAPACITY PAYMENTS					------>	
			(Method 5a)						(Method 5b)			
	CONTRACT PERIOD			Starting	Jan-03		Starting	Jan-02		Starting	Jan-01	
			O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL	O&M	CAPITAL	TOTAL	O&M
	YEAR	MONTHS	$/KW/MO	$/KW/MO	$/KW/MO	$/KW/MO	$/KW/MO	$/KW/MO	$/KW/MO	$/KW/MO	$/KW/MO	$/KW/MO
1	2003	Jan - Dec.	0.95	2.98	3.93	0.88	2.78	3.65	0.82	2.59	3.41	0.76
2	2004	Jan - Dec.	0.98	3.08	4.06	0.91	2.87	3.78	0.85	2.67	3.52	0.79
3	2005	Jan - Dec.	1.01	3.18	4.19	0.94	2.96	3.90	0.87	2.76	3.63	0.82

Hines 2

Revenue requirement - based on Corporate Framework Energy Supply WACC

($000s)

	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Rate Base (year end)															
Gross Electric Plant	$ -	$ -	$ -	$ -	$ 203,132	$ 207,323	$ 226,255	$ 233,852	$ 234,041	$ 234,450	$ 238,903	$ 241,895	$ 242,166	$ 248,507	$ 248,796
Less accumulated depreciation	-	-	-	-	(1,354)	(9,936)	(19,341)	(29,092)	(38,851)	(48,631)	(58,646)	(68,826)	(79,023)	(89,615)	(100,227)
Equals total rate base	-	-	-	-	201,778	197,387	206,914	204,760	195,189	185,819	180,257	173,069	163,144	158,892	148,568
Interest Expense	0	0	0	0	942	5,527	5,794	5,733	5,465	5,203	5,047	4,846	4,568	4,449	4,160
Net Income	0	0	0	0	2,462	14,449	15,146	14,988	14,288	13,602	13,195	12,669	11,942	11,631	10,875
Income Taxes	0	0	0	0	1,546	9,074	9,512	9,413	8,973	8,542	8,286	7,956	7,500	7,304	6,830
Revenue Requirement on Rate Base	0	0	0	0	4,949	29,049	30,451	30,134	28,726	27,347	26,528	25,470	24,010	23,384	21,865
Direct Non-Fuel O&M	0	0	0	0	654	4,248	4,157	7,924	4,330	4,381	9,979	4,186	4,706	8,164	4,910
Fully Allocated Site Costs															
Fully Allocated Overheads	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation Expense	0	0	0	0	1,354	9,582	9,405	9,750	9,759	9,780	10,014	10,181	10,196	10,593	10,612
Dismantlement Expense	0	0	0	0	41	257	257	257	257	257	257	257	257	257	257
Taxes other than Income	0	0	0	0	628	3,778	4,025	4,283	3,980	3,884	4,175	3,781	3,686	3,874	3,545
Operating Expenses	0	0	0	0	2,678	16,866	17,844	22,214	18,327	18,302	24,426	18,405	18,846	22,888	19,324
Non-fuel Revenue Requirements	$ -	$ -	$ -	$ -	$ 7,627	$ 45,915	$ 48,296	$ 52,349	$ 47,053	$ 45,649	$ 50,954	$ 43,875	$ 42,856	$ 46,272	$ 41,189
Fuel Expense	$ -	$ -	$ -	$ -	$ 11,964	$ 65,804	$ 65,804	$ 67,069	$ 67,069	$ 68,124	$ 68,124	$ 68,805	$ 69,493	$ 70,188	$ 70,890
Total Revenue Requirements	$ -	$ -	$ -	$ -	$ 19,592	$ 111,719	$ 114,100	$ 119,418	$ 114,122	$ 113,773	$ 119,078	$ 112,680	$ 112,349	$ 116,460	$ 112,079
Total $/MWh	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 35.64	$ 36.95	$ 37.74	$ 39.50	$ 37.74	$ 37.63	$ 39.38	$ 37.27	$ 37.16	$ 38.52	$ 37.07
Capacity $/MWh	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 13.87	$ 15.19	$ 15.97	$ 17.31	$ 15.56	$ 15.10	$ 16.85	$ 14.51	$ 14.17	$ 15.30	$ 13.62
Fuel $/MWh	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ 21.76	$ 21.76	$ 21.76	$ 22.18	$ 22.18	$ 22.53	$ 22.53	$ 22.76	$ 22.98	$ 23.21	$ 23.45
Total $/MWh in 1997 Dollars			#DIV/0!	#DIV/0!	$32.28	$32.81	$32.85	$33.71	$31.58	$30.87	$31.68	$29.39	$28.72	$29.19	$27.54
Average over life			#DIV/0!												
Original Capacity Factor	0%	0%	0%	0%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%	65%
Original Forecast GWh Production	0	0	0	0	550	3,024	3,024	3,024	3,024	3,024	3,024	3,024	3,024	3,024	3,024
After-tax WACC			9.0%												
Non-fuel Revenue Requirements			$ -	$ -	$ 7,627	$ 45,915	$ 48,296	$ 52,349	$ 47,053	$ 45,649	$ 50,954	$ 43,875	$ 42,856	$ 46,272	$ 41,189
NPV @ 9% in 2001			398,730												
			343,178		$ 6,932	$ 41,409	$ 43,882	$ 44,168	$ 42,465	$ 41,011	$ 40,718	$ 39,432	$ 37,892	$ 37,851	$ 36,022
Fuel Savings					3,746	42,245	45,514	44,498	40,251	43,105	41,678	41,678	41,678	41,678	41,678
NPV @9% of Fuel Savings			375,113												
First five years Fuel Sav NPV			131,823												
First five yrs RR NPV			150,603												
Oct 98 Fuel Savings					*4,601*	*28,850*	*33,566*	*38,812*	*39,200*	*39,592*	*39,988*	*40,388*	*40,792*	*41,200*	*41,612*

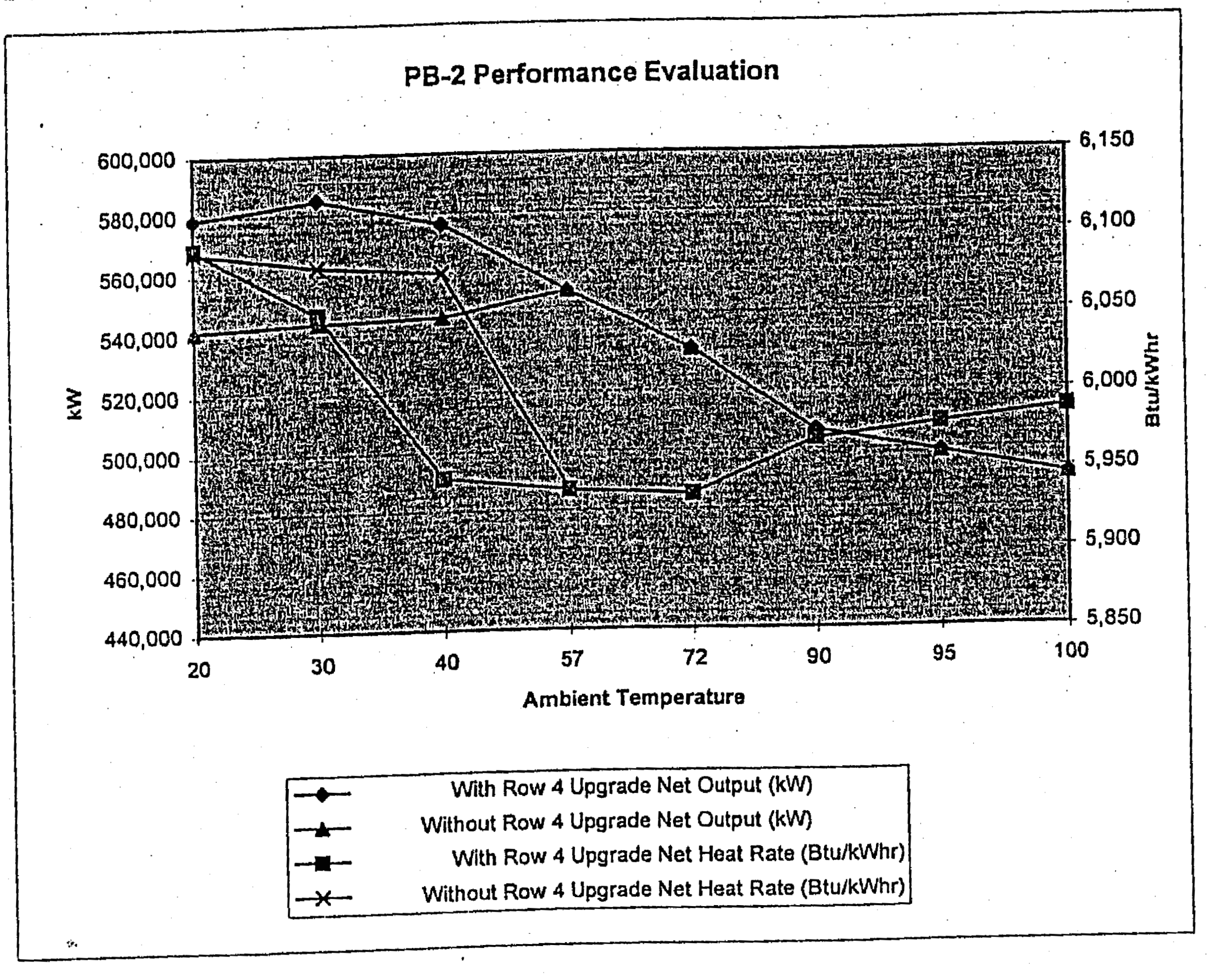
1	2	3	4	5	6
185,819	180,257	173,069	163,144	158,892	148,568
0%	0%	0%	0%	0%	0%
0	0	0	0	0	0

FPC 031

BATES NO. FPC 032
CONFIDENTIAL
PURSUANT TO FLORIDA
POWER CORPORATION'S
REQUST FOR CONFIDENTIAL
CLASSIFICATION FILED
AUGUST 7, 2000

Power Block 2 CT Performance Data

Ambient Temp. (deg. F)	With Row 4 Upgrade Net Output (kW)	With Row 4 Upgrade Net Heat Rate (Btu/kWhr)	Without Row 4 Upgrade Net Output (kW)	Without Row 4 Upgrade Net Heat Rate (Btu/kWhr)
20	578,950	6,092	541,900	6,090
30	584,895	6,050	544,040	6,080
40	576,395	5,946	545,430	6,075
57	553,685	5,938	553,685	5,938
72	534,105	5,935	534,105	5,935
90	506,400	5,969	506,400	5,969
95	498,704	5,978	498,704	5,978
100	491,008	5,988	491,008	5,988



Proposed Residential LM Strategy Plan

Existing Program – Close to New LM Installations, Grandfather Existing
(Remove existing participants at time of occupancy change beginning April 2001)

	Year-end Participants				LM Savings in MW (at the Generator)	
Year	Additions	Cancels	Turnover	Total	Winter (Jan)	Summer (Aug)
1999	4,500	25,000	0	472,629		
2000	0	25,000	0	447,629	842	460
2001	0	11,191	-65,466	370,973	801	411
2002	0	9,274	-45,212	316,486	668	348
2003	0	7,912	-30,857	277,716	573	303
2004	0	6,943	-27,077	243,696	505	267
2005	0	6,092	-23,760	213,843	446	236
2006	0	5,346	-20,850	187,648	393	208
2007	0	4,691	-18,296	164,661	347	184
2008	0	4,117	-16,054	144,490	306	162
2009	0	3,612	-14,088	126,790	270	143
2010	0	3,170	-12,362	111,258	238	126

New Winter LM Option – Load Control of Heating & WH during Winter Months Only

	Year-end Participants				LM Savings in MW (at the Generator)	
Year	Additions	Cancels	Turnover	Total	Winter (Jan)	Summer (Aug)
1999	0	0	0	0		
2000	5,000	0	0	5,000	0	0
2001	5,625	50	24,550	35,125	11	0
2002	6,250	351	16,955	57,978	80	0
2003	6,875	580	11,572	75,845	132	0
2004	7,500	758	10,154	92,740	173	0
2005	7,500	927	8,910	108,223	212	0
2006	6,875	1,082	7,819	121,834	247	0
2007	6,250	1,218	6,861	133,727	278	0
2008	5,625	1,337	6,020	144,035	305	0
2009	5,000	1,440	5,283	152,878	329	0
2010	4,500	1,529	4,636	160,485	349	0

Total LM Program = Existing LM Program + New LM Winter Only Option

	Year-end Participants				LM Savings in MW (at the Generator)	
Year	Additions	Cancels	Turnover	Total	Winter (Jan)	Summer (Aug)
1999	4,500	25,000	0	472,629		
2000	5,000	25,000	0	452,629	842	460
2001	5,625	11,241	-40,916	406,097	813	411
2002	6,250	9,626	-28,258	374,464	748	348
2003	6,875	8,492	-19,286	353,561	705	303
2004	7,500	7,701	-16,923	336,436	678	267
2005	7,500	7,020	-14,850	322,066	657	236
2006	6,875	6,428	-13,031	309,482	640	208
2007	6,250	5,910	-11,435	298,388	625	184
2008	5,625	5,454	-10,034	288,525	611	162
2009	5,000	5,053	-8,805	279,667	599	143
2010	4,500	4,699	-7,726	271,743	587	126

Ten Year Site Plan (April 1999)	
Winter (Jan)	Summer (Aug)
875	457
865	450
860	403
790	341
743	297
713	262
690	231
670	204
652	180
637	159
623	140
609	123

Table 41
Estimated Capital Cost Range for Alternatives

	Fuel	Capacity			Capital Cost		Capital Cost Range			
		Winter	Summer	Average			Low	High	Low	High
	Type	MW	MW	MW	$1,000	$/kw	$1,000	$1,000	$/kw	$/kw
GE 7EA Simple Cycle	N. Gas	88.9	74.2	81.6	30,700	376	28,600	33,300	351	408
GE 7EA Simple Cycle	Distillate	92.0	76.4	84.2	30,700	365	28,600	33,300	340	396
GE 7FA Simple Cycle	N. Gas	178	151	164	49,800	303	45,100	51,700	275	315
GE 7FA Simple Cycle	Distillate	185	161	173	49,800	288	45,100	51,700	261	299
Hines Unit #2	N. Gas	567	496	531	160,700	302	159,000	170,000	299	320
Hines Unit #2	Distillate	545	473	509	160,700	316	159,000	170,000	312	334
West. 501FC 2x1 CC	N. Gas	567	496	531	181,200	341	178,000	205,000	335	386
West. 501FC 2x1 CC	Distillate	545	473	509	181,200	356	178,000	205,000	349	403
West 501G 1x1 CC	N. Gas	366	323	345	156,100	453	148,000	169,000	430	491
Pulverized Coal	Coal	800	800	800	687,040	859	620,000	756,000	775	945
Fluidized Bed	Coal	500	500	500	477,100	954	425,000	512,500	850	1,025
IGCC	Coal	577	494	536	697,900	1303	560,000	725,000	1,046	1,354
Bartow #3 Repower	N. Gas	574	536	555	171,000	308	150,000	195,000	270	351
Bartow #1or #2 Repower	N. Gas	274	248	261	103,000	394	81,000	107,000	310	410
Higgins Repower	N. Gas	127	118	122	56,000	459	51,000	62,000	418	508
Turner Repower	N. Gas	248	230	239	88,000	368	80,000	102,000	335	427

Rocha, James R. /goc,openmail

From: McKeage, Mark D. /goc,openmail
Sent: Friday, May 26, 2000 12:16 PM
To: Rocha, James R. /goc,openmail
Subject: Difference between GulfBase & No Hines 2

Jim,

Please see attached.

Also, you may note that the year 2000 is slightly different than was included in the numbers I sent you during the RFP. This is due to the fact that PHB and I found an error in that year- I had neglected to include FPC's purchase from Lakeland. It affects the year 2000 only, and affects all cases equally, so no harm.

Year	GulfBase	NoHines2	Difference
2000	1,193,127	1,193,127	0
2001	1,240,870	1,240,870	0
2002	1,157,956	1,155,364	-2,592
2003	1,227,334	1,233,231	5,897
2004	1,233,324	1,284,136	50,812
2005	1,317,811	1,361,553	43,742
2006	1,324,769	1,359,966	35,197
2007	1,431,651	1,474,534	42,883
2008	1,446,962	1,471,865	24,903
2009	1,505,475	1,536,685	31,210
2010	1,463,414	1,507,941	44,527

Mark D. McKeage
Mark D. McKeage, PE
Principal Engineer

Integrated Resource Planning & Forecasting
Financial Services Division
Florida Power Corporation
One Power Plaza - MAC BB3G
263 13th Avenue South
St. Petersburg, Florida 33701-5511
external voice:(727) 826-4393
internal voice: 7-230-4393
external fax:(727) 826-4333
internal fax: 7-230-4333

COMPONENTS OF WINTER PEAK DEMAND

JANUARY 2000 FORECAST

Year	Regressed Firm Retail Unadj.	Retail IS/CS	Potential Total Retail	Non-Disp. DSM & SS Cogen	Total Retail before DLC	WHOLESALE REA	WHOLESALE BULK	WHOLESALE MUNI	WHOLESALE IS	WHOLESALE Total	Company Use	Total System before DLC	Total IS/CS	LM, VR & SBG	Total System Firm
2000	8,004	312	8,316	-423	7,893	626	771	236	14	1,647	30	9,570	-326	-985	8,259
2001	8,176	292	8,468	-444	8,024	588	924	205	14	1,731	30	9,785	-306	-951	8,528
2002	8,346	290	8,636	-468	8,168	605	459	196	14	1,274	30	9,472	-304	-886	8,282
2003	8,514	314	8,828	-495	8,333	558	153	203	14	928	30	9,291	-328	-843	8,120
2004	8,682	315	8,997	-523	8,474	503	153	206	14	877	30	9,381	-329	-821	8,230
2005	8,845	320	9,165	-552	8,613	525	153	198	14	890	30	9,533	-334	-805	8,394
2006	9,002	323	9,325	-582	8,743	600	153	200	14	968	30	9,741	-337	-794	8,609
2007	9,155	328	9,483	-613	8,870	676	153	203	14	1,046	30	9,946	-342	-784	8,820
2008	9,303	331	9,634	-643	8,991	755	153	206	14	1,129	30	10,150	-345	-775	9,029
2009	9,449	334	9,783	-672	9,111	833	153	209	14	1,210	30	10,351	-348	-769	9,233
2010	9,597	336	9,933	-701	9,232	912	153	212	14	1,291	30	10,553	-350	-763	9,440

JANUARY 1999 FORECAST

Year	Regressed Firm Retail Unadj.	Retail IS/CS	Potential Total Retail	Non-Disp. DSM & SS Cogen	Total Retail before DLC	WHOLESALE REA	WHOLESALE BULK	WHOLESALE MUNI	WHOLESALE IS	WHOLESALE Total	Company Use	Total System before DLC	Total IS/CS	LM, VR & SBG	Total System Firm
2000	8,018	312	8,330	-399	7,931	604	755	215	0	1,574	30	9,535	-312	-1003	8,220
2001	8,188	300	8,488	-424	8,064	566	905	197	0	1,668	30	9,762	-300	-1003	8,459
2002	8,357	297	8,654	-450	8,204	636	450	180	0	1,266	30	9,500	-297	-932	8,271
2003	8,524	299	8,823	-478	8,345	537	0	182	0	719	30	9,094	-299	-883	7,912
2004	8,689	296	8,985	-508	8,477	481	0	184	0	665	30	9,172	-296	-857	8,019
2005	8,852	298	9,150	-538	8,612	554	0	174	0	728	30	9,370	-298	-840	8,232
2006	9,014	300	9,314	-569	8,745	630	0	176	0	806	30	9,581	-300	-826	8,455
2007	9,177	302	9,479	-599	8,880	705	0	178	0	883	30	9,793	-302	-814	8,677
2008	9,340	304	9,644	-628	9,016	783	0	180	0	963	30	10,009	-304	-805	8,900
2009	9,504	306	9,810	-657	9,153	863	0	182	0	1,045	30	10,228	-306	-798	9,124
2010	9,669	308	9,977	-686	9,291	842	0	184	0	1,026	30	10,347	-308	-790	9,249

JANUARY 2000 FORECAST vs JANUARY 1999 FORECAST

Year	Regressed Firm Retail Unadj.	Retail IS/CS	Potential Total Retail	Non-Disp. DSM & SS Cogen	Total Retail before DLC	WHOLESALE REA	WHOLESALE BULK	WHOLESALE MUNI	WHOLESALE IS	WHOLESALE Total	Company Use	Total System before DLC	Total IS/CS	LM, VR & SBG	Total System Firm
2000	-14	0	-14	-24	-38	22	16	21	14	73	0	35	-14	18	39
2001	-12	-8	-20	-20	-40	22	19	8	14	63	0	23	-6	52	69
2002	-11	-7	-18	-18	-36	-32	9	16	14	8	0	-28	-7	46	11
2003	-10	15	5	-17	-12	21	153	21	14	209	0	197	-29	40	208
2004	-7	19	12	-15	-3	22	153	22	14	212	0	209	-33	36	211
2005	-7	22	15	-14	1	-29	153	24	14	162	0	163	-36	35	162
2006	-12	23	11	-13	-2	-30	153	24	14	162	0	160	-37	32	154
2007	-22	26	4	-14	-10	-29	153	25	14	163	0	153	-40	30	143
2008	-37	27	-10	-15	-25	-28	153	26	14	166	0	141	-41	30	129
2009	-55	28	-27	-15	-42	-30	153	27	14	165	0	123	-42	29	109
2010	-72	28	-44	-15	-59	70	153	28	14	265	0	206	-42	27	191

COMPONENTS OF SUMMER PEAK DEMAND

JANUARY 2000 FORECAST

Year	Regressed Firm Retail Unadj.	Retail IS/CS	Potential Total Retail	Non-Disp. DSM & SS Cogen	Total Retail before DLC	WHOLESALE REA	WHOLESALE BULK	WHOLESALE MUNI	WHOLESALE IS	WHOLESALE Total	Company Use	Total System before DLC	Total IS/CS	LM, VR & SBG	Total System Firm
2000	7,013	313	7326	-355	6971	239	771	253	14	1277	30	8,278	-327	-512	7,439
2001	7,173	294	7467	-368	7099	183	924	222	14	1343	30	8,472	-308	-463	7,701
2002	7,330	291	7621	-381	7240	184	459	209	14	867	30	8,137	-305	-400	7,431
2003	7,487	314	7801	-395	7406	121	153	218	14	506	30	7,942	-328	-356	7,258
2004	7,641	315	7956	-410	7546	48	153	221	14	436	30	8,012	-329	-322	7,361
2005	7,790	321	8111	-425	7686	54	153	211	14	433	30	8,149	-335	-291	7,522
2006	7,934	325	8259	-441	7818	112	153	214	14	493	30	8,341	-339	-265	7,737
2007	8,074	329	8403	-456	7947	171	153	217	14	555	30	8,532	-343	-242	7,947
2008	8,211	332	8543	-471	8072	231	153	220	14	618	30	8,720	-346	-222	8,152
2009	8,348	335	8683	-486	8197	291	153	223	14	681	30	8,908	-349	-205	8,354
2010	8,487	337	8824	-492	8332	353	153	226	14	747	30	9,109	-351	-189	8,569

JANUARY 1999 FORECAST

Year	Regressed Firm Retail Unadj.	Retail IS/CS	Potential Total Retail	Non-Disp. DSM & SS Cogen	Total Retail before DLC	WHOLESALE REA	WHOLESALE BULK	WHOLESALE MUNI	WHOLESALE IS	WHOLESALE Total	Company Use	Total System before DLC	Total IS/CS	LM, VR & SBG	Total System Firm
2000	7,083	313	7,396	-353	7,043	216	755	226	0	1,197	30	8,270	-313	-498	7,459
2001	7,254	301	7,555	-366	7,189	160	905	211	0	1,276	30	8,495	-301	-453	7,741
2002	7,423	298	7,721	-379	7,342	214	300	191	0	705	30	8,077	-298	-394	7,385
2003	7,590	300	7,890	-393	7,497	98	0	191	0	289	30	7,816	-300	-353	7,163
2004	7,755	297	8,052	-408	7,644	25	0	194	0	219	30	7,893	-297	-321	7,275
2005	7,919	299	8,218	-423	7,795	82	0	183	0	265	30	8,090	-299	-293	7,498
2006	8,083	301	8,384	-439	7,945	140	0	186	0	326	30	8,301	-301	-269	7,731
2007	8,248	303	8,551	-454	8,097	199	0	189	0	388	30	8,515	-303	-248	7,964
2008	8,412	305	8,717	-468	8,249	259	0	192	0	451	30	8,730	-305	-230	8,195
2009	8,578	307	8,885	-483	8,402	319	0	194	0	513	30	8,945	-307	-215	8,423
2010	8,744	309	9,053	-497	8,556	382	0	197	0	579	30	9,165	-309	-202	8,654

JANUARY 2000 FORECAST vs JANUARY 1999 FORECAST

Year	Regressed Firm Retail Unadj.	Retail IS/CS	Potential Total Retail	Non-Disp. DSM & SS Cogen	Total Retail before DLC	WHOLESALE REA	WHOLESALE BULK	WHOLESALE MUNI	WHOLESALE IS	WHOLESALE Total	Company Use	Total System before DLC	Total IS/CS	LM, VR & SBG	Total System Firm
2000	-70	0	-70	-2	-72	23	16	27	14	80	0	8	-14	-14	-20
2001	-81	-7	-88	-2	-90	23	19	11	14	67	0	-23	-7	-10	-40
2002	-93	-7	-100	-2	-102	-30	159	18	14	162	0	60	-7	-6	46
2003	-103	14	-89	-2	-91	23	153	27	14	217	0	126	-28	-3	95
2004	-114	18	-96	-2	-98	23	153	27	14	217	0	119	-32	-1	86
2005	-129	22	-107	-2	-109	-28	153	28	14	168	0	59	-36	2	24
2006	-149	24	-125	-2	-127	-28	153	28	14	167	0	40	-38	4	6
2007	-174	26	-148	-2	-150	-28	153	28	14	167	0	17	-40	6	-17
2008	-201	27	-174	-3	-177	-28	153	28	14	167	0	-10	-41	8	-43
2009	-230	28	-202	-3	-205	-28	153	29	14	168	0	-37	-42	10	-69
2010	-257	28	-229	5	-224	-29	153	29	14	168	0	-56	-42	13	-85

Current Perspective

Key Issues	Current Thinking
Hines Site	Offered to Bidders
Need	530 MW in 11/03
Block Size	Flexible
Contract Duration	Flexible
Self-Build Costs	Refined Estimate
Basis of Analysis	NPV Revenue Requirements
Fuel Scenario	FGT Supply (Base)
Initial Screening	ProVIEW Optimization
Detailed Analysis	ProSym/Pro-Forma
FPC Tx Impact	Study Short List Proposals
Contract Options	Valuation Adjustment
Non-Price Attributes	Non-Numeric Analysis

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

2000 SERC RATINGS, COGENERATION = 991231

JANUARY 2000 LONG-TERM FORECAST (S000101)

Bulk Power Sales Included In Demand & Energy Forecast

2000 Ten-Year Site Plan Analysis * Future Capacity Additions for 20 % RM * Base Case

		WINTER 00/01 Jan-2001	WINTER 01/02 Jan-2002	WINTER 02/03 Jan-2003	WINTER 03/04 Jan-2004	WINTER 04/05 Jan-2005	WINTER 05/06 Jan-2006	WINTER 06/07 Jan-2007	WINTER 07/08 Jan-2008	WINTER 08/09 Jan-2009	WINTER 09/10 Jan-2010
Existing FPC Capacity	MW	8,267	8,590	8,607	8,607	9,028	9,028	9,445	9,349	9,916	9,916
New FPC Capacity	MW	323	17	0	567	0	567	0	567	0	567
Retired FPC Capacity	MW	0	0	0	146	0	150	96	0	0	0
Total Installed Capacity	MW	8,590	8,607	8,607	9,028	9,028	9,445	9,349	9,916	9,916	10,483
Firm Purchase Capacity	MW	469	469	469	469	479	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	818	818	818	818	813	798	689	548
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	9,890	9,907	9,894	10,315	10,325	10,742	10,641	11,193	11,084	11,510
Potential Total Retail Demand	MW	8,468	8,636	8,828	8,997	9,165	9,325	9,483	9,634	9,783	9,933
Wholesale (REA)	MW	894	911	558	503	525	600	676	755	833	912
Wholesale (Bulk Power)	MW	632	167	167	167	167	167	167	167	167	167
Wholesale (Municipal)	MW	205	196	203	206	198	200	203	206	209	212
Total Wholesale Demand	MW	1,731	1,274	928	877	890	968	1,046	1,129	1,210	1,291
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	10,229	9,940	9,786	9,904	10,085	10,323	10,559	10,793	11,023	11,254
Non-Dispatchable DSM and Self-Service QF	MW	444	468	495	523	552	582	613	643	672	701
Normal Weather Demand (Before Load Control)	**MW**	**9,785**	**9,472**	**9,291**	**9,381**	**9,533**	**9,741**	**9,946**	**10,150**	**10,351**	**10,553**
Normal Weather Reserves (Before Load Control)	MW	105	435	603	935	792	1,002	695	1,043	733	957
Normal Weather Reserve Margin (Before Load Control)	**%**	**1.1%**	**4.6%**	**6.5%**	**10.0%**	**8.3%**	**10.3%**	**7.0%**	**10.3%**	**7.1%**	**9.1%**
Normal Weather Load Management	MW	833	771	730	707	688	674	661	650	641	632
Normal Weather Demand (After Load Management)	MW	8,952	8,701	8,561	8,674	8,845	9,067	9,285	9,499	9,710	9,921
Normal Weather Reserves (After Load Management)	MW	938	1,206	1,333	1,641	1,480	1,675	1,356	1,693	1,374	1,589
Normal Weather Reserve Margin (After Load Management)	%	10.5%	13.9%	15.6%	18.9%	16.7%	18.5%	14.6%	17.8%	14.1%	16.0%
Normal Weather Interruptible Load	MW	306	304	328	329	334	337	342	345	348	350
Normal Weather Voltage Reduction	MW	118	115	113	114	117	120	123	125	128	131
Normal Weather Demand (After All Load Control)	**MW**	**8,528**	**8,282**	**8,120**	**8,231**	**8,394**	**8,610**	**8,820**	**9,029**	**9,234**	**9,440**
Normal Weather Reserves (After All Load Control)	MW	1,362	1,625	1,774	2,084	1,931	2,132	1,821	2,163	1,850	2,070
Normal Weather Reserve Margin (After All Load Control)	**%**	**16.0%**	**19.6%**	**21.9%**	**25.3%**	**23.0%**	**24.8%**	**20.6%**	**24.0%**	**20.0%**	**21.9%**
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,706	1,656	1,624	1,646	1,679	1,722	1,764	1,806	1,847	1,888
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-344	-32	150	438	252	410	57	358	3	182
Normal Weather "DLC" Reserve Margin Contribution	%	92.3%	73.2%	66.0%	55.2%	59.0%	53.0%	61.9%	51.8%	60.4%	53.8%

Note: Suwannee River Steam Units 1-3 Retired 12/31/2003
Higgins Peakers P1-P4 Retired 12/31/2005
Rio Pinar Peaker P1 Retired 12/31/2005
Avon Park Peakers P1-P2 Retired 12/31/2006
Turner Peakers P1-P2 Retired 12/31/2006

FPC 038

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY
2000 SERC RATINGS, COGENERATION = 991231
JANUARY 2000 LONG-TERM FORECAST (S000101)
Bulk Power Sales Included in Demand & Energy Forecast

2000 Ten-Year Site Plan Analysis * Future Capacity Additions for 20 % RM * Base Case

		SUMMER 00 Aug-2000	SUMMER 01 Aug-2001	SUMMER 02 Aug-2002	SUMMER 03 Aug-2003	SUMMER 04 Aug-2004	SUMMER 05 Aug-2005	SUMMER 06 Aug-2006	SUMMER 07 Aug-2007	SUMMER 08 Aug-2008	SUMMER 09 Aug-2009
Existing FPC Capacity	MW	7,553	7,553	7,817	7,834	7,834	8,186	8,186	8,546	8,468	8,963
New FPC Capacity	MW	0	264	17	0	495	0	495	0	495	0
Retired FPC Capacity	MW	0	0	0	0	143	0	135	78	0	0
Total Installed Capacity	MW	7,553	7,817	7,834	7,834	8,186	8,186	8,546	8,468	8,963	8,963
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	818	818	818	818	818	813	798	689
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	8,853	9,117	9,121	9,121	9,473	9,483	9,843	9,760	10,240	10,131
Potential Total Retail Demand	MW	7,326	7,467	7,621	7,801	7,956	8,111	8,259	8,403	8,543	8,683
Wholesale (REA)	MW	392	489	490	121	48	54	112	171	231	291
Wholesale (Bulk Power)	MW	632	632	167	167	167	167	167	167	167	167
Wholesale (Municipal)	MW	253	222	209	218	221	211	214	217	220	223
Total Wholesale Demand	MW	1,277	1,343	867	506	436	433	493	555	618	681
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	8,633	8,840	8,518	8,337	8,422	8,574	8,782	8,988	9,191	9,394
Non-Dispatchable DSM and Self-Service QF	MW	355	368	381	395	410	425	441	456	471	486
Normal Weather Demand (Before Load Control)	**MW**	**8,278**	**8,472**	**8,137**	**7,942**	**8,012**	**8,149**	**8,341**	**8,532**	**8,720**	**8,908**
Normal Weather Reserves (Before Load Control)	MW	575	645	985	1,179	1,461	1,335	1,502	1,228	1,519	1,222
Normal Weather Reserve Margin (Before Load Control)	**%**	**6.9%**	**7.6%**	**12.1%**	**14.8%**	**18.2%**	**16.4%**	**18.0%**	**14.4%**	**17.4%**	**13.7%**
Normal Weather Load Management	MW	512	463	400	356	322	291	265	242	222	205
Normal Weather Demand (After Load Management)	MW	7,766	8,009	7,736	7,586	7,690	7,857	8,078	8,290	8,498	8,703
Normal Weather Reserves (After Load Management)	MW	1,087	1,108	1,385	1,536	1,783	1,626	1,767	1,470	1,742	1,427
Normal Weather Reserve Margin (After Load Management)	%	14.0%	13.8%	17.9%	20.2%	23.2%	20.7%	21.9%	17.7%	20.5%	16.4%
Normal Weather Interruptible Load	MW	327	308	305	328	329	335	339	343	346	349
Normal Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After All Load Control)	**MW**	**7,439**	**7,701**	**7,431**	**7,258**	**7,361**	**7,522**	**7,737**	**7,947**	**8,152**	**8,354**
Normal Weather Reserves (After All Load Control)	MW	1,414	1,416	1,690	1,864	2,112	1,961	2,106	1,813	2,088	1,776
Normal Weather Reserve Margin (After All Load Control)	**%**	**19.0%**	**18.4%**	**22.7%**	**25.7%**	**28.7%**	**26.1%**	**27.2%**	**22.8%**	**25.6%**	**21.3%**
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,488	1,540	1,486	1,452	1,472	1,504	1,547	1,589	1,630	1,671
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-74	-124	204	412	639	456	559	223	457	105
Normal Weather "DLC" Reserve Margin Contribution	%	59.3%	54.4%	41.7%	36.7%	30.8%	31.9%	28.7%	32.3%	27.2%	31.2%

FPC 039

BATES NOS. FPC 040
CONFIDENTIAL
PURSUANT TO FLORIDA
POWER CORPORATION'S
REQUST FOR CONFIDENTIAL
CLASSIFICATION FILED
AUGUST 7, 2000

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

1998 SERC RATINGS, COGENERATION = 981231

JANUARY 1999 LONG-TERM FORECAST (S981208)

Bulk Power Sales (GPC, OPC, SECI & MEAG) Included in Demand & Energy Forecast

1999 Ten-Year Site Plan

		WINTER 98/99 Jan-1999	WINTER 99/00 Jan-2000	WINTER 00/01 Jan-2001	WINTER 01/02 Jan-2002	WINTER 02/03 Jan-2003	WINTER 03/04 Jan-2004	WINTER 04/05 Jan-2005	WINTER 05/06 Jan-2006	WINTER 06/07 Jan-2007	WINTER 07/08 Jan-2008
Existing FPC Capacity	MW	8,232	8,265	8,306	8,620	8,473	8,473	8,307	8,774	8,774	9,341
New FPC Capacity	MW	0	0	297	0	0	0	567	0	567	0
Retired FPC Capacity	MW	0	0	0	147	0	166	100	0	0	0
Total Installed Capacity	MW	8,232	8,265	8,603	8,473	8,473	8,307	8,774	8,774	9,341	9,341
Firm Purchase Capacity	MW	469	469	469	469	469	469	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831	831
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	25	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	9,507	9,565	9,903	9,773	9,773	9,607	10,084	10,084	10,651	10,651
Potential Total Retail Demand	MW	8,166	8,330	8,488	8,654	8,823	8,985	9,150	9,314	9,479	9,644
Wholesale (REA)	MW	669	754	866	936	537	481	554	630	705	783
Wholesale (Bulk Power)	MW	605	605	605	150	0	0	0	0	0	0
Wholesale (Municipal)	MW	253	216	197	180	183	185	174	176	178	180
Total Wholesale Demand	MW	1,527	1,575	1,668	1,266	720	666	728	806	883	963
Wholesale (Interruptible)	MW	0	0	0	0	0	0	0	0	0	0
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	9,723	9,935	10,186	9,950	9,573	9,681	9,908	10,150	10,392	10,637
Non-Dispatchable DSM and Self-Service QF	MW	378	399	424	450	478	508	538	569	599	628
Normal Weather Demand (Before Load Control)	MW	9,345	9,536	9,762	9,500	9,095	9,173	9,370	9,581	9,793	10,009
Normal Weather Interruptible Load	MW	322	312	300	297	299	296	298	300	302	304
Normal Weather Load Management	MW	895	889	886	817	773	746	726	709	694	682
Normal Weather Voltage Reduction	MW	112	114	117	115	110	111	114	117	120	123
Normal Weather Demand (After Load Management)	MW	8,450	8,647	8,876	8,683	8,322	8,427	8,644	8,872	9,099	9,327
Normal Weather Demand (After All Load Control)	MW	8,016	8,221	8,459	8,271	7,913	8,020	8,232	8,455	8,677	8,900
Normal Weather Reserves (Before Load Control)	MW	162	29	141	273	678	434	714	503	858	642
Normal Weather Reserve Margin (Before Load Control)	%	1.7%	0.3%	1.4%	2.9%	7.5%	4.7%	7.6%	5.2%	8.8%	6.4%
Normal Weather Reserves (After Load Management)	MW	1,057	918	1,027	1,090	1,451	1,180	1,440	1,212	1,552	1,324
Normal Weather Reserve Margin (After Load Management)	%	12.5%	10.6%	11.6%	12.6%	17.4%	14.0%	16.7%	13.7%	17.1%	14.2%
Normal Weather Reserves (After All Load Control)	MW	1,491	1,344	1,444	1,502	1,860	1,587	1,852	1,629	1,974	1,751
Normal Weather Reserve Margin (After All Load Control)	%	18.6%	16.3%	17.1%	18.2%	23.5%	19.8%	22.5%	19.3%	22.7%	19.7%
Normal Weather Reserves (After All Load Control) Required For 15 %	MW	1,202	1,233	1,269	1,241	1,187	1,203	1,235	1,268	1,302	1,335
Normal Weather Reserves (After All Load Control) Above 15 %	MW	289	111	175	261	673	384	617	361	672	416
Normal Weather "DLC" Reserve Margin Contribution	%	69.1%	97.8%	90.2%	81.6%	63.5%	72.7%	61.4%	69.1%	56.5%	63.3%

FPC 041

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

1998 SERC RATINGS, COGENERATION = 981231

JANUARY 1999 LONG-TERM FORECAST (S981208)

Bulk Power Sales (GPC, OPC, SECI & MEAG) Included in Demand & Energy Forecast

1999 Ten-Year Site Plan

		SUMMER 99 Aug-1999	SUMMER 00 Aug-2000	SUMMER 01 Aug-2001	SUMMER 02 Aug-2002	SUMMER 03 Aug-2003	SUMMER 04 Aug-2004	SUMMER 05 Aug-2005	SUMMER 06 Aug-2006	SUMMER 07 Aug-2007	SUMMER 08 Aug-2008
Existing FPC Capacity	MW	7,469	7,510	7,510	7,776	7,631	7,631	7,488	7,895	7,895	8,390
New FPC Capacity	MW	0	0	249	0	0	0	495	0	495	0
Retired FPC Capacity	MW	0	0	0	145	0	143	88	0	0	0
Total Installed Capacity	MW	7,469	7,510	7,759	7,631	7,631	7,488	7,895	7,895	8,390	8,390
Firm Purchase Capacity	MW	469	469	469	469	469	469	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831	831
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	25	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	8,744	8,810	9,059	8,931	8,931	8,788	9,205	9,205	9,700	9,700
Potential Total Retail Demand	MW	7,234	7,396	7,555	7,721	7,890	8,052	8,218	8,384	8,551	8,717
Wholesale (REA)	MW	299	366	460	514	98	25	82	140	199	259
Wholesale (Bulk Power)	MW	880	605	605	150	0	0	0	0	0	0
Wholesale (Municipal)	MW	279	226	211	190	191	194	183	185	189	192
Total Wholesale Demand	MW	1,458	1,197	1,276	854	289	219	265	325	388	451
Wholesale (Interruptible)	MW	0	0	0	0	0	0	0	0	0	0
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	8,722	8,623	8,861	8,605	8,209	8,301	8,513	8,739	8,969	9,198
Non-Dispatchable DSM and Self-Service QF	MW	342	353	366	379	393	408	423	439	454	468
Normal Weather Demand (Before Load Control)	MW	8,380	8,270	8,495	8,226	7,816	7,893	8,090	8,300	8,515	8,730
Normal Weather Interruptible Load	MW	324	313	301	298	300	297	299	301	303	305
Normal Weather Load Management	MW	502	498	453	394	353	321	293	269	248	230
Normal Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After Load Management)	MW	7,878	7,772	8,042	7,832	7,463	7,572	7,797	8,031	8,267	8,500
Normal Weather Demand (After All Load Control)	MW	7,554	7,459	7,741	7,534	7,163	7,275	7,498	7,730	7,964	8,195
Normal Weather Reserves (Before Load Control)	MW	364	540	564	705	1,115	895	1,115	905	1,185	970
Normal Weather Reserve Margin (Before Load Control)	%	4.3%	6.5%	6.6%	8.6%	14.3%	11.3%	13.8%	10.9%	13.9%	11.1%
Normal Weather Reserves (After Load Management)	MW	866	1,038	1,017	1,099	1,468	1,216	1,408	1,174	1,433	1,200
Normal Weather Reserve Margin (After Load Management)	%	11.0%	13.4%	12.6%	14.0%	19.7%	16.1%	18.1%	14.6%	17.3%	14.1%
Normal Weather Reserves (After All Load Control)	MW	1,190	1,351	1,318	1,397	1,768	1,513	1,707	1,475	1,736	1,505
Normal Weather Reserve Margin (After All Load Control)	%	15.8%	18.1%	17.0%	18.5%	24.7%	20.8%	22.8%	19.1%	21.8%	18.4%
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,511	1,492	1,548	1,507	1,433	1,455	1,500	1,546	1,593	1,639
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-321	-141	-230	-110	335	58	207	-71	143	-134
Normal Weather "DLC" Reserve Margin Contribution	%	69.4%	60.0%	57.2%	49.5%	38.9%	40.8%	34.7%	38.6%	31.7%	35.5%

FPC 042

FLORIDA POWER CORPORATION
NET MAXIMUM DEPENDABLE GENERATING CAPACITY
EFFECTIVE BEGINNING JANUARY 1, 2000

NOTE: These are preliminary ratings to be used in the EIA-411 filing on 2/15/00.

		WINTER CAPABILITY		SUMMER CAPABILITY		SUMMER DERATION
	UNIT	UNIT MW	PLANT MW	UNIT MW	PLANT MW	(%)
NUCLEAR STEAM						
Crystal River	3	782*	782	765*	765	2.1739
FOSSIL STEAM						
Anclote	1	522	1044	498	993	4.5977
	2	522		495		5.1724
Bartow	1	123	452	121	444	1.6260
	2	121		119		1.6529
	3	208		204		1.9231
Crystal River South	1	373	842	369	833	1.0724
	2	469		464		1.0661
Crystal River North	4	717	1449	697	1414	2.7894
	5	732		717		2.0492
Suwannee	1	33	146	32	143	3.0303
	2	32		31		3.1250
	3	81		80		1.2346
COMBUSTION TURBINES						
Avon Park	P1 & P2	32 ea.	64	26 ea.	52	18.7500
Bartow	P1 to P3	53 ea.	159	46 ea.	138	13.2075
Bartow	P4	60 ea.	60	49 ea.	49	18.3333
Bayboro	P1 to P4	58 ea.	232	46 ea.	184	20.6897
DeBary	P1 to P6	65 ea.	390	54 ea.	324	16.9231
DeBary	P7 to P9	93 ea.	279	80 ea.	240	13.9785
DeBary	P10	93	93	79	79	15.0538
Higgins	P1 & P2	32 ea.	64	27 ea.	54	15.6250
Higgins	P3 & P4	35 ea.	70	34 ea.	68	2.8571
Intercession City	P1 to P6	61 ea.	366	49 ea.	294	19.6721
Intercession City	P7 to P10	94 ea.	376	88 ea.	352	6.3830
Intercession City	P11	170	170	143	143	15.8824
Rio Pinar	P1	16	16	13	13	18.7500
Suwannee	P1 & P3	67 ea.	134	55 ea.	110	17.9104
Suwannee	P2	67	67	54	54	19.4030
Turner	P1 & P2	16 ea.	32	13 ea.	26	18.7500
Turner	P3	82	82	65	65	20.7317
Turner	P4	80	80	63	63	21.2500
University of Florida Cogen	P1	41	41	35	35	14.6341
COMBINED CYCLE						
Hines	1	529	529	482	482	8.8847
Tiger Bay	1	223	223	207	207	7.1749
NUCLEAR STEAM (91.7806%)			782		765	
FOSSIL STEAM			3933		3827	
COMB. TURBINES			2775		2343	
COMBINED CYCLE			752		689	
SYSTEM TOTAL *			8242		7624	

Microsoft Excel - tysp2000.xls

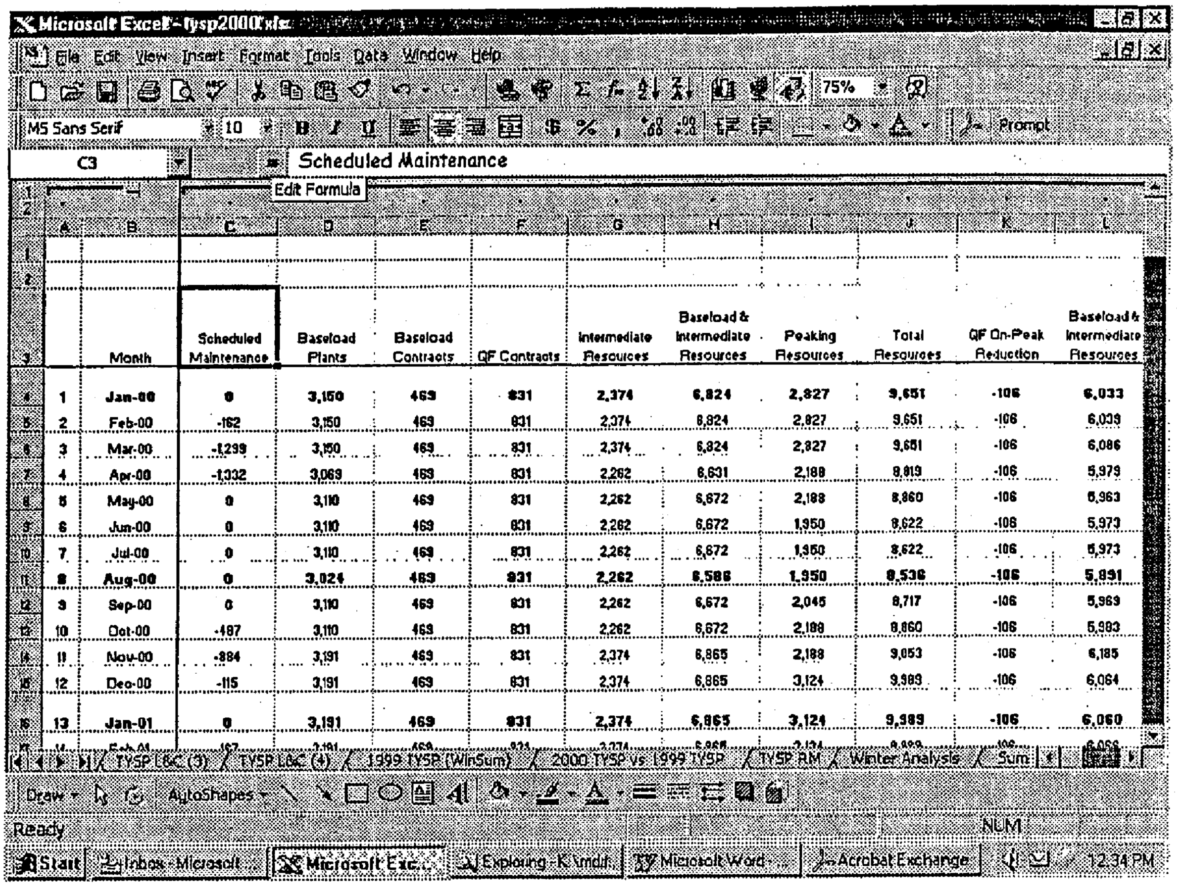
Scheduled Maintenance

	Month	Scheduled Maintenance	Baseload Plants	Baseload Contracts	QF Contracts	Intermediate Resources	Baseload & Intermediate Resources	Peaking Resources	Total Resources	QF On-Peak Reduction	Baseload & Intermediate Resources
1	**Jan-00**	**0**	**3,150**	**469**	**831**	**2,374**	**6,824**	**2,827**	**9,651**	**-106**	**6,033**
2	Feb-00	-162	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,039
3	Mar-00	-1,299	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,086
4	Apr-00	-1,332	3,069	469	831	2,262	6,631	2,188	8,819	-106	5,979
5	May-00	0	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,963
6	Jun-00	0	3,110	469	831	2,262	6,672	1,950	8,622	-106	5,973
7	Jul-00	0	3,110	469	831	2,262	6,672	1,950	8,622	-106	5,973
8	**Aug-00**	**0**	**3,024**	**469**	**831**	**2,262**	**6,586**	**1,950**	**8,536**	**-106**	**5,891**
9	Sep-00	0	3,110	469	831	2,262	6,672	2,046	8,717	-106	5,969
10	Oct-00	-487	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,983
11	Nov-00	-884	3,191	469	831	2,374	6,866	2,188	9,053	-106	6,185
12	Dec-00	-115	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,084
13	**Jan-01**	**0**	**3,191**	**469**	**831**	**2,374**	**6,865**	**3,124**	**9,989**	**-106**	**6,060**

Steam / Peaking / TYSP Load / TYSP High Load / TYSP Low Load / TYSP Capacity / TYSP L&C / TYSP L&C (2) / TYSP

Ready NUM

Start | Inbox - Microsoft ... | Microsoft Exc... | Exploring - K:\indil... | Microsoft Word - ... | Acrobat Exchange | 12:33 PM



Microsoft Excel - tysp2000.xls

C3 = Scheduled Maintenance

	Month	Scheduled Maintenance	Baseload Plants	Baseload Contracts	QF Contracts	Intermediate Resources	Baseload & Intermediate Resources	Peaking Resources	Total Resources	QF On-Peak Reduction	Baseload & Intermediate Resources
1	Jan-00	0	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,033
2	Feb-00	-162	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,039
3	Mar-00	-1,299	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,086
4	Apr-00	-1,332	3,069	469	831	2,262	6,631	2,188	8,819	-106	5,979
5	May-00	0	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,963
6	Jun-00	0	3,110	469	831	2,262	6,672	1,950	8,622	-106	5,973
7	Jul-00	0	3,110	469	831	2,262	6,672	1,950	8,622	-106	5,973
8	Aug-00	0	3,024	469	831	2,262	6,586	1,950	8,536	-106	5,891
9	Sep-00	0	3,110	469	831	2,262	6,672	2,045	8,717	-106	5,969
10	Oct-00	-487	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,983
11	Nov-00	-884	3,191	469	831	2,374	6,865	2,188	9,053	-106	6,185
12	Dec-00	-115	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,064
13	Jan-01	0	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,060

TYSP L&C (3) / TYSP L&C (4) / 1999 TYSP (WinSum) / 2000 TYSP vs 1999 TYSP / TYSP RM / Winter Analysis / Sum

Microsoft Excel - tysp2000.xls

C3 = Scheduled Maintenance

	Month	Scheduled Maintenance	Baseload Plants	Baseload Contracts	QF Contracts	Intermediate Resources	Baseload & Intermediate Resources	Peaking Resources	Total Resources	QF On-Peak Reduction	Baseload & Intermediate Resources
1	**Jan-00**	**0**	**3,150**	**469**	**831**	**2,374**	**6,824**	**2,827**	**9,651**	**-106**	**6,033**
2	Feb-00	-162	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,039
3	Mar-00	-1,299	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,086
4	Apr-00	-1,332	3,069	469	831	2,262	6,631	2,188	8,819	-106	5,979
5	May-00	0	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,963
6	Jun-00	0	3,110	469	831	2,262	6,672	1,950	8,622	-106	5,973
7	Jul-00	0	3,110	469	831	2,262	6,672	1,950	8,622	-106	5,973
8	**Aug-00**	**0**	**3,024**	**469**	**831**	**2,262**	**6,586**	**1,950**	**8,536**	**-106**	**5,891**
9	Sep-00	0	3,110	469	831	2,262	6,672	2,045	8,717	-106	5,969
10	Oct-00	-497	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,983
11	Nov-00	-884	3,191	469	831	2,374	6,865	2,188	9,053	-106	6,186
12	Dec-00	-115	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,064
13	**Jan-01**	**0**	**3,191**	**469**	**831**	**2,374**	**6,865**	**3,124**	**9,989**	**-106**	**6,060**

Summer Analysis / Normal Load / Normal Capacity / Normal L&C / Normal RM / Normal 24-MO. / TMY Load / TMY L

Ready NUM

Microsoft Excel - tysp2000.xls

File Edit View Insert Format Tools Data Window Help

C3 = Scheduled Maintenance

	Month	Scheduled Maintenance	Baseload Plants	Baseload Contracts	QF Contracts	Intermediate Resources	Baseload & Intermediate Resources	Peaking Resources	Total Resources	QF On-Peak Reduction	Baseload & Intermediate Resources
1	Jan-00	0	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,033
2	Feb-00	-162	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,039
3	Mar-00	-1,299	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,086
4	Apr-00	-1,332	3,069	469	831	2,262	6,631	2,188	8,819	-106	5,979
5	May-00	0	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,963
6	Jun-00	0	3,110	469	831	2,262	6,672	1,950	8,622	-106	5,973
7	Jul-00	0	3,110	469	831	2,262	6,672	1,950	8,622	-106	5,973
8	Aug-00	0	3,024	469	831	2,262	6,586	1,950	8,536	-106	5,891
9	Sep-00	0	3,110	469	831	2,262	6,672	2,045	8,717	-106	5,969
10	Oct-00	-487	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,983
11	Nov-00	-884	3,191	469	831	2,374	6,865	2,188	9,053	-106	6,185
12	Dec-00	-115	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,064
13	Jan-01	0	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,060

TMY Load / TMY L&C / Extreme Load / Extreme L&C / Extreme RM / Mild Load / Mild L&C / Mild RM

Ready NUM

Fossil Steam Plant Rating Summary

	2000 TYSP		1999 Baseline Ratings			
	Winter	Summer	Base Winter	Peak Winter	Base Summer	Peak Summer
ANC - 1	522	498	512	512	507	507
ANC - 2	522	495	522	522	502	502
BAR - 1	123	121	116	116	113	113
BAR - 2	121	119	117	117	113	113
BAR - 3	208	204	210	210	207	207
CRY - 1	383	379	386	386	381	381
CRY - 2	479	474	480	480	469	469
CRY - 4	722	712	724	724	704	704
CRY - 5	732	717	734	734	714	714
SUW - 1	33	32	34	34	33	33
SUW - 2	32	31	33	33	32	32
SUW - 3	81	80	85	85	85	85
Subtotal	***3,958***	***3,862***	***3,953***	***3,953***	***3,860***	***3,860***
UF	41	35	44	44	36	36
TIG	223	207	240	240	200	200
HEC - 1	529	482	505	505	470	470
Subtotal	***793***	***724***	***789***	***789***	***706***	***706***
CRY - 3	782	765	782	782	765	765
TOTAL	***5,533***	***5,351***	***5,524***	***5,524***	***5,331***	***5,331***
Ref to TYSP			***(9)***		***(20)***	

FPC 048

Peaking Unit Ratings

	2000 SERC		*1999 Winter Ratings*				*1999 Summer Ratings*			
	Win.	Sum.	WB@40	WP@40	WB@32	WP@32	SB@90	SP@90	SB@95	SP@95
GAS PEAKERS										
AVP - 1	32	26	32	34	33	34	24	29	19	24
BAP - 2	53	46	53	53	54	54	46	46	46	46
BAP - 4	60	49	58	58	59	62	49	49	49	49
DEP - 7	93	80	91	99	91	98	76	83	69	76
DEP - 8	93	80	91	99	89	96	76	83	69	76
DEP - 9	93	80	91	99	91	98	76	83	69	76
HGP - 1	32	27	30	33	31	34	25	26	24	25
HGP - 2	32	27	30	33	31	34	25	26	24	25
HGP - 3	35	34	35	35	36	36	31	33	29	31
HGP - 4	35	34	35	35	36	36	31	33	29	31
ICP - 7	94	88	89	93	91	98	83	85	81	83
ICP - 8	94	88	89	93	91	98	83	85	81	83
ICP - 9	94	88	89	93	91	98	83	85	81	83
ICP - 10	94	88	89	93	91	98	83	85	81	83
SUP - 1	67	55	63	67	65	68	49	54	44	49
SUP - 3	67	55	63	67	65	68	49	54	44	49
SUBTOTAL	***1,068***	***945***	***1,028***	***1,084***	***1,045***	***1,110***	***889***	***939***	***839***	***889***
L.O. PEAKERS										
AVP - 2	32	26	32	34	33	34	24	29	19	24
BAP - 1	53	46	53	53	54	54	46	46	46	46
BAP - 3	53	46	53	53	54	54	46	46	46	46
BYP - 1	58	46	56	58	58	60	44	47	41	44
BYP - 2	58	46	56	58	58	60	44	47	41	44
BYP - 3	58	46	56	58	58	60	44	47	41	44
BYP - 4	58	46	56	58	58	60	44	47	41	44
DEP - 1	65	54	59	65	61	67	49	54	44	49
DEP - 2	65	54	59	65	61	67	49	54	44	49
DEP - 3	65	54	59	65	61	67	49	54	44	49
DEP - 4	65	54	59	65	61	67	49	54	44	49
DEP - 5	65	54	59	65	61	67	49	54	44	49
DEP - 6	65	54	59	65	61	67	49	54	44	49
DEP - 10	93	79	91	99	89	96	76	83	69	76
ICP - 1	61	49	58	58	62	62	47	47	47	47
ICP - 2	61	49	58	58	62	62	47	47	47	47
ICP - 3	61	49	58	58	62	62	47	47	47	47
ICP - 4	61	49	58	58	62	62	47	47	47	47
ICP - 5	61	49	58	58	62	62	47	47	47	47
ICP - 6	61	49	58	58	62	62	47	47	47	47
ICP - 11	170	143	168	168	172	172	143	143	143	143
RPP - 1	16	13	16	18	17	19	13	15	11	13
SUP - 2	67	54	63	67	65	68	51	54	48	51
TUP - 1	16	13	16	18	17	19	13	15	11	13
TUP - 2	16	13	16	18	17	19	13	15	11	13
TUP - 3	82	65	76	82	78	84	61	65	57	61
TUP - 4	80	63	76	82	78	84	61	65	57	61
SUBTOTAL	***1,666***	***1,363***	***1,586***	***1,662***	***1,644***	***1,717***	***1,299***	***1,370***	***1,228***	***1,299***
TOTAL	***2,734***	***2,308***	***2,614***	***2,746***	***2,689***	***2,827***	***2,188***	***2,309***	***2,067***	***2,188***
Delta from SERC			120	-12			120	-1		

	SERC		Baseline Ratings				Peak Weather Adjusted Ratings			
	Winter	Summer	Base Winter	Peak Winter	Base Summer	Peak Summer	Base Winter	Peak Winter	Base Summer	Peak Summer
Gas Units	*1,068*	*945*	*1,028*	*1,084*	*889*	*939*	*1,045*	*1,110*	*839*	*889*
Oil Units	*1,666*	*1,363*	*1,586*	*1,662*	*1,299*	*1,370*	*1,644*	*1,717*	*1,228*	*1,299*
TOTAL	*2,734*	*2,308*	*2,614*	*2,746*	*2,188*	*2,309*	*2,689*	*2,827*	*2,067*	*2,188*

JANUARY 2000 LONG-TERM FORECAST (S000101)

Normal Weather

Bulk Power Sales Included

SEASON	MONTH	REGRESSED FIRM RETAIL UNADJ. (MW)	RETAIL IS/CS (MW)	POTENTIAL TOTAL RETAIL (MW)	NON-DISP. DSM & S.S. COGEN (MW)	TOTAL RETAIL BEFORE LOAD CONTROL (MW)	WHOLESALE REA (MW)	WHOLESALE BULK (MW)	WHOLESALE MUNI (MW)	WHOLESALE TOTAL (MW)	CO. USE (MW)	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	WHLSE IS (MW)	TOTAL IS/CS (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	COMMERCIAL LOAD MGT. (MW)	STANDBY GENERATION (MW)	TOTAL DLC PROGRAMS (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)	TOTAL IS/CS plus VOLTAGE REDUCTION
WINTER 99/00	Jan-2000	8,004	312	8,316	423	7,893	780	632	236	1,647	30	9,570	14	326	849	0	21	870	1,195	115	8,259	115	441
WINTER 99/00	Feb-2000	6,888	312	7,200	410	6,790	778	525	186	1,489	30	8,309	14	326	701	0	21	722	1,048	0	7,261	100	
WINTER 99/00	Mar-2000	6,076	312	6,388	381	6,007	289	474	191	954	30	6,991	14	326	543	0	21	564	890	0	6,101	85	
SUMMER 00	Apr-2000	5,635	313	5,948	304	5,644	15	479	182	676	30	6,350	14	327	285	21	21	328	655	0	5,695	79	
SUMMER 00	May-2000	6,452	313	6,765	329	6,436	172	555	206	933	30	7,399	14	327	360	24	22	406	733	0	6,666	92	
SUMMER 00	Jun-2000	6,790	313	7,103	343	6,760	295	632	239	1,166	30	7,956	14	327	449	25	22	497	824	0	7,132	98	
SUMMER 00	Jul-2000	6,967	313	7,280	347	6,933	351	632	233	1,216	30	8,179	14	327	444	26	22	492	819	0	7,360	101	
SUMMER 00	Aug-2000	7,013	313	7,326	355	6,971	392	632	253	1,277	30	8,278	14	327	464	26	23	512	839	0	7,439	103	327
SUMMER 00	Sep-2000	6,625	313	6,938	346	6,592	244	632	223	1,099	30	7,721	14	327	408	25	23	456	783	0	6,938	98	
SUMMER 00	Oct-2000	6,053	314	6,367	320	6,047	12	555	183	750	30	6,827	14	328	249	21	23	293	621	0	6,206	86	
WINTER 00/01	Nov-2000	5,423	314	5,737	361	5,376	141	474	166	781	30	6,187	14	328	387	0	23	410	738	0	5,448	76	
WINTER 00/01	Dec-2000	6,467	314	6,781	404	6,377	557	550	219	1,336	30	7,743	14	328	465	0	23	488	816	0	6,927	96	
WINTER 00/01	Jan-2001	8,176	292	8,468	444	8,024	894	632	205	1,731	30	9,785	14	306	809	0	24	833	1,139	118	8,528	118	424
WINTER 00/01	Feb-2001	7,036	293	7,329	432	6,897	888	530	170	1,588	30	8,515	14	307	670	0	24	694	1,001	0	7,514	103	
WINTER 00/01	Mar-2001	6,207	293	6,500	403	6,097	382	474	174	1,030	30	7,157	14	307	515	0	24	539	846	0	6,311	87	
SUMMER 01	Apr-2001	5,764	293	6,057	316	5,741	137	484	157	777	30	6,548	14	307	259	19	25	303	610	0	5,938	82	
SUMMER 01	May-2001	6,599	293	6,892	341	6,551	301	565	181	1,047	30	7,628	14	307	325	22	25	372	679	0	6,949	96	
SUMMER 01	Jun-2001	6,945	293	7,238	355	6,883	385	632	209	1,225	30	8,138	14	307	403	23	25	451	758	0	7,380	101	
SUMMER 01	Jul-2001	7,126	294	7,420	359	7,061	447	632	202	1,281	30	8,372	14	308	398	23	25	446	754	0	7,617	105	
SUMMER 01	Aug-2001	7,173	294	7,467	368	7,099	489	632	222	1,343	30	8,472	14	308	414	23	26	463	771	0	7,701	106	308
SUMMER 01	Sep-2001	6,776	294	7,070	358	6,712	331	632	195	1,158	30	7,900	14	308	361	22	26	409	717	0	7,183	99	
SUMMER 01	Oct-2001	6,191	294	6,485	332	6,153	91	565	166	823	30	7,006	14	308	217	19	26	262	570	0	6,435	89	
WINTER 01/02	Nov-2001	5,536	294	5,830	384	5,446	278	474	151	903	30	6,379	14	308	359	0	26	385	693	0	5,686	79	
WINTER 01/02	Dec-2001	6,601	294	6,895	428	6,467	667	576	187	1,430	30	7,927	14	308	429	0	27	455	763	0	7,164	99	
WINTER 01/02	Jan-2002	8,345	290	8,635	468	8,168	911	167	196	1,274	30	9,472	14	304	744	0	27	771	1,075	115	8,282	115	419
WINTER 01/02	Feb-2002	7,182	291	7,473	456	7,017	904	167	165	1,237	30	8,284	14	305	617	0	27	644	949	0	7,335	101	
WINTER 01/02	Mar-2002	6,336	291	6,627	428	6,199	377	167	168	713	30	6,942	14	305	474	0	27	501	805	0	6,136	85	
SUMMER 02	Apr-2002	5,890	290	6,180	329	5,851	130	167	146	444	30	6,325	14	304	218	17	28	262	566	0	5,758	80	
SUMMER 02	May-2002	6,744	290	7,034	354	6,680	305	167	169	643	30	7,353	14	304	273	20	28	321	625	0	6,728	93	
SUMMER 02	Jun-2002	7,097	290	7,387	368	7,019	378	167	197	742	30	7,791	14	304	340	21	28	389	692	0	7,098	98	
SUMMER 02	Jul-2002	7,282	290	7,572	372	7,200	447	167	189	803	30	8,033	14	304	335	21	29	385	689	0	7,344	101	
SUMMER 02	Aug-2002	7,330	291	7,621	381	7,240	490	157	209	857	30	8,137	14	305	351	21	29	400	705	0	7,431	102	305
SUMMER 02	Sep-2002	6,924	291	7,215	372	6,843	322	167	184	673	30	7,546	14	305	305	20	29	356	661	0	6,885	95	
SUMMER 02	Oct-2002	6,327	291	6,618	346	6,272	75	167	159	401	30	6,703	14	305	185	17	29	231	536	0	6,167	86	
WINTER 02/03	Nov-2002	5,647	292	5,939	410	5,529	269	167	145	583	30	6,142	14	306	335	0	29	364	670	0	5,471	76	
WINTER 02/03	Dec-2002	6,734	292	7,026	454	6,572	670	167	175	1,012	30	7,614	14	306	402	0	30	431	737	0	6,877	95	
WINTER 02/03	Jan-2003	8,514	314	8,828	495	8,333	558	157	203	928	30	9,291	14	328	701	0	30	730	1,059	113	8,120	113	441
WINTER 02/03	Feb-2003	7,327	314	7,641	483	7,158	552	157	170	890	30	8,078	14	328	581	0	30	612	940	0	7,138	99	
WINTER 02/03	Mar-2003	6,463	314	6,777	454	6,323	3	167	173	343	30	6,695	14	328	447	0	30	477	[illegible]	0	5,891	82	
SUMMER 03	Apr-2003	6,016	314	6,330	343	5,987	0	167	152	320	30	6,337	14	328	188	15	31	234	562	0	5,775	81	
SUMMER 03	May-2003	6,888	314	7,202	368	6,834	0	167	177	344	30	7,208	14	329	236	18	31	285	613	0	6,595	91	
SUMMER 03	Jun-2003	7,249	314	7,563	382	7,181	0	167	205	372	30	7,583	14	328	294	19	31	344	672	0	6,911	95	
SUMMER 03	Jul-2003	7,438	314	7,752	386	7,365	77	167	197	441	30	7,837	14	328	292	19	32	342	[illegible]	0	7,167	99	
SUMMER 03	Aug-2003	7,487	314	7,801	395	7,406	121	167	218	505	30	7,942	14	328	305	19	32	356	[illegible]	0	7,258	100	328
SUMMER 03	Sep-2003	7,073	315	7,388	386	7,002	0	167	192	359	30	7,391	14	329	268	18	32	318	[illegible]	0	6,744	93	
SUMMER 03	Oct-2003	6,462	315	6,777	360	6,417	0	157	164	332	30	6,779	14	329	162	15	33	210	[illegible]	0	6,240	87	
WINTER 03/04	Nov-2003	5,759	316	6,075	438	5,637	0	167	151	319	30	5,986	14	330	319	0	33	352	[illegible]	0	5,304	74	
WINTER 03/04	Dec-2003	6,867	316	7,183	482	6,701	303	167	182	652	30	7,383	14	330	384	0	33	417	[illegible]	0	5,636	92	
WINTER 03/04	Jan-2004	8,682	315	8,997	523	8,474	503	167	205	877	30	9,381	14	329	673	0	33	707	[illegible]	114	8,231	114	443
WINTER 03/04	Feb-2004	7,471	315	7,785	511	7,275	503	157	174	844	30	8,149	14	329	559	0	33	592	[illegible]	0	7,228	100	
WINTER 03/04	Mar-2004	5,591	316	5,907	482	5,425	0	167	175	343	30	6,798	14	330	429	0	34	463	[illegible]	0	6,005	84	
SUMMER 04	Apr-2004	5,140	315	5,455	358	5,097	0	157	155	322	30	6,449	14	329	165	14	34	214	[illegible]	[illegible]	5,906	82	
SUMMER 04	May-2004	7,030	315	7,345	383	6,952	0	157	172	345	30	7,338	14	329	209	16	34	259	[illegible]	0	6,750	93	
SUMMER 04	Jun-2004	7,398	315	7,713	397	7,316	0	157	207	374	30	7,720	14	329	260	17	35	311	[illegible]	[illegible]	7,080	98	
SUMMER 04	Jul-2004	7,591	315	7,906	401	7,505	2	157	200	[illegible]	30	7,904	14	329	257	17	35	309	[illegible]	[illegible]	7,255	100	
SUMMER 04	Aug-2004	7,641	315	7,956	410	7,546	[illegible]	157	[illegible]	[illegible]	30	8,012	14	329	259	17	35	322	[illegible]	[illegible]	7,351	102	329
SUMMER 04	Sep-2004	7,218	315	7,534	401	7,133	[illegible]	157	[illegible]	[illegible]	30	7,524	14	330	235	15	35	289	[illegible]	[illegible]	6,506	95	

JANUARY 2000 LONG-TERM FORECAST (S000101)

Normal Weather

Bulk Power Sales Included

SEASON	MONTH	REGRESSED FIRM RETAIL UNADJ. (MW)	RETAIL IS/CS (MW)	POTENTIAL TOTAL RETAIL (MW)	NON-DISP. DSM & S.S. COGEN (MW)	TOTAL RETAIL BEFORE LOAD CONTROL (MW)	WHOLESALE REA (MW)	WHOLESALE BULK (MW)	WHOLESALE MUNI (MW)	WHOLESALE TOTAL (MW)	CO. USE (MW)	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	WHLSE IS (MW)	TOTAL IS/CS (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	COMMERCIAL LOAD MGT. (MW)	STANDBY GENERATION (MW)	TOTAL DLC PROGRAMS (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)	TOTAL IS/CS plus VOLTAGE REDUCTION
SUMMER 04	Oct-2004	6,595	316	6,911	375	6,536	0	167	167	335	30	6,901	14	330	143	14	36	192	522	0	6,379	69	
WINTER 04/05	Nov-2004	5,867	317	6,184	467	5,717	0	167	153	321	30	6,069	14	331	307	0	36	343	674	0	5,394	76	
WINTER 04/05	Dec-2004	6,996	317	7,313	511	6,802	232	167	184	583	30	7,415	14	331	371	0	36	407	738	0	6,677	93	
WINTER 04/05	Jan-2005	8,845	320	9,165	552	8,613	525	167	198	890	30	9,533	14	334	652	0	36	688	1,022	117	8,394	117	451
WINTER 04/05	Feb-2005	7,612	321	7,933	540	7,393	520	167	173	860	30	8,283	14	335	541	0	36	578	913	0	7,371	102	
WINTER 04/05	Mar-2005	6,714	321	7,035	512	6,523	0	167	174	342	30	6,895	14	335	415	0	37	452	787	0	6,108	85	
SUMMER 05	Apr-2005	6,259	320	6,579	373	6,206	0	167	151	319	30	6,555	14	334	148	12	37	198	530	0	6,025	84	
SUMMER 05	May-2005	7,167	320	7,487	398	7,089	0	167	177	344	30	7,453	14	334	184	14	38	236	570	0	6,883	95	
SUMMER 05	Jun-2005	7,542	320	7,862	412	7,450	0	167	198	365	30	7,845	14	334	229	15	38	282	616	0	7,229	100	
SUMMER 05	Jul-2005	7,739	320	8,059	416	7,643	7	167	190	365	30	8,038	14	334	227	15	38	280	614	0	7,423	102	
SUMMER 05	Aug-2005	7,790	321	8,111	425	7,686	54	167	211	433	30	8,149	14	335	238	15	38	291	626	0	7,522	104	335
SUMMER 05	Sep-2005	7,359	321	7,680	416	7,264	0	167	191	359	30	7,653	14	335	208	15	39	262	597	0	7,056	98	
SUMMER 05	Oct-2005	6,724	321	7,045	391	6,654	0	167	165	333	30	7,017	14	335	126	12	39	177	512	0	6,505	90	
WINTER 05/06	Nov-2005	5,971	322	6,293	497	5,796	0	167	152	320	30	6,148	14	336	297	0	39	336	672	0	5,474	77	
WINTER 05/06	Dec-2005	7,120	322	7,442	541	6,901	239	167	181	587	30	7,518	14	336	360	0	39	399	735	0	6,783	94	
WINTER 05/06	Jan-2006	9,002	323	9,325	582	8,743	600	167	200	968	30	9,741	14	337	635	0	39	674	1,011	120	8,610	120	457
WINTER 05/06	Feb-2006	7,747	324	8,071	571	7,500	596	167	176	939	30	8,469	14	338	526	0	40	566	904	0	7,565	104	
WINTER 05/06	Mar-2006	6,834	324	7,158	542	6,616	0	167	177	344	30	6,990	14	338	403	0	40	443	781	0	6,209	85	
SUMMER 06	Apr-2006	6,375	324	6,699	389	6,310	0	167	154	321	30	6,661	14	338	129	11	40	181	519	0	6,142	85	
SUMMER 06	May-2006	7,299	324	7,623	413	7,210	0	167	179	346	30	7,586	14	338	162	13	41	216	554	0	7,032	97	
SUMMER 06	Jun-2006	7,682	324	8,006	428	7,578	0	167	200	367	30	7,975	14	338	202	13	41	257	595	0	7,381	102	
SUMMER 06	Jul-2006	7,882	324	8,206	432	7,774	65	167	193	425	30	8,229	14	338	200	14	41	255	593	0	7,636	105	
SUMMER 06	Aug-2006	7,934	325	8,259	441	7,818	112	167	214	493	30	8,341	14	339	210	14	42	265	604	0	7,737	107	339
SUMMER 06	Sep-2006	7,495	325	7,820	432	7,388	0	167	194	361	30	7,779	14	339	184	13	42	239	578	0	7,201	100	
SUMMER 06	Oct-2006	6,848	325	7,173	406	6,767	0	167	168	335	30	7,132	14	339	111	11	42	164	503	0	6,629	92	
WINTER 06/07	Nov-2006	6,072	325	6,397	528	5,869	0	167	155	322	30	6,221	14	339	289	0	42	331	670	0	5,551	78	
WINTER 06/07	Dec-2006	7,241	325	7,566	572	6,994	296	167	183	646	30	7,670	14	339	350	0	42	393	732	0	6,939	95	
WINTER 06/07	Jan-2007	9,155	328	9,483	613	8,870	676	167	203	1,046	30	9,946	14	342	619	0	42	661	1,003	123	8,820	123	455
WINTER 06/07	Feb-2007	7,879	328	8,207	601	7,606	672	167	179	1,019	30	8,655	14	342	513	0	43	556	898	0	7,756	107	
WINTER 06/07	Mar-2007	6,950	328	7,278	572	6,705	22	167	180	368	30	7,105	14	342	393	0	43	436	778	0	6,327	88	
SUMMER 07	Apr-2007	6,488	328	6,816	404	6,412	0	167	156	323	30	6,765	14	342	114	10	44	167	509	0	6,256	87	
SUMMER 07	May-2007	7,428	328	7,756	429	7,327	0	167	181	348	30	7,705	14	342	143	12	44	199	541	0	7,165	99	
SUMMER 07	Jun-2007	7,817	328	8,145	443	7,702	10	167	203	381	30	8,113	14	342	178	12	44	235	577	0	7,536	104	
SUMMER 07	Jul-2007	8,021	329	8,350	447	7,903	122	167	196	485	30	8,418	14	343	177	12	44	234	577	0	7,841	108	
SUMMER 07	Aug-2007	8,074	329	8,403	456	7,947	171	167	217	555	30	8,532	14	343	185	12	45	242	585	0	7,947	109	343
SUMMER 07	Sep-2007	7,627	329	7,956	447	7,509	0	167	197	364	30	7,903	14	343	162	12	45	219	562	0	7,341	101	
SUMMER 07	Oct-2007	6,969	329	7,298	422	6,876	0	167	170	337	30	7,243	14	343	98	10	45	153	496	0	6,747	94	
WINTER 07/08	Nov-2007	6,171	329	6,500	558	5,942	0	167	157	324	30	6,296	14	343	281	0	45	326	669	0	5,627	79	
WINTER 07/08	Dec-2007	7,358	329	7,687	602	7,085	354	167	186	707	30	7,822	14	343	342	0	45	387	730	0	7,092	98	
WINTER 07/08	Jan-2008	9,303	331	9,634	643	8,991	755	167	206	1,129	30	10,150	14	345	605	0	45	650	995	125	9,029	125	470
WINTER 07/08	Feb-2008	8,006	331	8,337	631	7,706	759	167	181	1,107	30	8,843	14	345	502	0	45	547	892	0	7,951	110	
WINTER 07/08	Mar-2008	7,062	331	7,393	603	6,790	73	167	182	422	30	7,242	14	345	384	0	46	430	775	0	6,467	90	
SUMMER 08	Apr-2008	6,598	331	6,929	419	6,510	0	167	158	325	30	6,865	14	345	100	9	47	156	501	0	6,364	83	
SUMMER 08	May-2008	7,554	331	7,885	444	7,441	0	167	184	352	30	7,823	14	345	126	10	47	184	529	0	7,294	101	
SUMMER 08	Jun-2008	7,950	332	8,282	458	7,824	58	167	206	432	30	8,285	14	346	157	11	47	216	562	0	7,724	107	
SUMMER 08	Jul-2008	8,157	332	8,489	453	8,026	181	167	199	547	30	8,603	14	346	155	11	49	215	561	0	8,042	111	
SUMMER 08	Aug-2008	8,211	332	8,543	471	8,072	231	167	220	618	30	8,720	14	346	163	11	48	222	568	0	8,152	112	345
SUMMER 08	Sep-2008	7,757	332	8,089	462	7,627	0	167	199	366	30	8,023	14	345	143	11	48	202	548	0	7,475	103	
SUMMER 08	Oct-2008	7,087	332	7,419	437	6,982	0	167	172	340	30	7,352	14	345	87	9	48	144	490	0	6,862	95	
WINTER 08/09	Nov-2008	6,257	332	6,589	598	6,011	0	167	159	326	30	6,367	14	345	274	0	48	322	668	0	5,699	80	
WINTER 08/09	Dec-2008	7,474	332	7,807	632	7,175	414	167	188	769	30	7,974	14	347	334	0	48	382	729	0	7,245	100	
WINTER 08/09	Jan-2009	9,449	334	9,783	672	9,111	833	167	209	1,210	30	10,351	14	348	592	0	49	641	989	128	9,234	128	476
WINTER 08/09	Feb-2009	8,132	334	8,466	661	7,805	831	167	164	1,162	30	9,017	14	348	491	0	49	540	888	0	8,129	112	
WINTER 08/09	Mar-2009	7,173	334	7,507	632	6,875	124	167	184	475	30	7,381	14	348	375	0	49	424	772	0	6,608	92	
SUMMER 09	Apr-2009	6,708	334	7,042	434	6,608	0	167	160	327	30	6,965	14	348	89	9	50	147	495	0	6,471	90	
SUMMER 09	May-2009	7,590	334	7,924	459	7,555	54	167	181	409	30	7,993	14	348	111	9	50	171	519	0	7,474	103	
SUMMER 09	Jun-2009	8,083	335	8,419	473	7,945	107	167	209	483	30	8,458	14	349	139	10	50	199	548	0	7,910	102	

JANUARY 2000 LONG-TERM FORECAST (S000101)
Normal Weather
Bulk Power Sales Included

SEASON	MONTH	REGRESSED FIRM RETAIL UNADJ. (MW)	RETAIL IS/CS (MW)	POTENTIAL TOTAL RETAIL (MW)	NON-DISP. DSM & S.S. COGEN (MW)	TOTAL RETAIL BEFORE LOAD CONTROL (MW)	WHOLESALE REA (MW)	WHOLESALE BULK (MW)	WHOLESALE MUNI (MW)	WHOLESALE TOTAL (MW)	CO. USE (MW)	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	WHLSE IS (MW)	TOTAL IS/CS (MW)	DIRECT LOAD CONTROL PROGRAMS RESIDENTIAL LOAD MGT. (MW)	DIRECT LOAD CONTROL PROGRAMS COMMERCIAL LOAD MGT. (MW)	DIRECT LOAD CONTROL PROGRAMS STANDBY GENERATION (MW)	DIRECT LOAD CONTROL PROGRAMS TOTAL DLC PROGRAMS (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)	TOTAL IS/CS plus VOLTAGE REDUCTION
SUMMER 09	Jul-2009	8,293	335	8,628	477	8,151	240	167	202	610	30	8,791	14	349	138	10	51	198	547	0	8,243	113	
SUMMER 09	Aug-2009	8,348	335	8,683	486	8,197	291	167	223	681	30	8,908	14	349	144	10	51	205	554	0	8,354	115	349
SUMMER 09	Sep-2009	7,886	335	8,221	477	7,744	32	167	202	401	30	8,175	14	349	126	10	51	187	536	0	7,639	105	
SUMMER 09	Oct-2009	7,205	335	7,540	451	7,089	0	167	175	343	30	7,482	14	349	76	8	52	136	485	0	6,977	97	
WINTER 09/10	Nov-2009	6,366	335	6,701	617	6,084	0	167	161	328	30	6,442	14	349	268	0	51	319	668	0	5,774	81	
WINTER 09/10	Dec-2009	7,591	336	7,927	661	7,266	474	167	190	832	30	8,128	14	350	327	0	52	378	728	0	7,399	102	
WINTER 09/10	Jan-2010	9,597	336	9,933	701	9,232	912	167	212	1,291	30	10,553	14	350	580	0	52	632	982	131	9,440	131	481
WINTER 09/10	Feb-2010	8,259	336	8,595	687	7,908	912	167	186	1,266	30	9,204	14	350	481	0	52	533	883	0	8,321	114	
WINTER 09/10	Mar-2010	7,285	336	7,621	656	6,965	177	167	186	530	30	7,525	14	350	367	0	52	419	769	0	6,756	94	
SUMMER 10	Apr-2010	6,819	336	7,155	445	6,710	0	167	162	330	30	7,070	14	350	78	7	53	138	488	0	6,582	91	
SUMMER 10	May-2010	7,808	337	8,145	469	7,676	114	167	189	471	30	8,177	14	351	98	8	53	159	510	0	7,666	105	
SUMMER 10	Jun-2010	8,217	337	8,554	482	8,072	157	167	212	536	30	8,638	14	351	122	9	53	184	535	0	8,103	112	
SUMMER 10	Jul-2010	8,431	337	8,768	485	8,283	301	167	205	674	30	8,987	14	351	121	9	53	183	534	0	8,453	116	
SUMMER 10	Aug-2010	8,487	337	8,824	492	8,332	353	167	226	747	30	9,109	14	351	127	9	53	189	540	0	8,569	118	351
SUMMER 10	Sep-2010	8,017	337	8,354	482	7,872	79	167	205	452	30	8,354	14	351	111	9	53	172	523	0	7,830	109	
SUMMER 10	Oct-2010	7,325	337	7,662	455	7,207	0	167	177	345	30	7,582	14	351	67	7	53	127	478	0	7,104	95	
WINTER 10/11	Nov-2010	6,465	338	6,803	621	6,182	0	167	163	330	30	6,542	14	352	262	0	52	314	665	0	5,878	82	
WINTER 10/11	Dec-2010	7,710	338	8,048	663	7,385	536	167	192	895	30	8,311	14	352	320	0	52	372	724	0	7,587	105	

FPC 052

7/19/00 @ 12:14 PM

JANUARY 2000 FORECAST (S000102)

High Retail Scenario

Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
WINTER 99/00	Jan-2000	9,692	849	21	870	326	1,196	116	8,380	116
WINTER 99/00	Feb-2000	8,410	701	21	722	326	1,048	0	7,362	101
WINTER 99/00	Mar-2000	7,077	543	21	564	326	890	0	6,187	86
SUMMER 00	Apr-2000	6,428	285	42	328	327	655	0	5,773	81
SUMMER 00	May-2000	7,493	360	46	406	327	733	0	6,760	94
SUMMER 00	Jun-2000	8,056	449	47	497	327	824	0	7,232	100
SUMMER 00	Jul-2000	8,282	444	48	492	327	819	0	7,463	103
SUMMER 00	Aug-2000	8,382	464	48	512	327	839	0	7,543	104
SUMMER 00	Sep-2000	7,818	408	48	456	327	783	0	7,035	97
SUMMER 00	Oct-2000	6,913	249	44	293	328	621	0	6,292	87
WINTER 00/01	Nov-2000	6,263	387	23	410	328	738	0	5,524	77
WINTER 00/01	Dec-2000	7,839	465	23	488	328	816	0	7,023	97
WINTER 00/01	Jan-2001	9,913	809	24	833	306	1,139	120	8,654	120
WINTER 00/01	Feb-2001	8,621	670	24	694	307	1,001	0	7,620	105
WINTER 00/01	Mar-2001	7,247	515	24	539	307	846	0	6,401	89
SUMMER 01	Apr-2001	6,631	259	43	303	307	610	0	6,021	84
SUMMER 01	May-2001	7,727	325	47	372	307	679	0	7,048	97
SUMMER 01	Jun-2001	8,244	403	48	451	307	758	0	7,486	103
SUMMER 01	Jul-2001	8,461	398	49	446	308	754	0	7,726	106
SUMMER 01	Aug-2001	8,582	414	49	463	308	771	0	7,811	107
SUMMER 01	Sep-2001	8,002	361	48	409	308	717	0	7,285	100
SUMMER 01	Oct-2001	7,097	217	45	262	308	570	0	6,526	90
WINTER 01/02	Nov-2001	6,475	359	26	385	308	693	0	5,782	80
WINTER 01/02	Dec-2001	8,047	429	27	455	308	763	0	7,284	100
WINTER 01/02	Jan-2002	9,631	744	27	771	304	1,075	117	8,439	117
WINTER 01/02	Feb-2002	8,416	617	27	644	305	949	0	7,467	103
WINTER 01/02	Mar-2002	7,055	474	27	501	305	806	0	6,249	87
SUMMER 02	Apr-2002	6,431	218	45	262	304	566	0	5,864	81
SUMMER 02	May-2002	7,478	273	48	321	304	625	0	6,853	94
SUMMER 02	Jun-2002	7,924	340	49	388	304	692	0	7,231	99
SUMMER 02	Jul-2002	8,170	336	50	385	304	689	0	7,481	103
SUMMER 02	Aug-2002	8,275	351	50	400	305	705	0	7,569	104
SUMMER 02	Sep-2002	7,675	306	49	356	305	661	0	7,014	97
SUMMER 02	Oct-2002	6,819	185	46	231	305	536	0	6,283	87
WINTER 02/03	Nov-2002	6,254	335	29	364	306	670	0	5,583	78
WINTER 02/03	Dec-2002	7,753	402	30	431	306	737	0	7,016	97
WINTER 02/03	Jan-2003	9,475	701	30	730	328	1,058	115	8,301	115
WINTER 02/03	Feb-2003	8,232	581	30	612	328	940	0	7,292	101
WINTER 02/03	Mar-2003	6,328	447	30	477	328	805	0	6,023	84

FPC 053

JANUARY 2000 FORECAST (S000102)

High Retail Scenario

Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	DIRECT LOAD CONTROL PROGRAMS: OTHER DLC PROGRAMS (MW)	DIRECT LOAD CONTROL PROGRAMS: TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 03	Apr-2003	6,461	188	46	234	328	562	0	5,899	82
SUMMER 03	May-2003	7,353	236	49	285	328	613	0	6,740	93
SUMMER 03	Jun-2003	7,737	294	50	344	328	672	0	7,065	98
SUMMER 03	Jul-2003	7,996	292	51	342	328	670	0	7,326	101
SUMMER 03	Aug-2003	8,102	305	51	356	328	684	0	7,418	102
SUMMER 03	Sep-2003	7,541	268	50	318	329	647	0	6,894	95
SUMMER 03	Oct-2003	6,914	162	48	210	329	539	0	6,375	83
WINTER 03/04	Nov-2003	6,146	319	33	352	330	682	0	5,464	76
WINTER 03/04	Dec-2003	7,578	384	33	417	330	747	0	6,831	95
WINTER 03/04	Jan-2004	9,636	673	33	707	329	1,036	118	8,482	118
WINTER 03/04	Feb-2004	8,364	559	33	592	329	921	0	7,443	103
WINTER 03/04	Mar-2004	6,984	429	34	463	330	793	0	6,191	86
SUMMER 04	Apr-2004	6,624	166	48	214	329	543	0	6,081	85
SUMMER 04	May-2004	7,542	209	50	259	329	588	0	6,954	96
SUMMER 04	Jun-2004	7,936	260	51	311	329	640	0	7,296	101
SUMMER 04	Jul-2004	8,127	257	52	309	329	638	0	7,489	103
SUMMER 04	Aug-2004	8,236	269	52	322	329	651	0	7,585	104
SUMMER 04	Sep-2004	7,734	236	52	288	330	618	0	7,116	98
SUMMER 04	Oct-2004	7,091	143	49	192	330	522	0	6,569	91
WINTER 04/05	Nov-2004	6,248	307	36	343	331	674	0	5,574	78
WINTER 04/05	Dec-2004	7,635	371	36	407	331	738	0	6,897	95
WINTER 04/05	Jan-2005	9,819	652	36	688	334	1,022	121	8,677	121
WINTER 04/05	Feb-2005	8,524	541	36	578	335	913	0	7,612	105
WINTER 04/05	Mar-2005	7,104	415	37	452	335	787	0	6,317	88
SUMMER 05	Apr-2005	6,753	146	50	196	334	530	0	6,223	87
SUMMER 05	May-2005	7,693	184	52	236	334	570	0	7,123	98
SUMMER 05	Jun-2005	8,088	229	53	282	334	616	0	7,472	103
SUMMER 05	Jul-2005	8,288	227	53	280	334	614	0	7,673	106
SUMMER 05	Aug-2005	8,401	238	54	291	335	626	0	7,774	107
SUMMER 05	Sep-2005	7,890	208	53	262	335	597	0	7,293	101
SUMMER 05	Oct-2005	7,231	126	51	177	335	512	0	6,719	93
WINTER 05/06	Nov-2005	6,368	297	39	336	336	672	0	5,696	80
WINTER 05/06	Dec-2005	7,788	360	39	399	336	735	0	7,053	98
WINTER 05/06	Jan-2006	10,091	635	39	674	337	1,011	124	8,955	124
WINTER 05/06	Feb-2006	8,765	526	40	566	338	904	0	7,861	108
WINTER 05/06	Mar-2006	7,248	403	40	443	338	781	0	6,467	90
SUMMER 06	Apr-2006	6,905	129	52	181	338	519	0	6,386	89
SUMMER 06	May-2006	7,870	162	54	216	338	554	0	7,316	101
SUMMER 06	Jun-2006	8,275	202	54	257	338	595	0	7,681	106

FPC 054

JANUARY 2000 FORECAST (S000102)

High Retail Scenario

Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 06	Jul-2006	8,537	200	55	255	338	593	0	7,944	109
SUMMER 06	Aug-2006	8,651	210	55	265	339	604	0	8,047	111
SUMMER 06	Sep-2006	8,070	184	55	239	339	578	0	7,492	103
SUMMER 06	Oct-2006	7,396	111	53	164	339	503	0	6,893	95
WINTER 06/07	Nov-2006	6,447	289	42	331	339	670	0	5,777	81
WINTER 06/07	Dec-2006	7,945	350	42	393	339	732	0	7,214	100
WINTER 06/07	Jan-2007	10,303	619	42	661	342	1,003	127	9,172	127
WINTER 06/07	Feb-2007	8,957	513	43	556	342	898	0	8,058	111
WINTER 06/07	Mar-2007	7,368	393	43	436	342	778	0	6,590	92
SUMMER 07	Apr-2007	7,014	114	54	167	342	509	0	6,505	90
SUMMER 07	May-2007	7,994	143	56	199	342	541	0	7,454	103
SUMMER 07	Jun-2007	8,418	178	56	235	342	577	0	7,841	108
SUMMER 07	Jul-2007	8,732	177	57	234	343	577	0	8,155	112
SUMMER 07	Aug-2007	8,848	185	57	242	343	585	0	8,263	114
SUMMER 07	Sep-2007	8,200	162	57	219	343	562	0	7,638	105
SUMMER 07	Oct-2007	7,512	98	55	153	343	496	0	7,016	97
WINTER 07/08	Nov-2007	6,568	281	45	326	343	669	0	5,899	82
WINTER 07/08	Dec-2007	8,152	342	45	387	343	730	0	7,422	102
WINTER 07/08	Jan-2008	10,577	605	46	650	345	995	131	9,450	131
WINTER 07/08	Feb-2008	9,205	502	46	547	345	892	0	8,313	114
WINTER 07/08	Mar-2008	7,557	384	46	430	345	775	0	6,782	94
SUMMER 08	Apr-2008	7,166	100	56	156	345	501	0	6,665	93
SUMMER 08	May-2008	8,171	126	58	184	345	529	0	7,642	105
SUMMER 08	Jun-2008	8,653	157	58	216	346	562	0	8,091	111
SUMMER 08	Jul-2008	8,981	156	59	215	346	561	0	8,420	116
SUMMER 08	Aug-2008	9,100	163	59	222	346	568	0	8,532	117
SUMMER 08	Sep-2008	8,380	143	59	202	346	548	0	7,832	108
SUMMER 08	Oct-2008	7,677	87	57	144	346	490	0	7,187	99
WINTER 08/09	Nov-2008	6,671	274	48	322	346	668	0	6,003	84
WINTER 08/09	Dec-2008	8,342	334	48	382	347	729	0	7,613	105
WINTER 08/09	Jan-2009	10,827	592	49	641	348	989	134	9,703	134
WINTER 08/09	Feb-2009	9,420	491	49	540	348	888	0	8,532	117
WINTER 08/09	Mar-2009	7,733	375	49	424	348	772	0	6,960	96
SUMMER 09	Apr-2009	7,302	89	58	147	348	495	0	6,808	94
SUMMER 09	May-2009	8,382	111	60	171	348	519	0	7,863	108
SUMMER 09	Jun-2009	8,869	139	60	199	349	548	0	8,321	114
SUMMER 09	Jul-2009	9,213	138	61	198	349	547	0	8,665	119
SUMMER 09	Aug-2009	9,333	144	61	205	349	554	0	8,779	120
SUMMER 09	Sep-2009	8,575	125	61	187	349	536	0	8,039	111

FPC 055

JANUARY 2000 FORECAST (S000102)

High Retail Scenario

Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 09	Oct-2009	7,825	76	60	136	349	485	0	7,340	101
WINTER 09/10	Nov-2009	6,784	268	51	319	349	668	0	6,116	85
WINTER 09/10	Dec-2009	8,542	327	52	378	350	728	0	7,813	108
WINTER 09/10	Jan-2010	11,087	580	52	632	350	982	138	9,967	138
WINTER 09/10	Feb-2010	9,657	481	52	533	350	883	0	8,774	120
WINTER 09/10	Mar-2010	7,921	367	52	419	350	769	0	7,152	99
SUMMER 10	Apr-2010	7,450	78	60	138	350	488	0	6,962	97
SUMMER 10	May-2010	8,616	98	61	159	351	510	0	8,105	112
SUMMER 10	Jun-2010	9,101	122	61	184	351	535	0	8,566	118
SUMMER 10	Jul-2010	9,463	121	62	183	351	534	0	8,929	122
SUMMER 10	Aug-2010	9,588	127	62	189	351	540	0	9,048	124
SUMMER 10	Sep-2010	8,805	111	61	172	351	523	0	8,281	114
SUMMER 10	Oct-2010	7,992	67	60	127	351	478	0	7,514	104
WINTER 10/11	Nov-2010	6,920	262	52	314	352	666	0	6,254	87
WINTER 10/11	Dec-2010	8,768	320	52	372	352	724	0	8,044	111

FPC 056

JANUARY 2000 FORECAST (S000103)

Low Retail Scenario

Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	DIRECT LOAD CONTROL PROGRAMS: OTHER DLC PROGRAMS (MW)	DIRECT LOAD CONTROL PROGRAMS: TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
WINTER 99/00	Jan-2000	9,360	849	21	870	326	1,196	112	8,052	112
WINTER 99/00	Feb-2000	8,124	701	21	722	326	1,048	0	7,076	98
WINTER 99/00	Mar-2000	6,824	543	21	564	326	890	0	5,934	83
SUMMER 00	Apr-2000	6,191	285	42	328	327	655	0	5,536	77
SUMMER 00	May-2000	7,222	360	46	406	327	733	0	6,489	90
SUMMER 00	Jun-2000	7,772	449	47	497	327	824	0	6,948	96
SUMMER 00	Jul-2000	7,991	444	48	492	327	819	0	7,172	99
SUMMER 00	Aug-2000	8,089	464	48	512	327	839	0	7,250	100
SUMMER 00	Sep-2000	7,541	408	48	456	327	783	0	6,758	94
SUMMER 00	Oct-2000	6,659	249	44	293	328	621	0	6,038	84
WINTER 00/01	Nov-2000	6,020	387	23	410	328	738	0	5,281	74
WINTER 00/01	Dec-2000	7,550	465	23	488	328	816	0	6,734	93
WINTER 00/01	Jan-2001	9,550	809	24	833	306	1,139	115	8,296	115
WINTER 00/01	Feb-2001	8,309	670	24	694	307	1,001	0	7,308	101
WINTER 00/01	Mar-2001	6,971	515	24	539	307	846	0	6,125	85
SUMMER 01	Apr-2001	6,372	259	43	303	307	610	0	5,762	80
SUMMER 01	May-2001	7,431	325	47	372	307	679	0	6,752	93
SUMMER 01	Jun-2001	7,933	403	48	451	307	758	0	7,175	99
SUMMER 01	Jul-2001	8,162	398	49	446	308	754	0	7,407	102
SUMMER 01	Aug-2001	8,261	414	49	463	308	771	0	7,490	103
SUMMER 01	Sep-2001	7,699	361	48	409	308	717	0	6,982	96
SUMMER 01	Oct-2001	6,819	217	45	262	308	570	0	6,248	87
WINTER 01/02	Nov-2001	6,207	359	26	385	308	693	0	5,514	77
WINTER 01/02	Dec-2001	7,728	429	27	455	308	763	0	6,965	96
WINTER 01/02	Jan-2002	9,229	744	27	771	304	1.075	112	8,043	112
WINTER 01/02	Feb-2002	8,071	617	27	644	305	949	0	7,122	98
WINTER 01/02	Mar-2002	6,750	474	27	501	305	806	0	5,944	82
SUMMER 02	Apr-2002	6,142	218	45	262	304	566	0	5,575	78
SUMMER 02	May-2002	7,149	273	48	321	304	625	0	6,524	90
SUMMER 02	Jun-2002	7,578	340	49	388	304	692	0	6,885	95
SUMMER 02	Jul-2002	7,815	336	50	385	304	689	0	7,126	98
SUMMER 02	Aug-2002	7,918	351	50	400	305	705	0	7,212	99
SUMMER 02	Sep-2002	7,337	306	49	356	305	661	0	6,676	92
SUMMER 02	Oct-2002	6,509	185	46	231	305	536	0	5,973	83
WINTER 02/03	Nov-2002	5,934	335	29	364	306	670	0	5,263	74
WINTER 02/03	Dec-2002	7,372	402	30	431	306	737	0	6,635	92
WINTER 02/03	Jan-2003	8,992	701	30	730	328	1.058	109	7,825	109
WINTER 02/03	Feb-2003	7,817	581	30	612	328	940	0	6.877	95
WINTER 02/03	Mar-2003	6,462	447	30	477	328	805	0	5.657	79

FPC 057

JANUARY 2000 FORECAST (S000103)

Low Retail Scenario

Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	DIRECT LOAD CONTROL PROGRAMS: OTHER DLC PROGRAMS (MW)	DIRECT LOAD CONTROL PROGRAMS: TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 03	Apr-2003	6,114	188	46	234	328	562	0	5,552	78
SUMMER 03	May-2003	6,957	236	49	285	328	613	0	6,344	88
SUMMER 03	Jun-2003	7,321	294	50	344	328	672	0	6,649	92
SUMMER 03	Jul-2003	7,569	292	51	342	328	670	0	6,899	95
SUMMER 03	Aug-2003	7,673	305	51	356	328	684	0	6,989	97
SUMMER 03	Sep-2003	7,135	268	50	318	329	647	0	6,488	90
SUMMER 03	Oct-2003	6,542	162	48	210	329	539	0	6,003	84
WINTER 03/04	Nov-2003	5,763	319	33	352	330	682	0	5,081	71
WINTER 03/04	Dec-2003	7,124	384	33	417	330	747	0	6,377	89
WINTER 03/04	Jan-2004	9,061	673	33	707	329	1,036	110	7,915	110
WINTER 03/04	Feb-2004	7,870	559	33	592	329	921	0	6,949	96
WINTER 03/04	Mar-2004	6,548	429	34	463	330	793	0	5,755	80
SUMMER 04	Apr-2004	6,211	166	48	214	329	543	0	5,668	79
SUMMER 04	May-2004	7,070	209	50	259	329	588	0	6,482	90
SUMMER 04	Jun-2004	7,440	260	51	311	329	640	0	6,800	94
SUMMER 04	Jul-2004	7,617	257	52	309	329	638	0	6,979	96
SUMMER 04	Aug-2004	7,724	269	52	322	329	651	0	7,073	98
SUMMER 04	Sep-2004	7,250	236	52	288	330	618	0	6,632	92
SUMMER 04	Oct-2004	6,648	143	49	192	330	522	0	6,126	85
WINTER 04/05	Nov-2004	5,820	307	36	343	331	674	0	5,146	72
WINTER 04/05	Dec-2004	7,126	371	36	407	331	738	0	6,388	89
WINTER 04/05	Jan-2005	9,175	652	36	688	334	1,022	112	8,041	112
WINTER 04/05	Feb-2005	7,971	541	36	578	335	913	0	7,059	98
WINTER 04/05	Mar-2005	6,617	415	37	452	335	787	0	5,830	81
SUMMER 05	Apr-2005	6,288	146	50	196	334	530	0	5,758	80
SUMMER 05	May-2005	7,163	184	52	236	334	570	0	6,593	91
SUMMER 05	Jun-2005	7,531	229	53	282	334	616	0	6,915	96
SUMMER 05	Jul-2005	7,717	227	53	280	334	614	0	7,102	98
SUMMER 05	Aug-2005	7,826	238	54	291	335	626	0	7,199	99
SUMMER 05	Sep-2005	7,346	208	53	262	335	597	0	6,749	94
SUMMER 05	Oct-2005	6,733	126	51	177	335	512	0	6,221	87
WINTER 05/06	Nov-2005	5,871	297	39	336	336	672	0	5,199	73
WINTER 05/06	Dec-2005	7,197	360	39	399	336	735	0	6,462	90
WINTER 05/06	Jan-2006	9,342	635	39	674	337	1,011	114	8,216	114
WINTER 05/06	Feb-2006	8,122	526	40	566	338	904	0	7,218	100
WINTER 05/06	Mar-2006	6,681	403	40	443	338	781	0	5,900	82
SUMMER 06	Apr-2006	6,365	129	52	181	338	519	0	5,846	82
SUMMER 06	May-2006	7,252	162	54	216	338	554	0	6,698	93
SUMMER 06	Jun-2006	7,625	202	54	257	338	595	0	7,031	97

FPC 058

JANUARY 2000 FORECAST (S000103)

Low Retail Scenario

Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	DIRECT LOAD CONTROL PROGRAMS: OTHER DLC PROGRAMS (MW)	DIRECT LOAD CONTROL PROGRAMS: TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 06	Jul-2006	7,871	200	55	255	338	593	0	7,278	101
SUMMER 06	Aug-2006	7,981	210	55	265	339	604	0	7,377	102
SUMMER 06	Sep-2006	7,437	184	55	239	339	578	0	6,859	95
SUMMER 06	Oct-2006	6,816	111	53	164	339	503	0	6,313	88
WINTER 06/07	Nov-2006	5,919	289	42	331	339	670	0	5,249	74
WINTER 06/07	Dec-2006	7,316	350	42	393	339	732	0	6,585	91
WINTER 06/07	Jan-2007	9,505	619	42	661	342	1,003	117	8,385	117
WINTER 06/07	Feb-2007	8,273	513	43	556	342	898	0	7,374	102
WINTER 06/07	Mar-2007	6,764	393	43	436	342	778	0	5,986	84
SUMMER 07	Apr-2007	6,437	114	54	167	342	509	0	5,928	83
SUMMER 07	May-2007	7,335	143	56	199	342	541	0	6,795	94
SUMMER 07	Jun-2007	7,725	178	56	235	342	577	0	7,148	99
SUMMER 07	Jul-2007	8,021	177	57	234	343	577	0	7,444	103
SUMMER 07	Aug-2007	8,133	185	57	242	343	585	0	7,548	104
SUMMER 07	Sep-2007	7,524	162	57	219	343	562	0	6,962	96
SUMMER 07	Oct-2007	6,894	98	55	153	343	496	0	6,398	89
WINTER 07/08	Nov-2007	5,965	281	45	326	343	669	0	5,296	74
WINTER 07/08	Dec-2007	7,433	342	45	387	343	730	0	6,703	93
WINTER 07/08	Jan-2008	9,665	605	46	650	345	995	119	8,550	119
WINTER 07/08	Feb-2008	8,423	502	46	547	345	892	0	7,531	104
WINTER 07/08	Mar-2008	6,868	384	46	430	345	775	0	6,093	85
SUMMER 08	Apr-2008	6,505	100	56	156	345	501	0	6,004	84
SUMMER 08	May-2008	7,416	126	58	184	345	529	0	6,887	95
SUMMER 08	Jun-2008	7,860	157	58	216	346	562	0	7,298	101
SUMMER 08	Jul-2008	8,166	156	59	215	346	561	0	7,605	105
SUMMER 08	Aug-2008	8,281	163	59	222	346	568	0	7,713	106
SUMMER 08	Sep-2008	7,607	143	59	202	346	548	0	7,059	98
SUMMER 08	Oct-2008	6,968	87	57	144	346	490	0	6,478	90
WINTER 08/09	Nov-2008	6,008	274	48	322	346	668	0	5,340	75
WINTER 08/09	Dec-2008	7,552	334	48	382	347	729	0	6,823	95
WINTER 08/09	Jan-2009	9,823	592	49	641	348	989	121	8,713	121
WINTER 08/09	Feb-2009	8,560	491	49	540	348	888	0	7,672	106
WINTER 08/09	Mar-2009	6,975	375	49	424	348	772	0	6,202	86
SUMMER 09	Apr-2009	6,574	89	58	147	348	495	0	6,080	85
SUMMER 09	May-2009	7,550	111	60	171	348	519	0	7,031	97
SUMMER 09	Jun-2009	7,994	139	60	199	349	548	0	7,446	103
SUMMER 09	Jul-2009	8,316	138	61	198	349	547	0	7,768	107
SUMMER 09	Aug-2009	8,430	144	61	205	349	554	0	7,876	109
SUMMER 09	Sep-2009	7,722	126	61	187	349	536	0	7,186	99

FPC 059

JANUARY 2000 FORECAST (S000103)

Low Retail Scenario

Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 09	Oct-2009	7,045	76	60	136	349	485	0	6,560	91
WINTER 09/10	Nov-2009	6,061	268	51	319	349	668	0	5,393	76
WINTER 09/10	Dec-2009	7,679	327	52	378	350	728	0	6,950	96
WINTER 09/10	Jan-2010	9,991	580	52	632	350	982	124	8,885	124
WINTER 09/10	Feb-2010	8,718	481	52	533	350	883	0	7,835	108
WINTER 09/10	Mar-2010	7,094	367	52	419	350	769	0	6,325	88
SUMMER 10	Apr-2010	6,653	78	60	138	350	488	0	6,165	86
SUMMER 10	May-2010	7,705	98	61	159	351	510	0	7,194	100
SUMMER 10	Jun-2010	8,143	122	61	184	351	535	0	7,608	105
SUMMER 10	Jul-2010	8,480	121	62	183	351	534	0	7,946	110
SUMMER 10	Aug-2010	8,599	127	62	189	351	540	0	8,059	111
SUMMER 10	Sep-2010	7,871	111	61	172	351	523	0	7,347	102
SUMMER 10	Oct-2010	7,137	67	60	127	351	478	0	6,659	93
WINTER 10/11	Nov-2010	6,148	262	52	314	352	666	0	5,482	77
WINTER 10/11	Dec-2010	7,846	320	52	372	352	724	0	7,122	99

FPC 060

	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
Baseload Plants (Summer and Winter TYSP Ratings)																								
Crystal River 1	383	383	383	379	379	379	379	379	379	379	383	383	383	383	383	379	379	379	379	379	379	379	383	383
Crystal River 2	479	479	479	474	474	474	474	474	474	474	479	479	503	503	503	498	498	498	498	498	498	498	503	503
Crystal River 4	722	722	722	712	729	729	729	729	729	729	739	739	739	739	739	729	729	729	729	729	729	729	739	739
Crystal River 5	732	732	732	717	717	717	717	717	717	717	732	732	732	732	732	717	717	717	717	717	717	717	732	732
Crystal River 3	782	782	782	765	765	765	765	765	765	765	782	782	782	782	782	765	765	765	765	765	765	765	782	782
University of Florida Cogen	41	41	41	35	35	35	35	35	35	35	41	41	41	41	41	35	35	35	35	35	35	35	41	41
Baseload Contracts (Firm Purchase Capacity)																								
UPS Purchase from Southern Company	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409
TECO Purchase for Sebring Load	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
QF Contracts																								
PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
TIMBER ENERGY 1	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
BAY COUNTY RES REC	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
LFC MADISON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LFC JEFFERSON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
PASCO COUNTY RES REC	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
CARGILL	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
RIDGE GENERATING STA.	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
ROYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
CFR-BIOGEN (ORANGE CO)	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
US AGRICHEM	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Intermediate Resources (Summer and Winter TYSP Ratings)																								
Anclote 1	522	522	522	498	498	498	498	498	498	498	522	522	522	522	522	498	498	498	498	498	498	498	522	522
Anclote 2	522	522	522	495	495	495	495	495	495	495	522	522	522	522	522	495	495	495	495	495	495	495	522	522
Bartow 1	123	123	123	121	121	121	121	121	121	121	123	123	123	123	123	121	121	121	121	121	121	121	123	123
Bartow 2	121	121	121	119	119	119	119	119	119	119	121	121	121	121	121	119	119	119	119	119	119	119	121	121
Bartow 3	208	208	208	204	204	204	204	204	204	204	208	208	208	208	208	204	204	204	204	204	204	204	208	208
Suwannee River 1	33	33	33	32	32	32	32	32	32	32	33	33	33	33	33	32	32	32	32	32	32	32	33	33
Suwannee River 2	32	32	32	31	31	31	31	31	31	31	32	32	32	32	32	31	31	31	31	31	31	31	32	32
Suwannee River 3	81	81	81	80	80	80	80	80	80	80	81	81	81	81	81	80	80	80	80	80	80	80	81	81
Tiger Bay Cogen	223	223	223	207	207	207	207	207	207	207	223	223	223	223	223	207	207	207	207	207	207	207	223	223
Hines Energy Complex 1	529	529	529	482	482	482	482	482	482	482	529	529	529	529	529	482	482	482	482	482	482	482	529	529
Hines Energy Complex 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hines Energy Complex 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hines Energy Complex 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hines Energy Complex 5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Peaking Resources (Summer and Winter TYSP Ratings)																								
Avon Park P1	32	32	32	26	26	26	26	26	26	26	26	32	32	32	32	26	26	26	26	26	26	26	26	32
Bartow P2	53	53	53	46	46	46	46	46	46	46	46	53	53	53	53	46	46	46	46	46	46	46	46	53
Bartow P4	60	60	60	49	49	49	49	49	49	49	49	60	60	60	60	49	49	49	49	49	49	49	49	60
Debary P7	93	93	93	80	80	85	85	85	85	80	80	93	93	93	93	80	80	85	85	85	85	80	80	93
Debary P8	93	93	93	80	80	85	85	85	85	80	80	93	93	93	93	80	80	85	85	85	85	80	80	93
Debary P9	93	93	93	80	80	85	85	85	85	80	80	93	93	93	93	80	80	85	85	85	85	80	80	93
Higgins P1	32	32	32	27	27	27	27	27	27	27	27	32	32	32	32	27	27	27	27	27	27	27	27	32
Higgins P2	32	32	32	27	27	27	27	27	27	27	27	32	32	32	32	27	27	27	27	27	27	27	27	32
Higgins P3	35	35	35	34	34	34	34	34	34	34	34	35	35	35	35	34	34	34	34	34	34	34	34	35

Higgins P4	35	35	35	34	34	34	34	34	34	34	34	35	35	35	35	34	34	34	34	34	34	34	34	35
Intercession City P7	94	94	94	80	80	85	85	85	85	80	80	94	94	94	94	80	80	85	85	85	85	80	80	94
Intercession City P8	94	94	94	80	80	85	85	85	85	80	80	94	94	94	94	80	80	85	85	85	85	80	80	94
Intercession City P9	94	94	94	80	80	85	85	85	85	80	80	94	94	94	94	80	80	85	85	85	85	80	80	94
Intercession City P10	94	94	94	80	80	85	85	85	85	80	80	94	94	94	94	80	80	85	85	85	85	80	80	94
Intercession City P12	0	0	0	0	0	0	0	0	0	0	0	94	94	94	94	80	80	80	80	80	80	80	80	94
Intercession City P13	0	0	0	0	0	0	0	0	0	0	0	94	94	94	94	80	80	80	80	80	80	80	80	94
Intercession City P14	0	0	0	0	0	0	0	0	0	0	0	94	94	94	94	80	80	80	80	80	80	80	80	94
Suwannee River P1	67	67	67	55	55	55	55	55	55	55	55	67	67	67	67	55	55	55	55	55	55	55	55	67
Suwannee River P3	67	67	67	55	55	55	55	55	55	55	55	67	67	67	67	55	55	55	55	55	55	55	55	67
Light Oil Peaking Resources (Summer and Winter TYSP Ratings)																								
Avon Park P2	32	32	32	26	26	26	26	26	26	26	26	32	32	32	32	26	26	26	26	26	26	26	26	32
Bartow P1	53	53	53	46	46	46	46	46	46	46	46	53	53	53	53	46	46	46	46	46	46	46	46	53
Bartow P3	53	53	53	46	46	46	46	46	46	46	46	53	53	53	53	46	46	46	46	46	46	46	46	53
Bayboro P1	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Bayboro P2	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Bayboro P3	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Bayboro P4	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Debary P1	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P2	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P3	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P4	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P5	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P6	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P10	93	93	93	79	79	84	84	84	84	79	79	93	93	93	93	79	79	84	84	84	84	79	79	93
Intercession City P1	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P2	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P3	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P4	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P5	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P6	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P11	170	170	170	143	143	0	0	0	0	143	143	170	170	170	170	143	143	0	0	0	0	143	143	170
Rio Pinar P1	16	16	16	13	13	13	13	13	13	13	13	16	16	16	16	13	13	13	13	13	13	13	13	16
Suwannee River P2	67	67	67	54	54	54	54	54	54	54	54	67	67	67	67	67	54	54	54	54	54	54	54	67
Turner P1	16	16	16	13	13	13	13	13	13	13	13	16	16	16	16	13	13	13	13	13	13	13	13	16
Turner P2	16	16	16	13	13	13	13	13	13	13	13	16	16	16	16	13	13	13	13	13	13	13	13	16
Turner P3	82	82	82	65	65	65	65	65	65	65	65	82	82	82	82	82	65	65	65	65	65	65	65	82
Turner P4	80	80	80	63	63	63	63	63	63	63	63	80	80	80	80	80	63	63	63	63	63	63	63	80
Total Baseload Plants	3,139	3,139	3,139	3,032	3,099	3,099	3,099	3,099	3,099	3,099	3,156	3,156	3,130	3,130	3,130	3,123	3,123	3,123	3,123	3,123	3,123	3,123	3,130	3,130
Total Baseload Contracts	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469
Total QF Contracts	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831
Total Intermediate Resources	2,394	2,394	2,394	2,269	2,269	2,269	2,269	2,269	2,269	2,269	2,394	2,394	2,394	2,394	2,394	2,269	2,269	2,269	2,269	2,269	2,269	2,269	2,394	2,394
Total Gas Peaking Resources	1,068	1,068	1,068	913	913	960	960	960	960	913	913	1,350	1,350	1,350	1,350	1,153	1,153	1,200	1,200	1,200	1,200	1,153	1,153	1,350
Total Light Oil Peaking Resources	1,666	1,666	1,666	1,363	1,363	1,225	1,225	1,225	1,225	1,363	1,363	1,666	1,666	1,666	1,666	1,410	1,363	1,225	1,225	1,225	1,225	1,363	1,363	1,666
Total Available Resources	9,567	9,567	9,567	8,927	8,944	8,853	8,853	8,853	8,853	8,944	9,126	9,866	9,890	9,890	9,890	9,255	9,208	9,117	9,117	9,117	9,117	9,208	9,390	9,890
	8,267												8,590											

FPC 062

	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03
Baseload Plants (Summer and Winter TYSP Ratings)																								
Crystal River 1	400	400	400	396	396	396	396	396	396	396	400	400	400	400	400	396	396	396	396	396	396	396	400	400
Crystal River 2	503	503	503	498	498	498	498	498	498	498	503	503	503	503	503	498	498	498	498	498	498	498	503	503
Crystal River 4	739	739	739	729	729	729	729	729	729	729	739	739	739	739	739	729	729	729	729	729	729	729	739	739
Crystal River 5	732	732	732	717	717	717	717	717	717	717	732	732	732	732	732	717	717	717	717	717	717	717	732	732
Crystal River 3	782	782	782	765	765	765	765	765	765	765	782	782	782	782	782	765	765	765	765	765	765	765	782	782
University of Florida Cogen	41	41	41	35	35	35	35	35	35	35	41	41	41	41	41	35	35	35	35	35	35	35	41	41
Baseload Contracts (Firm Purchase Capacity)																								
UPS Purchase from Southern Company	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409
TECO Purchase for Sebring Load	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
QF Contracts																								
PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
TIMBER ENERGY 1	13	13	13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BAY COUNTY RES REC	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
LFC MADISON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LFC JEFFERSON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
PASCO COUNTY RES REC	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
CARGILL	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
RIDGE GENERATING STA.	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
ROYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
CFR-BIOGEN (ORANGE CO)	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
US AGRICHEM	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Intermediate Resources (Summer and Winter TYSP Ratings)																								
Anclote 1	522	522	522	498	498	498	498	498	498	498	522	522	522	522	522	498	498	498	498	498	498	498	522	522
Anclote 2	522	522	522	495	495	495	495	495	495	495	522	522	522	522	522	495	495	495	495	495	495	495	522	522
Bartow 1	123	123	123	121	121	121	121	121	121	121	123	123	123	123	123	121	121	121	121	121	121	121	123	123
Bartow 2	121	121	121	119	119	119	119	119	119	119	121	121	121	121	121	119	119	119	119	119	119	119	121	121
Bartow 3	208	208	208	204	204	204	204	204	204	204	208	208	208	208	208	204	204	204	204	204	204	204	208	208
Suwannee River 1	33	33	33	32	32	32	32	32	32	32	33	33	33	33	33	32	32	32	32	32	32	32	33	33
Suwannee River 2	32	32	32	31	31	31	31	31	31	31	32	32	32	32	32	31	31	31	31	31	31	31	32	32
Suwannee River 3	81	81	81	80	80	80	80	80	80	80	81	81	81	81	81	80	80	80	80	80	80	80	81	81
Tiger Bay Cogen	223	223	223	207	207	207	207	207	207	207	223	223	223	223	223	207	207	207	207	207	207	207	223	223
Hines Energy Complex 1	529	529	529	482	482	482	482	482	482	482	529	529	529	529	529	482	482	482	482	482	482	482	529	529
Hines Energy Complex 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	567	567
Hines Energy Complex 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hines Energy Complex 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hines Energy Complex 5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Peaking Resources (Summer and Winter TYSP Ratings)																								
Avon Park P1	32	32	32	26	26	26	26	26	26	26	26	32	32	32	32	26	26	26	26	26	26	26	26	32
Bartow P2	53	53	53	46	46	46	46	46	46	46	46	53	53	53	53	46	46	46	46	46	46	46	46	53
Bartow P4	60	60	60	49	49	49	49	49	49	49	49	60	60	60	60	49	49	49	49	49	49	49	49	60
Debary P7	93	93	93	80	80	85	85	85	85	80	80	93	93	93	93	80	80	85	85	85	85	80	80	93
Debary P8	93	93	93	80	80	85	85	85	85	80	80	93	93	93	93	80	80	85	85	85	85	80	80	93
Debary P9	93	93	93	80	80	85	85	85	85	80	80	93	93	93	93	80	80	85	85	85	85	80	80	93
Higgins P1	32	32	32	27	27	27	27	27	27	27	27	32	32	32	32	27	27	27	27	27	27	27	27	32
Higgins P2	32	32	32	27	27	27	27	27	27	27	27	32	32	32	32	27	27	27	27	27	27	27	27	32
Higgins P3	35	35	35	34	34	34	34	34	34	34	34	35	35	35	35	34	34	34	34	34	34	34	34	35

Higgins P4	35	35	35	34	34	34	34	34	34	34	34	35	35	35	35	34	34	34	34	34	34	34	34	35
Intercession City P7	94	94	94	80	80	88	88	88	88	80	80	94	94	94	94	80	80	88	88	88	88	80	80	94
Intercession City P8	94	94	94	80	80	88	88	88	88	80	80	94	94	94	94	80	80	88	88	88	88	80	80	94
Intercession City P9	94	94	94	80	80	88	88	88	88	80	80	94	94	94	94	80	80	88	88	88	88	80	80	94
Intercession City P10	94	94	94	80	80	88	88	88	88	80	80	94	94	94	94	80	80	88	88	88	88	80	80	94
Intercession City P12	94	94	94	80	80	80	80	80	80	80	80	94	94	94	94	80	80	80	80	80	80	80	80	94
Intercession City P13	94	94	94	80	80	80	80	80	80	80	80	94	94	94	94	80	80	80	80	80	80	80	80	94
Intercession City P14	94	94	94	80	80	80	80	80	80	80	80	94	94	94	94	80	80	80	80	80	80	80	80	94
Suwannee River P1	67	67	67	55	55	55	55	55	55	55	55	67	67	67	67	55	55	55	55	55	55	55	55	67
Suwannee River P3	67	67	67	55	55	55	55	55	55	55	55	67	67	67	67	55	55	55	55	55	55	55	55	67
Light Oil Peaking Resources (Summer and Winter TYSP Ratings)																								
Avon Park P2	32	32	32	26	26	26	26	26	26	26	26	32	32	32	32	26	26	26	26	26	26	26	26	32
Bartow P1	53	53	53	46	46	46	46	46	46	46	46	53	53	53	53	46	46	46	46	46	46	46	46	53
Bartow P3	53	53	53	46	46	46	46	46	46	46	46	53	53	53	53	46	46	46	46	46	46	46	46	53
Bayboro P1	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Bayboro P2	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Bayboro P3	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Bayboro P4	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Debary P1	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P2	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P3	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P4	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P5	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P6	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P10	93	93	93	79	79	84	84	84	84	79	79	93	93	93	93	79	79	84	84	84	84	79	79	93
Intercession City P1	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	6
Intercession City P2	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	6
Intercession City P3	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	6
Intercession City P4	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	6
Intercession City P5	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	6
Intercession City P6	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	[illegible]
Intercession City P11	170	170	170	143	143	0	0	0	0	143	143	170	170	170	170	143	143	0	0	0	0	143	143	1
Rio Pinar P1	16	16	16	13	13	13	13	13	13	13	13	16	16	16	16	13	13	13	13	13	13	13	13	
Suwannee River P2	67	67	67	67	54	54	54	54	54	54	54	67	67	67	67	67	54	54	54	54	54	54	54	
Turner P1	16	16	16	13	13	13	13	13	13	13	13	16	16	16	16	13	13	13	13	13	13	13	13	
Turner P2	16	16	16	13	13	13	13	13	13	13	13	16	16	16	16	13	13	13	13	13	13	13	13	
Turner P3	82	82	82	82	65	65	65	65	65	65	65	82	82	82	82	82	65	65	65	65	65	65	65	
Turner P4	80	80	80	80	63	63	63	63	63	63	63	80	80	80	80	80	63	63	63	63	63	63	63	
Total Baseload Plants	3,197	3,197	3,197	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,197	3,197	3,197	3,197	3,197	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,197	3,
Total Baseload Contracts	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	
Total QF Contracts	831	831	831	818	818	818	818	818	818	818	818	818	818	818	818	818	818	818	818	818	818	818	818	
Total Intermediate Resources	2,394	2,394	2,394	2,269	2,269	2,269	2,269	2,269	2,269	2,269	2,394	2,394	2,394	2,394	2,394	2,269	2,269	2,269	2,269	2,269	2,269	2,269	2,961	2
Total Gas Peaking Resources	1,350	1,350	1,350	1,153	1,153	1,200	1,200	1,200	1,200	1,153	1,153	1,350	1,350	1,350	1,350	1,153	1,153	1,200	1,200	1,200	1,200	1,153	1,153	
Total Light Oil Peaking Resources	1,666	1,666	1,666	1,410	1,363	1,225	1,225	1,225	1,225	1,363	1,363	1,666	1,666	1,666	1,666	1,410	1,363	1,225	1,225	1,225	1,225	1,363	1,363	
Total Available Resources	9,907	9,907	9,907	9,259	9,212	9,121	9,121	9,121	9,121	9,212	9,394	9,394	9,394	9,394	9,394	9,259	9,212	9,121	9,121	9,121	9,121	9,212	9,961	[illegible]

FPC 064

	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05	Oct-05	Nov-05	Dec-05
Baseload Plants (Summer and Winter TYSP Ratings)																								
Crystal River 1	400	400	400	396	396	396	396	396	396	396	400	400	400	400	400	396	396	396	396	396	396	396	400	400
Crystal River 2	503	503	503	498	498	498	498	498	498	498	503	503	503	503	503	498	498	498	498	498	498	498	503	503
Crystal River 4	739	739	739	729	729	729	729	729	729	729	739	739	739	739	739	729	729	729	729	729	729	729	739	739
Crystal River 5	732	732	732	717	717	717	717	717	717	717	732	732	732	732	732	717	717	717	717	717	717	717	732	732
Crystal River 3	782	782	782	765	765	765	765	765	765	765	782	782	782	782	782	765	765	765	765	765	765	765	782	782
University of Florida Cogen	41	41	41	35	35	35	35	35	35	35	41	41	41	41	41	35	35	35	35	35	35	35	41	41
Baseload Contracts (Firm Purchase Capacity)																								
UPS Purchase from Southern Company	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409
TECO Purchase for Sebring Load	60	60	60	60	60	60	60	60	60	60	60	60	70	70	70	70	70	70	70	70	70	70	70	70
QF Contracts																								
PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
TIMBER ENERGY 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BAY COUNTY RES REC	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
LFC MADISON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LFC JEFFERSON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
PASCO COUNTY RES REC	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	2
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	4
CARGILL	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	1
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	11
PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	10
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	7
RIDGE GENERATING STA.	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	4
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	11
ROYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	3
MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	7
CFR-BIOGEN (ORANGE CO)	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	7
US AGRICHEM	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	
Intermediate Resources (Summer and Winter TYSP Ratings)																								
Anclote 1	522	522	522	498	498	498	498	498	498	498	522	522	522	522	522	498	498	498	498	498	498	498	522	52
Anclote 2	522	522	522	495	495	495	495	495	495	495	522	522	522	522	522	495	495	495	495	495	495	495	522	52
Bartow 1	123	123	123	121	121	121	121	121	121	121	123	123	123	123	123	121	121	121	121	121	121	121	123	12
Bartow 2	121	121	121	119	119	119	119	119	119	119	121	121	121	121	121	119	119	119	119	119	119	119	121	12
Bartow 3	208	208	208	204	204	204	204	204	204	204	208	208	208	208	208	204	204	204	204	204	204	204	208	20
Suwannee River 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Suwannee River 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Suwannee River 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Tiger Bay Cogen	223	223	223	207	207	207	207	207	207	207	223	223	223	223	223	207	207	207	207	207	207	207	223	22
Hines Energy Complex 1	529	529	529	482	482	482	482	482	482	482	529	529	529	529	529	482	482	482	482	482	482	482	529	52
Hines Energy Complex 2	567	567	567	495	495	495	495	495	495	495	567	567	567	567	567	495	495	495	495	495	495	495	567	56
Hines Energy Complex 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	567	56
Hines Energy Complex 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Hines Energy Complex 5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas Peaking Resources (Summer and Winter TYSP Ratings)																								
Avon Park P1	32	32	32	26	26	26	26	26	26	26	26	32	32	32	32	26	26	26	26	26	26	26	26	[illegible]
Bartow P2	53	53	53	46	46	46	46	46	46	46	46	53	53	53	53	46	46	46	46	46	46	46	46	[illegible]
Bartow P4	60	60	60	49	49	49	49	49	49	49	49	60	60	60	60	49	49	49	49	49	49	49	49	[illegible]
Debary P7	93	93	93	80	80	85	85	85	85	80	80	93	93	93	93	80	80	85	85	85	85	80	80	[illegible]
Debary P8	93	93	93	80	80	85	85	85	85	80	80	93	93	93	93	80	80	85	85	85	85	80	80	[illegible]
Debary P9	93	93	93	80	80	85	85	85	85	80	80	93	93	93	93	80	80	85	85	85	85	80	80	[illegible]
Higgins P1	32	32	32	27	27	27	27	27	27	27	27	32	32	32	32	27	27	27	27	27	27	27	27	[illegible]
Higgins P2	32	32	32	27	27	27	27	27	27	27	27	32	32	32	32	27	27	27	27	27	27	27	27	[illegible]
Higgins P3	35	35	35	34	34	34	34	34	34	34	34	35	35	35	35	34	34	34	34	34	34	34	34	[illegible]

Higgins P4	35	35	35	34	34	34	34	34	34	34	34	35	35	35	35	34	34	34	34	34	34	34	34	35
Intercession City P7	94	94	94	80	80	88	88	88	88	80	80	94	94	94	94	80	80	88	88	88	88	80	80	94
Intercession City P8	94	94	94	80	80	88	88	88	88	80	80	94	94	94	94	80	80	88	88	88	88	80	80	94
Intercession City P9	94	94	94	80	80	88	88	88	88	80	80	94	94	94	94	80	80	88	88	88	88	80	80	94
Intercession City P10	94	94	94	80	80	88	88	88	88	80	80	94	94	94	94	80	80	88	88	88	88	80	80	94
Intercession City P12	94	94	94	80	80	80	80	80	80	80	80	94	94	94	94	80	80	80	80	80	80	80	80	94
Intercession City P13	94	94	94	80	80	80	80	80	80	80	80	94	94	94	94	80	80	80	80	80	80	80	80	94
Intercession City P14	94	94	94	80	80	80	80	80	80	80	80	94	94	94	94	80	80	80	80	80	80	80	80	94
Suwannee River P1	67	67	67	55	55	55	55	55	55	55	55	67	67	67	67	55	55	55	55	55	55	55	55	67
Suwannee River P3	67	67	67	55	55	55	55	55	55	55	55	67	67	67	67	55	55	55	55	55	55	55	55	67
Light Oil Peaking Resources (Summer and Winter TYSP Ratings)																								
Avon Park P2	32	32	32	26	26	26	26	26	26	26	26	32	32	32	32	26	26	26	26	26	26	26	26	32
Bartow P1	53	53	53	46	46	46	46	46	46	46	46	53	53	53	53	46	46	46	46	46	46	46	46	53
Bartow P3	53	53	53	46	46	46	46	46	46	46	46	53	53	53	53	46	46	46	46	46	46	46	46	53
Bayboro P1	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Bayboro P2	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Bayboro P3	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Bayboro P4	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Debary P1	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P2	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P3	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P4	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P5	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P6	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P10	93	93	93	79	79	84	84	84	84	79	79	93	93	93	93	79	79	84	84	84	84	79	79	93
Intercession City P1	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P2	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P3	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P4	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	6
Intercession City P5	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	6
Intercession City P6	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	6
Intercession City P11	170	170	170	143	143	0	0	0	0	143	143	170	170	170	170	143	143	0	0	0	0	143	143	17
Rio Pinar P1	16	16	16	13	13	13	13	13	13	13	13	16	16	16	16	13	13	13	13	13	13	13	13	
Suwannee River P2	67	67	67	67	54	54	54	54	54	54	54	67	67	67	67	67	54	54	54	54	54	54	54	
Turner P1	16	16	16	13	13	13	13	13	13	13	13	16	16	16	16	13	13	13	13	13	13	13	13	
Turner P2	16	16	16	13	13	13	13	13	13	13	13	16	16	16	16	13	13	13	13	13	13	13	13	
Turner P3	82	82	82	82	65	65	65	65	65	65	65	82	82	82	82	82	65	65	65	65	65	65	65	
Turner P4	80	80	80	80	63	63	63	63	63	63	63	80	80	80	80	80	63	63	63	63	63	63	63	
Total Baseload Plants	3,197	3,197	3,197	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,197	3,197	3,197	3,197	3,197	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,197	3,1
Total Baseload Contracts	469	469	469	469	469	469	469	469	469	469	469	469	479	479	479	479	479	479	479	479	479	479	479	
Total QF Contracts	818	818	818	818	818	818	818	818	818	818	818	818	818	818	818	818	818	818	818	818	818	818	818	
Total Intermediate Resources	2,815	2,815	2,815	2,621	2,621	2,621	2,621	2,621	2,621	2,621	2,815	2,815	2,815	2,815	2,815	2,621	2,621	2,621	2,621	2,621	2,621	2,621	3,382	3
Total Gas Peaking Resources	1,350	1,350	1,350	1,153	1,153	1,200	1,200	1,200	1,200	1,153	1,153	1,350	1,350	1,350	1,350	1,153	1,153	1,200	1,200	1,200	1,200	1,153	1,153	1
Total Light Oil Peaking Resources	1,666	1,666	1,666	1,410	1,363	1,225	1,225	1,225	1,225	1,363	1,363	1,666	1,666	1,666	1,666	1,410	1,363	1,225	1,225	1,225	1,225	1,363	1,363	
Total Available Resources	10,315	10,315	10,315	9,611	9,564	9,473	9,473	9,473	9,473	9,564	9,815	10,315	10,325	10,325	10,325	9,621	9,574	9,483	9,483	9,483	9,483	9,574	10,392	1

FPC 066

7/19/00 @ 1:27 PM

	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07
Baseload Plants (Summer and Winter TYSP Ratings)																								
Crystal River 1	400	400	400	396	396	396	396	396	396	396	400	400	400	400	400	396	396	396	396	396	396	396	400	400
Crystal River 2	503	503	503	498	498	498	498	498	498	498	503	503	503	503	503	498	498	498	498	498	498	498	503	503
Crystal River 4	739	739	739	729	729	729	729	729	729	729	739	739	739	739	739	729	729	729	729	729	729	729	739	739
Crystal River 5	732	732	732	717	717	717	717	717	717	717	732	732	732	732	732	717	717	717	717	717	717	717	732	732
Crystal River 3	782	782	782	765	765	765	765	765	765	765	782	782	782	782	782	765	765	765	765	765	765	765	782	782
University of Florida Cogen	41	41	41	35	35	35	35	35	35	35	41	41	41	41	41	35	35	35	35	35	35	35	41	41
Baseload Contracts (Firm Purchase Capacity)																								
UPS Purchase from Southern Company	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409
TECO Purchase for Sebring Load	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
QF Contracts																								
PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
TIMBER ENERGY 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BAY COUNTY RES REC	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
LFC MADISON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LFC JEFFERSON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
PASCO COUNTY RES REC	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
CARGILL	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
RIDGE GENERATING STA.	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
ROYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	3
MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
CFR-BIOGEN (ORANGE CO)	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
US AGRICHEM	6	6	6	6	6	6	6	6	6	6	6	6	0	0	0	0	0	0	0	0	0	0	0	
Intermediate Resources (Summer and Winter TYSP Ratings)																								
Anclote 1	522	522	522	498	498	498	498	498	498	498	522	522	522	522	522	498	498	498	498	498	498	498	522	52
Anclote 2	522	522	522	495	495	495	495	495	495	495	522	522	522	522	522	495	495	495	495	495	495	495	522	52
Bartow 1	123	123	123	121	121	121	121	121	121	121	123	123	123	123	123	121	121	121	121	121	121	121	123	12
Bartow 2	121	121	121	119	119	119	119	119	119	119	121	121	121	121	121	119	119	119	119	119	119	119	121	12
Bartow 3	208	208	208	204	204	204	204	204	204	204	208	208	208	208	208	204	204	204	204	204	204	204	208	20
Suwannee River 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Suwannee River 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Suwannee River 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	- 0	
Tiger Bay Cogen	223	223	223	207	207	207	207	207	207	207	223	223	223	223	223	207	207	207	207	207	207	207	223	22
Hines Energy Complex 1	529	529	529	482	482	482	482	482	482	482	529	529	529	529	529	482	482	482	482	482	482	482	529	52
Hines Energy Complex 2	567	567	567	495	495	495	495	495	495	495	567	567	567	567	567	495	495	495	495	495	495	495	567	56
Hines Energy Complex 3	567	567	567	495	495	495	495	495	495	495	567	567	567	567	567	495	495	495	495	495	495	495	567	56
Hines Energy Complex 4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	567	56
Hines Energy Complex 5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Gas Peaking Resources (Summer and Winter TYSP Ratings)																								
Avon Park P1	32	32	32	26	26	26	26	26	26	26	26	32	0	0	0	0	0	0	0	0	0	0	0	
Bartow P2	53	53	53	46	46	46	46	46	46	46	46	53	53	53	53	46	46	46	46	46	46	46	46	5
Bartow P4	60	60	60	49	49	49	49	49	49	49	49	60	60	60	60	49	49	49	49	49	49	49	49	6
Debary P7	93	93	93	80	80	85	85	85	85	80	80	93	93	93	93	80	80	85	85	85	85	80	80	9
Debary P8	93	93	93	80	80	85	85	85	85	80	80	93	93	93	93	80	80	85	85	85	85	80	80	9
Debary P9	93	93	93	80	80	85	85	85	85	80	80	93	93	93	93	80	80	85	85	85	85	80	80	9
Higgins P1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Higgins P2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Higgins P3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

Higgins P4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intercession City P7	94	94	94	80	80	88	88	88	88	80	80	94	94	94	94	80	80	88	88	88	88	80	80	94
Intercession City P8	94	94	94	80	80	88	88	88	88	80	80	94	94	94	94	80	80	88	88	88	88	80	80	94
Intercession City P9	94	94	94	80	80	88	88	88	88	80	80	94	94	94	94	80	80	88	88	88	88	80	80	94
Intercession City P10	94	94	94	80	80	88	88	88	88	80	80	94	94	94	94	80	80	88	88	88	88	80	80	94
Intercession City P12	94	94	94	80	80	80	80	80	80	80	80	94	94	94	94	80	80	80	80	80	80	80	80	94
Intercession City P13	94	94	94	80	80	80	80	80	80	80	80	94	94	94	94	80	80	80	80	80	80	80	80	94
Intercession City P14	94	94	94	80	80	80	80	80	80	80	80	94	94	94	94	80	80	80	80	80	80	80	80	94
Suwannee River P1	67	67	67	55	55	55	55	55	55	55	55	67	67	67	67	55	55	55	55	55	55	55	55	67
Suwannee River P3	67	67	67	55	55	55	55	55	55	55	55	67	67	67	67	55	55	55	55	55	55	55	55	67
Light Oil Peaking Resources (Summer and Winter TYSP Ratings)																								
Avon Park P2	32	32	32	26	26	26	26	26	26	26	26	32	0	0	0	0	0	0	0	0	0	0	0	0
Bartow P1	53	53	53	46	46	46	46	46	46	46	46	53	53	53	53	46	46	46	46	46	46	46	46	53
Bartow P3	53	53	53	46	46	46	46	46	46	46	46	53	53	53	53	46	46	46	46	46	46	46	46	53
Bayboro P1	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Bayboro P2	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Bayboro P3	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Bayboro P4	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Debary P1	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P2	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P3	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P4	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P5	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P6	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P10	93	93	93	79	79	84	84	84	84	79	79	93	93	93	93	79	79	84	84	84	84	79	79	93
Intercession City P1	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P2	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P3	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P4	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P5	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P6	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P11	170	170	170	143	143	0	0	0	0	143	143	170	170	170	170	143	143	0	0	0	0	143	143	170
Rio Pinar P1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suwannee River P2	67	67	67	67	54	54	54	54	54	54	54	67	67	67	67	67	54	54	54	54	54	54	54	67
Turner P1	16	16	16	13	13	13	13	13	13	13	13	16	0	0	0	0	0	0	0	0	0	0	0	0
Turner P2	16	16	16	13	13	13	13	13	13	13	13	16	0	0	0	0	0	0	0	0	0	0	0	0
Turner P3	32	32	32	32	65	65	65	65	65	65	65	32	32	32	32	32	65	65	65	65	65	65	65	32
Turner P4	80	30	80	30	63	63	63	63	63	63	63	30	80	30	30	30	63	63	63	63	63	63	63	30
Total Baseload Plants	3,197	3,197	3,197	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,197	3,197	3,197	3,197	3,197	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,197	3,197
Total Baseload Contracts	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479
Total QF Contracts	818	818	818	818	818	818	818	818	818	818	818	818	813	813	813	813	813	813	813	813	813	813	813	813
Total Intermediate Resources	3,382	3,382	3,382	3,116	3,116	3,116	3,116	3,116	3,116	3,116	3,382	3,382	3,382	3,382	3,382	3,116	3,116	3,116	3,116	3,116	3,116	3,116	3,949	3,949
Total Gas Peaking Resources	1,216	1,216	1,216	1,031	1,031	1,078	1,078	1,078	1,078	1,031	1,031	1,216	1,184	1,184	1,184	1,005	1,005	1,052	1,052	1,052	1,052	1,005	1,005	1,184
Total Light Oil Peaking Resources	1,650	1,650	1,650	1,397	1,350	1,212	1,212	1,212	1,212	1,350	1,350	1,650	1,536	1,536	1,536	1,345	1,298	1,160	1,160	1,160	1,160	1,298	1,298	1,536
Total Available Resources	10,742	10,742	10,742	9,981	9,934	9,843	9,843	9,843	9,843	9,934	10,257	10,742	10,641	10,641	10,641	9,898	9,851	9,760	9,760	9,760	9,760	9,851	10,741	11,203

FPC 068

	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09
Baseload Plants (Summer and Winter TYSP Ratings)																								
Crystal River 1	400	400	400	396	396	396	396	396	396	396	400	400	400	400	400	396	396	396	396	396	396	396	400	400
Crystal River 2	503	503	503	498	498	498	498	498	498	498	503	503	503	503	503	498	498	498	498	498	498	498	503	503
Crystal River 4	739	739	739	729	729	729	729	729	729	729	739	739	739	739	739	729	729	729	729	729	729	729	739	739
Crystal River 5	732	732	732	717	717	717	717	717	717	717	732	732	732	732	732	717	717	717	717	717	717	717	732	73
Crystal River 3	782	782	782	765	765	765	765	765	765	765	782	782	782	782	782	765	765	765	765	765	765	765	782	78
University of Florida Cogen	41	41	41	35	35	35	35	35	35	35	41	41	41	41	41	35	35	35	35	35	35	35	41	41
Baseload Contracts (Firm Purchase Capacity)																								
UPS Purchase from Southern Company	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	40
TECO Purchase for Sebring Load	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	7
QF Contracts																								
PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	4
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	1
TIMBER ENERGY 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
BAY COUNTY RES REC	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	1
LFC MADISON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	
LFC JEFFERSON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	1
PASCO COUNTY RES REC	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	2
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	4
CARGILL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	11
PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	0	0	0	0	0	0	0	0	0	0	0	
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	7
RIDGE GENERATING STA.	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	4
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	11
ROYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	0	0	0	
MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	
CFR-BIOGEN (ORANGE CO)	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	
US AGRICHEM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Intermediate Resources (Summer and Winter TYSP Ratings)																								
Anclote 1	522	522	522	498	498	498	498	498	498	498	522	522	522	522	522	498	498	498	498	498	498	498	522	5
Anclote 2	522	522	522	495	495	495	495	495	495	495	522	522	522	522	522	495	495	495	495	495	495	495	522	5
Bartow 1	123	123	123	121	121	121	121	121	121	121	123	123	123	123	123	121	121	121	121	121	121	121	123	1
Bartow 2	121	121	121	119	119	119	119	119	119	119	121	121	121	121	121	119	119	119	119	119	119	119	121	1
Bartow 3	208	208	208	204	204	204	204	204	204	204	208	208	208	208	208	204	204	204	204	204	204	204	208	2
Suwannee River 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Suwannee River 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Suwannee River 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Tiger Bay Cogen	223	223	223	207	207	207	207	207	207	207	223	223	223	223	223	207	207	207	207	207	207	207	223	2
Hines Energy Complex 1	529	529	529	432	432	432	432	432	432	432	529	529	529	529	529	432	432	432	432	432	432	432	529	5
Hines Energy Complex 2	567	567	567	495	495	495	495	495	495	495	567	567	567	567	567	495	495	495	495	495	495	495	567	5
Hines Energy Complex 3	567	567	567	495	495	495	495	495	495	495	567	567	567	567	567	495	495	495	495	495	495	495	567	5
Hines Energy Complex 4	567	567	567	495	495	495	495	495	495	495	567	567	567	567	567	495	495	495	495	495	495	495	567	5
Hines Energy Complex 5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	567	5
Gas Peaking Resources (Summer and Winter TYSP Ratings)																								
Avon Park P1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Bartow P2	53	53	53	46	46	46	46	46	46	46	46	53	53	53	53	46	46	46	46	46	46	46	46	
Bartow P4	60	60	60	49	49	49	49	49	49	49	49	60	60	60	60	49	49	49	49	49	49	49	49	
Debary P7	93	93	93	80	80	85	85	85	85	80	80	93	93	93	93	80	80	85	85	85	85	80	80	
Debary P8	93	93	93	80	80	85	85	85	85	80	80	93	93	93	93	80	80	85	85	85	85	80	80	
Debary P9	93	93	93	80	80	85	85	85	85	80	80	93	93	93	93	80	80	85	85	85	85	80	80	
Higgins P1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Higgins P2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Higgins P3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

Higgins P4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Intercession City P7	94	94	94	80	80	83	83	83	88	80	80	94	94	94	94	80	80	83	83	83	88	80	80	94
Intercession City P8	94	94	94	80	80	88	83	88	88	80	80	94	94	94	94	80	80	83	88	88	88	80	80	94
Intercession City P9	94	94	94	80	80	88	83	88	88	80	80	94	94	94	94	80	80	83	88	88	83	80	80	94
Intercession City P10	94	94	94	80	80	88	88	88	85	80	80	94	94	94	94	80	80	83	88	88	83	80	80	94
Intercession City P12	94	94	94	80	80	80	80	80	80	80	80	94	94	94	94	80	80	80	80	80	80	80	80	94
Intercession City P13	94	94	94	80	80	80	80	80	80	80	80	94	94	94	94	80	80	80	80	80	80	80	80	94
Intercession City P14	94	94	94	80	80	80	80	80	80	80	80	94	94	94	94	80	80	80	80	80	80	80	80	94
Suwannee River P1	67	67	67	55	55	55	55	55	55	55	55	67	67	67	67	55	55	55	55	55	55	55	55	67
Suwannee River P3	67	67	67	55	55	55	55	55	55	55	55	67	67	67	67	55	55	55	55	55	55	55	55	67
Light Oil Peaking Resources (Summer and Winter TYSP Ratings)																								
Avon Park P2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bartow P1	53	53	53	46	46	46	46	46	46	46	46	53	53	53	53	46	46	46	46	46	46	46	46	53
Bartow P3	53	53	53	46	46	46	46	46	46	46	46	53	53	53	53	46	46	46	46	46	46	46	46	53
Bayboro P1	53	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	53
Bayboro P2	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	58
Bayboro P3	58	58	58	46	46	46	46	46	46	46	46	58	58	53	58	46	46	46	46	46	46	46	46	53
Bayboro P4	58	58	58	46	46	46	46	46	46	46	46	58	58	58	58	46	46	46	46	46	46	46	46	53
Debary P1	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P2	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P3	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P4	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P5	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P6	65	65	65	54	54	54	54	54	54	54	54	65	65	65	65	54	54	54	54	54	54	54	54	65
Debary P10	93	93	93	79	79	84	84	84	84	79	79	93	93	93	93	79	79	84	84	84	84	79	79	93
Intercession City P1	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P2	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P3	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P4	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P5	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P6	61	61	61	49	49	49	49	49	49	49	49	61	61	61	61	49	49	49	49	49	49	49	49	61
Intercession City P11	170	170	170	143	143	0	0	0	0	143	143	170	170	170	170	143	143	0	0	0	0	143	143	170
Rio Pinar P1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suwannee River P2	67	67	67	67	54	54	54	54	54	54	54	67	67	67	67	67	54	54	54	54	54	54	54	67
Turner P1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Turner P2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Turner P3	82	82	82	82	65	65	65	65	65	65	65	82	82	82	82	82	65	65	65	65	65	65	65	82
Turner P4	80	80	80	80	63	63	63	63	63	63	63	80	80	80	80	80	63	63	63	63	63	63	63	80
Total Baseload Plants	3,197	3,197	3,197	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,197	3,197	3,197	3,197	3,197	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,197	3,197
Total Baseload Contracts	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479
Total QF Contracts	798	798	798	798	798	798	798	798	798	798	798	798	639	639	639	639	639	639	639	639	658	658	658	658
Total Intermediate Resources	3,949	3,949	3,949	3,611	3,611	3,611	3,611	3,611	3,611	3,611	3,949	3,949	3,949	3,949	3,949	3,611	3,611	3,611	3,611	3,611	3,611	3,611	4,516	4,516
Total Gas Peaking Resources	1,184	1,184	1,184	1,005	1,005	1,052	1,052	1,052	1,052	1,005	1,005	1,184	1,184	1,184	1,184	1,005	1,005	1,052	1,052	1,052	1,052	1,005	1,005	1,184
Total Light Oil Peaking Resources	1,586	1,586	1,586	1,345	1,298	1,160	1,160	1,160	1,160	1,298	1,298	1,586	1,586	1,586	1,586	1,345	1,298	1,160	1,160	1,160	1,160	1,298	1,298	1,586
Total Available Resources	11,193	11,193	11,193	10,378	10,331	10,240	10,240	10,240	10,240	10,331	10,726	11,193	11,034	11,034	11,034	10,269	10 222	10,131	10,131	10,131	10,100	10,191	11,153	11,620

FPC 070

	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Comments	
Baseload Plants (Summer and Winter TYSP Ratings)														
Crystal River 1	400	400	400	396	396	396	396	396	396	396	400	400	Turbine upgrade 12/2001	
Crystal River 2	503	503	503	498	498	498	498	498	498	498	503	503	Turbine upgrade 12/2000	
Crystal River 4	739	739	739	729	729	729	729	729	729	729	739	739	Turbine upgrade 4/2000	
Crystal River 5	732	732	732	717	717	717	717	717	717	717	732	732		
Crystal River 3	782	782	782	765	765	765	765	765	765	765	782	782		
University of Florida Cogen	41	41	41	35	35	35	35	35	35	35	41	41		
Baseload Contracts (Firm Purchase Capacity)														
UPS Purchase from Southern Company	409	409	409	409	409	0	0	0	0	0	0	0	Contract Expires 6/2010	
TECO Purchase for Sebring Load	70	70	70	70	70	70	70	70	70	70	70	70	Contract Expires 3/2011	
QF Contracts														
PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	4/1/83	Contract
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	6/1/86	Contract
TIMBER ENERGY 1	0	0	0	0	0	0	0	0	0	0	0	0	7/1/88	Contract Expires 4/2002
BAY COUNTY RES REC	11	11	11	11	11	11	11	11	11	11	11	11	4/1/88	Contract
LFC MADISON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9/1/89	Contract
LFC JEFFERSON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	6/1/90	Contract
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	9/1/90	Contract
PASCO COUNTY RES REC	23	23	23	23	23	23	23	23	23	23	23	23	3/1/91	Contract
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	11/1/91	Contract
CARGILL	0	0	0	0	0	0	0	0	0	0	0	0	10/1/92	Contract Expires 1/2003
LAKE COGEN	0	0	0	0	0	0	0	0	0	0	0	0	7/1/93	Contract Expires 1/2010
PASCO COGEN	0	0	0	0	0	0	0	0	0	0	0	0	7/1/93	Contract Expires 1/2009
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	10/1/93	Contract
RIDGE GENERATING STA.	40	40	40	40	40	40	40	40	40	40	40	40	5/1/94	Contract
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	7/1/94	Contract
ROYSTER (PPP)	0	0	0	0	0	0	0	0	0	0	0	0	7/1/94	Contract Expires 9/2009
MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	7/1/94	Contract
CFR-BIOGEN (ORANGE CO)	74	74	74	74	74	74	74	74	74	74	74	74	6/1/95	Contract
US AGRICHEM	0	0	0	0	0	0	0	0	0	0	0	0	1/1/97	Contract Expires 1/2007
Intermediate Resources (Summer and Winter TYSP Ratings)														
Anclote 1	522	522	522	498	498	498	498	498	498	498	522	522		
Anclote 2	522	522	522	495	495	495	495	495	495	495	522	522		
Bartow 1	123	123	123	121	121	121	121	121	121	121	123	123		
Bartow 2	121	121	121	119	119	119	119	119	119	119	121	121		
Bartow 3	208	208	208	204	204	204	204	204	204	204	208	208		
Suwannee River 1	0	0	0	0	0	0	0	0	0	0	0	0	Unit Retirement 12/31/2003	
Suwannee River 2	0	0	0	0	0	0	0	0	0	0	0	0	Unit Retirement 12/31/2003	
Suwannee River 3	0	0	0	0	0	0	0	0	0	0	0	0	Unit Retirement 12/31/2003	
Tiger Bay Cogen	223	223	223	207	207	207	207	207	207	207	223	223		
Hines Energy Complex 1	529	529	529	482	482	482	482	482	482	482	529	529		
Hines Energy Complex 2	567	567	567	495	495	495	495	495	495	495	567	567	Unit Addition 11/2003	
Hines Energy Complex 3	567	567	567	495	495	495	495	495	495	495	567	567	Unit Addition 11/2005	
Hines Energy Complex 4	567	567	567	495	495	495	495	495	495	495	567	567	Unit Addition 11/2007	
Hines Energy Complex 5	567	567	567	495	495	495	495	495	495	495	567	567	Unit Addition 11/2009	
Gas Peaking Resources (Summer and Winter TYSP Ratings)														
Avon Park P1	0	0	0	0	0	0	0	0	0	0	0	0	Unit Retirement 12/31/2006	
Bartow P2	53	53	53	46	46	46	46	46	46	46	46	53		
Bartow P4	60	60	60	49	49	49	49	49	49	49	49	60		
Debary P7	93	93	93	80	80	85	85	85	85	80	80	93	Inlet fogging installed 5/2000 (Jun, Jul, Aug & Sep)	
Debary P8	93	93	93	80	80	85	85	85	85	80	80	93	Inlet fogging installed 5/2000 (Jun, Jul, Aug & Sep)	
Debary P9	93	93	93	80	80	85	85	85	85	80	80	93	Inlet fogging installed 5/2000 (Jun, Jul, Aug & Sep)	
Higgins P1	0	0	0	0	0	0	0	0	0	0	0	0	Unit Retirement 12/31/2005	
Higgins P2	0	0	0	0	0	0	0	0	0	0	0	0	Unit Retirement 12/31/2005	
Higgins P3	0	0	0	0	0	0	0	0	0	0	0	0	Unit Retirement 12/31/2005	

Higgins P4	0	0	0	0	0	0	0	0	0	0	0	0	Unit Retirement 12/31/2005
Intercession City P7	94	94	94	80	80	85	85	85	85	80	80	94	Inlet fogging (Jun, Jul, Aug & Sep)
Intercession City P8	94	94	94	80	80	85	85	85	85	80	80	94	Inlet fogging (Jun, Jul, Aug & Sep)
Intercession City P9	94	94	94	80	80	85	85	85	85	80	80	94	Inlet fogging (Jun, Jul, Aug & Sep)
Intercession City P10	94	94	94	80	80	85	85	85	85	80	80	94	Inlet fogging (Jun, Jul, Aug & Sep)
Intercession City P12	94	94	94	80	80	80	80	80	80	80	80	94	Commercial operation 12/2000
Intercession City P13	94	94	94	80	80	80	80	80	80	80	80	94	Commercial operation 12/2000
Intercession City P14	94	94	94	80	80	80	80	80	80	80	80	94	Commercial operation 12/2000
Suwannee River P1	67	67	67	55	55	55	55	55	55	55	55	67	
Suwannee River P3	67	67	67	55	55	55	55	55	55	55	55	67	
Light Oil Peaking Resources (Summer and Winter TYSP Ratings)													
Avon Park P2	0	0	0	0	0	0	0	0	0	0	0	0	Unit Retirement 12/31/2006
Bartow P1	53	53	53	46	46	46	46	46	46	46	46	53	
Bartow P3	53	53	53	46	46	46	46	46	46	46	46	53	
Bayboro P1	58	58	58	46	46	46	46	46	46	46	46	58	
Bayboro P2	58	58	58	46	46	46	46	46	46	46	46	58	
Bayboro P3	58	58	58	46	46	46	46	46	46	46	46	58	
Bayboro P4	58	58	58	46	46	46	46	46	46	46	46	58	
Debary P1	65	65	65	54	54	54	54	54	54	54	54	65	
Debary P2	65	65	65	54	54	54	54	54	54	54	54	65	
Debary P3	65	65	65	54	54	54	54	54	54	54	54	65	
Debary P4	65	65	65	54	54	54	54	54	54	54	54	65	
Debary P5	65	65	65	54	54	54	54	54	54	54	54	65	
Debary P6	65	65	65	54	54	54	54	54	54	54	54	65	
Debary P10	93	93	93	79	79	84	84	84	84	79	79	93	Inlet fogging installed 5/2000 (Jun, Jul, Aug & Sep)
Intercession City P1	61	61	61	49	49	49	49	49	49	49	49	61	
Intercession City P2	61	61	61	49	49	49	49	49	49	49	49	61	
Intercession City P3	61	61	61	49	49	49	49	49	49	49	49	61	
Intercession City P4	61	61	61	49	49	49	49	49	49	49	49	61	
Intercession City P5	61	61	61	49	49	49	49	49	49	49	49	61	
Intercession City P6	61	61	61	49	49	49	49	49	49	49	49	61	
Intercession City P11	170	170	170	143	143	0	0	0	0	143	143	170	Southern summer ownership (Jun through Sep)
Rio Pinar P1	0	0	0	0	0	0	0	0	0	0	0	0	Unit Retirement 12/31/2005
Suwannee River P2	67	67	67	67	54	54	54	54	54	54	54	67	
Turner P1	0	0	0	0	0	0	0	0	0	0	0	0	Unit Retirement 12/31/2006
Turner P2	0	0	0	0	0	0	0	0	0	0	0	0	Unit Retirement 12/31/2006
Turner P3	82	82	82	82	65	65	65	65	65	65	65	82	
Turner P4	80	80	80	80	63	63	63	63	63	63	63	80	
Total Baseload Plants	3,197	3,197	3,197	3,140	3,140	3,140	3,140	3,140	3,140	3,140	3,197	3,197	
Total Baseload Contracts	479	479	479	479	479	70	70	70	70	70	70	70	
Total QF Contracts	548	548	548	548	548	548	548	548	548	548	548	548	
Total Intermediate Resources	4,516	4,516	4,516	4,106	4,106	4,106	4,106	4,106	4,106	4,106	4,516	4,516	
Total Gas Peaking Resources	1,134	1,134	1,134	1,005	1,005	1,052	1,052	1,052	1,052	1,005	1,005	1,134	
Total Light Oil Peaking Resources	1,536	1,536	1,536	1,345	1,298	1,160	1,160	1,160	1,160	1,298	1,298	1,536	
Total Available Resources	11,510	11,510	11,510	10,623	10,576	10,076	10,076	10,076	10,076	10,167	10,634	11,101	

FPC 072

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY
2000 SERC RATINGS, COGENERATION = 991231
JANUARY 2000 LONG-TERM FORECAST (S000101)
Bulk Power Sales Included in Demand & Energy Forecast

2000 Ten-Year Site Plan Analysis * Future Capacity Additions for 20 % RM * Base Case

		WINTER 00/01 Jan-2001	WINTER 01/02 Jan-2002	WINTER 02/03 Jan-2003	WINTER 03/04 Jan-2004	WINTER 04/05 Jan-2005	WINTER 05/06 Jan-2006	WINTER 06/07 Jan-2007	WINTER 07/08 Jan-2008	WINTER 08/09 Jan-2009	WINTER 09/10 Jan-2010
Existing FPC Capacity	MW	8,267	8,590	8,607	8,607	9,028	9,028	9,445	9,349	9,916	9,916
New FPC Capacity	MW	323	17	0	567	0	567	0	567	0	567
Retired FPC Capacity	MW	0	0	0	146	0	150	96	0	0	0
Total Installed Capacity	MW	8,590	8,607	8,607	9,028	9,028	9,445	9,349	9,916	9,916	10,483
Firm Purchase Capacity	MW	469	469	469	469	479	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	818	818	818	818	813	798	689	548
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	9,890	9,907	9,894	10,315	10,325	10,742	10,641	11,193	11,084	11,510
Potential Total Retail Demand	MW	8,468	8,636	8,828	8,997	9,165	9,325	9,483	9,634	9,783	9,933
Wholesale (REA)	MW	894	911	558	503	525	600	676	755	833	912
Wholesale (Bulk Power)	MW	632	167	167	167	167	167	167	167	167	167
Wholesale (Municipal)	MW	205	196	203	206	198	200	203	206	209	212
Total Wholesale Demand	MW	1,731	1,274	928	877	890	968	1,046	1,129	1,210	1,291
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	10,229	9,940	9,786	9,904	10,085	10,323	10,559	10,793	11,023	11,254
Non-Dispatchable DSM and Self-Service QF	MW	444	468	495	523	552	582	613	643	672	701
Normal Weather Demand (Before Load Control)	MW	9,785	9,472	9,291	9,381	9,533	9,741	9,946	10,150	10,351	10,553
Normal Weather Reserves (Before Load Control)	MW	105	435	603	935	792	1,002	695	1,043	733	957
Normal Weather Reserve Margin (Before Load Control)	%	1.1%	4.6%	6.5%	10.0%	8.3%	10.3%	7.0%	10.3%	7.1%	9.1%
Normal Weather Load Management	MW	833	771	730	707	688	674	661	650	641	632
Normal Weather Demand (After Load Management)	MW	8,952	8,701	8,561	8,674	8,845	9,067	9,285	9,499	9,710	9,921
Normal Weather Reserves (After Load Management)	MW	938	1,206	1,333	1,641	1,480	1,675	1,356	1,693	1,374	1,589
Normal Weather Reserve Margin (After Load Management)	%	10.5%	13.9%	15.6%	18.9%	16.7%	18.5%	14.6%	17.8%	14.1%	16.0%
Normal Weather Interruptible Load	MW	306	304	328	329	334	337	342	345	348	350
Normal Weather Voltage Reduction	MW	118	115	113	114	117	120	123	125	128	131
Normal Weather Demand (After All Load Control)	MW	8,528	8,282	8,120	8,231	8,394	8,610	8,820	9,029	9,234	9,440
Normal Weather Reserves (After All Load Control)	MW	1,362	1,625	1,774	2,084	1,931	2,132	1,821	2,163	1,850	2,070
Normal Weather Reserve Margin (After All Load Control)	%	16.0%	19.6%	21.9%	25.3%	23.0%	24.8%	20.6%	24.0%	20.0%	21.9%
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,706	1,656	1,624	1,646	1,679	1,722	1,764	1,806	1,847	1,888
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-344	-32	150	438	252	410	57	358	3	182
Normal Weather "DLC" Reserve Margin Contribution	%	92.3%	73.2%	66.0%	55.2%	59.0%	53.0%	61.9%	51.8%	60.4%	53.8%

Note: Suwannee River Steam Units 1-3 Retired 12/31/2003
Higgins Peakers P1-P4 Retired 12/31/2005
Rio Pinar Peaker P1 Retired 12/31/2005
Avon Park Peakers P1-P2 Retired 12/31/2006
Turner Peakers P1-P2 Retired 12/31/2006

FPC 073

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

2000 SERC RATINGS, COGENERATION = 991231

JANUARY 2000 LONG-TERM FORECAST (S000101)

Bulk Power Sales Included in Demand & Energy Forecast

2000 Ten-Year Site Plan Analysis • Future Capacity Additions for 20 % RM • Base Case

		SUMMER 00 Aug-2000	SUMMER 01 Aug-2001	SUMMER 02 Aug-2002	SUMMER 03 Aug-2003	SUMMER 04 Aug-2004	SUMMER 05 Aug-2005	SUMMER 06 Aug-2006	SUMMER 07 Aug-2007	SUMMER 08 Aug-2008	SUMMER 09 Aug-2009
Existing FPC Capacity	MW	7,553	7,553	7,817	7,834	7,834	8,186	8,186	8,546	8,468	8,963
New FPC Capacity	MW	0	264	17	0	495	0	495	0	495	0
Retired FPC Capacity	MW	0	0	0	0	143	0	135	78	0	0
Total Installed Capacity	MW	7,553	7,817	7,834	7,834	8,186	8,186	8,546	8,468	8,963	8,963
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	818	818	818	818	818	813	798	689
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	8,853	9,117	9,121	9,121	9,473	9,483	9,843	9,760	10,240	10,131
Potential Total Retail Demand	MW	7,326	7,467	7,621	7,801	7,956	8,111	8,259	8,403	8,543	8,683
Wholesale (REA)	MW	392	489	490	121	48	54	112	171	231	291
Wholesale (Bulk Power)	MW	632	632	167	167	167	167	167	167	167	167
Wholesale (Municipal)	MW	253	222	209	218	221	211	214	217	220	223
Total Wholesale Demand	MW	1,277	1,343	867	506	436	433	493	555	618	681
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	8,633	8,840	8,518	8,337	8,422	8,574	8,782	8,988	9,191	9,394
Non-Dispatchable DSM and Self-Service QF	MW	355	368	381	395	410	425	441	456	471	486
Normal Weather Demand (Before Load Control)	MW	8,278	8,472	8,137	7,942	8,012	8,149	8,341	8,532	8,720	8,908
Normal Weather Reserves (Before Load Control)	MW	575	645	985	1,179	1,461	1,335	1,502	1,228	1,519	1,222
Normal Weather Reserve Margin (Before Load Control)	%	6.9%	7.6%	12.1%	14.8%	18.2%	16.4%	18.0%	14.4%	17.4%	13.7%
Normal Weather Load Management	MW	512	463	400	356	322	291	265	242	222	205
Normal Weather Demand (After Load Management)	MW	7,766	8,009	7,736	7,586	7,690	7,857	8,076	8,290	8,498	8,703
Normal Weather Reserves (After Load Management)	MW	1,087	1,108	1,385	1,536	1,783	1,626	1,767	1,470	1,742	1,427
Normal Weather Reserve Margin (After Load Management)	%	14.0%	13.8%	17.9%	20.2%	23.2%	20.7%	21.9%	17.7%	20.5%	16.4%
Normal Weather Interruptible Load	MW	327	308	305	328	329	335	339	343	346	349
Normal Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After All Load Control)	MW	7,439	7,701	7,431	7,258	7,361	7,522	7,737	7,947	8,152	8,354
Normal Weather Reserves (After All Load Control)	MW	1,414	1,416	1,690	1,864	2,112	1,961	2,106	1,813	2,088	1,776
Normal Weather Reserve Margin (After All Load Control)	%	19.0%	18.4%	22.7%	25.7%	28.7%	26.1%	27.2%	22.8%	25.6%	21.3%
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,488	1,540	1,486	1,452	1,472	1,504	1,547	1,589	1,630	1,671
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-74	-124	204	412	639	456	559	223	457	105
Normal Weather "DLC" Reserve Margin Contribution	%	59.3%	54.4%	41.7%	36.7%	30.8%	31.9%	28.7%	32.3%	27.2%	31.2%

FPC 074

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY
2000 SERC RATINGS, COGENERATION = 991231
JANUARY 2000 LONG-TERM FORECAST (S000101)
Bulk Power Sales Included in Demand & Energy Forecast

2000 Ten-Year Site Plan Analysis * Future Capacity Additions for 20 % RM * No Peaker Retirements

		WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08	WINTER 08/09	WINTER 09/10
		Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008	Jan-2009	Jan-2010
Existing FPC Capacity	MW	8,267	8,590	8,607	8,607	9,028	9,028	9,035	9,602	9,602	10,169
New FPC Capacity	MW	323	17	0	567	0	7	567	0	567	132
Retired FPC Capacity	MW	0	0	0	146	0	0	0	0	0	0
Total Installed Capacity	MW	8,590	8,607	8,607	9,028	9,028	9,035	9,602	9,602	10,169	10,301
Firm Purchase Capacity	MW	469	469	469	469	479	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	818	818	818	818	813	798	689	548
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	9,890	9,907	9,894	10,315	10,325	10,332	10,894	10,879	11,337	11,328
Potential Total Retail Demand	MW	8,468	8,636	8,828	8,997	9,165	9,325	9,483	9,634	9,783	9,933
Wholesale (REA)	MW	894	911	558	503	525	600	676	755	833	912
Wholesale (Bulk Power)	MW	632	167	167	167	167	167	167	167	167	167
Wholesale (Municipal)	MW	205	196	203	206	198	200	203	206	209	212
Total Wholesale Demand	MW	1,731	1,274	928	877	890	968	1,046	1,129	1,210	1,291
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	10,229	9,940	9,786	9,904	10,085	10,323	10,559	10,793	11,023	11,254
Non-Dispatchable DSM and Self-Service QF	MW	444	468	495	523	552	582	613	643	672	701
Normal Weather Demand (Before Load Control)	MW	9,785	9,472	9,291	9,381	9,533	9,741	9,946	10,150	10,351	10,553
Normal Weather Reserves (Before Load Control)	MW	105	435	603	935	792	592	948	729	986	775
Normal Weather Reserve Margin (Before Load Control)	%	1.1%	4.6%	6.5%	10.0%	8.3%	6.1%	9.5%	7.2%	9.5%	7.3%
Normal Weather Load Management	MW	833	771	730	707	688	674	661	650	641	632
Normal Weather Demand (After Load Management)	MW	8,952	8,701	8,561	8,674	8,845	9,067	9,285	9,499	9,710	9,921
Normal Weather Reserves (After Load Management)	MW	938	1,206	1,333	1,641	1,480	1,265	1,609	1,379	1,627	1,407
Normal Weather Reserve Margin (After Load Management)	%	10.5%	13.9%	15.6%	18.9%	16.7%	14.0%	17.3%	14.5%	16.8%	14.2%
Normal Weather Interruptible Load	MW	306	304	328	329	334	337	342	345	348	350
Normal Weather Voltage Reduction	MW	118	115	113	114	117	120	123	125	126	131
Normal Weather Demand (After All Load Control)	MW	8,528	8,282	8,120	8,231	8,394	8,610	8,820	9,029	9,234	9,440
Normal Weather Reserves (After All Load Control)	MW	1,362	1,625	1,774	2,084	1,931	1,722	2,074	1,849	2,103	1,888
Normal Weather Reserve Margin (After All Load Control)	%	16.0%	19.6%	21.9%	25.3%	23.0%	20.0%	23.5%	20.5%	22.8%	20.0%
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,706	1,656	1,624	1,646	1,679	1,722	1,764	1,806	1,847	1,888
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-344	-32	150	438	252	0	310	44	256	0
Normal Weather "DLC" Reserve Margin Contribution	%	92.3%	73.2%	66.0%	55.2%	59.0%	65.7%	54.3%	60.6%	53.1%	59.0%

Note: Suwannee River Steam Units 1-3 Retired 12/31/2003
Higgins Peakers P1-P4 Retired 12/31/2005
Rio Pinar Peaker P1 Retired 12/31/2005
Avon Park Peakers P1-P2 Retired 12/31/2006
Turner Peakers P1-P2 Retired 12/31/2006

FPC 075

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY
2000 SERC RATINGS, COGENERATION = 991231
JANUARY 2000 LONG-TERM FORECAST (S000101)
Bulk Power Sales Included In Demand & Energy Forecast

2000 Ten-Year Site Plan Analysis * Future Capacity Additions for 20 % RM * No Peaker Retirements

		SUMMER 00 Aug-2000	SUMMER 01 Aug-2001	SUMMER 02 Aug-2002	SUMMER 03 Aug-2003	SUMMER 04 Aug-2004	SUMMER 05 Aug-2005	SUMMER 06 Aug-2006	SUMMER 07 Aug-2007	SUMMER 08 Aug-2008	SUMMER 09 Aug-2009
Existing FPC Capacity	MW	7,553	7,553	7,817	7,834	7,834	8,186	8,186	8,186	8,681	8,681
New FPC Capacity	MW	0	264	17	0	495	0	0	495	0	495
Retired FPC Capacity	MW	0	0	0	0	143	0	0	0	0	0
Total Installed Capacity	MW	7,553	7,817	7,834	7,834	8,186	8,186	8,186	8,681	8,681	9,176
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	818	818	818	818	818	813	798	689
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	8,853	9,117	9,121	9,121	9,473	9,483	9,483	9,973	9,958	10,344
Potential Total Retail Demand	MW	7,326	7,467	7,621	7,801	7,956	8,111	8,259	8,403	8,543	8,683
Wholesale (REA)	MW	392	489	490	121	48	54	112	171	231	291
Wholesale (Bulk Power)	MW	632	632	167	167	167	167	167	167	167	167
Wholesale (Municipal)	MW	253	222	209	218	221	211	214	217	220	223
Total Wholesale Demand	MW	1,277	1,343	867	506	436	433	493	555	618	681
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	8,633	8,840	8,518	8,337	8,422	8,574	8,782	8,988	9,191	9,394
Non-Dispatchable DSM and Self-Service QF	MW	355	368	381	395	410	425	441	456	471	486
Normal Weather Demand (Before Load Control)	MW	8,278	8,472	8,137	7,942	8,012	8,149	8,341	8,532	8,720	8,908
Normal Weather Reserves (Before Load Control)	MW	575	645	985	1,179	1,461	1,335	1,142	1,441	1,237	1,435
Normal Weather Reserve Margin (Before Load Control)	%	6.9%	7.6%	12.1%	14.8%	18.2%	16.4%	13.7%	16.9%	14.2%	16.1%
Normal Weather Load Management	MW	512	463	400	356	322	291	265	242	222	205
Normal Weather Demand (After Load Management)	MW	7,766	8,009	7,736	7,586	7,690	7,857	8,076	8,290	8,498	8,703
Normal Weather Reserves (After Load Management)	MW	1,087	1,108	1,385	1,536	1,783	1,626	1,407	1,683	1,460	1,640
Normal Weather Reserve Margin (After Load Management)	%	14.0%	13.8%	17.9%	20.2%	23.2%	20.7%	17.4%	20.3%	17.2%	18.8%
Normal Weather Interruptible Load	MW	327	308	305	328	329	335	339	343	346	349
Normal Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After All Load Control)	MW	7,439	7,701	7,431	7,258	7,361	7,522	7,737	7,947	8,152	8,354
Normal Weather Reserves (After All Load Control)	MW	1,414	1,416	1,690	1,864	2,112	1,961	1,746	2,026	1,806	1,989
Normal Weather Reserve Margin (After All Load Control)	%	19.0%	18.4%	22.7%	25.7%	28.7%	26.1%	22.6%	25.5%	22.1%	23.8%
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,488	1,540	1,486	1,452	1,472	1,504	1,547	1,589	1,630	1,671
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-74	-124	204	412	639	456	199	436	175	318
Normal Weather "DLC" Reserve Margin Contribution	%	59.3%	54.4%	41.7%	36.7%	30.8%	31.9%	34.6%	28.9%	31.5%	27.8%

FPC 076

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

2000 SERC RATINGS, COGENERATION = 991231

JANUARY 2000 LONG-TERM FORECAST (S000101)

Bulk Power Sales Included in Demand & Energy Forecast

2000 Ten-Year Site Plan Analysis * Without Future Capacity Additions for 20 % RM * With Retirements

		WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08	WINTER 08/09	WINTER 09/10
		Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008	Jan-2009	Jan-2010
Existing FPC Capacity	MW	8,267	8,590	8,607	8,607	8,461	8,461	8,311	8,215	8,215	8,215
New FPC Capacity	MW	323	17	0	0	0	0	0	0	0	0
Retired FPC Capacity	MW	0	0	0	146	0	150	96	0	0	0
Total Installed Capacity	MW	8,590	8,607	8,607	8,461	8,461	8,311	8,215	8,215	8,215	8,215
Firm Purchase Capacity	MW	469	469	469	469	479	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	818	818	818	818	813	798	689	548
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	9,890	9,907	9,894	9,748	9,758	9,608	9,507	9,492	9,383	9,242
Potential Total Retail Demand	MW	8,468	8,636	8,828	8,997	9,165	9,325	9,483	9,634	9,783	9,933
Wholesale (REA)	MW	894	911	558	503	525	600	676	755	833	912
Wholesale (Bulk Power)	MW	632	167	167	167	167	167	167	167	167	167
Wholesale (Municipal)	MW	205	196	203	206	198	200	203	206	209	212
Total Wholesale Demand	MW	1,731	1,274	928	877	890	968	1,046	1,129	1,210	1,291
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	10,229	9,940	9,786	9,904	10,085	10,323	10,559	10,793	11,023	11,254
Non-Dispatchable DSM and Self-Service QF	MW	444	468	495	523	552	582	613	643	672	701
Normal Weather Demand (Before Load Control)	MW	9,785	9,472	9,291	9,381	9,533	9,741	9,946	10,150	10,351	10,553
Normal Weather Reserves (Before Load Control)	MW	105	435	603	368	225	-132	-440	-658	-968	-1,311
Normal Weather Reserve Margin (Before Load Control)	%	1.1%	4.6%	6.5%	3.9%	2.4%	-1.4%	-4.4%	-6.5%	-9.4%	-12.4%
Normal Weather Load Management	MW	833	771	730	707	688	674	661	650	641	632
Normal Weather Demand (After Load Management)	MW	8,952	8,701	8,561	8,674	8,845	9,067	9,285	9,499	9,710	9,921
Normal Weather Reserves (After Load Management)	MW	938	1,206	1,333	1,074	913	541	222	-8	-327	-679
Normal Weather Reserve Margin (After Load Management)	%	10.5%	13.9%	15.6%	12.4%	10.3%	6.0%	2.4%	-0.1%	-3.4%	-6.8%
Normal Weather Interruptible Load	MW	306	304	328	329	334	337	342	345	348	350
Normal Weather Voltage Reduction	MW	118	115	113	114	117	120	123	125	128	131
Normal Weather Demand (After All Load Control)	MW	8,528	8,282	8,120	8,231	8,394	8,610	8,820	9,029	9,234	9,440
Normal Weather Reserves (After All Load Control)	MW	1,362	1,625	1,774	1,517	1,364	998	687	462	149	-198
Normal Weather Reserve Margin (After All Load Control)	%	16.0%	19.6%	21.9%	18.4%	16.3%	11.6%	7.8%	5.1%	1.6%	-2.1%
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,706	1,656	1,624	1,646	1,679	1,722	1,764	1,806	1,847	1,888
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-344	-32	150	-129	-315	-724	-1,077	-1,343	-1,698	-2,086
Normal Weather "DLC" Reserve Margin Contribution	%	92.3%	73.2%	66.0%	75.8%	83.5%	113.3%	164.0%	242.3%	751.2%	-562.0%

Note: Suwannee River Steam Units 1-3 Retired 12/31/2003
Higgins Peakers P1-P4 Retired 12/31/2005
Rio Pinar Peaker P1 Retired 12/31/2005
Avon Park Peakers P1-P2 Retired 12/31/2006
Turner Peakers P1-P2 Retired 12/31/2006

FPC 077

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

2000 SERC RATINGS, COGENERATION = 991231

JANUARY 2000 LONG-TERM FORECAST (S000101)

Bulk Power Sales Included in Demand & Energy Forecast

2000 Ten-Year Site Plan Analysis * Without Future Capacity Additions for 20 % RM * With Retirements

		SUMMER 00	SUMMER 01	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 06	SUMMER 07	SUMMER 08	SUMMER 09
		Aug-2000	Aug-2001	Aug-2002	Aug-2003	Aug-2004	Aug-2005	Aug-2006	Aug-2007	Aug-2008	Aug-2009
Existing FPC Capacity	MW	7,553	7,553	7,817	7,834	7,834	7,691	7,691	7,556	7,478	7,478
New FPC Capacity	MW	0	264	17	0	0	0	0	0	0	0
Retired FPC Capacity	MW	0	0	0	0	143	0	135	78	0	0
Total Installed Capacity	MW	7,553	7,817	7,834	7,834	7,691	7,691	7,556	7,478	7,478	7,478
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	818	818	818	818	818	813	798	689
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	8,853	9,117	9,121	9,121	8,978	8,988	8,853	8,770	8,755	8,646
Potential Total Retail Demand	MW	7,326	7,467	7,621	7,801	7,956	8,111	8,259	8,403	8,543	8,683
Wholesale (REA)	MW	392	489	490	121	48	54	112	171	231	291
Wholesale (Bulk Power)	MW	632	632	167	167	167	167	167	167	167	167
Wholesale (Municipal)	MW	253	222	209	218	221	211	214	217	220	223
Total Wholesale Demand	MW	1,277	1,343	867	506	436	433	493	555	618	681
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	8,633	8,840	8,518	8,337	8,422	8,574	8,782	8,988	9,191	9,394
Non-Dispatchable DSM and Self-Service QF	MW	355	368	381	395	410	425	441	456	471	486
Normal Weather Demand (Before Load Control)	MW	8,278	8,472	8,137	7,942	8,012	8,149	8,341	8,532	8,720	8,908
Normal Weather Reserves (Before Load Control)	MW	575	645	985	1,179	966	840	512	238	34	-263
Normal Weather Reserve Margin (Before Load Control)	%	6.9%	7.6%	12.1%	14.8%	12.1%	10.3%	6.1%	2.8%	0.4%	-3.0%
Normal Weather Load Management	MW	512	463	400	356	322	291	265	242	222	205
Normal Weather Demand (After Load Management)	MW	7,766	8,009	7,736	7,586	7,690	7,857	8,076	8,290	8,498	8,703
Normal Weather Reserves (After Load Management)	MW	1,087	1,108	1,385	1,536	1,288	1,131	777	480	257	-58
Normal Weather Reserve Margin (After Load Management)	%	14.0%	13.8%	17.9%	20.2%	16.7%	14.4%	9.6%	5.8%	3.0%	-0.7%
Normal Weather Interruptible Load	MW	327	308	305	328	329	335	339	343	346	349
Normal Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After All Load Control)	MW	7,439	7,701	7,431	7,258	7,361	7,522	7,737	7,947	8,152	8,354
Normal Weather Reserves (After All Load Control)	MW	1,414	1,416	1,690	1,864	1,617	1,466	1,116	823	603	291
Normal Weather Reserve Margin (After All Load Control)	%	19.0%	18.4%	22.7%	25.7%	22.0%	19.5%	14.4%	10.4%	7.4%	3.5%
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,488	1,540	1,486	1,452	1,472	1,504	1,547	1,589	1,630	1,671
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-74	-124	204	412	144	-39	-431	-767	-1,028	-1,380
Normal Weather "DLC" Reserve Margin Contribution	%	59.3%	54.4%	41.7%	36.7%	40.2%	42.7%	54.1%	71.1%	94.3%	190.3%

FPC 078

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY
2000 SERC RATINGS, COGENERATION = 991231
JANUARY 2000 LONG-TERM FORECAST (S000101)
Bulk Power Sales Included in Demand & Energy Forecast

2000 Ten-Year Site Plan Analysis * Without Future Capacity Additions for 20 % RM * No Retirements

		WINTER 00/01 Jan-2001	WINTER 01/02 Jan-2002	WINTER 02/03 Jan-2003	WINTER 03/04 Jan-2004	WINTER 04/05 Jan-2005	WINTER 05/06 Jan-2006	WINTER 06/07 Jan-2007	WINTER 07/08 Jan-2008	WINTER 08/09 Jan-2009	WINTER 09/10 Jan-2010
Existing FPC Capacity	MW	8,267	8,590	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607
New FPC Capacity	MW	323	17	0	0	0	0	0	0	0	0
Retired FPC Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Installed Capacity	MW	8,590	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607	8,607
Firm Purchase Capacity	MW	469	469	469	469	479	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	818	818	818	818	813	798	689	548
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	9,890	9,907	9,894	9,894	9,904	9,904	9,899	9,884	9,775	9,634
Potential Total Retail Demand	MW	8,468	8,636	8,828	8,997	9,165	9,325	9,483	9,634	9,783	9,933
Wholesale (REA)	MW	894	911	558	503	525	600	676	755	833	912
Wholesale (Bulk Power)	MW	632	167	167	167	167	167	167	167	167	167
Wholesale (Municipal)	MW	205	196	203	206	198	200	203	206	209	212
Total Wholesale Demand	MW	1,731	1,274	928	877	890	968	1,046	1,129	1,210	1,291
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	10,229	9,940	9,786	9,904	10,085	10,323	10,559	10,793	11,023	11,254
Non-Dispatchable DSM and Self-Service QF	MW	444	468	495	523	552	582	613	643	672	701
Normal Weather Demand (Before Load Control)	MW	9,785	9,472	9,291	9,381	9,533	9,741	9,946	10,150	10,351	10,553
Normal Weather Reserves (Before Load Control)	MW	105	435	603	514	371	164	-48	-266	-576	-919
Normal Weather Reserve Margin (Before Load Control)	%	1.1%	4.6%	6.5%	5.5%	3.9%	1.7%	-0.5%	-2.6%	-5.6%	-8.7%
Normal Weather Load Management	MW	833	771	730	707	688	674	661	650	641	632
Normal Weather Demand (After Load Management)	MW	8,952	8,701	8,561	8,674	8,845	9,067	9,285	9,499	9,710	9,921
Normal Weather Reserves (After Load Management)	MW	938	1,206	1,333	1,220	1,059	837	614	384	65	-287
Normal Weather Reserve Margin (After Load Management)	%	10.5%	13.9%	15.6%	14.1%	12.0%	9.2%	6.6%	4.0%	0.7%	-2.9%
Normal Weather Interruptible Load	MW	306	304	328	329	334	337	342	345	348	350
Normal Weather Voltage Reduction	MW	118	115	113	114	117	120	123	125	128	131
Normal Weather Demand (After All Load Control)	MW	8,528	8,282	8,120	8,231	8,394	8,610	8,820	9,029	9,234	9,440
Normal Weather Reserves (After All Load Control)	MW	1,362	1,625	1,774	1,663	1,510	1,294	1,079	854	541	194
Normal Weather Reserve Margin (After All Load Control)	%	16.0%	19.6%	21.9%	20.2%	18.0%	15.0%	12.2%	9.5%	5.9%	2.1%
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,706	1,656	1,624	1,646	1,679	1,722	1,764	1,806	1,847	1,888
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-344	-32	150	17	-169	-428	-685	-951	-1,306	-1,694
Normal Weather "DLC" Reserve Margin Contribution	%	92.3%	73.2%	66.0%	69.1%	75.4%	87.4%	104.4%	131.1%	206.6%	574.1%

Note: Suwannee River Steam Units 1-3 Retired 12/31/2003
Higgins Peakers P1-P4 Retired 12/31/2005
Rio Pinar Peaker P1 Retired 12/31/2005
Avon Park Peakers P1-P2 Retired 12/31/2006
Turner Peakers P1-P2 Retired 12/31/2006

FPC 079

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

2000 SERC RATINGS, COGENERATION = 991231

JANUARY 2000 LONG-TERM FORECAST (S000101)

Bulk Power Sales Included in Demand & Energy Forecast

2000 Ten-Year Site Plan Analysis * Without Future Capacity Additions for 20 % RM * No Retirements

		SUMMER 00 Aug-2000	SUMMER 01 Aug-2001	SUMMER 02 Aug-2002	SUMMER 03 Aug-2003	SUMMER 04 Aug-2004	SUMMER 05 Aug-2005	SUMMER 06 Aug-2006	SUMMER 07 Aug-2007	SUMMER 08 Aug-2008	SUMMER 09 Aug-2009
Existing FPC Capacity	MW	7,553	7,553	7,817	7,834	7,834	7,834	7,834	7,834	7,834	7,834
New FPC Capacity	MW	0	284	17	0	0	0	0	0	0	0
Retired FPC Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Installed Capacity	MW	7,553	7,817	7,834	7,834	7,834	7,834	7,834	7,834	7,834	7,834
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	818	818	818	818	818	813	798	689
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	8,853	9,117	9,121	9,121	9,121	9,131	9,131	9,126	9,111	9,002
Potential Total Retail Demand	MW	7,326	7,467	7,621	7,801	7,956	8,111	8,259	8,403	8,543	8,683
Wholesale (REA)	MW	392	489	490	121	48	54	112	171	231	291
Wholesale (Bulk Power)	MW	632	632	167	167	167	167	167	167	167	167
Wholesale (Municipal)	MW	253	222	209	218	221	211	214	217	220	223
Total Wholesale Demand	MW	1,277	1,343	867	506	436	433	493	555	618	681
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	8,633	8,840	8,518	8,337	8,422	8,574	8,782	8,988	9,191	9,394
Non-Dispatchable DSM and Self-Service QF	MW	355	368	381	395	410	425	441	456	471	486
Normal Weather Demand (Before Load Control)	MW	8,278	8,472	8,137	7,942	8,012	8,149	8,341	8,532	8,720	8,908
Normal Weather Reserves (Before Load Control)	MW	575	645	985	1,179	1,109	983	790	594	390	93
Normal Weather Reserve Margin (Before Load Control)	%	6.9%	7.6%	12.1%	14.8%	13.8%	12.1%	9.5%	7.0%	4.5%	1.0%
Normal Weather Load Management	MW	512	463	400	356	322	291	265	242	222	205
Normal Weather Demand (After Load Management)	MW	7,766	8,009	7,736	7,586	7,690	7,857	8,076	8,290	8,498	8,703
Normal Weather Reserves (After Load Management)	MW	1,087	1,108	1,385	1,536	1,431	1,274	1,055	836	613	298
Normal Weather Reserve Margin (After Load Management)	%	14.0%	13.8%	17.9%	20.2%	18.6%	16.2%	13.1%	10.1%	7.2%	3.4%
Normal Weather Interruptible Load	MW	327	308	305	328	329	335	339	343	346	349
Normal Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After All Load Control)	MW	7,439	7,701	7,431	7,258	7,361	7,522	7,737	7,947	8,152	8,354
Normal Weather Reserves (After All Load Control)	MW	1,414	1,416	1,690	1,864	1,760	1,609	1,394	1,179	959	647
Normal Weather Reserve Margin (After All Load Control)	%	19.0%	18.4%	22.7%	25.7%	23.9%	21.4%	18.0%	14.8%	11.8%	7.7%
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,488	1,540	1,486	1,452	1,472	1,504	1,547	1,589	1,630	1,671
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-74	-124	204	412	287	104	-153	-411	-672	-1,024
Normal Weather "DLC" Reserve Margin Contribution	%	59.3%	54.4%	41.7%	36.7%	37.0%	38.9%	43.3%	49.6%	59.3%	85.6%

FPC 080

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY
1998 SERC RATINGS, COGENERATION = 981231
JANUARY 1999 LONG-TERM FORECAST (S981208)
Bulk Power Sales (GPC, OPC, SECI & MEAG) Included in Demand & Energy Forecast

1999 Ten-Year Site Plan

		WINTER 99/00	WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08
		Jan-2000	Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008
Existing FPC Capacity	MW	8,265	8,306	8,620	8,473	8,473	8,307	8,774	8,774	9,341
New FPC Capacity	MW	0	297	0	0	0	567	0	567	0
Retired FPC Capacity	MW	0	0	147	0	166	100	0	0	0
Total Installed Capacity	MW	8,265	8,603	8,473	8,473	8,307	8,774	8,774	9,341	9,341
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	9,565	9,903	9,773	9,773	9,607	10,084	10,084	10,651	10,651
Potential Total Retail Demand	MW	8,330	8,488	8,654	8,823	8,985	9,150	9,314	9,479	9,644
Wholesale (REA)	MW	754	866	936	537	481	554	630	705	783
Wholesale (Bulk Power)	MW	605	605	150	0	0	0	0	0	0
Wholesale (Municipal)	MW	216	197	180	183	185	174	176	178	180
Total Wholesale Demand	MW	1,575	1,668	1,266	720	666	728	806	883	963
Company Use	MW	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	9,935	10,186	9,950	9,573	9,681	9,908	10,150	10,392	10,637
Non-Dispatchable DSM and Self-Service QF	MW	399	424	450	478	508	538	569	599	628
Normal Weather Demand (Before Load Control)	**MW**	**9,536**	**9,762**	**9,500**	**9,095**	**9,173**	**9,370**	**9,581**	**9,793**	**10,009**
Normal Weather Reserves (Before Load Control)	MW	29	141	273	678	434	714	503	858	642
Normal Weather Reserve Margin (Before Load Control)	**%**	**0.3%**	**1.4%**	**2.9%**	**7.5%**	**4.7%**	**7.6%**	**5.2%**	**8.8%**	**6.4%**
Normal Weather Load Management	MW	889	886	817	773	746	726	709	694	682
Normal Weather Demand (After Load Management)	MW	8,647	8,876	8,683	8,322	8,427	8,644	8,872	9,099	9,327
Normal Weather Reserves (After Load Management)	MW	918	1,027	1,090	1,451	1,180	1,440	1,212	1,552	1,324
Normal Weather Reserve Margin (After Load Management)	%	10.6%	11.6%	12.6%	17.4%	14.0%	16.7%	13.7%	17.1%	14.2%
Normal Weather Interruptible Load	MW	312	300	297	299	296	298	300	302	304
Normal Weather Voltage Reduction	MW	114	117	115	110	111	114	117	120	123
Normal Weather Demand (After All Load Control)	**MW**	**8,221**	**8,459**	**8,271**	**7,913**	**8,020**	**8,232**	**8,455**	**8,677**	**8,900**
Normal Weather Reserves (After All Load Control)	MW	1,344	1,444	1,502	1,860	1,587	1,852	1,629	1,974	1,751
Normal Weather Reserve Margin (After All Load Control)	**%**	**16.3%**	**17.1%**	**18.2%**	**23.5%**	**19.8%**	**22.5%**	**19.3%**	**22.7%**	**19.7%**
Normal Weather Reserves (After All Load Control) Required For 15 %	MW	1,233	1,269	1,241	1,187	1,203	1,235	1,268	1,302	1,335
Normal Weather Reserves (After All Load Control) Above 15 %	MW	111	175	261	673	384	617	361	672	416
Normal Weather "DLC" Reserve Margin Contribution	%	97.8%	90.2%	81.8%	63.5%	72.7%	61.4%	69 1%	56.5%	63.3%

FPC 081

7/19/00 @ 12:19 PM

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY
1998 SERC RATINGS, COGENERATION = 981231
JANUARY 1999 LONG-TERM FORECAST (S981208)
Bulk Power Sales (GPC, OPC, SECI & MEAG) Included In Demand & Energy Forecast

1999 Ten-Year Site Plan

		SUMMER 00 Aug-2000	SUMMER 01 Aug-2001	SUMMER 02 Aug-2002	SUMMER 03 Aug-2003	SUMMER 04 Aug-2004	SUMMER 05 Aug-2005	SUMMER 06 Aug-2006	SUMMER 07 Aug-2007	SUMMER 08 Aug-2008
Existing FPC Capacity	MW	7,510	7,510	7,776	7,631	7,631	7,488	7,895	7,895	8,390
New FPC Capacity	MW	0	249	0	0	0	495	0	495	0
Retired FPC Capacity	MW	0	0	145	0	143	88	0	0	0
Total Installed Capacity	MW	7,510	7,759	7,631	7,631	7,488	7,895	7,895	8,390	8,390
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	8,810	9,059	8,931	8,931	8,788	9,205	9,205	9,700	9,700
Potential Total Retail Demand	MW	7,396	7,555	7,721	7,890	8,052	8,218	8,384	8,551	8,717
Wholesale (REA)	MW	366	460	514	98	25	82	140	199	259
Wholesale (Bulk Power)	MW	605	605	150	0	0	0	0	0	0
Wholesale (Municipal)	MW	226	211	190	191	194	183	185	189	192
Total Wholesale Demand	MW	1,197	1,276	854	289	219	265	325	388	451
Company Use	MW	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	8,623	8,861	8,605	8,209	8,301	8,513	8,739	8,969	9,198
Non-Dispatchable DSM and Self-Service QF	MW	353	366	379	393	408	423	439	454	468
Normal Weather Demand (Before Load Control)	**MW**	**8,270**	**8,495**	**8,226**	**7,816**	**7,893**	**8,090**	**8,300**	**8,515**	**8,730**
Normal Weather Reserves (Before Load Control)	MW	540	564	705	1,115	895	1,115	905	1,185	970
Normal Weather Reserve Margin (Before Load Control)	**%**	**6.5%**	**6.6%**	**8.6%**	**14.3%**	**11.3%**	**13.8%**	**10.9%**	**13.9%**	**11.1%**
Normal Weather Load Management	MW	498	453	394	353	321	293	269	248	230
Normal Weather Demand (After Load Management)	MW	7,772	8,042	7,832	7,463	7,572	7,797	8,031	8,267	8,500
Normal Weather Reserves (After Load Management)	MW	1,038	1,017	1,099	1,468	1,216	1,408	1,174	1,433	1,200
Normal Weather Reserve Margin (After Load Management)	%	13.4%	12.6%	14.0%	19.7%	16.1%	18.1%	14.6%	17.3%	14.1%
Normal Weather Interruptible Load	MW	313	301	298	300	297	299	301	303	305
Normal Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After All Load Control)	**MW**	**7,459**	**7,741**	**7,534**	**7,163**	**7,275**	**7,498**	**7,730**	**7,964**	**8,195**
Normal Weather Reserves (After All Load Control)	MW	1,351	1,318	1,397	1,768	1,513	1,707	1,475	1,736	1,505
Normal Weather Reserve Margin (After All Load Control)	**%**	**18.1%**	**17.0%**	**18.5%**	**24.7%**	**20.8%**	**22.8%**	**19.1%**	**21.8%**	**18.4%**
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,492	1,548	1,507	1,433	1,455	1,500	1,546	1,593	1,639
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-141	-230	-110	335	58	207	-71	143	-134
Normal Weather "DLC" Reserve Margin Contribution	%	60.0%	57.2%	49.5%	36.9%	40.8%	34.7%	38.6%	31.7%	35.5%

FPC 082

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

2000 TYSP (DRAFT)
vs.
1999 TYSP

		WINTER 99/00	WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08
		Jan-2000	Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008
Existing FPC Capacity	MW	#REF!	-39	-30	134	134	721	254	671	8
New FPC Capacity	MW	#REF!	26	17	0	567	-567	567	-567	567
Retired FPC Capacity	MW	#REF!	0	-147	0	-20	-100	150	96	0
Total Installed Capacity	MW	#REF!	-13	134	134	721	254	671	8	575
Firm Purchase Capacity	MW	#REF!	0	0	0	0	0	0	0	0
Firm QF Purchase Capacity	MW	#REF!	0	0	-13	-13	-13	-13	-18	-33
Seasonal Purchase Capacity	MW	#REF!	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	#REF!	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	#REF!	0	0	0	0	0	0	0	0
Total Available Capacity	MW	#REF!	-13	134	121	708	241	658	-10	542
Potential Total Retail Demand	MW	#REF!	-20	-18	5	12	15	11	4	-10
Wholesale (REA)	MW	#REF!	28	-25	21	22	-29	-30	-29	-28
Wholesale (Bulk Power)	MW	#REF!	27	17	167	167	167	167	167	167
Wholesale (Municipal)	MW	#REF!	8	16	20	21	24	24	25	26
Total Wholesale Demand	MW	#REF!	63	8	208	211	162	162	163	166
Company Use	MW	#REF!	0	0	0	0	0	0	0	0
Potential Total System Demand	MW	#REF!	43	-10	213	223	177	173	167	156
Non-Dispatchable DSM and Self-Service QF	MW	#REF!	20	18	17	15	14	13	14	15
Normal Weather Demand (Before Load Control)	MW	#REF!	23	-28	196	208	163	160	153	141
Normal Weather Reserves (Before Load Control)	MW	#REF!	-36	162	-75	501	78	499	-164	401
Normal Weather Reserve Margin (Before Load Control)	%	#REF!	-0.4%	1.7%	-1.0%	5.2%	0.7%	5.0%	-1.8%	3.9%
Normal Weather Load Management	MW	#REF!	-53	-46	-43	-39	-38	-35	-33	-32
Normal Weather Demand (After Load Management)	MW	#REF!	76	18	239	247	201	195	186	172
Normal Weather Reserves (After Load Management)	MW	#REF!	-89	116	-118	461	40	463	-196	369
Normal Weather Reserve Margin (After Load Management)	%	#REF!	-1.1%	1.3%	-1.9%	4.9%	0.1%	4.8%	-2.5%	3.6%
Normal Weather Interruptible Load	MW	#REF!	6	7	29	33	36	37	40	41
Normal Weather Voltage Reduction	MW	#REF!	1	0	3	3	3	3	3	2
Normal Weather Demand (After All Load Control)	MW	#REF!	69	11	207	211	162	155	143	129
Normal Weather Reserves (After All Load Control)	MW	#REF!	-82	123	-86	497	79	503	-153	412
Normal Weather Reserve Margin (After All Load Control)	%	#REF!	-1.1%	1.5%	-1.7%	5.5%	0.5%	5.5%	-2.1%	4.3%
Normal Weather "DLC" Reserve Margin Contribution	%	#REF!	2.1%	-8.6%	2.5%	-17.5%	-2.4%	-16.1%	5.3%	-11.5%

FPC 083

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

2000 TYSP (DRAFT)
vs.
1999 TYSP

		SUMMER 00 Aug-2000	SUMMER 01 Aug-2001	SUMMER 02 Aug-2002	SUMMER 03 Aug-2003	SUMMER 04 Aug-2004	SUMMER 05 Aug-2005	SUMMER 06 Aug-2006	SUMMER 07 Aug-2007	SUMMER 08 Aug-2008
Existing FPC Capacity	MW	43	43	41	203	203	698	291	651	78
New FPC Capacity	MW	0	15	17	0	495	-495	495	-495	495
Retired FPC Capacity	MW	0	0	-145	0	0	-88	135	78	0
Total Installed Capacity	MW	43	58	203	203	698	291	651	78	573
Firm Purchase Capacity	MW	0	0	0	0	0	0	0	0	0
Firm QF Purchase Capacity	MW	0	0	-13	-13	-13	-13	-13	-18	-33
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	43	58	190	190	685	278	638	60	540
Potential Total Retail Demand	MW	-70	-88	-100	-89	-96	-107	-125	-148	-174
Wholesale (REA)	MW	26	29	-24	23	23	-28	-28	-28	-28
Wholesale (Bulk Power)	MW	27	27	17	167	167	167	167	167	167
Wholesale (Municipal)	MW	27	11	19	27	27	28	29	28	28
Total Wholesale Demand	MW	80	67	13	217	217	168	168	167	167
Company Use	MW	0	0	0	0	0	0	0	0	0
Potential Total System Demand	MW	10	-21	-87	128	121	61	43	19	-7
Non-Dispatchable DSM and Self-Service QF	MW	2	2	2	2	2	2	2	2	3
Normal Weather Demand (Before Load Control)	**MW**	**8**	**-23**	**-89**	**126**	**119**	**59**	**41**	**17**	**-10**
Normal Weather Reserves (Before Load Control)	MW	35	81	280	64	566	220	597	43	549
Normal Weather Reserve Margin (Before Load Control)	**%**	**0.4%**	**1.0%**	**3.5%**	**0.6%**	**6.9%**	**2.8%**	**7.1%**	**0.5%**	**6.3%**
Normal Weather Load Management	MW	14	10	6	3	1	-2	-4	-6	-8
Normal Weather Demand (After Load Management)	MW	-6	-33	-96	123	118	60	45	23	-2
Normal Weather Reserves (After Load Management)	MW	49	91	286	68	567	218	593	37	542
Normal Weather Reserve Margin (After Load Management)	%	0.6%	1.2%	3.9%	0.6%	7.1%	2.6%	7.3%	0.4%	6.4%
Normal Weather Interruptible Load	MW	14	7	7	28	32	36	38	40	41
Normal Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After All Load Control)	**MW**	**-20**	**-40**	**-103**	**95**	**86**	**24**	**7**	**-17**	**-43**
Normal Weather Reserves (After All Load Control)	MW	63	98	293	96	599	254	631	77	583
Normal Weather Reserve Margin (After All Load Control)	**%**	**0.9%**	**1.4%**	**4.2%**	**1.0%**	**7.9%**	**3.3%**	**8.1%**	**1.0%**	**7.2%**
Normal Weather "DLC" Reserve Margin Contribution	%	-0.7%	-2.8%	-7.8%	-0.2%	-10.0%	-2.7%	-10.0%	0.5%	-8.3%

FPC 084

Normal Weather

5.5%

	Month	Scheduled Maintenance	Baseload Plants	Baseload Contracts	QF Contracts	Intermediate Resources	Baseload & Intermediate Resources	Peaking Resources	Total Resources	QF On-Peak Reduction	Baseload & Intermediate Resources	Peaking Resources	Operating Requirements	FPC Available Resources EFOR	Total Peak Before DLC	Supply Variance	Supply Reserve Margin	Total DLC (Including IS/CS and Volt. Red.)	Firm Peak After DLC	Total Variance	Total Reserve Margin
1	Jan-00	0	3,139	469	831	2,394	6,833	2,734	9,567	-106	6,045	2,626	341	-485	9,579	-3	-0.03%	1,311	8,268	1,308	13.83%
2	Feb-00	-182	3,139	469	831	2,394	6,833	2,734	9,567	-106	6,052	2,323	341	-446	8,308	1,087	13.20%	1,048	7,261	2,144	29.53%
3	Mar-00	-1,299	3,139	469	831	2,394	6,833	2,734	9,567	-106	6,099	2,638	341	-383	6,981	1,277	18.28%	880	6,101	2,157	35.52%
4	Apr-00	-1,332	3,082	469	831	2,269	6,651	2,276	8,927	-106	5,994	2,189	291	-348	6,350	1,245	19.61%	655	5,695	1,900	33.36%
5	May-00	0	3,099	469	831	2,269	6,668	2,276	8,944	-106	5,956	2,171	291	-420	7,398	1,545	20.88%	733	6,666	2,278	34.17%
6	Jun-00	0	3,099	469	831	2,269	6,668	2,185	8,853	-106	5,958	2,061	291	-415	7,958	887	11.28%	824	7,132	1,721	24.13%
7	Jul-00	0	3,099	469	831	2,269	6,668	2,185	8,853	-106	5,958	2,081	291	-415	8,179	674	8.24%	819	7,360	1,493	20.29%
8	Aug-00	0	3,099	469	831	2,269	6,668	2,185	8,853	-106	5,958	2,081	291	-418	8,278	575	6.94%	838	7,439	1,414	19.01%
9	Sep-00	0	3,099	469	831	2,269	6,668	2,185	8,853	-106	5,958	2,081	291	-418	7,721	1,132	14.66%	783	6,938	1,915	27.59%
10	Oct-00	-487	3,099	469	831	2,269	6,668	2,276	8,944	-106	5,876	2,178	291	-394	6,827	1,630	23.88%	621	6,206	2,251	36.27%
11	Nov-00	-884	3,156	469	831	2,394	6,850	2,276	9,126	-106	6,197	2,181	291	-382	6,187	2,056	33.22%	736	5,446	2,794	51.28%
12	Dec-00	-118	3,156	469	831	2,394	6,850	3,016	9,866	-106	6,054	2,900	341	-485	7,743	2,006	25.93%	816	6,927	2,824	40.78%
13	Jan-01	0	3,180	469	831	2,394	6,874	3,016	9,890	-106	6,873	2,896	341	-472	9,785	105	1.07%	1,257	8,528	1,362	15.97%
14	Feb-01	-167	3,180	469	831	2,394	6,874	3,016	9,890	-106	6,060	2,900	341	-463	8,515	1,206	14.16%	1,001	7,514	2,209	29.40%
15	Mar-01	-501	3,180	469	831	2,394	6,874	3,016	9,890	-106	6,093	2,805	341	-445	7,157	2,232	31.18%	846	6,311	3,078	48.77%
16	Apr-01	-1,096	3,123	469	831	2,269	6,692	2,563	9,255	-106	6,012	2,468	291	-377	6,544	1,611	24.60%	610	5,934	2,221	37.40%
17	May-01	-806	3,123	469	831	2,269	6,692	2,516	9,208	-106	6,002	2,418	291	-391	7,626	774	10.15%	679	6,949	1,453	20.91%
18	Jun-01	0	3,123	469	831	2,269	6,692	2,425	9,117	-106	5,973	2,316	291	-430	8,138	979	12.03%	758	7,380	1,737	23.54%
19	Jul-01	0	3,123	469	831	2,269	6,692	2,425	9,117	-106	5,973	2,316	291	-430	8,372	748	8.80%	754	7,617	1,500	19.69%
20	Aug-01	0	3,123	469	831	2,269	6,692	2,425	9,117	-106	5,973	2,316	291	-430	8,472	646	7.61%	771	7,701	1,416	18.39%
21	Sep-01	0	3,123	469	831	2,269	6,692	2,425	9,117	-106	5,973	2,316	291	-430	7,900	1,217	15.41%	717	7,183	1,934	26.93%
22	Oct-01	-628	3,123	469	831	2,269	6,692	2,516	9,208	-106	5,995	2,418	291	-400	7,006	1,575	22.48%	570	6,435	2,145	33.33%
23	Nov-01	-1,487	3,180	469	831	2,394	6,874	2,516	9,390	-106	6,204	2,425	291	-364	6,379	1,544	24.20%	693	5,686	2,237	39.34%
24	Dec-01	-1,152	3,180	469	831	2,394	6,874	3,016	9,890	-106	6,120	2,914	341	-409	7,927	811	10.23%	763	7,164	1,574	21.98%
25	Jan-02	0	3,197	469	831	2,394	6,891	3,016	9,907	-106	6,069	2,896	341	-473	9,472	435	4.59%	1,196	8,282	1,625	19.62%
26	Feb-02	0	3,197	469	831	2,394	6,891	3,016	9,907	-106	6,069	2,896	341	-473	8,284	1,623	19.60%	949	7,335	2,572	35.06%
27	Mar-02	-541	3,197	469	831	2,394	6,891	3,016	9,907	-106	6,128	2,911	341	-422	6,942	2,024	29.16%	806	6,136	2,830	46.13%
28	Apr-02	-1,101	3,140	469	818	2,269	6,696	2,563	9,259	-106	6,016	2,469	291	-378	6,325	1,634	25.99%	566	5,759	2,400	41.68%
29	May-02	-484	3,140	469	818	2,269	6,696	2,516	9,212	-106	5,982	2,414	291	-408	7,353	1,375	18.70%	625	6,728	2,000	29.73%
30	Jun-02	0	3,140	469	818	2,269	6,696	2,425	9,121	-106	5,978	2,317	291	-431	7,791	1,331	17.08%	692	7,099	2,023	28.50%
31	Jul-02	0	3,140	469	818	2,269	6,696	2,425	9,121	-106	5,978	2,317	291	-431	8,033	1,088	13.54%	688	7,344	1,777	24.20%
32	Aug-02	0	3,140	469	818	2,269	6,696	2,425	9,121	-106	5,978	2,317	291	-431	8,137	984	12.10%	705	7,431	1,690	22.74%
33	Sep-02	0	3,140	469	818	2,269	6,696	2,425	9,121	-106	5,978	2,317	291	-431	7,546	1,575	20.87%	661	6,885	2,236	32.47%
34	Oct-02	-401	3,140	469	818	2,269	6,696	2,516	9,212	-106	5,987	2,415	291	-403	6,703	1,908	28.46%	536	6,167	2,444	39.63%
35	Nov-02	-708	3,197	469	818	2,394	6,878	2,516	9,394	-106	6,178	2,414	291	-407	6,142	2,545	41.43%	670	5,471	3,215	58.76%
36	Dec-02	-712	3,197	469	818	2,394	6,878	3,016	9,894	-106	6,106	2,907	341	-434	7,814	1,568	20.58%	737	6,677	2,305	33.52%
37	Jan-03	0	3,197	469	818	2,394	6,878	3,016	9,894	-106	6,078	2,894	341	-473	9,291	603	6.49%	1,171	8,120	1,774	21.83%
38	Feb-03		3,197	469	818	2,394	6,878	3,016	9,894	-106	6,076	2,896	341	-473	8,078	1,817	22.49%	940	7,138	2,756	38.61%
39	Mar-03		3,197	469	818	2,394	6,878	3,016	9,894	-106	6,076	2,896	341	-473	6,698	3,196	47.77%	805	5,891	4,003	67.96%
40	Apr-03		3,140	469	818	2,269	6,696	2,563	9,259	-106	5,970	2,453	291	-438	6,337	2,923	46.12%	562	5,775	3,484	60.34%
41	May-03		3,140	469	818	2,269	6,696	2,516	9,212	-106	5,972	2,407	291	-436	7,208	2,004	27.80%	613	6,595	2,617	39.69%
42	Jun-03		3,140	469	818	2,269	6,696	2,425	9,121	-106	5,976	2,317	291	-431	7,583	1,538	20.28%	672	6,911	2,210	31.98%
43	Jul-03		3,140	469	818	2,269	6,696	2,425	9,121	-106	5,976	2,317	291	-431	7,837	1,284	16.38%	670	7,167	1,954	27.27%
44	Aug-03	0	3,140	469	818	2,269	6,696	2,425	9,121	-106	5,976	2,317	291	-431	7,942	1,179	14.85%	684	7,258	1,864	25.68%
45	Sep-03		3,140	469	818	2,269	6,696	2,425	9,121	-106	5,976	2,317	291	-431	7,391	1,730	23.41%	647	6,744	2,377	35.25%
46	Oct-03		3,140	469	818	2,269	6,696	2,516	9,212	-106	5,972	2,407	291	-436	6,778	2,434	35.90%	538	6,240	2,972	47.63%
47	Nov-03		3,197	469	818	2,961	7,445	2,516	9,961	-106	6,690	2,397	291	-477	5,986	3,976	66.42%	682	5,304	4,657	87.81%
48	Dec-03		3,197	469	818	2,961	7,445	3,016	10,461	-106	6,620	2,830	341	-505	7,383	3,078	41.69%	747	6,636	3,825	57.65%
49	Jan-04	0	3,197	469	818	2,815	7,299	3,016	10,315	-106	6,480	2,892	341	-497	9,381	934	9.96%	1,150	8,231	2,084	25.32%
50	Feb-04		3,197	469	818	2,815	7,299	3,016	10,315	-106	6,480	2,892	341	-497	8,149	2,166	26.58%	921	7,228	3,087	42.71%
51	Mar-04		3,197	469	818	2,815	7,299	3,016	10,315	-106	6,480	2,892	341	-497	6,798	3,517	51.73%	793	6,005	4,310	71.76%
52	Apr-04		3,140	469	818	2,621	7,048	2,563	9,611	-106	6,308	2,449	291	-458	6,449	3,162	49.04%	543	5,906	3,705	62.73%
53	May-04		3,140	469	818	2,621	7,048	2,516	9,564	-106	6,310	2,402	291	-455	7,338	2,226	30.33%	588	6,750	2,814	41.68%
54	Jun-04		3,140	469	818	2,621	7,048	2,425	9,473	-106	6,314	2,312	291	-450	7,720	1,753	22.71%	640	7,080	2,393	33.80%
55	Jul-04		3,140	469	818	2,621	7,048	2,425	9,473	-106	6,314	2,312	291	-450	7,904	1,569	19.85%	638	7,266	2,207	30.38%
56	Aug-04	0	3,140	469	818	2,621	7,048	2,425	9,473	-106	6,314	2,312	291	-450	8,012	1,461	18.24%	651	7,361	2,112	28.69%
57	Sep-04		3,140	469	818	2,621	7,048	2,425	9,473	-106	6,314	2,312	291	-450	7,524	1,949	25.90%	618	6,906	2,567	37.18%
58	Oct-04		3,140	469	818	2,621	7,048	2,516	9,564	-106	6,310	2,402	291	-455	6,901	2,664	38.60%	522	6,379	3,186	49.94%
59	Nov-04		3,197	469	818	2,815	7,299	2,516	9,815	-106	6,550	2,399	291	-468	6,068	3,747	61.76%	674	5,394	4,421	81.97%
60	Dec-04		3,197	469	818	2,815	7,299	3,016	10,315	-106	6,480	2,892	341	-497	7,415	2,900	39.12%	738	6,677	3,638	54.50%
61	Jan-05	0	3,197	479	818	2,815	7,309	3,016	10,325	-106	6,490	2,892	341	-497	9,533	792	8.31%	1,139	8,394	1,931	23.01%
62	Feb-05		3,197	479	818	2,815	[illegible]	3,016	10,325	-106	6,480	2,882	341	-497	8,283	2,042	24.65%	913	7,371	2,954	40.08%
63	Mar-05		3,197	479	818	2,815	[illegible]	3,016	10,325	-106	6,490	2,892	341	-497	6,895	3,430	49.75%	787	6,108	4,217	69.04%
64	Apr-05		3,140	479	818	2,621	[illegible]	2,563	9,621	-106	6,318	2,449	291	-458	6,555	3,066	46.78%	530	6,025	3,596	59.69%
65	May-05		3,140	479	818	2,621	[illegible]	2,516	9,574	-105	6,320	2,402	291	-455	7,463	2,111	28.29%	570	6,893	2,681	38.90%
66	Jun-05		3,140	479	818	2,521	[illegible]	2,425	9,483	106	6,324	2,312	291	-450	7,845	1,638	20.88%	518	7,329	2,754	31.18%

67	Jul-05		3,140	479	818	2,621	7,058	2,425	9,483	-106	8,324	2,312	291	-450	8,038	1,445	17.98%	614	7,423	2,080	27.75%
68	Aug-05	•	3,140	479	818	2,621	7,058	2,425	9,483	-106	8,324	2,312	291	-450	8,149	1,333	16.38%	628	7,522	1,961	26.07%
69	Sep-05		3,140	479	818	2,621	7,058	2,425	9,483	-106	8,324	2,312	291	-450	7,853	1,831	23.92%	567	7,058	2,427	34.40%
70	Oct-05		3,140	479	818	2,621	7,058	2,516	9,574	-106	8,320	2,402	291	-455	7,017	2,557	36.44%	512	6,505	3,069	47.19%
71	Nov-05		3,197	479	818	3,382	7,876	2,516	10,392	-106	7,104	2,391	291	-500	6,146	4,246	69.09%	672	5,474	4,918	89.86%
72	Dec-05		3,197	479	818	3,382	7,876	3,016	10,892	-106	7,033	2,684	341	-526	7,518	3,374	44.88%	735	6,783	4,109	60.58%
73	Jan-06	•	3,197	479	818	3,382	7,876	2,866	10,742	-106	7,840	2,736	341	-619	9,741	1,902	19.28%	1,131	8,610	2,132	24.77%
74	Feb-06		3,197	479	818	3,382	7,876	2,866	10,742	-106	7,040	2,736	341	-519	8,469	2,273	26.84%	904	7,565	3,177	42.00%
75	Mar-06		3,197	479	818	3,382	7,876	2,866	10,742	-106	7,040	2,736	341	-519	6,990	3,752	53.68%	781	6,209	4,534	73.02%
76	Apr-06		3,140	479	818	3,116	7,553	2,428	9,981	-106	6,798	2,308	291	-478	6,661	3,320	49.85%	519	6,142	3,838	62.49%
77	May-06		3,140	479	818	3,116	7,553	2,381	9,934	-106	6,800	2,262	291	-475	7,586	2,348	30.95%	554	7,032	2,902	41.27%
78	Jun-06		3,140	479	818	3,116	7,553	2,290	9,843	-106	6,604	2,172	291	-470	7,975	1,868	23.42%	595	7,381	2,463	33.37%
79	Jul-06		3,140	479	818	3,116	7,553	2,290	9,843	-106	6,604	2,172	291	-470	8,229	1,614	19.61%	590	7,636	2,207	28.91%
80	Aug-06	•	3,140	479	818	3,116	7,553	2,290	9,843	-106	6,604	2,172	291	-478	8,341	1,502	18.01%	604	7,737	2,106	27.22%
81	Sep-06		3,140	479	818	3,116	7,553	2,290	9,843	-106	6,604	2,172	291	-470	7,779	2,064	26.54%	578	7,201	2,642	36.69%
82	Oct-06		3,140	479	818	3,116	7,553	2,381	9,934	-106	6,800	2,262	291	-478	7,132	2,802	39.29%	503	6,629	3,305	49.86%
83	Nov-06		3,197	479	818	3,382	7,876	2,381	10,257	-106	7,110	2,258	291	-483	6,221	4,036	64.88%	670	5,551	4,706	84.78%
84	Dec-06		3,197	479	818	3,382	7,876	2,866	10,742	-106	7,040	2,736	341	-619	7,670	3,072	40.05%	732	6,939	3,804	54.82%
85	Jan-07	•	3,197	479	813	3,382	7,871	2,770	10,641	-106	7,036	2,641	341	-614	9,946	695	6.54%	1,126	8,820	1,821	20.63%
86	Feb-07		3,197	479	813	3,382	7,871	2,770	10,641	-106	7,036	2,641	341	-514	8,655	1,986	22.95%	898	7,758	2,884	37.18%
87	Mar-07		3,197	479	813	3,382	7,871	2,770	10,641	-106	7,036	2,641	341	-514	7,105	3,536	49.76%	778	6,327	4,314	68.18%
88	Apr-07		3,140	479	813	3,116	7,548	2,350	9,898	-106	6,796	2,232	291	-473	6,765	3,133	46.30%	508	6,256	3,642	58.22%
89	May-07		3,140	479	813	3,116	7,548	2,303	9,851	-106	6,798	2,185	291	-471	7,705	2,146	27.84%	541	7,165	2,686	37.48%
90	Jun-07		3,140	479	813	3,116	7,548	2,212	9,760	-106	6,801	2,098	291	-466	8,113	1,647	20.30%	577	7,536	2,224	29.51%
91	Jul-07		3,140	479	813	3,116	7,548	2,212	9,760	-106	6,801	2,098	291	-466	8,418	1,342	15.94%	577	7,841	1,918	24.47%
92	Aug-07	•	3,140	479	813	3,116	7,548	2,212	9,760	-106	6,801	2,098	291	-466	8,532	1,228	14.39%	585	7,947	1,813	22.81%
93	Sep-07		3,140	479	813	3,116	7,548	2,212	9,760	-106	6,801	2,098	291	-466	7,903	1,857	23.49%	562	7,341	2,418	32.94%
94	Oct-07		3,140	479	813	3,116	7,548	2,303	9,851	-106	6,798	2,185	291	-471	7,243	2,607	36.00%	496	6,747	3,104	46.00%
95	Nov-07		3,197	479	813	3,949	8,438	2,303	10,741	-106	7,851	2,173	291	-520	6,296	4,445	70.59%	669	5,627	5,114	90.88%
96	Dec-07		3,197	479	813	3,949	8,438	2,770	11,208	-106	7,582	2,634	341	-545	7,822	3,386	43.29%	730	7,082	4,116	58.04%
97	Jan-08	•	3,197	479	798	3,949	8,423	2,770	11,193	-106	7,567	2,634	341	-545	10,150	1,043	10.28%	1,128	9,629	2,163	23.96%
98	Feb-08		3,197	479	798	3,949	8,423	2,770	11,193	-106	7,567	2,634	341	-545	8,843	2,350	26.57%	882	7,951	3,242	40.78%
99	Mar-08		3,197	479	798	3,949	8,423	2,770	11,193	-106	7,567	2,634	341	-545	7,242	3,951	54.58%	775	6,467	4,728	73.06%
100	Apr-08		3,140	479	798	3,611	8,028	2,350	10,378	-106	7,256	2,225	291	-501	6,865	3,512	51.16%	501	6,364	4,014	63.07%
101	May-08		3,140	479	798	3,611	8,028	2,303	10,331	-106	7,257	2,178	291	-498	7,823	2,508	32.06%	529	7,294	3,037	41.64%
102	Jun-08		3,140	479	798	3,611	8,028	2,212	10,240	-106	7,261	2,089	291	-493	8,286	1,954	23.58%	562	7,724	2,515	32.56%
103	Jul-08		3,140	479	798	3,611	8,028	2,212	10,240	-106	7,261	2,089	291	-493	8,603	1,637	19.02%	561	8,042	2,197	27.32%
104	Aug-08	•	3,140	479	798	3,611	8,028	2,212	10,240	-106	7,261	2,089	291	-493	8,728	1,519	17.42%	568	8,152	2,088	25.61%
105	Sep-08		3,140	479	798	3,611	8,028	2,212	10,240	-106	7,261	2,089	291	-493	8,073	2,216	27.62%	548	7,475	2,764	36.98%
106	Oct-08		3,140	479	798	3,611	8,028	2,303	10,331	-106	7,257	2,178	291	-498	7,352	2,979	40.52%	490	6,862	3,468	50.56%
107	Nov-08		3,197	479	798	3,949	8,423	2,303	10,726	-106	7,836	2,173	291	-520	6,367	4,358	68.45%	668	5,698	5,027	88.21%
108	Dec-08		3,197	479	798	3,949	8,423	2,770	11,193	-106	7,587	2,634	341	-545	7,974	3,218	40.36%	729	7,245	3,948	54.49%
109	Jan-09	•	3,197	479	689	3,949	8,314	2,770	11,084	-106	7,458	2,634	341	-648	10,351	733	7.08%	1,117	9,234	1,850	20.03%
110	Feb-09		3,197	479	689	3,949	8,314	2,770	11,084	-106	7,458	2,634	341	-545	9,017	2,066	22.92%	866	8,129	2,954	36.34%
111	Mar-09		3,197	479	689	3,949	8,314	2,770	11,084	-106	7,458	2,634	341	-545	7,381	3,703	50.17%	772	6,608	4,475	67.72%
112	Apr-09		3,140	479	689	3,611	7,919	2,350	10,269	-106	7,146	2,225	291	-501	6,965	3,303	47.42%	495	6,471	3,798	58.69%
113	May-09		3,140	479	689	3,611	7,919	2,303	10,222	-106	7,148	2,178	291	-498	7,993	2,229	27.88%	519	7,474	2,748	36.76%
114	Jun-09		3,140	479	689	3,611	7,919	2,212	10,131	-106	7,152	2,089	291	-493	8,458	1,673	19.78%	548	7,910	2,221	28.08%
115	Jul-09		3,140	479	689	3,611	7,919	2,212	10,131	-106	7,152	2,089	291	-493	8,791	1,340	15.24%	547	8,243	1,887	22.89%
116	Aug-09	•	3,140	479	689	3,611	7,919	2,212	10,131	-106	7,152	2,089	291	-493	8,809	1,322	13.72%	554	8,354	1,778	21.28%
117	Sep-09		3,140	479	658	3,611	7,888	2,212	10,100	-106	7,121	2,088	291	-493	8,175	1,925	23.54%	536	7,638	2,461	32.21%
118	Oct-09		3,140	479	658	3,611	7,888	2,303	10,191	-106	7,117	2,178	291	-498	7,462	2,729	36.58%	485	6,977	3,214	46.07%
119	Nov-09		3,197	479	658	4,516	8,850	2,303	11,153	-106	8,040	2,165	291	-551	6,442	4,711	73.12%	668	5,774	5,379	93.15%
120	Dec-09		3,197	479	658	4,516	8,850	2,770	11,620	-106	7,970	2,626	341	-577	8,128	3,492	42.97%	728	7,399	4,220	57.04%
121	Jan-10	•	3,197	479	548	4,516	8,740	2,770	11,510	-106	7,860	2,626	341	-577	10,553	957	9.07%	1,113	9,440	2,070	21.93%
122	Feb-10		3,197	479	548	4,516	8,740	2,770	11,510	-106	7,860	2,626	341	-577	9,204	2,306	25.05%	883	8,321	3,189	38.32%
123	Mar-10		3,197	479	548	4,516	8,740	2,770	11,510	-106	7,860	2,626	341	-577	7,525	3,985	52.95%	769	6,756	4,754	70.37%
124	Apr-10		3,140	479	548	4,106	8,273	2,350	10,623	-106	7,480	2,218	291	-526	7,070	3,553	50.26%	488	6,582	4,041	61.40%
125	May-10		3,140	479	548	4,106	8,273	2,303	10,576	-106	7,442	2,172	291	-525	8,177	2,399	29.34%	510	7,668	2,909	37.95%
126	Jun-10		3,140	70	548	4,106	7,864	2,212	10,076	-106	7,077	2,082	291	-520	8,638	1,438	16.65%	535	8,103	1,973	24.35%
127	Jul-10		3,140	70	548	4,106	7,864	2,212	10,076	-106	7,077	2,082	291	-520	8,987	1,089	12.12%	534	8,453	1,623	19.20%
128	Aug-10	•	3,140	70	548	4,106	7,864	2,212	10,076	-106	7,077	2,082	291	-520	9,109	967	10.61%	548	8,569	1,506	17.58%
129	Sep-10		3,140	70	548	4,106	7,864	2,212	10,076	-106	7,077	2,082	291	-520	8,354	1,722	20.62%	523	7,830	2,246	28.68%
130	Oct-10		3,140	70	548	4,106	7,864	2,303	10,167	-106	7,073	2,172	291	-525	7,582	2,585	34.09%	478	7,104	3,063	43.12%
131	Nov-10		3,197	70	548	4,516	8,331	2,303	10,634	-106	7,521	2,165	291	-551	6,542	4,091	62.54%	666	5,876	4,757	80.95%
132	Dec-10		3,197	70	548	4,516	8,331	2,770	11,101	-106	7,451	2,626	341	-577	8,311	2,790	33.57%	724	7,587	3,514	46.32%

2000-2009 Resource Assessment
Peak Capacity Evaluation with Variable Weather Conditions
Hines 2 in 11/2003

	WINTER PEAK (JANUARY)									
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Total Available Resources Without Load Mgmt. *	9,651	9,989	10,006	10,006	10,421	10,431	10,431	10,998	10,998	10,99
Scheduled Maintenance	0	0	0	0	0	0	0	0	0	0
Qualified Facility (QF) Contractually-Allowed On-Peak Capacity Reduction	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106
Total Supply Capability	9,545	9,883	9,900	9,900	10,315	10,325	10,325	10,892	10,892	10,89

Total Demand (before DLC) for Mild Weather Peak	(8,841)	(9,035)	(8,674)	(8,324)	(8,479)	(8,564)	(8,717)	(8,879)	(9,041)	(9,204
Supply Variance	704	848	1226	1576	1836	1761	1608	2013	1851	1688
Supply Reserve Margin (%)	8.0%	9.4%	14.1%	18.9%	21.7%	20.6%	18.4%	22.7%	20.5%	18.3%
Total DLC (Including IS/CS)	687	667	637	624	612	608	605	604	603	602
Total Variance	1391	1515	1863	2200	2448	2369	2213	2617	2454	2290
Total Reserve Margin (%)	17.1%	18.1%	23.2%	28.6%	31.1%	29.8%	27.3%	31.6%	29.1%	26.6%
Total Demand (before DLC) for Normal Weather Peak	(9,591)	(9,784)	(9,424)	(9,074)	(9,229)	(9,314)	(9,466)	(9,628)	(9,790)	(9,953
Supply Variance	(46)	99	476	826	1086	1011	859	1264	1102	939
Supply Reserve Margin (%)	-0.5%	1.0%	5.1%	9.1%	11.8%	10.9%	9.1%	13.1%	11.3%	9.4%
Total DLC (Including IS/CS)	1084	1050	991	959	936	923	913	905	898	892
Total Variance	1038	1149	1467	1785	2022	1934	1772	2169	2000	1831
Total Reserve Margin (%)	12.2%	13.2%	17.4%	22.0%	24.4%	23.0%	20.7%	24.9%	22.5%	20.2%
Total Demand (before DLC) for TMY Peak	(9,737)	(9,933)	(9,588)	(9,247)	(9,414)	(9,505)	(9,660)	(9,816)	(9,970)	(10,121
Supply Variance	(192)	(50)	312	653	901	820	665	1076	922	771
Supply Reserve Margin (%)	-2.0%	-0.5%	3.3%	7.1%	9.6%	8.6%	6.9%	11.0%	9.2%	7.6%
Total DLC (Including IS/CS)	1084	1050	991	959	936	923	913	905	898	892
Total Variance	893	1001	1303	1612	1837	1742	1578	1981	1820	1663
Total Reserve Margin (%)	10.3%	11.3%	15.2%	19.5%	21.7%	20.3%	18.0%	22.2%	20.1%	18.0%
Total Demand (before DLC) for Extreme Weather Peak	(10,965)	(11,158)	(10,798)	(10,448)	(10,603)	(10,688)	(10,841)	(11,002)	(11,165)	(11,327
Supply Variance	(1420)	(1275)	(898)	(548)	(288)	(363)	(516)	(110)	(273)	(435
Supply Reserve Margin (%)	-13.0%	-11.4%	-8.3%	-5.2%	-2.7%	-3.4%	-4.8%	-1.0%	-2.4%	-3.8%
Total DLC (Including IS/CS)	1299	1258	1183	1141	1112	1094	1080	1068	1058	1049
Total Variance	(121)	(17)	285	593	824	731	564	958	785	614
Total Reserve Margin (%)	-1.2%	-0.2%	3.0%	6.4%	8.7%	7.6%	5.8%	9.6%	7.8%	6.0%

*** Normal Weather Plant Ratings**

FPC 087

2000-2009 Resource Assessment
Peak Capacity Evaluation with Variable Weather Conditions
Hines 2 in 11/2003

	WINTER PEAK (JANUARY)									
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Spinning Reserves	(191)	(191)	(191)	(191)	(191)	(191)	(191)	(191)	(191)	(191
Load Following	(150)	(150)	(150)	(150)	(150)	(150)	(150)	(150)	(150)	(150
Baseload Contract Contractually-Allowed On-Peak Capacity Reduction	0	0	0	0	0	0	0	0	0	
Remainder of Available Resources	9,204	9,542	9,559	9,559	9,974	9,984	9,984	10,551	10,551	10,55
Total Demand (before DLC) for Mild Weather Peak	(8,841)	(9,035)	(8,674)	(8,324)	(8,479)	(8,564)	(8,717)	(8,879)	(9,041)	(9,204
Supply Variance	363	507	885	1235	1495	1420	1267	1672	1510	1347
Remaining Supply Reserve Margin (%)	4.1%	5.6%	10.2%	14.8%	17.6%	16.6%	14.5%	18.8%	16.7%	14.6%
Total DLC (Including IS/CS)	687	667	637	624	612	608	605	604	603	602
Total Variance	1050	1174	1522	1859	2107	2028	1872	2276	2113	1949
Remaining Total Reserve Margin (%)	12.9%	14.0%	18.9%	24.1%	26.8%	25.5%	23.1%	27.5%	25.0%	22.7%
Total Demand (before DLC) for Normal Weather Peak	(9,591)	(9,784)	(9,424)	(9,074)	(9,229)	(9,314)	(9,466)	(9,628)	(9,790)	(9,953
Supply Variance	(387)	(242)	135	485	745	670	518	923	761	598
Remaining Supply Reserve Margin (%)	-4.0%	-2.5%	1.4%	5.3%	8.1%	7.2%	5.5%	9.6%	7.8%	6.0%
Total DLC (Including IS/CS)	1084	1050	991	959	936	923	913	905	898	892
Total Variance	697	808	1126	1444	1681	1593	1431	1828	1659	1490
Remaining Total Reserve Margin (%)	8.2%	9.3%	13.4%	17.8%	20.3%	19.0%	16.7%	21.0%	18.7%	16.4%
Total Demand (before DLC) for TMY Peak	(9,737)	(9,933)	(9,588)	(9,247)	(9,414)	(9,505)	(9,660)	(9,816)	(9,970)	(10,121
Supply Variance	(533)	(391)	(29)	312	560	479	324	735	581	430
Remaining Supply Reserve Margin (%)	-5.5%	-3.9%	-0.3%	3.4%	6.0%	5.0%	3.4%	7.5%	5.8%	4.3%
Total DLC (Including IS/CS)	1084	1050	991	959	936	923	913	905	898	892
Total Variance	552	660	962	1271	1496	1401	1237	1640	1479	1322
Remaining Total Reserve Margin (%)	6.4%	7.4%	11.2%	15.3%	17.6%	16.3%	14.1%	18.4%	16.3%	14.3%
Total Demand (before DLC) for Extreme Weather Peak	(10,965)	(11,158)	(10,798)	(10,448)	(10,603)	(10,688)	(10,841)	(11,002)	(11,165)	(11,327
Supply Variance	(1761)	(1616)	(1239)	(889)	(629)	(704)	(857)	(451)	(614)	(776
Remaining Supply Reserve Margin (%)	-16.1%	-14.5%	-11.5%	-8.5%	-5.9%	-6.6%	-7.9%	-4.1%	-5.5%	-6.9%
Total DLC (Including IS/CS)	1299	1258	1183	1141	1112	1094	1080	1068	1058	1049
Total Variance	(462)	(358)	(56)	252	483	390	223	617	444	273
Remaining Total Reserve Margin (%)	-4.8%	-3.6%	-0.6%	2.7%	5.1%	4.1%	2.3%	6.2%	4.4%	2.7%

FPC 088

2000-2009 Resource Assessment
Peak Capacity Evaluation with Variable Weather Conditions
Hines 2 in 11/2003

	WINTER PEAK (JANUARY)									
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Actual Forced Outages (5.5% EFOR)	(459)	(478)	(479)	(479)	(502)	(502)	(502)	(533)	(533)	(533)
Remainder of Available Resources	8,745	9,064	9,080	9,080	9,472	9,482	9,482	10,018	10,018	10,018
Total Demand (before DLC) for Mild Weather Peak	(8,841)	(9,035)	(8,674)	(8,324)	(8,479)	(8,564)	(8,717)	(8,879)	(9,041)	(9,204)
Supply Variance	(96)	29	406	756	993	918	765	1139	977	814
Remaining Supply Reserve Margin (%)	-1.1%	0.3%	4.7%	9.1%	11.7%	10.7%	8.8%	12.8%	10.8%	8.8%
Total DLC (Including IS/CS)	687	667	637	624	612	608	605	604	603	602
Total Variance	591	696	1043	1380	1605	1526	1371	1743	1580	1417
Remaining Total Reserve Margin (%)	7.2%	8.3%	13.0%	17.9%	20.4%	19.2%	16.9%	21.1%	18.7%	16.5%
Total Demand (before DLC) for Normal Weather Peak	(9,591)	(9,784)	(9,424)	(9,074)	(9,229)	(9,314)	(9,466)	(9,628)	(9,790)	(9,953)
Supply Variance	(846)	(720)	(344)	6	243	168	16	390	228	65
Remaining Supply Reserve Margin (%)	-8.8%	-7.4%	-3.6%	0.1%	2.6%	1.8%	0.2%	4.1%	2.3%	0.7%
Total DLC (Including IS/CS)	1084	1050	991	959	936	923	913	905	898	892
Total Variance	238	330	647	965	1179	1091	929	1295	1126	957
Remaining Total Reserve Margin (%)	2.8%	3.8%	7.7%	11.9%	14.2%	13.0%	10.9%	14.8%	12.7%	10.6%
Total Demand (before DLC) for TMY Peak	(9,737)	(9,933)	(9,588)	(9,247)	(9,414)	(9,505)	(9,660)	(9,816)	(9,970)	(10,121
Supply Variance	(992)	(868)	(508)	(167)	59	(23)	(177)	202	48	(103
Remaining Supply Reserve Margin (%)	-10.2%	-8.7%	-5.3%	-1.8%	0.6%	-0.2%	-1.8%	2.1%	0.5%	-1.0%
Total DLC (Including IS/CS)	1084	1050	991	959	936	923	913	905	898	892
Total Variance	92	182	483	792	994	900	736	1107	946	789
Remaining Total Reserve Margin (%)	1.1%	2.0%	5.6%	9.6%	11.7%	10.5%	8.4%	12.4%	10.4%	8.6%
Total Demand (before DLC) for Extreme Weather Peak	(10,965)	(11,158)	(10,798)	(10,448)	(10,603)	(10,688)	(10,841)	(11,002)	(11,165)	(11,327
Supply Variance	(2220)	(2094)	(1718)	(1368)	(1131)	(1206)	(1359)	(984)	(1147)	(1309
Remaining Supply Reserve Margin (%)	-20.2%	-18.8%	-15.9%	-13.1%	-10.7%	-11.3%	-12.5%	-8.9%	-10.3%	-11.6%
Total DLC (Including IS/CS)	1299	1258	1183	1141	1112	1094	1080	1068	1058	1049
Total Variance	(921)	(836)	(534)	(227)	(19)	(112)	(279)	84	(89)	(25
Remaining Total Reserve Margin (%)	-9.5%	-8.4%	-5.6%	-2.4%	-0.2%	-1.2%	-2.9%	0.8%	-0.9%	-2.5

FPC 089

2000-2009 Resource Assessment
Peak Capacity Evaluation with Variable Weather Conditions
Hines 2 in 11/2003

	WINTER PEAK (JANUARY)									
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Worst-Case Forced Outages (9.7% EFOR)	(810)	(843)	(844)	(844)	(885)	(885)	(885)	(940)	(940)	(940)
Remainder of Available Resources	8,394	8,699	8,715	8,715	9,089	9,099	9,099	9,611	9,611	9,611
Total Demand (before DLC) for Mild Weather Peak	(8,841)	(9,035)	(8,674)	(8,324)	(8,479)	(8,564)	(8,717)	(8,879)	(9,041)	(9,204)
Supply Variance	(447)	(336)	41	391	610	535	382	732	570	407
Remaining Supply Reserve Margin (%)	-5.1%	-3.7%	0.5%	4.7%	7.2%	6.3%	4.4%	8.2%	6.3%	4.4%
Total DLC (Including IS/CS)	687	667	637	624	612	608	605	604	603	602
Total Variance	240	331	677	1014	1222	1143	988	1336	1173	1010
Remaining Total Reserve Margin (%)	2.9%	4.0%	8.4%	13.2%	15.5%	14.4%	12.2%	16.1%	13.9%	11.7%
Total Demand (before DLC) for Normal Weather Peak	(9,591)	(9,784)	(9,424)	(9,074)	(9,229)	(9,314)	(9,466)	(9,628)	(9,790)	(9,953)
Supply Variance	(1197)	(1085)	(709)	(359)	(140)	(215)	(367)	(17)	(179)	(342)
Remaining Supply Reserve Margin (%)	-12.5%	-11.1%	-7.5%	-4.0%	-1.5%	-2.3%	-3.9%	-0.2%	-1.8%	-3.4%
Total DLC (Including IS/CS)	1084	1050	991	959	936	923	913	905	898	892
Total Variance	(113)	(35)	282	599	796	708	546	888	719	550
Remaining Total Reserve Margin (%)	-1.3%	-0.4%	3.3%	7.4%	9.6%	8.4%	6.4%	10.2%	8.1%	6.1%
Total Demand (before DLC) for TMY Peak	(9,737)	(9,933)	(9,588)	(9,247)	(9,414)	(9,505)	(9,660)	(9,816)	(9,970)	(10,121)
Supply Variance	(1343)	(1233)	(873)	(532)	(324)	(406)	(560)	(205)	(359)	(510)
Remaining Supply Reserve Margin (%)	-13.8%	-12.4%	-9.1%	-5.8%	-3.4%	-4.3%	-5.8%	-2.1%	-3.6%	-5.0%
Total DLC (Including IS/CS)	1084	1050	991	959	936	923	913	905	898	892
Total Variance	(259)	(183)	118	427	611	517	352	700	539	382
Remaining Total Reserve Margin (%)	-3.0%	-2.1%	1.4%	5.1%	7.2%	6.0%	4.0%	7.9%	5.9%	4.1%
Total Demand (before DLC) for Extreme Weather Peak	(10,965)	(11,158)	(10,798)	(10,448)	(10,603)	(10,688)	(10,841)	(11,002)	(11,165)	(11,327)
Supply Variance	(2571)	(2459)	(2083)	(1733)	(1514)	(1589)	(1742)	(1391)	(1554)	(1716)
Remaining Supply Reserve Margin (%)	-23.4%	-22.0%	-19.3%	-16.6%	-14.3%	-14.9%	-16.1%	-12.6%	-13.9%	-15.1%
Total DLC (Including IS/CS)	1299	1258	1183	1141	1112	1094	1080	1068	1058	1049
Total Variance	(1272)	(1201)	(900)	(592)	(402)	(495)	(662)	(323)	(496)	(666)
Remaining Total Reserve Margin (%)	-13.2%	-12.1%	-9.4%	-6.4%	-4.2%	-5.2%	-6.8%	-3.2%	-4.9%	-6.5%

FPC 090

2000-2009 Resource Assessment
Peak Capacity Evaluation with Variable Weather Conditions
Hines 2 in 11/2003

	SUMMER PEAK (AUGUST)									
	2000	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
Total Available Resources Without Load Mgmt. *	8,536	8,785	8,802	8,802	9,147	9,157	9,157	9,652	9,652	9,652
Scheduled Maintenance	0	0	0	0	0	0	0	0	0	0
Qualified Facility (QF) Contractually-Allowed On-Peak Capacity Reduction	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)
Total Supply Capability	8,430	8,679	8,696	8,696	9,041	9,051	9,051	9,546	9,546	9,546
Total Demand (before DLC) for Mild Weather Peak	(8,229)	(8,396)	(8,046)	(7,683)	(7,836)	(7,926)	(8,079)	(8,239)	(8,400)	(8,562)
Supply Variance	201	283	650	1013	1205	1125	972	1307	1146	984
Supply Reserve Margin (%)	2.4%	3.4%	8.1%	13.2%	15.4%	14.2%	12.0%	15.9%	13.6%	11.5%
Total DLC (Including IS/CS)	761	711	658	626	596	575	556	541	528	517
Total Variance	962	994	1308	1638	1800	1699	1528	1848	1674	1501
Total Reserve Margin (%)	12.9%	12.9%	17.7%	23.2%	24.9%	23.1%	20.3%	24.0%	21.3%	18.7%
Total Demand (before DLC) for Normal Weather Peak	(8,328)	(8,495)	(8,145)	(7,782)	(7,935)	(8,025)	(8,178)	(8,338)	(8,499)	(8,661)
Supply Variance	102	184	551	914	1106	1026	873	1208	1047	885
Supply Reserve Margin (%)	1.2%	2.2%	6.8%	11.7%	13.9%	12.8%	10.7%	14.5%	12.3%	10.2%
Total DLC (Including IS/CS)	819	762	701	663	629	604	582	564	548	535
Total Variance	920	946	1252	1577	1735	1630	1455	1771	1595	1420
Total Reserve Margin (%)	12.3%	12.2%	16.8%	22.2%	23.7%	22.0%	19.2%	22.8%	20.1%	17.5%
Total Demand (before DLC) for TMY Peak	(8,482)	(8,656)	(8,326)	(7,977)	(8,143)	(8,237)	(8,389)	(8,542)	(8,692)	(8,841)
Supply Variance	(52)	23	369	719	898	814	661	1004	853	704
Supply Reserve Margin (%)	-0.6%	0.3%	4.4%	9.0%	11.0%	9.9%	7.9%	11.8%	9.8%	8.0%
Total DLC (Including IS/CS)	819	762	701	663	629	604	582	564	548	535
Total Variance	767	785	1071	1382	1527	1418	1244	1568	1401	1239
Total Reserve Margin (%)	10.0%	10.0%	14.0%	18.9%	20.3%	18.6%	15.9%	19.7%	17.2%	14.9%
Total Demand (before DLC) for Extreme Weather Peak	(8,470)	(8,637)	(8,287)	(7,924)	(8,078)	(8,167)	(8,320)	(8,480)	(8,642)	(8,803)
Supply Variance	(40)	42	409	772	963	884	731	1066	904	743
Supply Reserve Margin (%)	-0.5%	0.5%	4.9%	9.7%	11.9%	10.8%	8.8%	12.6%	10.5%	8.4%
Total DLC (Including IS/CS)	840	782	718	677	642	615	592	572	556	542
Total Variance	800	823	1126	1449	1604	1499	1323	1638	1459	1284
Total Reserve Margin (%)	10.5%	10.5%	14.9%	20.0%	21.6%	19.8%	17.1%	20.7%	18.0%	15.5%

*** Normal Weather Plant Ratings**

FPC 091

2000-2009 Resource Assessment
Peak Capacity Evaluation with Variable Weather Conditions
Hines 2 in 11/2003

	SUMMER PEAK (AUGUST)									
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Spinning Reserves	(191)	(191)	(191)	(191)	(191)	(191)	(191)	(191)	(191)	(191)
Load Following	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)
Baseload Contract Contractually-Allowed On-Peak Capacity Reduction	0	0	0	0	0	0	0	0	0	0
Remainder of Available Resources	8,139	8,388	8,405	8,405	8,750	8,760	8,760	9,255	9,255	9,255
Total Demand (before DLC) for Mild Weather Peak	(8,229)	(8,396)	(8,046)	(7,683)	(7,836)	(7,926)	(8,079)	(8,239)	(8,400)	(8,562)
Supply Variance	(90)	(8)	359	722	914	834	681	1016	855	693
Remaining Supply Reserve Margin (%)	-1.1%	-0.1%	4.5%	9.4%	11.7%	10.5%	8.4%	12.3%	10.2%	8.1%
Total DLC (Including IS/CS)	761	711	658	626	596	575	556	541	528	517
Total Variance	671	703	1017	1347	1509	1408	1237	1557	1383	1210
Remaining Total Reserve Margin (%)	9.0%	9.1%	13.8%	19.1%	20.8%	19.2%	16.4%	20.2%	17.6%	15.0%
Total Demand (before DLC) for Normal Weather Peak	(8,328)	(8,495)	(8,145)	(7,782)	(7,935)	(8,025)	(8,178)	(8,338)	(8,499)	(8,661)
Supply Variance	(189)	(107)	260	623	815	735	582	917	756	594
Remaining Supply Reserve Margin (%)	-2.3%	-1.3%	3.2%	8.0%	10.3%	9.2%	7.1%	11.0%	8.9%	6.9%
Total DLC (Including IS/CS)	819	762	701	663	629	604	582	564	548	535
Total Variance	629	655	961	1286	1444	1339	1164	1480	1304	1129
Remaining Total Reserve Margin (%)	8.4%	8.5%	12.9%	18.1%	19.8%	18.0%	15.3%	19.0%	16.4%	13.9%
Total Demand (before DLC) for TMY Peak	(8,482)	(8,656)	(8,326)	(7,977)	(8,143)	(8,237)	(8,389)	(8,542)	(8,692)	(8,841)
Supply Variance	(343)	(268)	78	428	607	523	370	713	562	413
Remaining Supply Reserve Margin (%)	-4.0%	-3.1%	0.9%	5.4%	7.5%	6.3%	4.4%	8.3%	6.5%	4.7%
Total DLC (Including IS/CS)	819	762	701	663	629	604	582	564	548	535
Total Variance	476	494	780	1091	1236	1127	953	1277	1110	948
Remaining Total Reserve Margin (%)	6.2%	6.3%	10.2%	14.9%	16.4%	14.8%	12.2%	16.0%	13.6%	11.4%
Total Demand (before DLC) for Extreme Weather Peak	(8,470)	(8,637)	(8,287)	(7,924)	(8,078)	(8,167)	(8,320)	(8,480)	(8,642)	(8,803)
Supply Variance	(331)	(249)	118	481	672	593	440	775	613	452
Remaining Supply Reserve Margin (%)	-3.9%	-2.9%	1.4%	6.1%	8.3%	7.3%	5.3%	9.1%	7.1%	5.1%
Total DLC (Including IS/CS)	840	782	718	677	642	615	592	572	556	542
Total Variance	509	532	835	1158	1313	1208	1032	1347	1168	993
Remaining Total Reserve Margin (%)	6.7%	6.8%	11.0%	16.0%	17.7%	16.0%	13.3%	17.0%	14.4%	12.0%

FPC 092

2000-2009 Resource Assessment
Peak Capacity Evaluation with Variable Weather Conditions
Hines 2 in 11/2003

	SUMMER PEAK (AUGUST)									
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Actual Forced Outages (5.5% EFOR)	(398)	(412)	(413)	(413)	(432)	(432)	(432)	(459)	(459)	(45
Remainder of Available Resources	7,741	7,976	7,992	7,992	8,318	8,328	8,328	8,796	8,796	8,79
Total Demand (before DLC) for Mild Weather Peak	(8,229)	(8,396)	(8,046)	(7,683)	(7,836)	(7,926)	(8,079)	(8,239)	(8,400)	(8,56
Supply Variance	(488)	(420)	(54)	309	482	402	249	557	396	23
Remaining Supply Reserve Margin (%)	-5.9%	-5.0%	-0.7%	4.0%	6.2%	5.1%	3.1%	6.8%	4.7%	2.7
Total DLC (Including IS/CS)	761	711	658	626	596	575	556	541	528	51
Total Variance	273	291	604	935	1078	977	805	1098	924	75
Remaining Total Reserve Margin (%)	3.7%	3.8%	8.2%	13.2%	14.9%	13.3%	10.7%	14.3%	11.7%	9.3
Total Demand (before DLC) for Normal Weather Peak	(8,328)	(8,495)	(8,145)	(7,782)	(7,935)	(8,025)	(8,178)	(8,338)	(8,499)	(8,66
Supply Variance	(587)	(519)	(153)	210	383	303	150	458	297	13
Remaining Supply Reserve Margin (%)	-7.1%	-6.1%	-1.9%	2.7%	4.8%	3.8%	1.8%	5.5%	3.5%	1.6
Total DLC (Including IS/CS)	819	762	701	663	629	604	582	564	548	53
Total Variance	231	243	548	873	1012	907	732	1022	845	67
Remaining Total Reserve Margin (%)	3.1%	3.1%	7.4%	12.3%	13.9%	12.2%	9.6%	13.1%	10.6%	8.2
Total Demand (before DLC) for TMY Peak	(8,482)	(8,656)	(8,326)	(7,977)	(8,143)	(8,237)	(8,389)	(8,542)	(8,692)	(8,84
Supply Variance	(741)	(680)	(334)	15	175	91	(61)	254	104	(4
Remaining Supply Reserve Margin (%)	-8.7%	-7.9%	-4.0%	0.2%	2.2%	1.1%	-0.7%	3.0%	1.2%	-0.5
Total DLC (Including IS/CS)	819	762	701	663	629	604	582	564	548	53
Total Variance	78	83	367	678	804	695	521	818	652	49
Remaining Total Reserve Margin (%)	1.0%	1.0%	4.8%	9.3%	10.7%	9.1%	6.7%	10.3%	8.0%	5.9
Total Demand (before DLC) for Extreme Weather Peak	(8,470)	(8,637)	(8,287)	(7,924)	(8,078)	(8,167)	(8,320)	(8,480)	(8,642)	(8,80
Supply Variance	(729)	(661)	(295)	68	240	161	8	316	154	(7
Remaining Supply Reserve Margin (%)	-8.6%	-7.7%	-3.6%	0.9%	3.0%	2.0%	0.1%	3.7%	1.8%	-0.1%
Total DLC (Including IS/CS)	840	782	718	677	642	615	592	572	556	542
Total Variance	111	121	423	745	882	776	600	888	710	53
Remaining Total Reserve Margin (%)	1.5%	1.5%	5.6%	10.3%	11.9%	10.3%	7.8%	11.2%	8.8%	6.5

FPC 093

2000-2009 Resource Assessment
Peak Capacity Evaluation with Variable Weather Conditions
Hines 2 in 11/2003

	SUMMER PEAK (AUGUST)									
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Worst-Case Forced Outages (9.7% EFOR)	(702)	(726)	(728)	(728)	(761)	(761)	(761)	(809)	(809)	(8
Remainder of Available Resources	7,437	7,662	7,677	7,677	7,988	7,998	7,998	8,445	8,445	8,4
Total Demand (before DLC) for Mild Weather Peak	(8,229)	(8,396)	(8,046)	(7,683)	(7,836)	(7,926)	(8,079)	(8,239)	(8,400)	(8,56
Supply Variance	(792)	(734)	(369)	(6)	152	72	(81)	206	45	(11
Remaining Supply Reserve Margin (%)	-9.6%	-8.7%	-4.6%	-0.1%	1.9%	0.9%	-1.0%	2.5%	0.5%	-1.4
Total DLC (Including IS/CS)	761	711	658	626	596	575	556	541	528	51
Total Variance	(31)	(23)	289	619	748	647	476	747	573	40
Remaining Total Reserve Margin (%)	-0.4%	-0.3%	3.9%	8.8%	10.3%	8.8%	6.3%	9.7%	7.3%	5.0
Total Demand (before DLC) for Normal Weather Peak	(8,328)	(8,495)	(8,145)	(7,782)	(7,935)	(8,025)	(8,178)	(8,338)	(8,499)	(8,66
Supply Variance	(891)	(833)	(468)	(105)	53	(27)	(180)	107	(54)	(21
Remaining Supply Reserve Margin (%)	-10.7%	-9.8%	-5.7%	-1.3%	0.7%	-0.3%	-2.2%	1.3%	-0.6%	-2.5
Total DLC (Including IS/CS)	819	762	701	663	629	604	582	564	548	53
Total Variance	(72)	(71)	233	558	683	577	403	671	495	31
Remaining Total Reserve Margin (%)	-1.0%	-0.9%	3.1%	7.8%	9.3%	7.8%	5.3%	8.6%	6.2%	3.9
Total Demand (before DLC) for TMY Peak	(8,482)	(8,656)	(8,326)	(7,977)	(8,143)	(8,237)	(8,389)	(8,542)	(8,692)	(8,84
Supply Variance	(1045)	(994)	(649)	(300)	(154)	(238)	(391)	(96)	(247)	(39
Remaining Supply Reserve Margin (%)	-12.3%	-11.5%	-7.8%	-3.8%	-1.9%	-2.9%	-4.7%	-1.1%	-2.8%	-4.5
Total DLC (Including IS/CS)	819	762	701	663	629	604	582	564	548	53
Total Variance	(226)	(232)	52	363	475	366	192	468	301	13
Remaining Total Reserve Margin (%)	-3.0%	-2.9%	0.7%	5.0%	6.3%	4.8%	2.5%	5.9%	3.7%	1.7
Total Demand (before DLC) for Extreme Weather Peak	(8,470)	(8,637)	(8,287)	(7,924)	(8,078)	(8,167)	(8,320)	(8,480)	(8,642)	(8,80
Supply Variance	(1033)	(975)	(610)	(247)	(90)	(169)	(322)	(35)	(197)	(35
Remaining Supply Reserve Margin (%)	-12.2%	-11.3%	-7.4%	-3.1%	-1.1%	-2.1%	-3.9%	-0.4%	-2.3%	-4.1
Total DLC (Including IS/CS)	840	782	718	677	642	615	592	572	556	54
Total Variance	(193)	(194)	107	430	552	446	271	538	359	18
Remaining Total Reserve Margin (%)	-2.5%	-2.5%	1.4%	5.9%	7.4%	5.9%	3.5%	6.8%	4.4%	2.2

FPC 094

JUNE 1999 BUDGET FORECAST (S990503)

Normal Weather

Bulk Power Sales Included

SEASON	MONTH	POTENTIAL TOTAL RETAIL (MW)	WHOLESALE REA (MW)	WHOLESALE BULK (MW)	WHOLESALE MUNI (MW)	WHOLESALE TOTAL (MW)	CO. USE (MW)	POTENTIAL TOTAL SYSTEM (MW)	NON-DISP. DSM & S.S. COGEN (MW)	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS RESIDENTIAL LOAD MGT. (MW)	DIRECT LOAD CONTROL PROGRAMS OTHER DLC PROGRAMS (MW)	DIRECT LOAD CONTROL PROGRAMS TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
WINTER 99/00	Jan-2000	8,330	779	631	220	1,630	30	9,990	399	9,591	735	23	758	326	1,084	0	8,507	115
WINTER 99/00	Feb-2000	7,619	778	524	178	1,480	30	9,129	386	8,743	559	23	583	326	909	0	7,834	105
WINTER 99/00	Mar-2000	6,771	289	473	172	934	30	7,735	352	7,383	396	23	419	326	745	0	6,638	89
SUMMER 00	Apr-2000	5,791	0	478	176	654	30	6,475	295	6,180	282	43	326	327	653	0	5,527	77
SUMMER 00	May-2000	6,617	173	555	199	927	30	7,574	322	7,252	353	47	400	327	727	0	6,525	90
SUMMER 00	Jun-2000	7,154	294	631	220	1,145	30	8,329	338	7,991	423	49	473	327	800	0	7,191	99
SUMMER 00	Jul-2000	7,284	351	631	223	1,205	30	8,519	343	8,176	440	50	490	327	817	0	7,359	102
SUMMER 00	Aug-2000	7,396	392	631	232	1,255	30	8,681	353	8,328	442	50	492	327	819	0	7,509	103
SUMMER 00	Sep-2000	7,111	244	631	211	1,086	30	8,227	344	7,883	390	49	439	327	766	0	7,117	97
SUMMER 00	Oct-2000	6,295	0	555	170	725	30	7,050	316	6,734	236	45	281	328	609	0	6,125	85
WINTER 00/01	Nov-2000	6,163	142	473	157	772	30	6,965	357	6,608	322	24	347	328	675	0	5,933	81
WINTER 00/01	Dec-2000	7,329	567	550	208	1,325	30	8,684	414	8,270	621	25	646	328	974	0	7,296	103
WINTER 00/01	Jan-2001	8,488	870	631	189	1,690	30	10,208	424	9,784	710	26	736	314	1,050	0	8,734	117
WINTER 00/01	Feb-2001	7,762	863	529	163	1,555	30	9,347	409	8,938	535	26	562	314	876	0	8,062	107
WINTER 00/01	Mar-2001	6,896	358	473	154	985	30	7,911	372	7,539	376	26	401	314	715	0	6,824	91
SUMMER 01	Apr-2001	5,911	113	483	150	746	30	6,687	304	6,383	257	46	303	314	617	0	5,766	80
SUMMER 01	May-2001	6,756	277	565	153	995	30	7,781	333	7,448	319	50	369	314	683	0	6,765	93
SUMMER 01	Jun-2001	7,308	360	631	169	1,160	30	8,498	350	8,148	380	52	432	315	747	0	7,401	101
SUMMER 01	Jul-2001	7,440	423	631	171	1,225	30	8,695	355	8,340	394	52	447	315	762	0	7,578	104
SUMMER 01	Aug-2001	7,555	465	631	180	1,276	30	8,861	366	8,495	395	52	447	315	762	0	7,733	106
SUMMER 01	Sep-2001	7,263	307	631	164	1,102	30	8,395	356	8,039	346	52	397	315	712	0	7,327	100
SUMMER 01	Oct-2001	6,427	67	565	136	768	30	7,225	326	6,899	206	47	254	315	569	0	6,330	87
WINTER 01/02	Nov-2001	6,271	254	473	130	857	30	7.158	377	6,781	299	27	326	315	641	0	6,140	84
WINTER 01/02	Dec-2001	7,461	643	575	161	1,379	30	8.870	438	8,432	576	27	602	316	918	0	7,514	105
WINTER 01/02	Jan-2002	8,654	893	167	130	1,190	30	9.874	450	9,424	653	27	680	311	991	0	8,433	114
WINTER 01/02	Feb-2002	7,913	886	167	119	1,172	30	9,115	434	8,681	493	27	520	311	831	0	7,850	105
WINTER 01/02	Mar-2002	7,029	359	167	107	633	30	7,692	395	7,297	346	27	374	311	685	0	6,612	89
SUMMER 02	Apr-2002	6,038	112	167	98	377	30	6.445	315	6,130	215	49	264	311	575	0	5,555	77
SUMMER 02	May-2002	6,904	293	167	117	577	30	7.511	345	7,166	268	53	321	311	632	0	6,534	90
SUMMER 02	Jun-2002	7,467	359	167	126	652	30	8.149	362	7,787	320	54	374	311	685	0	7,102	97
SUMMER 02	Jul-2002	7,603	428	167	128	723	30	8.356	368	7,988	333	55	388	312	700	0	7,288	100
SUMMER 02	Aug-2002	7,721	472	167	134	773	30	8.524	379	8,145	334	55	389	312	701	0	7,444	102
SUMMER 02	Sep-2002	7,422	306	167	123	596	30	8.048	368	7,680	293	54	347	312	659	0	7,021	96
SUMMER 02	Oct-2002	6,566	57	167	107	331	30	6.927	338	6,589	175	50	226	312	538	0	6,051	84
WINTER 02/03	Nov-2002	6.387	251	167	104	522	30	6.939	399	6,540	280	29	309	312	621	0	5,919	81
WINTER 02/03	Dec-2002	7,602	652	167	115	934	30	8.566	464	8,102	541	30	571	313	884	0	7,218	101
WINTER 02/03	Jan-2003	8,823	433	167	99	699	30	9.552	478	9,074	616	30	646	313	959	0	8,115	110
WINTER 02/03	Feb-2003	8,068	427	167	90	684	30	8.782	461	8,321	466	30	496	313	809	0	7,512	101
WINTER 02/03	Mar-2003	7,165	0	167	81	248	30	7.443	419	7,024	327	30	357	313	670	0	6,354	86

FPC 095

JUNE 1999 BUDGET FORECAST (S990503)

Normal Weather

Bulk Power Sales Included

SEASON	MONTH	POTENTIAL TOTAL RETAIL (MW)	WHOLESALE REA (MW)	WHOLESALE BULK (MW)	WHOLESALE MUNI (MW)	WHOLESALE TOTAL (MW)	CO. USE (MW)	POTENTIAL TOTAL SYSTEM (MW)	NON-DISP. DSM & S.S. COGEN (MW)	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS RESIDENTIAL LOAD MGT. (MW)	DIRECT LOAD CONTROL PROGRAMS OTHER DLC PROGRAMS (MW)	DIRECT LOAD CONTROL PROGRAMS TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 03	Apr-2003	6,170	0	167	74	241	30	6,441	326	6,115	186	52	238	313	551	0	5,564	77
SUMMER 03	May-2003	7,055	0	167	79	246	30	7,331	357	6,974	232	56	288	313	601	0	6,373	88
SUMMER 03	Jun-2003	7,631	0	167	86	253	30	7,914	376	7,538	278	57	335	314	649	0	6,889	95
SUMMER 03	Jul-2003	7,770	0	167	85	252	30	8,052	381	7,671	289	58	347	314	661	0	7,010	97
SUMMER 03	Aug-2003	7,890	0	167	88	255	30	8,175	393	7,782	291	58	349	314	663	0	7,119	98
SUMMER 03	Sep-2003	7,585	0	167	82	249	30	7,864	382	7,482	256	57	313	314	627	0	6,855	94
SUMMER 03	Oct-2003	6,709	0	167	75	242	30	6,981	350	6,631	154	53	207	314	521	0	6,110	85
WINTER 03/04	Nov-2003	6,507	0	167	72	239	30	6,776	421	6,355	267	33	300	314	614	0	5,741	79
WINTER 03/04	Dec-2003	7,745	178	167	83	428	30	8,203	491	7,712	520	33	552	315	867	0	6,845	96
WINTER 03/04	Jan-2004	8,985	461	167	94	722	30	9,737	508	9,229	593	33	626	310	936	0	8,293	112
WINTER 03/04	Feb-2004	8,215	461	167	87	715	30	8,960	490	8,470	448	33	481	310	791	0	7,679	103
WINTER 03/04	Mar-2004	7,295	0	167	77	244	30	7,569	444	7,125	314	34	348	310	658	0	6,467	87
SUMMER 04	Apr-2004	6,294	0	167	71	238	30	6,562	338	6,224	164	55	219	310	529	0	5,695	79
SUMMER 04	May-2004	7,198	0	167	79	246	30	7,474	371	7,103	205	59	264	310	574	0	6,529	90
SUMMER 04	Jun-2004	7,787	0	167	86	253	30	8,070	390	7,680	245	60	305	310	615	0	7,065	97
SUMMER 04	Jul-2004	7,929	0	167	86	253	30	8,212	396	7,816	255	61	316	311	627	0	7,189	99
SUMMER 04	Aug-2004	8,052	6	167	88	261	30	8,343	408	7,935	257	61	318	311	629	0	7,306	101
SUMMER 04	Sep-2004	7,740	0	167	84	251	30	8,021	397	7,624	226	60	286	311	597	0	7,027	96
SUMMER 04	Oct-2004	6,846	0	167	75	242	30	7,118	363	6,755	136	56	192	311	503	0	6,252	86
WINTER 04/05	Nov-2004	6,620	0	167	73	240	30	6,890	444	6,446	258	36	293	311	604	0	5,842	80
WINTER 04/05	Dec-2004	7,881	189	167	83	439	30	8,350	519	7,831	503	36	539	311	850	0	6,981	98
WINTER 04/05	Jan-2005	9,150	486	167	19	672	30	9,852	538	9,314	575	36	611	312	923	0	8,391	113
WINTER 04/05	Feb-2005	8,365	481	167	19	667	30	9,062	519	8,543	434	36	470	312	782	0	7,761	104
WINTER 04/05	Mar-2005	7,429	0	167	18	185	30	7,644	470	7,174	304	37	341	312	653	0	6,521	88
SUMMER 05	Apr-2005	6,423	0	167	17	184	30	6,637	350	6,287	145	58	203	312	515	0	5,772	80
SUMMER 05	May-2005	7,346	0	167	18	185	30	7,561	384	7,177	181	62	243	312	555	0	6,622	91
SUMMER 05	Jun-2005	7,948	0	167	18	185	30	8,163	404	7,759	216	63	280	313	593	0	7,166	98
SUMMER 05	Jul-2005	8,092	0	167	18	185	30	8,307	410	7,897	225	64	289	313	602	0	7,295	100
SUMMER 05	Aug-2005	8,218	15	167	18	200	30	8,448	423	8,025	227	64	291	313	604	0	7,421	102
SUMMER 05	Sep-2005	7,899	0	167	18	185	30	8,114	41[illegible]	7,703	199	63	263	313	576	0	7,127	98
SUMMER 05	Oct-2005	6,986	0	167	17	184	30	7,200	376	6,824	120	60	179	313	492	0	6,332	88
WINTER 05/06	Nov-2005	6,738	0	167	17	184	30	6,952	467	6,485	250	39	288	313	601	0	5,884	81
WINTER 05/06	Dec-2005	8,022	200	167	17	384	30	8,436	546	7,890	489	39	528	314	842	0	7,048	99
WINTER 05/06	Jan-2006	9,314	513	167	11	691	30	10,035	569	9,466	560	39	599	314	913	0	8,553	116
WINTER 05/06	Feb-2006	8,515	509	167	11	687	30	9,232	548	8,684	423	40	462	314	776	0	7,908	106
WINTER 05/06	Mar-2006	7,561	0	167	11	178	30	7,769	496	7,273	296	40	336	314	650	0	6,623	89
SUMMER 06	Apr-2006	6,552	0	167	11	178	30	6,760	362	6,398	128	61	189	314	503	0	5,895	82
SUMMER 06	May-2006	7,494	0	167	11	178	30	7,702	398	7,304	159	65	224	314	538	0	6,766	93
SUMMER 06	Jun-2005	8,108	0	167	11	178	30	8,316	419	7,897	191	66	257	315	572	0	7,325	101

FPC 096

JUNE 1999 BUDGET FORECAST (S990503)
Normal Weather
Bulk Power Sales Included

SEASON	MONTH	POTENTIAL TOTAL RETAIL (MW)	WHOLESALE REA (MW)	WHOLESALE BULK (MW)	WHOLESALE MUNI (MW)	WHOLESALE TOTAL (MW)	CO. USE (MW)	POTENTIAL TOTAL SYSTEM (MW)	NON-DISP. DSM & S.S. COGEN (MW)	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 06	Jul-2006	8,256	0	167	11	178	30	8,464	425	8,039	199	67	266	315	581	0	7,458	103
SUMMER 06	Aug-2006	8,384	25	167	11	203	30	8,617	439	8,178	200	67	267	315	582	0	7,596	104
SUMMER 06	Sep-2006	8,059	0	167	11	178	30	8,267	426	7,841	176	67	242	315	557	0	7,284	100
SUMMER 06	Oct-2006	7,127	0	167	11	178	30	7,335	389	6,946	105	63	168	315	483	0	6,463	89
WINTER 06/07	Nov-2006	6,856	0	167	11	178	30	7,064	491	6,573	243	42	285	315	600	0	5,973	82
WINTER 06/07	Dec-2006	8,164	209	167	11	387	30	8,581	574	8,007	477	42	519	316	835	0	7,172	100
WINTER 06/07	Jan-2007	9,479	540	167	11	718	30	10,227	599	9,628	546	42	589	316	905	0	8,723	118
WINTER 06/07	Feb-2007	8,666	536	167	11	714	30	9,410	577	8,833	412	43	455	316	771	0	8,062	108
WINTER 06/07	Mar-2007	7,694	0	167	11	178	30	7,902	522	7,380	289	43	332	316	648	0	6,732	91
SUMMER 07	Apr-2007	6,682	0	167	11	178	30	6,890	374	6,516	113	64	177	316	493	0	6,023	84
SUMMER 07	May-2007	7,643	0	167	11	178	30	7,851	411	7,440	141	68	209	316	525	0	6,915	95
SUMMER 07	Jun-2007	8,270	0	167	11	178	30	8,478	433	8,045	168	69	238	317	555	0	7,490	103
SUMMER 07	Jul-2007	8,420	0	167	11	178	30	8,628	440	8,188	175	70	246	317	563	0	7,625	105
SUMMER 07	Aug-2007	8,551	33	167	11	211	30	8,792	454	8,338	176	70	247	317	564	0	7,774	107
SUMMER 07	Sep-2007	8,219	0	167	11	178	30	8,427	441	7,986	155	70	225	317	542	0	7,444	102
SUMMER 07	Oct-2007	7,268	0	167	11	178	30	7,476	402	7,074	93	66	159	317	476	0	6,598	91
WINTER 07/08	Nov-2007	6,976	0	167	11	178	30	7,184	513	6,671	237	45	282	318	600	0	6,071	83
WINTER 07/08	Dec-2007	8,306	220	167	11	398	30	8,734	601	8,133	467	45	512	318	830	0	7,303	102
WINTER 07/08	Jan-2008	9,644	566	167	11	744	30	10,418	628	9,790	534	45	580	318	898	0	8,892	120
WINTER 07/08	Feb-2008	8,816	560	167	11	738	30	9,584	605	8,979	403	46	449	318	767	0	8,212	110
WINTER 07/08	Mar-2008	7,823	0	167	11	178	30	8,036	547	7,489	282	46	328	318	646	0	6,843	93
SUMMER 08	Apr-2008	6,810	0	167	11	178	30	7,018	385	6,633	99	67	167	318	485	0	6,148	85
SUMMER 08	May-2008	7,792	0	167	11	178	30	8,000	424	7,576	124	71	195	319	514	0	7,062	97
SUMMER 08	Jun-2008	8,430	0	167	11	178	30	8,638	447	8,191	148	73	221	319	540	0	7,651	105
SUMMER 08	Jul-2008	8,584	0	167	11	178	30	8,792	454	8,338	155	73	228	319	547	0	7,791	107
SUMMER 08	Aug-2008	8,717	42	167	11	220	30	8,967	468	8,499	156	74	229	319	548	0	7,951	109
SUMMER 08	Sep-2008	8,379	0	167	11	178	30	8,587	455	8,132	137	73	210	319	529	0	7,603	104
SUMMER 08	Oct-2008	7,408	0	167	11	178	30	7,616	415	7,201	82	69	151	319	470	0	6,731	93
WINTER 08/09	Nov-2008	7,095	0	167	11	178	30	7,303	535	6,768	231	48	279	320	599	0	6,169	85
WINTER 08/09	Dec-2008	8,448	230	167	11	408	30	8,886	627	8,259	457	48	505	320	825	0	7,434	104
WINTER 08/09	Jan-2009	9,810	592	167	11	770	30	10,610	657	9,953	523	49	572	320	892	0	9,061	123
WINTER 08/09	Feb-2009	8,968	587	167	11	765	30	9,763	633	9,130	395	49	444	320	764	0	8,366	112
WINTER 08/09	Mar-2009	7,962	0	167	11	178	30	8,170	572	7,598	276	49	325	320	645	0	6,953	94
SUMMER 09	Apr-2009	6,941	0	167	11	178	30	7,149	396	6,753	88	71	158	320	478	0	6,275	87
SUMMER 09	May-2009	7,942	0	167	11	178	30	8,150	437	7,713	109	74	184	321	505	0	7,208	99
SUMMER 09	Jun-2009	8,592	0	167	11	178	30	8,800	461	8,339	131	76	207	321	528	0	7,811	107
SUMMER 09	Jul-2009	8,749	0	167	11	178	30	8,957	468	8,489	136	76	213	321	534	0	7,955	109
SUMMER 09	Aug-2009	8,885	51	167	11	229	30	9,144	483	8,661	137	77	214	321	535	0	8,126	111
SUMMER 09	Sep-2009	8,540	0	167	11	178	30	8,748	469	8,279	121	76	197	321	518	0	7,761	106

FPC 097

JUNE 1999 BUDGET FORECAST (S990503)

Normal Weather

Bulk Power Sales Included

SEASON	MONTH	POTENTIAL TOTAL RETAIL (MW)	WHOLESALE REA (MW)	WHOLESALE BULK (MW)	WHOLESALE MUNI (MW)	WHOLESALE TOTAL (MW)	CO. USE (MW)	POTENTIAL TOTAL SYSTEM (MW)	NON-DISP. DSM & S.S. COGEN (MW)	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS RESIDENTIAL LOAD MGT. (MW)	DIRECT LOAD CONTROL PROGRAMS OTHER DLC PROGRAMS (MW)	DIRECT LOAD CONTROL PROGRAMS TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 09	Oct-2009	7,551	0	167	11	178	30	7,759	428	7,331	72	72	144	321	465	0	6,866	95
WINTER 09/10	Nov-2009	7,215	0	167	11	178	30	7,423	557	6,866	226	51	277	322	599	0	6,267	86
WINTER 09/10	Dec-2009	8,591	240	167	11	418	30	9,039	654	8,385	448	51	499	322	821	0	7,564	106

FPC 098

	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01
Baseload Plants (Summer and Winter Base Ratings)																							
Crystal River 1	386	386	386	381	381	381	381	295	381	381	386	386	386	386	386	381	381	381	381	295	381	381	386
Crystal River 2	480	480	480	469	493	493	493	493	493	493	504	504	504	504	504	493	493	493	493	493	493	493	504
Crystal River 4	724	724	724	704	721	721	721	721	721	721	741	741	741	741	741	721	721	721	721	721	721	721	741
Crystal River 5	734	734	734	714	714	714	714	714	714	714	734	734	734	734	734	714	714	714	714	714	714	714	734
Crystal River 3	782	782	782	765	765	765	765	765	765	765	782	782	782	782	782	765	765	765	765	765	765	765	782
University of Florida Cogen	44	44	44	36	36	36	36	36	36	36	44	44	44	44	44	36	36	36	36	36	36	36	44
Baseload Contracts (Firm Purchase Capacity)																							
UPS Purchase from Southern Company	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409
TECO Purchase for Sebring Load	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
QF Contracts																							
PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
TIMBER ENERGY 1	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
BAY COUNTY RES REC	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
LFC MADISON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LFC JEFFERSON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
PASCO COUNTY RES REC	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
CARGILL	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
RIDGE GENERATING STA.	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
ROYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
CFR-BIOGEN (ORANGE CO)	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
US AGRICHEM	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Intermediate Resources (Summer and Winter Base Ratings)																							
Anclote 1	512	512	512	507	507	507	507	507	507	507	512	512	512	512	512	507	507	507	507	507	507	507	512
Anclote 2	522	522	522	502	502	502	502	502	502	502	522	522	522	522	522	502	502	502	502	502	502	502	522
Bartow 1	116	116	116	113	113	113	113	113	113	113	116	116	116	116	116	113	113	113	113	113	113	113	116
Bartow 2	117	117	117	113	113	113	113	113	113	113	117	117	117	117	117	113	113	113	113	113	113	113	117
Bartow 3	210	210	210	207	207	207	207	207	207	207	210	210	210	210	210	207	207	207	207	207	207	207	210
Suwannee River 1	34	34	34	33	33	33	33	33	33	33	34	34	34	34	34	33	33	33	33	33	33	33	34
Suwannee River 2	33	33	33	32	32	32	32	32	32	32	33	33	33	33	33	32	32	32	32	32	32	32	33
Suwannee River 3	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Tiger Bay Cogen	240	240	240	200	200	200	200	200	200	200	240	240	240	240	240	200	200	200	200	200	200	200	240
Hines Energy Complex 1	505	505	505	470	470	470	470	470	470	470	505	505	505	505	505	470	470	470	470	470	470	470	505
Hines Energy Complex 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hines Energy Complex 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Peaking Resources (Summer Base Rating @ 95°F, Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)																							
Avon Park P1	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	19	19	19	24	24	24
Bartow P2	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46	46	46	46	46
Bartow P4	62	62	62	49	49	49	49	49	49	49	49	62	62	62	62	49	49	49	49	49	49	49	49
Debary P7	98	98	98	76	76	72	72	72	76	76	76	98	98	98	98	76	76	72	72	72	76	76	76
Debary P9	98	98	98	76	76	72	72	72	76	76	76	98	98	98	98	76	76	72	72	72	76	76	76
Higgins P1	34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	25	25	24	24	24	25	25	25
Higgins P2	34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	25	25	24	24	24	25	25	25
Higgins P3	36	36	36	31	31	29	29	29	31	31	31	36	36	36	36	31	31	29	29	29	31	31	31
Higgins P4	36	36	36	31	31	29	29	29	31	31	31	36	36	36	36	31	31	29	29	29	31	31	31

FPC 099

	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01
Intercession City P7	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84	83	83	83
Intercession City P8	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84	83	83	83
Intercession City P9	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84	83	83	83
Intercession City P10	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84	83	83	83
Intercession City P12	0	0	0	0	0	0	0	0	0	0	0	99	99	99	99	83	83	83	83	83	83	83	83
Intercession City P13	0	0	0	0	0	0	0	0	0	0	0	99	99	99	99	83	83	83	83	83	83	83	83
Intercession City P14	0	0	0	0	0	0	0	0	0	0	0	99	99	99	99	83	83	83	83	83	83	83	83
Suwannee River P1	68	68	68	49	49	44	44	44	49	49	49	68	68	68	68	49	49	44	44	44	49	49	49
Suwannee River P3	68	68	68	49	49	44	44	44	49	49	49	68	68	68	68	49	49	44	44	44	49	49	49
Light Oil Peaking Resources (Summer Base Rating @ 95°F, Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)																							
Avon Park P2	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	19	19	19	24	24	24
Bartow P1	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46	46	46	46	46
Bartow P3	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46	46	46	46	46
Bayboro P1	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44	44	44
Bayboro P2	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44	44	44
Bayboro P3	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44	44	44
Bayboro P4	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44	44	44
Debary P1	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49
Debary P2	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49
Debary P3	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49
Debary P4	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49
Debary P5	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49
Debary P6	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49
Debary P8	96	96	96	76	76	72	72	72	76	76	76	96	96	96	96	76	76	72	72	72	76	76	76
Debary P10	96	96	96	76	76	72	72	72	76	76	76	96	96	96	96	76	76	72	72	72	76	76	76
Intercession City P1	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47
Intercession City P2	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47
Intercession City P3	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47
Intercession City P4	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47
Intercession City P5	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47
Intercession City P6	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47
Intercession City P11	172	172	172	143	143	0	0	0	0	143	143	172	172	172	172	143	143	0	0	0	0	143	143
Rio Pinar P1	19	19	19	13	13	11	11	11	13	13	13	19	19	19	19	13	13	11	11	11	13	13	13
Suwannee River P2	68	68	68	51	51	48	48	48	51	51	51	68	68	68	68	68	51	48	48	48	51	51	51
Turner P1	19	19	19	13	13	11	11	11	13	13	13	19	19	19	19	19	13	11	11	11	13	13	13
Turner P2	19	19	19	13	13	11	11	11	13	13	13	19	19	19	19	19	13	11	11	11	13	13	13
Turner P3	84	84	84	61	61	57	57	57	61	61	61	84	84	84	84	84	61	57	57	57	61	61	61
Turner P4	84	84	84	61	61	57	57	57	61	61	61	84	84	84	84	84	61	57	57	57	61	61	61
Total Baseload Plants	3,150	3,150	3,150	3,069	3,110	3,110	3,110	3,024	3,110	3,110	3,191	3,191	3,191	3,191	3,191	3,110	3,110	3,110	3,110	3,024	3,110	3,110	3,191
Total Baseload Contracts	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469
Total QF Contracts	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831
Total Intermediate Resources	2,374	2,374	2,374	2,262	2,262	2,262	2,262	2,262	2,262	2,262	2,374	2,374	2,374	2,374	2,374	2,262	2,262	2,262	2,262	2,262	2,262	2,262	2,374
Total Gas Peaking Resources	1,014	1,014	1,014	813	813	789	789	789	813	813	813	1,311	1,311	1,311	1,311	1,062	1,062	1,038	1,038	1,038	1,062	1,062	1,062
Total Light Oil Peaking Resources	1,813	1,813	1,813	1,375	1,375	1,160	1,160	1,160	1,232	1,375	1,375	1,813	1,813	1,813	1,813	1,450	1,375	1,160	1,160	1,160	1,232	1,375	1,375
Total Available Resources	9,651	9,651	9,651	8,819	8,860	8,622	8,622	8,536	8,717	8,860	9,053	9,989	9,989	9,989	9,989	9,184	9,109	8,871	8,871	8,785	8,966	9,109	9,302

FPC 100

	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03
Baseload Plants (Summer and Winter Base Ratings)																							
Crystal River 1	386	403	403	403	398	398	398	398	312	398	398	403	403	403	403	403	398	398	398	398	312	398	398
Crystal River 2	504	504	504	504	493	493	493	493	493	493	493	504	504	504	504	504	493	493	493	493	493	493	493
Crystal River 4	741	741	741	741	721	721	721	721	721	721	721	741	741	741	741	741	721	721	721	721	721	721	721
Crystal River 5	734	734	734	734	714	714	714	714	714	714	714	734	734	734	734	734	714	714	714	714	714	714	714
Crystal River 3	782	782	782	782	765	765	765	765	765	765	765	782	782	782	782	782	765	765	765	765	765	765	765
University of Florida Cogen	44	44	44	44	36	36	36	36	36	36	36	44	44	44	44	44	36	36	36	36	36	36	36
Baseload Contracts (Firm Purchase Capacity)																							
UPS Purchase from Southern Company	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409
TECO Purchase for Sebring Load	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60	60
QF Contracts																							
PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
TIMBER ENERGY 1	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
BAY COUNTY RES REC	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
LFC MADISON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LFC JEFFERSON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
PASCO COUNTY RES REC	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
CARGILL	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
RIDGE GENERATING STA.	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
ROYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
CFR-BIOGEN (ORANGE CO)	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
US AGRICHEM	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Intermediate Resources (Summer and Winter Base Ratings)																							
Anclote 1	512	512	512	512	507	507	507	507	507	507	507	512	512	512	512	512	507	507	507	507	507	507	507
Anclote 2	522	522	522	522	502	502	502	502	502	502	502	522	522	522	522	522	502	502	502	502	502	502	502
Bartow 1	116	116	116	116	113	113	113	113	113	113	113	116	116	116	116	116	113	113	113	113	113	113	113
Bartow 2	117	117	117	117	113	113	113	113	113	113	113	117	117	117	117	117	113	113	113	113	113	113	113
Bartow 3	210	210	210	210	207	207	207	207	207	207	207	210	210	210	210	210	207	207	207	207	207	207	207
Suwannee River 1	34	34	34	34	33	33	33	33	33	33	33	34	34	34	34	34	33	33	33	33	33	33	33
Suwannee River 2	33	33	33	33	32	32	32	32	32	32	32	33	33	33	33	33	32	32	32	32	32	32	32
Suwannee River 3	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85	85
Tiger Bay Cogen	240	240	240	240	200	200	200	200	200	200	200	240	240	240	240	240	200	200	200	200	200	200	200
Hines Energy Complex 1	505	505	505	505	470	470	470	470	470	470	470	505	505	505	505	505	470	470	470	470	470	470	470
Hines Energy Complex 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hines Energy Complex 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Peaking Resources (Summer Base Rating @ 95°F, Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)																							
Avon Park P1	34	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	19	19	19	24	24
Bartow P2	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46	46	46	46
Bartow P4	62	62	62	62	49	49	49	49	49	49	49	49	62	62	62	62	49	49	49	49	49	49	49
Debary P7	98	98	98	98	76	76	72	72	72	76	76	76	98	98	98	98	76	76	72	72	72	76	76
Debary P9	98	98	98	98	76	76	72	72	72	76	76	76	98	98	98	98	76	76	72	72	72	76	76
Higgins P1	34	34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	25	25	24	24	24	25	25
Higgins P2	34	34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	25	25	24	24	24	25	25
Higgins P3	36	36	36	36	31	31	29	29	29	31	31	31	36	36	36	36	31	31	29	29	29	31	31
Higgins P4	36	36	36	36	31	31	29	29	29	31	31	31	36	36	36	36	31	31	29	29	29	31	31

FPC 101

	Dec-01	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03
Intercession City P7	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84	83	83
Intercession City P8	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84	83	83
Intercession City P9	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84	83	83
Intercession City P10	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84	83	83
Intercession City P12	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83	83	83	83
Intercession City P13	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83	83	83	83
Intercession City P14	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83	83	83	83
Suwannee River P1	68	68	68	68	49	49	44	44	44	49	49	49	68	68	68	68	49	49	44	44	44	49	49
Suwannee River P3	68	68	68	68	49	49	44	44	44	49	49	49	68	68	68	68	49	49	44	44	44	49	49
Light Oil Peaking Resources (Summer Base Rating @ 95°F, Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)																							
Avon Park P2	34	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	19	19	19	24	24
Barlow P1	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46	46	46	46
Barlow P3	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46	46	46	46
Bayboro P1	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44	44
Bayboro P2	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44	44
Bayboro P3	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44	44
Bayboro P4	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44	44
Debary P1	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49
Debary P2	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49
Debary P3	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49
Debary P4	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49
Debary P5	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49
Debary P6	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49	49
Debary P8	96	96	96	96	76	76	72	72	72	76	76	76	96	96	96	96	76	76	72	72	72	76	76
Debary P10	96	96	96	96	76	76	72	72	72	76	76	76	96	96	96	96	76	76	72	72	72	76	76
Intercession City P1	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47
Intercession City P2	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47
Intercession City P3	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47
Intercession City P4	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47
Intercession City P5	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47
Intercession City P6	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47	47
Intercession City P11	172	172	172	172	143	143	0	0	0	0	143	143	172	172	172	172	143	143	0	0	0	0	143
Rio Pinar P1	19	19	19	19	13	13	11	11	11	13	13	13	19	19	19	19	13	13	11	11	11	13	13
Suwannee River P2	68	68	68	68	68	51	48	48	48	51	51	51	68	68	68	68	68	51	48	48	48	51	51
Turner P1	19	19	19	19	19	13	11	11	11	13	13	13	19	19	19	19	19	13	11	11	11	13	13
Turner P2	19	19	19	19	19	13	11	11	11	13	13	13	19	19	19	19	19	13	11	11	11	13	13
Turner P3	84	84	84	84	84	61	57	57	57	61	61	61	84	84	84	84	84	61	57	57	57	61	61
Turner P4	84	84	84	84	84	61	57	57	57	61	61	61	84	84	84	84	84	61	57	57	57	61	61
Total Baseload Plants	3,191	3,208	3,208	3,208	3,127	3,127	3,127	3,127	3,041	3,127	3,127	3,208	3,208	3,208	3,208	3,208	3,127	3,127	3,127	3,127	3,041	3,127	3,127
Total Baseload Contracts	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469	469
Total QF Contracts	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831
Total Intermediate Resources	2,374	2,374	2,374	2,374	2,262	2,262	2,262	2,262	2,262	2,262	2,262	2,374	2,374	2,374	2,374	2,374	2,262	2,262	2,262	2,262	2,262	2,262	2,262
Total Gas Peaking Resources	1,311	1,311	1,311	1,311	1,062	1,062	1,038	1,038	1,038	1,062	1,062	1,062	1,311	1,311	1,311	1,311	1,062	1,062	1,038	1,038	1,038	1,062	1,062
Total Light Oil Peaking Resources	1,813	1,813	1,813	1,813	1,450	1,375	1,160	1,160	1,160	1,232	1,375	1,375	1,813	1,813	1,813	1,813	1,450	1,375	1,160	1,160	1,160	1,232	1,375
Total Available Resources	9,989	10,006	10,006	10,006	9,201	9,126	8,888	8,888	8,802	8,983	9,126	9,319	10,006	10,006	10,006	10,006	9,201	9,126	8,888	8,888	8,802	8,983	9,126

FPC 102

	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05
Baseload Plants (Summer and Winter Base Ratings)																							
Crystal River 1	403	403	403	403	403	398	398	398	398	312	398	398	403	403	403	403	403	398	398	398	398	312	398
Crystal River 2	504	504	504	504	504	493	493	493	493	493	493	493	504	504	504	504	504	493	493	493	493	493	493
Crystal River 4	741	741	741	741	741	721	721	721	721	721	721	721	741	741	741	741	741	721	721	721	721	721	721
Crystal River 5	734	734	734	734	734	714	714	714	714	714	714	714	734	734	734	734	734	714	714	714	714	714	714
Crystal River 3	782	782	782	782	782	765	765	765	765	765	765	765	782	782	782	782	782	765	765	765	765	765	765
University of Florida Cogen	44	44	44	44	44	36	36	36	36	36	36	36	44	44	44	44	44	36	36	36	36	36	36
Baseload Contracts (Firm Purchase Capacity)																							
UPS Purchase from Southern Company	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409
TECO Purchase for Sebring Load	60	60	60	60	60	60	60	60	60	60	60	60	60	60	70	70	70	70	70	70	70	70	70
QF Contracts																							
PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
TIMBER ENERGY 1	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
BAY COUNTY RES REC	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
LFC MADISON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LFC JEFFERSON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
PASCO COUNTY RES REC	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
CARGILL	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
RIDGE GENERATING STA.	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
ROYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
CFR-BIOGEN (ORANGE CO)	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
US AGRICHEM	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Intermediate Resources (Summer and Winter Base Ratings)																							
Anclote 1	512	512	512	512	512	507	507	507	507	507	507	507	512	512	512	512	512	507	507	507	507	507	507
Anclote 2	522	522	522	522	522	502	502	502	502	502	502	502	522	522	522	522	522	502	502	502	502	502	502
Bartow 1	116	116	116	116	116	113	113	113	113	113	113	113	116	116	116	116	116	113	113	113	113	113	113
Bartow 2	117	117	117	117	117	113	113	113	113	113	113	113	117	117	117	117	117	113	113	113	113	113	113
Bartow 3	210	210	210	210	210	207	207	207	207	207	207	207	210	210	210	210	210	207	207	207	207	207	207
Suwannee River 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suwannee River 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suwannee River 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tiger Bay Cogen	240	240	240	240	240	200	200	200	200	200	200	200	240	240	240	240	240	200	200	200	200	200	200
Hines Energy Complex 1	505	505	505	505	505	470	470	470	470	470	470	470	505	505	505	505	505	470	470	470	470	470	470
Hines Energy Complex 2	567	567	567	567	567	495	495	495	0	495	495	495	567	567	567	567	567	495	495	495	495	495	495
Hines Energy Complex 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Gas Peaking Resources (Summer Base Rating @ 95°F, Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)																							
Avon Park P1	24	34	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	19	19	19	24
Bartow P2	46	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46	46	46
Bartow P4	49	62	62	62	62	49	49	49	49	49	49	49	49	62	62	62	62	49	49	49	49	49	49
Debary P7	76	98	98	98	98	76	76	72	72	72	76	76	76	98	98	98	98	76	76	72	72	72	76
Debary P9	76	95	93	93	93	76	76	72	72	72	76	76	76	98	98	95	93	76	76	72	72	72	76
Higgins P1	25	34	34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	25	25	24	24	24	25
Higgins P2	25	34	34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	25	25	24	24	24	25
Higgins P3	31	36	36	36	36	31	31	29	29	29	31	31	31	36	36	36	36	31	31	29	29	29	31
Higgins P4	31	36	36	36	36	31	31	29	29	29	31	31	31	36	36	36	36	31	31	29	29	29	31

FPC 103

	Nov-03	Dec-03	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	Aug-05	Sep-05
Intercession City P7	83	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84	83
Intercession City P8	83	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84	83
Intercession City P9	83	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84	83
Intercession City P10	83	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84	83
Intercession City P12	83	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83	83	83
Intercession City P13	83	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83	83	83
Intercession City P14	83	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83	83	83
Suwannee River P1	49	68	68	68	68	49	49	44	44	44	49	49	49	68	68	68	68	49	49	44	44	44	49
Suwannee River P3	49	68	68	68	68	49	49	44	44	44	49	49	49	68	68	68	68	49	49	44	44	44	49
Light Oil Peaking Resources (Summer Base Rating @ 95°F, Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)																							
Avon Park P2	24	34	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	19	19	19	24
Bartow P1	46	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46	46	46
Bartow P3	46	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46	46	46
Bayboro P1	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44
Bayboro P2	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44
Bayboro P3	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44
Bayboro P4	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41	44
Debary P1	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49
Debary P2	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49
Debary P3	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49
Debary P4	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49
Debary P5	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49
Debary P6	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44	49
Debary P8	76	96	96	96	96	76	76	72	72	72	76	76	76	96	96	96	96	76	76	72	72	72	76
Debary P10	76	96	96	96	96	76	76	72	72	72	76	76	76	96	96	96	96	76	76	72	72	72	76
Intercession City P1	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47
Intercession City P2	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47
Intercession City P3	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47
Intercession City P4	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47
Intercession City P5	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47
Intercession City P6	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47	47
Intercession City P11	143	172	172	172	172	143	143	0	0	0	0	143	143	172	172	172	172	143	143	0	0	0	0
Rio Pinar P1	13	19	19	19	19	13	13	11	11	11	13	13	13	19	19	19	19	13	13	11	11	11	13
Suwannee River P2	51	68	68	68	68	68	51	48	48	48	51	51	51	68	68	68	68	68	51	48	48	48	51
Turner P1	13	19	19	19	19	19	13	11	11	11	13	13	13	19	19	19	19	19	13	11	11	11	13
Turner P2	13	19	19	19	19	19	13	11	11	11	13	13	13	19	19	19	19	19	13	11	11	11	13
Turner P3	61	84	84	84	84	84	61	57	57	57	61	61	61	84	84	84	84	84	61	57	57	57	61
Turner P4	61	84	84	84	84	84	61	57	57	57	61	61	61	84	84	84	84	84	61	57	57	57	61
Total Baseload Plants	3,208	3,208	3,208	3,208	3,208	3,127	3,127	3,127	3,127	3,041	3,127	3,127	3,208	3,208	3,208	3,208	3,208	3,127	3,127	3,127	3,127	3,041	3,127
Total Baseload Contracts	469	469	469	469	469	469	469	469	469	469	469	469	469	469	479	479	479	479	479	479	479	479	479
Total QF Contracts	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831
Total Intermediate Resources	2,789	2,789	2,789	2,789	2,789	2,607	2,607	2,607	2,112	2,607	2,607	2,607	2,789	2,789	2,789	2,789	2,789	2,607	2,607	2,607	2,607	2,607	2,607
Total Gas Peaking Resources	1,062	1,311	1,311	1,311	1,311	1,062	1,062	1,038	1,038	1,038	1,062	1,062	1,062	1,311	1,311	1,311	1,311	1,062	1,062	1,038	1,038	1,038	1,062
Total Light Oil Peaking Resources	1,375	1,813	1,813	1,813	1,813	1,450	1,375	1,160	1,160	1,160	1,232	1,375	1,375	1,813	1,813	1,813	1,813	1,450	1,375	1,160	1,160	1,160	1,232
Total Available Resources	9,734	10,421	10,421	10,421	10,421	9,546	9,471	9,233	8,738	9,147	9,328	9,471	9,734	10,421	10,431	10,431	10,431	9,556	9,481	9,243	9,243	9,157	9,338

FPC 104

	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07
Baseload Plants (Summer and Winter Base Ratings)																							
Crystal River 1	398	403	403	403	403	403	398	398	398	398	312	398	398	403	403	403	403	403	398	398	398	398	312
Crystal River 2	493	504	504	504	504	504	493	493	493	493	493	493	493	504	504	504	504	504	493	493	493	493	493
Crystal River 4	721	741	741	741	741	741	721	721	721	721	721	721	721	741	741	741	741	741	721	721	721	721	721
Crystal River 5	714	734	734	734	734	734	714	714	714	714	714	714	714	734	734	734	734	734	714	714	714	714	714
Crystal River 3	765	782	782	782	782	782	765	765	765	765	765	765	765	782	782	782	782	782	765	765	765	765	765
University of Florida Cogen	36	44	44	44	44	44	36	36	36	36	36	36	36	44	44	44	44	44	36	36	36	36	36
Baseload Contracts (Firm Purchase Capacity)																							
UPS Purchase from Southern Company	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409
TECO Purchase for Sebring Load	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
QF Contracts																							
PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
TIMBER ENERGY 1	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
BAY COUNTY RES REC	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
LFC MADISON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LFC JEFFERSON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
PASCO COUNTY RES REC	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
CARGILL	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
RIDGE GENERATING STA.	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
ROYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
CFR-BIOGEN (ORANGE CO)	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
US AGRICHEM	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Intermediate Resources (Summer and Winter Base Ratings)																							
Anclote 1	507	512	512	512	512	512	507	507	507	507	507	507	507	512	512	512	512	512	507	507	507	507	507
Anclote 2	502	522	522	522	522	522	502	502	502	502	502	502	502	522	522	522	522	522	502	502	502	502	502
Barlow 1	113	116	116	116	116	116	113	113	113	113	113	113	113	116	116	116	116	116	113	113	113	113	113
Bartow 2	113	117	117	117	117	117	113	113	113	113	113	113	113	117	117	117	117	117	113	113	113	113	113
Bartow 3	207	210	210	210	210	210	207	207	207	207	207	207	207	210	210	210	210	210	207	207	207	207	207
Suwannee River 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suwannee River 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suwannee River 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tiger Bay Cogen	200	240	240	240	240	240	200	200	200	200	200	200	200	240	240	240	240	240	200	200	200	200	200
Hines Energy Complex 1	470	505	505	505	505	505	470	470	470	470	470	470	470	505	505	505	505	505	470	470	470	470	470
Hines Energy Complex 2	495	567	567	567	567	567	495	495	495	495	495	495	495	567	567	567	567	567	495	495	495	495	495
Hines Energy Complex 3	0	0	0	0	0	0	0	0	0	0	0	0	0	567	567	567	567	567	495	495	495	495	495
Gas Peaking Resources (Summer Base Rating @ 95°F, Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)																							
Avon Park P1	24	24	34	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	19	19	19
Bartow P2	46	46	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46	46
Bartow P4	49	49	62	62	62	62	49	49	49	49	49	49	49	49	62	62	62	62	49	49	49	49	49
Debary P7	76	76	98	98	98	98	76	76	72	72	72	76	76	76	98	98	98	98	76	76	72	72	72
Debary P9	76	76	98	98	98	98	76	76	72	72	72	76	76	76	98	98	98	98	76	76	72	72	72
Higgins P1	25	25	34	34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	25	25	24	24	24
Higgins P2	25	25	34	34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	25	25	24	24	24
Higgins P3	31	31	36	36	36	36	31	31	29	29	29	31	31	31	36	36	36	36	31	31	29	29	29
Higgins P4	31	31	36	36	36	36	31	31	29	29	29	31	31	31	36	36	36	36	31	31	29	29	29

	Oct-05	Nov-05	Dec-05	Jan-06	Feb-06	Mar-06	Apr-06	May-06	Jun-06	Jul-06	Aug-06	Sep-06	Oct-06	Nov-06	Dec-06	Jan-07	Feb-07	Mar-07	Apr-07	May-07	Jun-07	Jul-07	Aug-07
Intercession City P7	83	83	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84
Intercession City P8	83	83	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84
Intercession City P9	83	83	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84
Intercession City P10	83	83	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84	84
Intercession City P12	83	83	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83	83
Intercession City P13	83	83	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83	83
Intercession City P14	83	83	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83	83
Suwannee River P1	49	49	68	68	68	68	49	49	44	44	44	49	49	49	68	68	68	68	49	49	44	44	44
Suwannee River P3	49	49	68	68	68	68	49	49	44	44	44	49	49	49	68	68	68	68	49	49	44	44	44
Light Oil Peaking Resources (Summer Base Rating @ 95°F, Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)																							
Avon Park P2	24	24	34	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	19	19	19
Barlow P1	46	46	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46	46
Barlow P3	46	46	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46	46
Bayboro P1	44	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41
Bayboro P2	44	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41
Bayboro P3	44	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41
Bayboro P4	44	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41	41
Debary P1	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44
Debary P2	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44
Debary P3	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44
Debary P4	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44
Debary P5	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44
Debary P6	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44	44
Debary P8	76	76	96	96	96	96	76	76	72	72	72	76	76	76	96	96	96	96	76	76	72	72	72
Debary P10	76	76	96	96	96	96	76	76	72	72	72	76	76	76	96	96	96	96	76	76	72	72	72
Intercession City P1	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47
Intercession City P2	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47
Intercession City P3	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47
Intercession City P4	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47
Intercession City P5	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47
Intercession City P6	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47	47
Intercession City P11	143	143	172	172	172	172	143	143	0	0	0	0	143	143	172	172	172	172	143	143	0	0	0
Rio Pinar P1	13	13	19	19	19	19	13	13	11	11	11	13	13	13	19	19	19	19	13	13	11	11	11
Suwannee River P2	51	51	68	68	68	68	68	51	48	48	48	51	51	51	68	68	68	68	68	51	48	48	48
Turner P1	13	13	19	19	19	19	19	13	11	11	11	13	13	13	19	19	19	19	19	13	11	11	11
Turner P2	13	13	19	19	19	19	19	13	11	11	11	13	13	13	19	19	19	19	19	13	11	11	11
Turner P3	61	61	84	84	84	84	84	61	57	57	57	61	61	61	84	84	84	84	84	61	57	57	57
Turner P4	61	61	84	84	84	84	84	61	57	57	57	61	61	61	84	84	84	84	84	61	57	57	57
Total Baseload Plants	3,127	3,208	3,208	3,208	3,208	3,208	3,127	3,127	3,127	3,127	3,041	3,127	3,127	3,208	3,208	3,208	3,208	3,208	3,127	3,127	3,127	3,127	3,041
Total Baseload Contracts	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479
Total QF Contracts	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831
Total Intermediate Resources	2,607	2,789	2,789	2,789	2,789	2,789	2,607	2,607	2,607	2,607	2,607	2,607	2,607	3,356	3,356	3,356	3,356	3,356	3,102	3,102	3,102	3,102	3,102
Total Gas Peaking Resources	1,062	1,062	1,311	1,311	1,311	1,311	1,062	1,062	1,038	1,038	1,038	1,062	1,062	1,062	1,311	1,311	1,311	1,311	1,062	1,062	1,038	1,038	1,038
Total Light Oil Peaking Resources	1,375	1,375	1,813	1,813	1,813	1,813	1,450	1,375	1,160	1,160	1,160	1,232	1,375	1,375	1,813	1,813	1,813	1,813	1,450	1,375	1,160	1,160	1,160
Total Available Resources	9,481	9,744	10,431	10,431	10,431	10,431	9,556	9,481	9,243	9,243	9,157	9,338	9,481	10,311	10,998	10,998	10,998	10,998	10,051	9,976	9,738	9,738	9,652

FPC 106

	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09
Baseload Plants (Summer and Winter Base Ratings)																							
Crystal River 1	398	398	403	403	403	403	403	398	398	398	398	312	398	398	403	403	403	403	403	398	398	398	398
Crystal River 2	493	493	504	504	504	504	504	493	493	493	493	493	493	493	504	504	504	504	504	493	493	493	493
Crystal River 4	721	721	741	741	741	741	741	721	721	721	721	721	721	721	741	741	741	741	741	721	721	721	721
Crystal River 5	714	714	734	734	734	734	734	714	714	714	714	714	714	714	734	734	734	734	734	714	714	714	714
Crystal River 3	765	765	782	782	782	782	782	765	765	765	765	765	765	765	782	782	782	782	782	765	765	765	765
University of Florida Cogen	36	36	44	44	44	44	44	36	36	36	36	36	36	36	44	44	44	44	44	36	36	36	36
Baseload Contracts (Firm Purchase Capacity)																							
UPS Purchase from Southern Company	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409	409
TECO Purchase for Sebring Load	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
QF Contracts																							
PINELLAS CO RES REC 1	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
PINELLAS CO RES REC 2	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
TIMBER ENERGY 1	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
BAY COUNTY RES REC	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
LFC MADISON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LFC JEFFERSON (APP)	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
LAKE COUNTY RES REC	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
PASCO COUNTY RES REC	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
DADE COUNTY RES REC	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43	43
CARGILL	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
LAKE COGEN	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110	110
PASCO COGEN	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
ORLANDO COGEN	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
RIDGE GENERATING STA.	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
EL DORADO (APP)	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114	114
ROYSTER (PPP)	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31	31
MULBERRY (PPP)	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
CFR-BIOGEN (ORANGE CO)	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74	74
US AGRICHEM	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Intermediate Resources (Summer and Winter Base Ratings)																							
Anclote 1	507	507	512	512	512	512	512	507	507	507	507	507	507	507	512	512	512	512	512	507	507	507	507
Anclote 2	502	502	522	522	522	522	522	502	502	502	502	502	502	502	522	522	522	522	522	502	502	502	502
Bartow 1	113	113	116	116	116	116	116	113	113	113	113	113	113	113	116	116	116	116	116	113	113	113	113
Bartow 2	113	113	117	117	117	117	117	113	113	113	113	113	113	113	117	117	117	117	117	113	113	113	113
Bartow 3	207	207	210	210	210	210	210	207	207	207	207	207	207	207	210	210	210	210	210	207	207	207	207
Suwannee River 1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suwannee River 2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Suwannee River 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Tiger Bay Cogen	200	200	240	240	240	240	240	200	200	200	200	200	200	200	240	240	240	240	240	200	200	200	200
Hines Energy Complex 1	470	470	505	505	505	505	505	470	470	470	470	470	470	470	505	505	505	505	505	470	470	470	470
Hines Energy Complex 2	495	495	567	567	567	567	567	495	495	495	495	495	495	495	567	567	567	567	567	495	495	495	495
Hines Energy Complex 3	495	495	567	567	567	567	567	495	495	495	495	495	495	495	567	567	567	567	567	495	495	495	495
Gas Peaking Resources (Summer Base Rating @ 95°F, Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)																							
Avon Park P1	24	24	24	34	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	19	19
Bartow P2	46	46	46	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46
Bartow P4	49	49	49	62	62	62	62	49	49	49	49	49	49	49	49	62	62	62	62	49	49	49	49
Debary P7	76	76	76	98	98	98	98	76	76	72	72	72	76	76	76	98	98	98	98	76	76	72	72
Debary P9	76	76	76	98	98	98	98	76	76	72	72	72	76	76	76	98	98	98	98	76	76	72	72
Higgins P1	25	25	25	34	34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	25	25	24	24
Higgins P2	25	25	25	34	34	34	34	25	25	24	24	24	25	25	25	34	34	34	34	25	25	24	24
Higgins P3	31	31	31	36	36	36	36	31	31	29	29	29	31	31	31	36	36	36	36	31	31	29	29
Higgins P4	31	31	31	36	36	36	36	31	31	29	29	29	31	31	31	36	36	36	36	31	31	29	29

FPC 107

	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	May-08	Jun-08	Jul-08	Aug-08	Sep-08	Oct-08	Nov-08	Dec-08	Jan-09	Feb-09	Mar-09	Apr-09	May-09	Jun-09	Jul-09
Intercession City P7	83	83	83	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84
Intercession City P8	83	83	83	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84
Intercession City P9	83	83	83	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84
Intercession City P10	83	83	83	98	98	98	98	83	83	84	84	84	83	83	83	98	98	98	98	83	83	84	84
Intercession City P12	83	83	83	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83
Intercession City P13	83	83	83	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83
Intercession City P14	83	83	83	99	99	99	99	83	83	83	83	83	83	83	83	99	99	99	99	83	83	83	83
Suwannee River P1	49	49	49	68	68	68	68	49	49	44	44	44	49	49	49	68	68	68	68	49	49	44	44
Suwannee River P3	49	49	49	68	68	68	68	49	49	44	44	44	49	49	49	68	68	68	68	49	49	44	44
<u>*Light Oil Peaking Resources (Summer Base Rating @ 95°F, Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)*</u>																							
Avon Park P2	24	24	24	34	34	34	34	24	24	19	19	19	24	24	24	34	34	34	34	24	24	19	19
Bartow P1	46	46	46	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46
Bartow P3	46	46	46	54	54	54	54	46	46	46	46	46	46	46	46	54	54	54	54	46	46	46	46
Bayboro P1	44	44	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41
Bayboro P2	44	44	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41
Bayboro P3	44	44	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41
Bayboro P4	44	44	44	60	60	60	60	44	44	41	41	41	44	44	44	60	60	60	60	44	44	41	41
Debary P1	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44
Debary P2	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44
Debary P3	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44
Debary P4	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44
Debary P5	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44
Debary P6	49	49	49	67	67	67	67	49	49	44	44	44	49	49	49	67	67	67	67	49	49	44	44
Debary P8	76	76	76	96	96	96	96	76	76	72	72	72	76	76	76	96	96	96	96	76	76	72	72
Debary P10	76	76	76	96	96	96	96	76	76	72	72	72	76	76	76	96	96	96	96	76	76	72	72
Intercession City P1	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47
Intercession City P2	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47
Intercession City P3	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47
Intercession City P4	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47
Intercession City P5	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47
Intercession City P6	47	47	47	62	62	62	62	47	47	47	47	47	47	47	47	62	62	62	62	47	47	47	47
Intercession City P11	0	143	143	172	172	172	172	143	143	0	0	0	0	143	143	172	172	172	172	143	143	0	0
Rio Pinar P1	13	13	13	19	19	19	19	13	13	11	11	11	13	13	13	19	19	19	19	13	13	11	11
Suwannee River P2	51	51	51	68	68	68	68	68	51	48	48	48	51	51	51	68	68	68	68	68	51	48	48
Turner P1	13	13	13	19	19	19	19	19	13	11	11	11	13	13	13	19	19	19	19	19	13	11	11
Turner P2	13	13	13	19	19	19	19	19	13	11	11	11	13	13	13	19	19	19	19	19	13	11	11
Turner P3	61	61	61	84	84	84	84	84	61	57	57	57	61	61	61	84	84	84	84	84	61	57	57
Turner P4	61	61	61	84	84	84	84	84	61	57	57	57	61	61	61	84	84	84	84	84	61	57	57
<u>*Total Baseload Plants*</u>	3,127	3,127	3,208	3,208	3,208	3,208	3,208	3,127	3,127	3,127	3,127	3,041	3,127	3,127	3,208	3,208	3,208	3,208	3,208	3,127	3,127	3,127	3,127
<u>*Total Baseload Contracts*</u>	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479	479
<u>*Total QF Contracts*</u>	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831	831
<u>*Total Intermediate Resources*</u>	3,102	3,102	3,356	3,356	3,356	3,356	3,356	3,102	3,102	3,102	3,102	3,102	3,102	3,102	3,356	3,356	3,356	3,356	3,356	3,102	3,102	3,102	3,102
<u>*Total Gas Peaking Resources*</u>	1,062	1,062	1,062	1,311	1,311	1,311	1,311	1,062	1,062	1,038	1,038	1,038	1,062	1,062	1,062	1,311	1,311	1,311	1,311	1,062	1,062	1,038	1,038
<u>*Total Light Oil Peaking Resources*</u>	1,232	1,375	1,375	1,813	1,813	1,813	1,813	1,450	1,375	1,160	1,160	1,160	1,232	1,375	1,375	1,813	1,813	1,813	1,813	1,450	1,375	1,160	1,160
<u>*Total Available Resources*</u>	9,833	9,976	10,311	10,998	10,998	10,998	10,998	10,051	9,976	9,738	9,738	9,652	9,833	9,976	10,311	10,998	10,998	10,998	10,998	10,051	9,976	9,738	9,738

FPC 108

	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09		Comments	
Baseload Plants (Summer and Winter Base Ratings)								
Crystal River 1	312	398	398	403	403		Derated by 86 MW in August due to POD Limitation. Turbine upgrade 12/01	
Crystal River 2	493	493	493	504	504		Turbine upgrade 4/00	
Crystal River 4	721	721	721	741	741		Turbine upgrade 4/00	
Crystal River 5	714	714	714	734	734		Turbine upgrade 5/99	
Crystal River 3	765	765	765	782	782		Turbine upgrade 10/99	
University of Florida Cogen	36	36	36	44	44			
Baseload Contracts (Firm Purchase Capacity)								
UPS Purchase from Southern Company	409	409	409	409	409			
TECO Purchase for Sebring Load	70	70	70	70	70			
QF Contracts								
PINELLAS CO RES REC 1	40	40	40	40	40		4/1/83	Contract
PINELLAS CO RES REC 2	15	15	15	15	15		6/1/86	Contract
TIMBER ENERGY 1	13	13	13	13	13		7/1/86	Contract
BAY COUNTY RES REC	11	11	11	11	11		4/1/88	Contract
LFC MADISON (APP)	9	9	9	9	9		9/1/89	Contract
LFC JEFFERSON (APP)	9	9	9	9	9		6/1/90	Contract
LAKE COUNTY RES REC	13	13	13	13	13		9/1/90	Contract
PASCO COUNTY RES REC	23	23	23	23	23		3/1/91	Contract
DADE COUNTY RES REC	43	43	43	43	43		11/1/91	Contract
CARGILL	15	15	15	15	15		10/1/92	Contract
LAKE COGEN	110	110	110	110	110		7/1/93	Contract
PASCO COGEN	109	109	109	109	109		7/1/93	Contract
ORLANDO COGEN	79	79	79	79	79		10/1/93.	Contract
RIDGE GENERATING STA.	40	40	40	40	40		5/1/94	Contract
EL DORADO (APP)	114	114	114	114	114		7/1/94	Contract
ROYSTER (PPP)	31	31	31	31	31		7/1/94	Contract
MULBERRY (PPP)	79	79	79	79	79		7/1/94	Contract
CFR-BIOGEN (ORANGE CO)	74	74	74	74	74		6/1/95	Contract
US AGRICHEM	6	6	6	6	6		1/1/97	Contract
Intermediate Resources (Summer and Winter Base Ratings)								
Anclote 1	507	507	507	512	512			
Anclote 2	502	502	502	522	522			
Bartow 1	113	113	113	116	116			
Bartow 2	113	113	113	117	117			
Bartow 3	207	207	207	210	210			
Suwannee River 1	0	0	0	0	0		Unit Retirement 11/03	
Suwannee River 2	0	0	0	0	0		Unit Retirement 11/03	
Suwannee River 3	0	0	0	0	0		Unit Retirement 11/03	
Tiger Bay Cogen	200	200	200	240	240			
Hines Energy Complex 1	470	470	470	505	505			
Hines Energy Complex 2	495	495	495	567	567		Unit Addition 11/03	
Hines Energy Complex 3	495	495	495	567	567		Unit Addition 11/06	
Gas Peaking Resources (Summer Base Rating @ 95°F, Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)								
Avon Park P1	19	24	24	24	34			
Bartow P2	46	46	46	46	54			
Bartow P4	49	49	49	49	62			
Debary P7	72	76	76	76	98		Inlet fogging installed 5/00 (Jun, Jul & Aug)	
Debary P9	72	76	76	76	98		Inlet fogging installed 5/00 (Jun, Jul & Aug)	
Higgins P1	24	25	25	25	34			
Higgins P2	24	25	25	25	34			
Higgins P3	29	31	31	31	36			
Higgins P4	29	31	31	31	36			

FPC 109

	Aug-09	Sep-09	Oct-09	Nov-09	Dec-09		Comments
Intercession City P7	84	83	83	83	98		Inlet fogging (Jun, Jul & Aug)
Intercession City P8	84	83	83	83	98		Inlet fogging (Jun, Jul & Aug)
Intercession City P9	84	83	83	83	98		Inlet fogging (Jun, Jul & Aug)
Intercession City P10	84	83	83	83	98		Inlet fogging (Jun, Jul & Aug)
Intercession City P12	83	83	83	83	99		Commercial operation 12/00
Intercession City P13	83	83	83	83	99		Commercial operation 12/00
Intercession City P14	83	83	83	83	99		Commercial operation 12/00
Suwannee River P1	44	49	49	49	68		
Suwannee River P3	44	49	49	49	68		
Light Oil Peaking Resources (Summer Base Rating @ 95°F, Spring/Fall Base Rating @ 90°F, Winter Peak Rating @ 32°F)							
Avon Park P2	19	24	24	24	34		
Bartow P1	46	46	46	46	54		
Bartow P3	46	46	46	46	54		
Bayboro P1	41	44	44	44	60		
Bayboro P2	41	44	44	44	60		
Bayboro P3	41	44	44	44	60		
Bayboro P4	41	44	44	44	60		
Debary P1	44	49	49	49	67		
Debary P2	44	49	49	49	67		
Debary P3	44	49	49	49	67		
Debary P4	44	49	49	49	67		
Debary P5	44	49	49	49	67		
Debary P6	44	49	49	49	67		
Debary P8	72	76	76	76	96		Inlet fogging installed 5/00 (Jun, Jul & Aug)
Debary P10	72	76	76	76	96		Inlet fogging installed 5/00 (Jun, Jul & Aug)
Intercession City P1	47	47	47	47	62		
Intercession City P2	47	47	47	47	62		
Intercession City P3	47	47	47	47	62		
Intercession City P4	47	47	47	47	62		
Intercession City P5	47	47	47	47	62		
Intercession City P6	47	47	47	47	62		
Intercession City P11	0	0	143	143	172		Southern summer ownership (Jun through Sep)
Rio Pinar P1	11	13	13	13	19		
Suwannee River P2	48	51	51	51	68		
Turner P1	11	13	13	13	19		
Turner P2	11	13	13	13	19		
Turner P3	57	61	61	61	84		
Turner P4	57	61	61	61	84		
Total Baseload Plants	3,041	3,127	3,127	3,208	3,208		
Total Baseload Contracts	479	479	479	479	479		
Total QF Contracts	831	831	831	831	831		
Total Intermediate Resources	3,102	3,102	3,102	3,356	3,356		
Total Gas Peaking Resources	1,038	1,062	1,062	1,062	1,311		
Total Light Oil Peaking Resources	1,160	1,232	1,375	1,375	1,813		
Total Available Resources	9,652	9,833	9,976	10,311	10,995		

FPC 110

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY
1999 SERC RATINGS, COGENERATION = 981231
JUNE 1999 FORECAST (S990503)
Bulk Power Sales Included in Demand & Energy Forecast

Hines 2 in 11/2003 : Normal Weather Analysis with Capacity @ "Base" Ratings

		WINTER 99/00 Jan-2000	WINTER 00/01 Jan-2001	WINTER 01/02 Jan-2002	WINTER 02/03 Jan-2003	WINTER 03/04 Jan-2004	WINTER 04/05 Jan-2005	WINTER 05/06 Jan-2006	WINTER 06/07 Jan-2007	WINTER 07/08 Jan-2008	WINTER 08/09 Jan-2009
Existing FPC Capacity	MW	8,351	8,351	8,689	8,706	8,706	9,121	9,121	9,121	9,688	9,688
New FPC Capacity	MW	0	338	17	0	567	0	0	567	0	0
Retired FPC Capacity	MW	0	0	0	0	152	0	0	0	0	0
Total Installed Capacity	MW	8,351	8,689	8,706	8,706	9,121	9,121	9,121	9,688	9,688	9,688
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831	831
QF Contractually-Allowed On-Peak Capacity Reduction	MW	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	9,545	9,883	9,900	9,900	10,315	10,325	10,325	10,892	10,892	10,892
Potential Total Retail Demand	MW	8,330	8,488	8,654	8,823	8,985	9,150	9,314	9,479	9,644	9,810
Wholesale (REA)	MW	779	870	893	433	461	486	513	540	566	592
Wholesale (Bulk Power)	MW	631	631	167	167	167	167	167	167	167	167
Wholesale (Municipal)	MW	220	189	130	99	94	19	11	11	11	11
Total Wholesale Demand	MW	1,630	1,690	1,190	699	722	672	691	718	744	770
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	9,990	10,208	9,874	9,552	9,737	9,852	10,035	10,227	10,418	10,610
Non-Dispatchable DSM and Self-Service QF	MW	399	424	450	478	508	538	569	599	628	657
Normal Weather Demand (Before Load Control)	**MW**	**9,591**	**9,784**	**9,424**	**9,074**	**9,229**	**9,314**	**9,466**	**9,628**	**9,790**	**9,953**
Normal Weather Reserves (Before Load Control)	MW	-46	99	476	826	1,086	1,011	859	1,264	1,102	939
Normal Weather Reserve Margin (Before Load Control)	**%**	**-0.5%**	**1.0%**	**5.1%**	**9.1%**	**11.8%**	**10.9%**	**9.1%**	**13.1%**	**11.3%**	**9.4%**
Normal Weather Load Management	MW	758	736	680	646	626	611	599	589	580	572
Normal Weather Demand (After Load Management)	MW	8,833	9,048	8,744	8,428	8,603	8,703	8,867	9,039	9,210	9,381
Normal Weather Reserves (After Load Management)	MW	712	835	1,156	1,472	1,712	1,622	1,458	1,853	1,682	1,511
Normal Weather Reserve Margin (After Load Management)	%	8.1%	9.2%	13.2%	17.5%	19.9%	18.6%	16.4%	20.5%	18.3%	16.1%
Normal Weather Interruptible Load	MW	326	314	311	313	310	312	314	316	318	320
Normal Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After All Load Control)	**MW**	**8,507**	**8,734**	**8,433**	**8,115**	**8,293**	**8,391**	**8,553**	**8,723**	**8,892**	**9,061**
Normal Weather Reserves (After All Load Control)	MW	1,038	1,149	1,467	1,785	2,022	1,934	1,772	2,169	2,000	1,831
Normal Weather Reserve Margin (After All Load Control)	**%**	**12.2%**	**13.2%**	**17.4%**	**22.0%**	**24.4%**	**23.0%**	**20.7%**	**24.9%**	**22.5%**	**20.2%**
Normal Weather Reserves (After All Load Control) Required For 15 %	MW	1,276	1,310	1,265	1,217	1,244	1,259	1,283	1,309	1,334	1,359
Normal Weather Reserves (After All Load Control) Above 15 %	MW	-238	-161	202	568	778	675	489	860	666	472
Normal Weather "DLC" Reserve Margin Contribution	%	104.4%	91.4%	67.6%	53.7%	46.3%	47.7%	51.5%	41.7%	44.9%	48.7%

FPC 111

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY
1999 SERC RATINGS, COGENERATION = 981231
JUNE 1999 FORECAST (S990503)
Bulk Power Sales Included in Demand & Energy Forecast

Hines 2 in 11/2003 : Normal Weather Analysis with Capacity @ "Base" Ratings

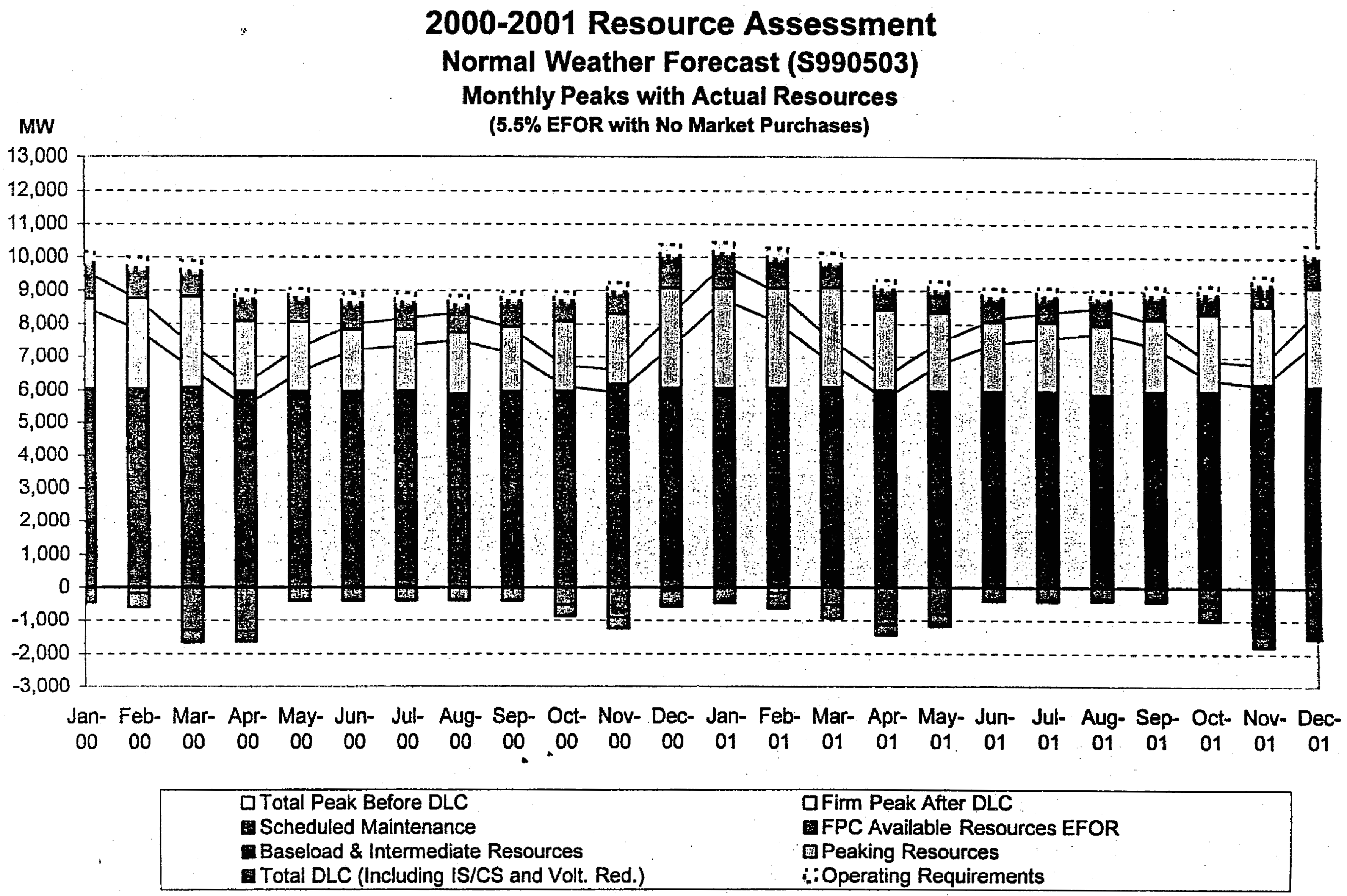
		SUMMER 00 Aug-2000	SUMMER 01 Aug-2001	SUMMER 02 Aug-2002	SUMMER 03 Aug-2003	SUMMER 04 Aug-2004	SUMMER 05 Aug-2005	SUMMER 06 Aug-2006	SUMMER 07 Aug-2007	SUMMER 08 Aug-2008	SUMMER 09 Aug-2009
Existing FPC Capacity	MW	7,236	7,236	7,485	7,502	7,502	7,847	7,847	7,847	8,342	8,342
New FPC Capacity	MW	0	249	17	0	495	0	0	495	0	0
Retired FPC Capacity	MW	0	0	0	0	150	0	0	0	0	0
Total Installed Capacity	MW	7,236	7,485	7,502	7,502	7,847	7,847	7,847	8,342	8,342	8,342
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831	831
QF Contractually-Allowed On-Peak Capacity Reduction	MW	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	8,430	8,679	8,696	8,696	9,041	9,051	9,051	9,546	9,546	9,546
Potential Total Retail Demand	MW	7,396	7,555	7,721	7,890	8,052	8,218	8,384	8,551	8,717	8,885
Wholesale (REA)	MW	392	465	472	0	6	15	25	33	42	51
Wholesale (Bulk Power)	MW	631	631	167	167	167	167	167	167	167	167
Wholesale (Municipal)	MW	232	180	134	88	88	18	11	11	11	11
Total Wholesale Demand	MW	1,255	1,276	773	255	261	200	203	211	220	229
Company Use	MW	30	30	30	30	30	30	30	30	30	30
Potential Total System Demand	MW	8,681	8,861	8,524	8,175	8,343	8,448	8,617	8,792	8,967	9,144
Non-Dispatchable DSM and Self-Service QF	MW	353	366	379	393	408	423	439	454	468	483
Normal Weather Demand (Before Load Control)	**MW**	**8,328**	**8,495**	**8,145**	**7,782**	**7,935**	**8,025**	**8,178**	**8,338**	**8,499**	**8,661**
Normal Weather Reserves (Before Load Control)	MW	102	184	551	914	1,106	1,026	873	1,208	1,047	885
Normal Weather Reserve Margin (Before Load Control)	**%**	**1.2%**	**2.2%**	**6.8%**	**11.7%**	**13.9%**	**12.8%**	**10.7%**	**14.5%**	**12.3%**	**10.2%**
Normal Weather Load Management	MW	492	447	389	349	318	291	267	247	229	214
Normal Weather Demand (After Load Management)	MW	7,836	8,048	7,756	7,433	7,617	7,734	7,911	8,091	8,270	8,447
Normal Weather Reserves (After Load Management)	MW	593	631	940	1,263	1,424	1,317	1,140	1,454	1,276	1,099
Normal Weather Reserve Margin (After Load Management)	%	7.6%	7.8%	12.1%	17.0%	18.7%	17.0%	14.4%	18.0%	15.4%	13.0%
Normal Weather Interruptible Load	MW	327	315	312	314	311	313	315	317	319	321
Normal Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Normal Weather Demand (After All Load Control)	**MW**	**7,509**	**7,733**	**7,444**	**7,119**	**7,306**	**7,421**	**7,596**	**7,774**	**7,951**	**8,126**
Normal Weather Reserves (After All Load Control)	MW	920	946	1,252	1,577	1,735	1,630	1,455	1,771	1,595	1,420
Normal Weather Reserve Margin (After All Load Control)	**%**	**12.3%**	**12.2%**	**16.8%**	**22.2%**	**23.7%**	**22.0%**	**19.2%**	**22.8%**	**20.1%**	**17.5%**
Normal Weather Reserves (After All Load Control) Required For 20 %	MW	1,502	1,547	1,489	1,424	1,461	1,484	1,519	1,555	1,590	1,625
Normal Weather Reserves (After All Load Control) Above 20 %	MW	-581	-601	-237	153	274	145	-64	217	5	-206
Normal Weather "DLC" Reserve Margin Contribution	%	89.0%	80.6%	56.0%	42.1%	36.3%	37.1%	40.0%	31.8%	34.4%	37.7%

FPC 112

Normal Weather

	Month	Scheduled Maintenance	Baseload Plants	Baseload Contracts	QF Contracts	Intermediate Resources	Baseload & Intermediate Resources	Peaking Resources	Total Resources	QF On-Peak Reduction	Baseload & Intermediate Resources	Peaking Resources	Operating Requirements	6.5% FPC Available Resources EFOR	8.7% FPC Available Resources EFOR	Total Peak Before DLC	Supply Variance	Supply Reserve Margin	Total DLC (Including IS/CS and Vol. Red.)	Firm Peak After DLC	Total Variance	Total Reserve Margin
1	Jan-00	0	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,033	2,712	341	-458	-819	9,591	60	0.63%	1,084	8,507	1,144	13.45%
2	Feb-00	-162	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,038	2,714	341	-450	-794	8,743	748	8.53%	909	7,834	1,855	21.12%
3	Mar-00	-1,299	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,046	2,730	341	-388	-684	7,383	968	13.12%	745	6,634	1,714	25.82%
4	Apr-00	-1,332	3,069	469	831	2,262	6,631	2,188	8,819	-106	5,978	2,103	291	-340	-600	6,180	1,307	21.15%	653	5,527	1,860	35.45%
5	May-00	0	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,963	2,084	291	-416	-733	7,252	1,608	22.17%	727	6,525	2,335	35.78%
6	Jun-00	0	3,110	469	831	2,262	6,672	1,950	8,622	-106	5,973	1,849	291	-403	-710	7,991	631	7.88%	800	7,191	1,430	19.89%
7	Jul-00	0	3,110	469	831	2,262	6,672	1,950	8,622	-106	5,973	1,849	291	-403	-710	8,176	446	5.45%	817	7,359	1,262	17.15%
8	Aug-00	0	3,024	469	831	2,262	6,586	1,950	8,536	-106	5,881	1,850	291	-398	-702	8,328	208	2.49%	819	7,509	1,026	13.67%
9	Sep-00	0	3,110	469	831	2,262	6,672	2,045	8,717	-106	5,968	1,943	291	-406	-719	7,883	834	10.58%	766	7,117	1,800	22.49%
10	Oct-00	-487	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,983	2,091	291	-349	-666	6,734	1,839	24.34%	809	6,125	2,248	36.70%
11	Nov-00	-864	3,191	469	831	2,374	6,865	2,188	9,053	-106	6,165	2,094	291	-378	-666	6,608	1,561	23.62%	675	5,933	2,236	37.68%
12	Dec-00	-115	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,064	3,006	341	-472	-832	8,270	1,604	19.40%	874	7,296	2,578	35.33%
13	Jan-01	0	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,060	3,005	341	-478	-843	8,784	205	2.10%	1,050	8,734	1,255	14.37%
14	Feb-01	-167	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,066	3,007	341	-468	-827	8,838	884	9.80%	878	8,062	1,760	21.83%
15	Mar-01	-501	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,060	3,011	341	-450	-794	7,539	1,948	25.85%	715	6,824	2,664	38.05%
16	Apr-01	-1,096	3,110	469	831	2,262	6,672	2,512	9,184	-106	5,995	2,419	291	-373	-658	6,383	1,705	26.71%	617	5,766	2,322	40.28%
17	May-01	-806	3,110	469	831	2,262	6,672	2,437	9,109	-106	5,988	2,341	291	-385	-679	7,448	855	11.48%	683	6,765	1,538	22.74%
18	Jun-01	0	3,110	469	831	2,262	6,672	2,199	8,871	-106	5,963	2,095	291	-416	-734	8,148	723	8.87%	747	7,401	1,470	19.86%
19	Jul-01	0	3,110	469	831	2,262	6,672	2,199	8,871	-106	5,963	2,095	291	-416	-734	8,340	531	6.36%	762	7,578	1,292	17.05%
20	Aug-01	0	3,024	469	831	2,262	6,586	2,199	8,785	-106	5,888	2,096	291	-412	-726	8,495	290	3.41%	762	7,733	1,052	13.60%
21	Sep-01	0	3,110	469	831	2,262	6,672	2,294	8,966	-106	5,958	2,189	291	-422	-744	8,039	927	11.53%	712	7,327	1,639	22.37%
22	Oct-01	-628	3,110	469	831	2,262	6,672	2,437	9,109	-106	5,978	2,338	291	-395	-697	6,889	1,582	22.83%	500	6,330	2,151	33.87%
23	Nov-01	-1,467	3,191	469	831	2,374	6,865	2,437	9,302	-106	6,198	2,347	291	-359	-634	6,781	1,054	15.54%	641	6,140	1,695	27.81%
24	Dec-01	-1,152	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,107	3,020	341	-415	-731	8,432	405	4.80%	918	7,514	1,323	17.61%
25	Jan-02	0	3,208	469	831	2,374	6,882	3,124	10,006	-106	6,076	3,004	341	-479	-844	9,424	542	6.18%	901	8,423	1,573	18.65%
26	Feb-02	0	3,208	469	831	2,374	6,882	3,124	10,006	-106	6,076	3,004	341	-479	-844	8,681	1,325	15.26%	831	7,850	2,156	27.47%
27	Mar-02	-841	3,208	469	831	2,374	6,882	3,124	10,006	-106	6,115	3,017	341	-427	-753	7,297	1,766	24.23%	685	6,612	2,453	37.08%
28	Apr-02	-1,101	3,127	469	831	2,262	6,689	2,512	9,201	-106	6,012	2,419	291	-374	-660	6,130	1,970	32.14%	575	5,555	2,545	45.82%
29	May-02	-484	3,127	469	831	2,262	6,689	2,437	9,126	-106	5,949	2,336	291	-404	-712	7,166	1,478	20.60%	632	6,534	2,108	32.28%
30	Jun-02	0	3,127	469	831	2,262	6,689	2,199	8,888	-106	5,979	2,094	291	-417	-738	7,787	1,101	14.13%	685	7,102	1,766	25.15%
31	Jul-02	0	3,127	469	831	2,262	6,689	2,199	8,888	-106	5,979	2,094	291	-417	-736	7,988	900	11.26%	700	7,288	1,599	21.94%
32	Aug-02	0	3,041	469	831	2,262	6,603	2,199	8,802	-106	5,897	2,095	291	-413	-728	8,145	657	8.06%	701	7,444	1,358	18.24%
33	Sep-02	0	3,127	469	831	2,262	6,689	2,294	8,983	-106	5,875	2,188	291	-423	-745	7,640	1,303	16.87%	658	7,021	1,962	27.85%
34	Oct-02	-601	3,127	469	831	2,262	6,689	2,437	9,126	-106	5,994	2,338	291	-387	-701	6,568	1,838	28.38%	538	6,051	2,474	40.88%
35	Nov-02	-708	3,208	469	831	2,374	6,882	2,437	9,319	-106	6,183	2,336	291	-402	-709	6,540	2,071	31.67%	621	5,919	2,662	45.48%
36	Dec-02	-712	3,208	469	831	2,374	6,882	3,124	10,006	-106	6,105	3,014	341	-440	-775	8,102	1,182	14.71%	884	7,218	2,076	28.78%
37	Jan-03	0	3,208	469	831	2,374	6,882	3,124	10,006	-106	6,076	3,004	341	-479	-844	9,074	932	10.27%	959	8,115	1,891	23.30%
38	Feb-03		3,208	469	831	2,374	6,882	3,124	10,006	-106	6,076	3,004	341	-479	-844	8,321	1,685	20.25%	809	7,512	2,494	33.20%
39	Mar-03		3,208	469	831	2,374	6,882	3,124	10,006	-106	6,076	3,004	341	-479	-844	7,024	2,982	42.45%	670	6,354	3,652	57.48%
40	Apr-03		3,127	469	831	2,262	6,689	2,512	9,201	-106	5,966	2,403	291	-435	-766	6,115	3,086	50.47%	551	5,564	3,637	65.36%
41	May-03		3,127	469	831	2,262	6,689	2,437	9,126	-106	5,969	2,329	291	-430	-759	6,974	2,152	30.86%	601	6,373	2,753	43.18%
42	Jun-03		3,127	469	831	2,262	6,689	2,199	8,888	-106	5,979	2,094	291	-417	-736	7,538	1,350	17.90%	649	6,889	1,999	29.01%
43	Jul-03		3,127	469	831	2,262	6,689	2,199	8,888	-106	5,979	2,094	291	-417	-736	7,671	1,217	15.86%	661	7,010	1,876	26.79%
44	Aug-03	0	3,041	469	831	2,262	6,603	2,199	8,802	-106	5,887	2,095	291	-413	-728	7,732	1,020	13.10%	663	7,118	1,683	23.64%
45	Sep-03		3,127	469	831	2,262	6,689	2,294	8,983	-106	5,975	2,188	291	-423	-745	7,482	1,501	20.06%	627	6,855	2,128	31.05%
46	Oct-03		3,127	469	831	2,262	6,689	2,437	9,126	-106	5,969	2,329	291	-430	-759	6,631	2,495	37.63%	521	6,110	3,016	49.36%
47	Nov-03		3,208	469	831	2,789	7,297	2,437	9,734	-106	6,552	2,321	291	-464	-818	6,355	3,378	53.17%	614	5,741	3,993	69.64%
48	Dec-03		3,208	469	831	2,789	7,297	3,124	10,421	-106	6,474	2,999	341	-502	-885	7,712	2,709	35.13%	867	6,845	3,578	52.25%
49	Jan-04	0	3,208	469	831	2,789	7,297	3,124	10,421	-106	6,474	2,999	341	-502	-885	9,229	1,192	12.92%	936	8,293	2,128	25.66%
50	Feb-04		3,208	469	831	2,789	7,297	3,124	10,421	-106	6,474	2,999	341	-502	-885	8,470	1,951	23.03%	791	7,679	2,742	35.71%
51	Mar-04		3,208	469	831	2,789	7,297	3,124	10,421	-106	6,474	2,999	341	-502	-885	7,125	3,296	46.26%	658	6,467	3,954	61.14%
52	Apr-04		3,127	469	831	2,607	7,034	2,512	9,546	-106	6,287	2,399	291	-454	-800	6,224	3,322	53.37%	529	5,695	3,851	67.62%
53	May-04		3,127	469	831	2,607	7,034	2,437	9,471	-106	6,300	2,325	291	-449	-793	7,103	2,368	33.34%	574	6,529	2,942	45.05%
54	Jun-04		3,127	469	831	2,607	7,034	2,199	9,233	-106	6,310	2,090	291	-434	-769	7,660	1,553	20.22%	615	7,065	2,188	30.69%
55	Jul-04		3,127	469	831	2,112	6,539	2,199	8,738	-106	5,835	2,098	291	-409	-721	7,816	822	11.79%	627	7,189	1,549	21.55%
56	Aug-04	0	3,041	469	831	2,607	6,948	2,199	9,147	-106	6,227	2,081	291	-432	-761	7,935	1,212	15.27%	629	7,306	1,841	25.19%
57	Sep-04		3,127	469	831	2,607	7,034	2,294	9,328	-106	6,306	2,184	291	-442	-779	7,624	1,704	22.35%	597	7,027	2,301	32.75%
58	Oct-04		3,127	469	831	2,607	7,034	2,437	9,471	-106	6,300	2,325	291	-449	-793	6,755	2,716	40.21%	503	6,252	3,219	51.49%
59	Nov-04		3,208	469	831	2,789	7,297	2,437	9,734	-106	6,552	2,321	291	-464	-818	6,446	3,288	51.01%	604	5,842	3,892	66.63%

60	Dec-04		3,208	469	831	2,789	7,297	3,124	10,421	-106	6,474	2,989	341	-502	-885	7,831	2,580	33.07%	850	6,981	3,440	49.27%
61	Jan-05	0	3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,999	341	-502	-885	9,314	1,117	11.99%	923	8,391	2,040	24.31%
62	Feb-05		3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,999	341	-502	-885	8,543	1,888	22.10%	782	7,761	2,670	34.41%
63	Mar-05		3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,999	341	-502	-885	7,174	3,257	45.40%	653	6,521	3,910	59.96%
64	Apr-05		3,127	479	831	2,607	7,044	2,512	9,556	-106	6,307	2,399	291	-454	-800	6,287	3,269	52.00%	515	5,772	3,784	65.55%
65	May-05		3,127	479	831	2,607	7,044	2,437	9,481	-106	6,310	2,325	291	-449	-793	7,177	2,304	32.10%	555	6,622	2,858	43.16%
66	Jun-05		3,127	479	831	2,607	7,044	2,199	9,243	-106	6,320	2,090	291	-436	-768	7,759	1,484	19.12%	593	7,166	2,076	28.97%
67	Jul-05		3,127	479	831	2,607	7,044	2,199	9,243	-106	6,320	2,090	291	-436	-768	7,897	1,346	17.04%	602	7,295	1,948	26.70%
68	Aug-05	0	3,041	479	831	2,607	6,958	2,199	9,157	-106	6,237	2,091	291	-432	-761	8,025	1,132	14.10%	604	7,421	1,736	23.39%
69	Sep-05		3,127	479	831	2,607	7,044	2,294	9,338	-106	6,318	2,184	291	-442	-779	7,703	1,635	21.23%	576	7,127	2,211	31.02%
70	Oct-05		3,127	479	831	2,607	7,044	2,437	9,481	-106	6,310	2,325	291	-449	-793	6,824	2,657	38.94%	492	6,332	3,149	49.73%
71	Nov-05		3,208	479	831	2,789	7,307	2,437	9,744	-106	6,562	2,321	291	-484	-818	6,485	3,259	50.25%	601	5,884	3,860	65.61%
72	Dec-05		3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,999	341	-502	-885	7,890	2,541	32.21%	842	7,048	3,383	48.01%
73	Jan-06	0	3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,999	341	-502	-885	9,466	965	10.19%	913	8,553	1,878	21.95%
74	Feb-06		3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,999	341	-502	-885	8,684	1,747	20.12%	776	7,908	2,523	31.91%
75	Mar-06		3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,999	341	-502	-885	7,273	3,158	43.42%	650	6,623	3,808	57.49%
76	Apr-06		3,127	479	831	2,607	7,044	2,512	9,556	-106	6,307	2,399	291	-454	-800	6,398	3,158	49.36%	503	5,895	3,661	62.10%
77	May-06		3,127	479	831	2,607	7,044	2,437	9,481	-106	6,310	2,325	291	-449	-793	7,304	2,177	29.81%	538	6,766	2,715	40.13%
78	Jun-06		3,127	479	831	2,607	7,044	2,199	9,243	-106	6,320	2,090	291	-436	-768	7,897	1,346	17.04%	572	7,325	1,918	26.18%
79	Jul-06		3,127	479	831	2,607	7,044	2,199	9,243	-106	6,320	2,090	291	-436	-768	8,039	1,204	14.97%	581	7,458	1,784	23.93%
80	Aug-06	0	3,041	479	831	2,607	6,958	2,199	9,157	-106	6,237	2,091	291	-432	-761	8,178	979	11.97%	582	7,596	1,561	20.55%
81	Sep-06		3,127	479	831	2,607	7,044	2,294	9,338	-106	6,318	2,184	291	-442	-779	7,841	1,497	19.09%	557	7,284	2,054	28.21%
82	Oct-06		3,127	479	831	2,607	7,044	2,437	9,481	-106	6,310	2,325	291	-448	-793	6,946	2,535	36.50%	483	6,463	3,018	46.70%
83	Nov-06		3,208	479	831	3,356	7,874	2,437	10,311	-106	7,106	2,313	291	-495	-873	6,573	3,738	56.87%	600	5,973	4,338	72.62%
84	Dec-06		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	8,007	2,991	37.35%	835	7,172	3,826	53.35%
85	Jan-07	0	3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	9,628	1,370	14.23%	905	8,723	2,275	26.08%
86	Feb-07		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	8,833	2,165	24.51%	771	8,062	2,936	36.42%
87	Mar-07		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	7,380	3,618	49.02%	648	6,732	4,266	63.36%
88	Apr-07		3,127	479	831	3,102	7,539	2,512	10,051	-106	6,781	2,392	291	-481	-848	6,516	3,535	54.25%	493	6,023	4,028	66.88%
89	May-07		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	7,440	2,536	34.09%	525	6,915	3,061	44.26%
90	Jun-07		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,045	1,693	21.04%	555	7,490	2,247	30.00%
91	Jul-07		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,188	1,550	18.93%	563	7,625	2,112	27.70%
92	Aug-07	0	3,041	479	831	3,102	7,453	2,199	9,652	-106	6,712	2,084	291	-458	-808	8,338	1,314	15.75%	564	7,774	1,877	24.15%
93	Sep-07		3,127	479	831	3,102	7,539	2,294	9,833	-106	6,790	2,177	291	-469	-827	7,986	1,847	23.13%	542	7,444	2,389	32.09%
94	Oct-07		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	7,074	2,902	41.02%	478	6,596	3,378	51.19%
95	Nov-07		3,208	479	831	3,356	7,874	2,437	10,311	-106	7,106	2,313	291	-495	-873	6,671	3,640	54.56%	600	6,071	4,240	69.83%
96	Dec-07		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	8,133	2,865	35.23%	830	7,303	3,695	50.59%
97	Jan-08	0	3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	9,780	1,298	12.34%	898	8,882	2,106	23.68%
98	Feb-08		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	8,979	2,019	22.49%	767	8,212	2,786	33.92%
99	Mar-08		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	7,488	3,509	46.86%	646	6,843	4,155	60.72%
100	Apr-08		3,127	479	831	3,102	7,539	2,512	10,051	-106	6,781	2,392	291	-481	-848	6,633	3,418	51.53%	485	6,148	3,903	63.48%
101	May-08		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	7,576	2,400	31.68%	514	7,062	2,914	41.27%
102	Jun-08		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,191	1,547	18.88%	540	7,651	2,087	27.27%
103	Jul-08		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,338	1,400	16.79%	547	7,791	1,947	24.98%
104	Aug-08	0	3,041	479	831	3,102	7,453	2,199	9,652	-106	6,712	2,084	291	-458	-808	8,499	1,153	13.56%	548	7,951	1,701	21.39%
105	Sep-08		3,127	479	831	3,102	7,539	2,294	9,833	-106	6,790	2,177	291	-469	-827	8,132	1,701	20.92%	529	7,603	2,230	29.32%
106	Oct-08		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	7,201	2,775	38.54%	470	6,731	3,245	48.21%
107	Nov-08		3,208	479	831	3,356	7,874	2,437	10,311	-106	7,106	2,313	291	-495	-873	6,768	3,543	52.35%	599	6,169	4,142	67.14%
108	Dec-08		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	8,258	2,738	33.16%	825	7,434	3,564	47.94%
109	Jan-09	0	3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	9,953	1,045	10.50%	892	9,061	1,937	21.38%
110	Feb-09		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	9,130	1,868	20.46%	764	8,366	2,632	31.45%
111	Mar-09		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	7,598	3,400	44.75%	645	6,953	4,045	58.18%
112	Apr-09		3,127	479	831	3,102	7,539	2,512	10,051	-106	6,781	2,392	291	-481	-848	6,753	3,298	48.84%	478	6,275	3,776	60.18%
113	May-09		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	7,713	2,263	29.34%	505	7,208	2,768	38.40%
114	Jun-09		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,339	1,399	16.77%	528	7,811	1,928	24.68%
115	Jul-09		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,488	1,248	14.71%	534	7,955	1,782	22.41%
116	Aug-09	0	3,041	479	831	3,102	7,453	2,199	9,652	-106	6,712	2,084	291	-459	-808	8,661	991	11.44%	535	8,126	1,526	18.77%
117	Sep-09		3,127	479	831	3,102	7,539	2,294	9,833	-106	6,790	2,177	291	-469	-827	8,279	1,554	18.77%	518	7,761	2,072	26.69%
118	Oct-09		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	7,331	2,645	36.08%	465	6,866	3,110	45.30%
119	Nov-09		3,208	479	831	3,356	7,874	2,437	10,311	-106	7,106	2,313	291	-495	-873	6,866	3,445	50.17%	599	6,267	4,044	64.53%
120	Dec-09		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	8,385	2,613	31.16%	821	7,564	3,434	45.40%



2000-2001 Resource Assessment
Normal Weather Forecast (S990503)
Monthly Peaks with Actual Resources
(5.5% EFOR with No Market Purchases)
MW
13,000
12,000
11,000
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
-1,000
-2,000
-3,000
Jan-00
Feb-00
Mar-00
Apr-00
May-00
Jun-00
Jul-00
Aug-00
Sep-00
Oct-00
Nov-00
Dec-00
Jan-01
Feb-01
Mar-01
Apr-01
May-01
Jun-01
Jul-01
Aug-01
Sep-01
Oct-01
Nov-01
Dec-01
Total Peak Before DLC
Firm Peak After DLC
Scheduled Maintenance
FPC Available Resources EFOR
Baseload & Intermediate Resources
Peaking Resources
Total DLC (Including IS/CS and Volt. Red.)
Operating Requirements

JUNE 1999 FORECAST (S990709)

TMY Weather

Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
WINTER 99/00	Jan-2000	9,737	735	23	758	326	1,084	0	8,652	115
WINTER 99/00	Feb-2000	8,413	559	23	583	326	909	0	7,505	105
WINTER 99/00	Mar-2000	6,939	396	23	419	326	745	0	6,194	89
SUMMER 00	Apr-2000	6,202	282	43	326	327	653	0	5,550	77
SUMMER 00	May-2000	7,670	353	47	400	327	727	0	6,942	90
SUMMER 00	Jun-2000	8,129	423	49	473	327	800	0	7,329	99
SUMMER 00	Jul-2000	8,295	440	50	490	327	817	0	7,478	102
SUMMER 00	Aug-2000	8,482	442	50	492	327	819	0	7,663	103
SUMMER 00	Sep-2000	7,728	390	49	439	327	766	0	6,961	97
SUMMER 00	Oct-2000	7,018	236	45	281	328	609	0	6,409	85
WINTER 00/01	Nov-2000	5,971	322	24	347	328	675	0	5,297	81
WINTER 00/01	Dec-2000	7,883	621	25	646	328	974	0	6,909	103
WINTER 00/01	Jan-2001	9,933	710	26	736	314	1,050	0	8,882	117
WINTER 00/01	Feb-2001	8,620	535	26	562	314	876	0	7,745	107
WINTER 00/01	Mar-2001	7,090	376	26	401	314	715	0	6,375	91
SUMMER 01	Apr-2001	6,411	257	46	303	314	617	0	5,793	80
SUMMER 01	May-2001	7,909	319	50	369	314	683	0	7,226	93
SUMMER 01	Jun-2001	8,295	380	52	432	315	747	0	7,548	101
SUMMER 01	Jul-2001	8,479	394	52	447	315	762	0	7,718	104
SUMMER 01	Aug-2001	8,656	395	52	447	315	762	0	7,893	106
SUMMER 01	Sep-2001	7,879	346	52	397	315	712	0	7,167	100
SUMMER 01	Oct-2001	7,196	206	47	254	315	569	0	6,628	87
WINTER 01/02	Nov-2001	6,139	299	27	326	315	641	0	5,498	84
WINTER 01/02	Dec-2001	8,037	576	27	602	316	918	0	7,118	105
WINTER 01/02	Jan-2002	9,588	653	27	680	311	991	0	8,597	114
WINTER 01/02	Feb-2002	8,379	493	27	520	311	831	0	7,548	105
WINTER 01/02	Mar-2002	6,849	346	27	374	311	685	0	6,164	89
SUMMER 02	Apr-2002	6,177	215	49	264	311	575	0	5,601	77
SUMMER 02	May-2002	7,679	268	53	321	311	632	0	7,047	90
SUMMER 02	Jun-2002	7,959	320	54	374	311	685	0	7,274	97
SUMMER 02	Jul-2002	8,161	333	55	388	312	700	0	7,461	100
SUMMER 02	Aug-2002	8,326	334	55	389	312	701	0	7,625	102
SUMMER 02	Sep-2002	7,527	293	54	347	312	659	0	6,868	96
SUMMER 02	Oct-2002	6,906	175	50	226	312	538	0	6,368	84
WINTER 02/03	Nov-2002	5,900	280	29	309	312	621	0	5,279	81
WINTER 02/03	Dec-2002	7,711	541	30	571	313	884	0	6,827	101
WINTER 02/03	Jan-2003	9,247	616	30	646	313	959	0	8,288	110
WINTER 02/03	Feb-2003	8,032	466	30	496	313	809	0	7,223	101
WINTER 02/03	Mar-2003	6,573	327	30	357	313	670	0	5,903	86

FPC 116

JUNE 1999 FORECAST (S990709)

TMY Weather

Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 03	Apr-2003	6,172	186	52	238	313	551	0	5,621	77
SUMMER 03	May-2003	7,533	232	56	288	313	601	0	6,932	88
SUMMER 03	Jun-2003	7,724	278	57	335	314	649	0	7,075	95
SUMMER 03	Jul-2003	7,867	289	58	347	314	661	0	7,205	97
SUMMER 03	Aug-2003	7,977	291	58	349	314	663	0	7,314	98
SUMMER 03	Sep-2003	7,329	256	57	313	314	627	0	6,701	94
SUMMER 03	Oct-2003	6,963	154	53	207	314	521	0	6,442	85
WINTER 03/04	Nov-2003	5,712	267	33	300	314	614	0	5,098	79
WINTER 03/04	Dec-2003	7,319	520	33	552	315	867	0	6,451	96
WINTER 03/04	Jan-2004	9,414	593	33	626	310	936	0	8,478	112
WINTER 03/04	Feb-2004	8,200	448	33	481	310	791	0	7,408	103
WINTER 03/04	Mar-2004	6,677	314	34	348	310	658	0	6,019	87
SUMMER 04	Apr-2004	6,296	164	55	219	310	529	0	5,767	79
SUMMER 04	May-2004	7,711	205	59	264	310	574	0	7,137	90
SUMMER 04	Jun-2004	7,884	245	60	305	310	615	0	7,269	97
SUMMER 04	Jul-2004	8,038	255	61	316	311	627	0	7,411	99
SUMMER 04	Aug-2004	8,143	257	61	318	311	629	0	7,514	101
SUMMER 04	Sep-2004	7,472	226	60	286	311	597	0	6,875	96
SUMMER 04	Oct-2004	7,103	136	56	192	311	503	0	6,600	86
WINTER 04/05	Nov-2004	5,800	258	36	293	311	604	0	5,196	80
WINTER 04/05	Dec-2004	7,434	503	36	539	311	850	0	6,584	98
WINTER 04/05	Jan-2005	9.505	575	36	611	312	923	0	8,583	113
WINTER 04/05	Feb-2005	8.287	434	36	470	312	782	0	7,504	104
WINTER 04/05	Mar-2005	6,722	304	37	341	312	653	0	6,069	88
SUMMER 05	Apr-2005	6.367	145	58	203	312	515	0	5,852	80
SUMMER 05	May-2005	7,822	181	62	243	312	555	0	7,268	91
SUMMER 05	Jun-2005	7,970	216	63	280	313	593	0	7,378	98
SUMMER 05	Jul-2005	8.135	225	64	289	313	602	0	7,533	100
SUMMER 05	Aug-2005	8.237	227	64	291	313	604	0	7,633	102
SUMMER 05	Sep-2005	7,542	199	63	263	313	576	0	6,966	98
SUMMER 05	Oct-2005	7.180	120	60	179	313	492	0	6,687	88
WINTER 05/06	Nov-2005	5.831	250	39	288	313	601	0	5,230	81
WINTER 05/06	Dec-2005	7.477	489	39	528	314	842	0	6,635	99
WINTER 05/06	Jan-2006	9.660	560	39	599	314	913	0	8,747	116
WINTER 05/06	Feb-2006	8 436	423	40	462	314	776	0	7,659	106
WINTER 05/06	Mar-2006	6.814	296	40	336	314	650	0	6,164	89
SUMMER 06	Apr-2006	6 480	128	61	189	314	503	0	5,977	82
SUMMER 06	May-2006	7.983	159	65	224	314	538	0	7,445	93
SUMMER 06	Jun-2006	8 112	191	66	257	315	572	0	7.540	101

FPC 117

JUNE 1999 FORECAST (S990709)

TMY Weather

Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	DIRECT LOAD CONTROL PROGRAMS: OTHER DLC PROGRAMS (MW)	DIRECT LOAD CONTROL PROGRAMS: TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 06	Jul-2006	8,286	199	67	266	315	581	0	7,705	103
SUMMER 06	Aug-2006	8,389	200	67	267	315	582	0	7,807	104
SUMMER 06	Sep-2006	7,667	176	67	242	315	557	0	7,110	100
SUMMER 06	Oct-2006	7,305	105	63	168	315	483	0	6,821	89
WINTER 06/07	Nov-2006	5,907	243	42	285	315	600	0	5,308	82
WINTER 06/07	Dec-2006	7,577	477	42	519	316	835	0	6,741	100
WINTER 06/07	Jan-2007	9,816	546	42	589	316	905	0	8,911	118
WINTER 06/07	Feb-2007	8,588	412	43	455	316	771	0	7,817	108
WINTER 06/07	Mar-2007	6,910	289	43	332	316	648	0	6,262	91
SUMMER 07	Apr-2007	6,595	113	64	177	316	493	0	6,102	84
SUMMER 07	May-2007	8,144	141	68	209	316	525	0	7,619	95
SUMMER 07	Jun-2007	8,256	168	69	238	317	555	0	7,702	103
SUMMER 07	Jul-2007	8,439	175	70	246	317	563	0	7,876	105
SUMMER 07	Aug-2007	8,542	176	70	247	317	564	0	7,978	107
SUMMER 07	Sep-2007	7,794	155	70	225	317	542	0	7,252	102
SUMMER 07	Oct-2007	7,431	93	66	159	317	476	0	6,955	91
WINTER 07/08	Nov-2007	5,987	237	45	282	318	600	0	5,388	83
WINTER 07/08	Dec-2007	7,680	467	45	512	318	830	0	6,851	102
WINTER 07/08	Jan-2008	9,970	534	45	580	318	898	0	9,072	120
WINTER 07/08	Feb-2008	8,734	403	46	449	318	767	0	7,967	110
WINTER 07/08	Mar-2008	7,005	282	46	328	318	646	0	6,359	93
SUMMER 08	Apr-2008	6,709	99	67	167	318	485	0	6,224	85
SUMMER 08	May-2008	8,302	124	71	195	319	514	0	7,788	97
SUMMER 08	Jun-2008	8,397	148	73	221	319	540	0	7,857	105
SUMMER 08	Jul-2008	8,589	155	73	228	319	547	0	8,042	107
SUMMER 08	Aug-2008	8,692	156	74	229	319	548	0	8,144	109
SUMMER 08	Sep-2008	7,919	137	73	210	319	529	0	7,391	104
SUMMER 08	Oct-2008	7,555	82	69	151	319	470	0	7,085	93
WINTER 08/09	Nov-2008	6,065	231	48	279	320	599	0	5,466	85
WINTER 08/09	Dec-2008	7,780	457	48	505	320	825	0	6,955	104
WINTER 08/09	Jan-2009	10,121	523	49	572	320	892	0	9,229	123
WINTER 08/09	Feb-2009	8,880	395	49	444	320	764	0	8,116	112
WINTER 08/09	Mar-2009	7,096	276	49	325	320	645	0	6,451	94
SUMMER 09	Apr-2009	6,820	88	71	158	320	478	0	6,342	87
SUMMER 09	May-2009	8,457	109	74	184	321	505	0	7,952	99
SUMMER 09	Jun-2009	8,535	131	76	207	321	528	0	8,008	107
SUMMER 09	Jul-2009	8,737	136	76	213	321	534	0	8,203	109
SUMMER 09	Aug-2009	8,841	137	77	214	321	535	0	8,306	111
SUMMER 09	Sep-2009	8,043	121	76	197	321	518	0	7,526	106

FPC 118

JUNE 1999 FORECAST (S990709)
TMY Weather
Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 09	Oct-2009	7,677	72	72	144	321	465	0	7,211	95
WINTER 09/10	Nov-2009	6,142	226	51	277	322	599	0	5,543	86
WINTER 09/10	Dec-2009	7,881	448	51	499	322	821	0	7,060	106

FPC 119

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

1999 SERC RATINGS, COGENERATION = 981231

JUNE 1999 FORECAST (S990506)

Bulk Power Sales Included in Demand & Energy Forecast

Hines 2 in 11/2003 : "TMY" Weather Analysis with Capacity @ "Base" Ratings

		WINTER 99/00 Jan-2000	WINTER 00/01 Jan-2001	WINTER 01/02 Jan-2002	WINTER 02/03 Jan-2003	WINTER 03/04 Jan-2004	WINTER 04/05 Jan-2005	WINTER 05/06 Jan-2006	WINTER 06/07 Jan-2007	WINTER 07/08 Jan-2008	WINTER 08/09 Jan-2009
Existing FPC Capacity	MW	8,351	8,351	8,689	8,706	8,706	9,121	9,121	9,121	9,688	9,688
New FPC Capacity	MW	0	338	17	0	567	0	0	567	0	0
Retired FPC Capacity	MW	0	0	0	0	152	0	0	0	0	0
Total Installed Capacity	MW	8,351	8,689	8,706	8,706	9,121	9,121	9,121	9,688	9,688	9,688
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831	831
QF Contractually-Allowed On-Peak Capacity Reduction	MW	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	9,545	9,883	9,900	9,900	10,315	10,325	10,325	10,892	10,892	10,892
TMY Weather Demand (Before Load Control)	MW	9,737	9,933	9,588	9,247	9,414	9,505	9,660	9,816	9,970	10,121
TMY Weather Reserves (Before Load Control)	MW	-192	-50	312	653	901	820	665	1,076	922	771
TMY Weather Reserve Margin (Before Load Control)	%	-2.0%	-0.5%	3.3%	7.1%	9.6%	8.6%	6.9%	11.0%	9.2%	7.6%
TMY Weather Load Management	MW	758	736	680	646	626	611	599	589	580	572
TMY Weather Demand (After Load Management)	MW	8,978	9,196	8,908	8,601	8,788	8,895	9,061	9,227	9,390	9,549
TMY Weather Reserves (After Load Management)	MW	567	687	992	1,299	1,527	1,430	1,264	1,665	1,502	1,343
TMY Weather Reserve Margin (After Load Management)	%	6.3%	7.5%	11.1%	15.1%	17.4%	16.1%	14.0%	18.0%	16.0%	14.1%
TMY Weather Interruptible Load	MW	326	314	311	313	310	312	314	316	318	320
TMY Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
TMY Weather Demand (After All Load Control)	MW	8,652	8,882	8,597	8,288	8,478	8,583	8,747	8,911	9,072	9,229
TMY Weather Reserves (After All Load Control)	MW	893	1,001	1,303	1,612	1,837	1,742	1,578	1,981	1,820	1,663
TMY Weather Reserve Margin (After All Load Control)	%	10.3%	11.3%	15.2%	19.5%	21.7%	20.3%	18.0%	22.2%	20.1%	18.0%
TMY Weather Reserves (After All Load Control) Required For 15 %	MW	1,298	1,332	1,290	1,243	1,272	1,287	1,312	1,337	1,361	1,384
TMY Weather Reserves (After All Load Control) Above 15 %	MW	-405	-332	14	369	565	455	266	644	459	279
TMY Weather "DLC" Reserve Margin Contribution	%	121.5%	105.0%	76.0%	59.5%	50.9%	53.0%	57.8%	45.7%	49.3%	53.6%

FPC 120

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

1999 SERC RATINGS, COGENERATION = 981231

JUNE 1999 FORECAST (S990506)

Bulk Power Sales Included In Demand & Energy Forecast

Hines 2 in 11/2003 : "TMY" Weather Analysis with Capacity @ "Base" Ratings

		SUMMER 00	SUMMER 01	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 06	SUMMER 07	SUMMER 08	SUMMER 09
		Aug-2000	Aug-2001	Aug-2002	Aug-2003	Aug-2004	Aug-2005	Aug-2006	Aug-2007	Aug-2008	Aug-2009
Existing FPC Capacity	MW	7,236	7,236	7,485	7,502	7,502	7,847	7,847	7,847	8,342	8,342
New FPC Capacity	MW	0	249	17	0	495	0	0	495	0	0
Retired FPC Capacity	MW	0	0	0	0	(160)	0	0	0	0	0
Total Installed Capacity	MW	7,236	7,485	7,502	7,502	7,847	7,847	7,847	8,342	8,342	8,342
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831	831
QF Contractually-Allowed On-Peak Capacity Reduction	MW	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	8,430	8,679	8,696	8,696	9,041	9,051	9,051	9,546	9,546	9,546
TMY Weather Demand (Before Load Control)	MW	8,482	8,656	8,326	7,977	8,143	8,237	8,389	8,542	8,692	8,841
TMY Weather Reserves (Before Load Control)	MW	-52	23	369	719	898	814	661	1,004	853	704
TMY Weather Reserve Margin (Before Load Control)	%	-0.6%	0.3%	4.4%	9.0%	11.0%	9.9%	7.9%	11.8%	9.8%	8.0%
TMY Weather Load Management	MW	492	447	389	349	318	291	267	247	229	214
TMY Weather Demand (After Load Management)	MW	7,990	8,208	7,937	7,628	7,825	7,946	8,122	8,295	8,463	8,627
TMY Weather Reserves (After Load Management)	MW	440	470	759	1,068	1,216	1,105	929	1,251	1,082	918
TMY Weather Reserve Margin (After Load Management)	%	5.5%	5.7%	9.6%	14.0%	15.5%	13.9%	11.4%	15.1%	12.8%	10.6%
TMY Weather Interruptible Load	MW	327	315	312	314	311	313	315	317	319	321
TMY Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
TMY Weather Demand (After All Load Control)	MW	7,663	7,893	7,625	7,314	7,514	7,633	7,807	7,978	8,144	8,306
TMY Weather Reserves (After All Load Control)	MW	767	785	1,071	1,382	1,527	1,418	1,244	1,568	1,401	1,239
TMY Weather Reserve Margin (After All Load Control)	%	10.0%	10.0%	14.0%	18.9%	20.3%	18.6%	15.9%	19.7%	17.2%	14.9%
TMY Weather Reserves (After All Load Control) Required For 20 %	MW	1,533	1,579	1,525	1,463	1,503	1,527	1,561	1,596	1,629	1,661
TMY Weather Reserves (After All Load Control) Above 20 %	MW	-766	-793	-454	-81	24	-109	-318	-28	-227	-422
TMY Weather "DLC" Reserve Margin Contribution	%	106.8%	97.1%	65.5%	48.0%	41.2%	42.6%	46.8%	36.0%	39.1%	43.2%

FPC 121

JUNE 1999 FORECAST (S990506)

Extreme Weather

Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
WINTER 99/00	Jan-2000	10,965	950	23	973	326	1,299	0	9,666	133
WINTER 99/00	Feb-2000	9,996	833	23	856	326	1,182	0	8,814	121
WINTER 99/00	Mar-2000	8,490	691	23	714	326	1,040	0	7,450	104
SUMMER 00	Apr-2000	6,290	301	43	344	327	671	0	5,619	79
SUMMER 00	May-2000	7,379	379	47	426	327	753	0	6,626	92
SUMMER 00	Jun-2000	8,129	453	49	502	327	829	0	7,300	100
SUMMER 00	Jul-2000	8,315	502	50	551	327	878	0	7,437	103
SUMMER 00	Aug-2000	8,470	463	50	513	327	840	0	7,630	105
SUMMER 00	Sep-2000	8,019	426	49	475	327	802	0	7,217	99
SUMMER 00	Oct-2000	6,854	271	45	316	328	644	0	6,210	86
WINTER 00/01	Nov-2000	7,589	444	24	468	328	796	0	6,793	94
WINTER 00/01	Dec-2000	9,447	958	25	983	328	1,311	0	8,136	118
WINTER 00/01	Jan-2001	11,158	918	26	944	314	1,258	0	9,900	136
WINTER 00/01	Feb-2001	10,191	797	26	824	314	1,138	0	9,053	124
WINTER 00/01	Mar-2001	8,646	656	26	682	314	996	0	7,650	106
SUMMER 01	Apr-2001	6,493	274	46	320	314	634	0	5,859	81
SUMMER 01	May-2001	7,575	343	50	393	314	707	0	6,868	95
SUMMER 01	Jun-2001	8,285	407	52	459	315	774	0	7,511	103
SUMMER 01	Jul-2001	8,480	450	52	502	315	817	0	7,663	106
SUMMER 01	Aug-2001	8,637	414	52	467	315	782	0	7,855	108
SUMMER 01	Sep-2001	8,176	377	52	429	315	744	0	7,432	102
SUMMER 01	Oct-2001	7,019	237	47	284	315	599	0	6,420	89
WINTER 01/02	Nov-2001	7,762	414	27	440	315	755	0	7,007	97
WINTER 01/02	Dec-2001	9,610	890	27	917	316	1,233	0	8,377	121
WINTER 01/02	Jan-2002	10,798	846	27	872	311	1,183	0	9,615	132
WINTER 01/02	Feb-2002	9,934	736	27	763	311	1,074	0	8,860	121
WINTER 01/02	Mar-2002	8,404	607	27	634	311	945	0	7,459	104
SUMMER 02	Apr-2002	6,240	230	49	279	311	590	0	5,650	79
SUMMER 02	May-2002	7,292	288	53	341	311	652	0	6,640	92
SUMMER 02	Jun-2002	7,924	343	54	397	311	708	0	7,216	99
SUMMER 02	Jul-2002	8,128	380	55	434	312	746	0	7,382	102
SUMMER 02	Aug-2002	8,287	351	55	406	312	718	0	7,569	104
SUMMER 02	Sep-2002	7,817	320	54	374	312	686	0	7,131	98
SUMMER 02	Oct-2002	6,709	202	50	252	312	564	0	6,145	85
WINTER 02/03	Nov-2002	7,521	387	29	417	312	729	0	6,792	94
WINTER 02/03	Dec-2002	9,279	838	30	868	313	1,181	0	8,098	117
WINTER 02/03	Jan-2003	10,448	798	30	828	313	1,141	0	9,307	128
WINTER 02/03	Feb-2003	9,573	696	30	726	313	1,039	0	8,534	117
WINTER 02/03	Mar-2003	8,131	574	30	605	313	918	0	7,213	100

FPC 122

JUNE 1999 FORECAST (S990506)
Extreme Weather
Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 03	Apr-2003	6,224	198	52	250	313	563	0	5,661	79
SUMMER 03	May-2003	7,100	249	56	305	313	618	0	6,482	90
SUMMER 03	Jun-2003	7,675	297	57	354	314	668	0	7,007	96
SUMMER 03	Jul-2003	7,810	330	58	388	314	702	0	7,108	99
SUMMER 03	Aug-2003	7,924	305	58	363	314	677	0	7,247	100
SUMMER 03	Sep-2003	7,618	279	57	337	314	651	0	6,967	96
SUMMER 03	Oct-2003	6,751	177	53	230	314	544	0	6,207	86
WINTER 03/04	Nov-2003	7,336	371	33	403	314	717	0	6,619	92
WINTER 03/04	Dec-2003	8,889	806	33	839	315	1,154	0	7,735	112
WINTER 03/04	Jan-2004	10,603	769	33	802	310	1,112	0	9,491	130
WINTER 03/04	Feb-2004	9,722	670	33	703	310	1,013	0	8,709	119
WINTER 03/04	Mar-2004	8,232	554	34	587	310	897	0	7,335	102
SUMMER 04	Apr-2004	6,335	175	55	230	310	540	0	5,795	81
SUMMER 04	May-2004	7,231	220	59	279	310	589	0	6,642	92
SUMMER 04	Jun-2004	7,818	262	60	322	310	632	0	7,186	99
SUMMER 04	Jul-2004	7,957	291	61	352	311	663	0	7,294	101
SUMMER 04	Aug-2004	8,078	269	61	331	311	642	0	7,436	102
SUMMER 04	Sep-2004	7,761	247	60	307	311	618	0	7,143	98
SUMMER 04	Oct-2004	6,875	156	56	212	311	523	0	6,352	88
WINTER 04/05	Nov-2004	7,428	358	36	394	311	705	0	6,723	93
WINTER 04/05	Dec-2004	9,008	782	36	818	311	1,129	0	7,879	113
WINTER 04/05	Jan-2005	10,688	746	36	782	312	1,094	0	9,594	131
WINTER 04/05	Feb-2005	9,796	650	36	687	312	999	0	8,797	121
WINTER 04/05	Mar-2005	8,281	537	37	574	312	886	0	7,395	103
SUMMER 05	Apr-2005	6,397	154	58	212	312	524	0	5,873	82
SUMMER 05	May-2005	7,304	194	62	256	312	568	0	6,736	93
SUMMER 05	Jun-2005	7,896	231	63	295	313	608	0	7,288	100
SUMMER 05	Jul-2005	8,037	257	64	321	313	634	0	7,403	102
SUMMER 05	Aug-2005	8,167	238	64	302	313	615	0	7,552	104
SUMMER 05	Sep-2005	7,840	217	63	281	313	594	0	7,246	100
SUMMER 05	Oct-2005	6,944	137	60	197	313	510	0	6,434	89
WINTER 05/06	Nov-2005	7,467	348	39	387	313	700	0	6,767	94
WINTER 05/06	Dec-2005	9,068	762	39	801	314	1,115	0	7,953	114
WINTER 05/06	Jan-2006	10,841	727	39	766	314	1,080	0	9,761	134
WINTER 05/06	Feb-2006	9,937	634	40	673	314	987	0	8,950	123
WINTER 05/06	Mar-2006	8,381	524	40	564	314	878	0	7,503	104
SUMMER 06	Apr-2006	6,508	136	61	197	314	511	0	5,997	83
SUMMER 06	May-2006	7,431	171	65	236	314	550	0	6,831	95
SUMMER 06	Jun-2006	8,035	204	66	270	315	585	0	7,450	102

FPC 123

JUNE 1999 FORECAST (S990506)
Extreme Weather
Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 06	Jul-2006	8,179	227	67	294	315	609	0	7,570	105
SUMMER 06	Aug-2006	8,320	210	67	277	315	592	0	7,728	106
SUMMER 06	Sep-2006	7,977	192	67	258	315	573	0	7,404	102
SUMMER 06	Oct-2006	7,066	121	63	184	315	499	0	6,567	91
WINTER 06/07	Nov-2006	7,555	339	42	381	315	696	0	6,859	95
WINTER 06/07	Dec-2006	9,184	744	42	786	316	1,102	0	8,082	116
WINTER 06/07	Jan-2007	11,002	710	42	752	316	1,068	0	9,934	136
WINTER 06/07	Feb-2007	10,085	619	43	662	316	978	0	9,107	125
WINTER 06/07	Mar-2007	8,487	512	43	555	316	871	0	7,616	106
SUMMER 07	Apr-2007	6,625	120	64	184	316	500	0	6,125	85
SUMMER 07	May-2007	7,567	151	68	219	316	535	0	7,032	97
SUMMER 07	Jun-2007	8,182	180	69	249	317	566	0	7,616	105
SUMMER 07	Jul-2007	8,328	200	70	270	317	587	0	7,741	107
SUMMER 07	Aug-2007	8,480	185	70	255	317	572	0	7,908	109
SUMMER 07	Sep-2007	8,123	169	70	239	317	556	0	7,567	104
SUMMER 07	Oct-2007	7,194	107	66	173	317	490	0	6,704	93
WINTER 07/08	Nov-2007	7,653	331	45	376	318	694	0	6,959	96
WINTER 07/08	Dec-2007	9,311	728	45	773	318	1,091	0	8,220	118
WINTER 07/08	Jan-2008	11,165	695	45	740	318	1,058	0	10,107	138
WINTER 07/08	Feb-2008	10,232	606	46	652	318	970	0	9,262	127
WINTER 07/08	Mar-2008	8,596	501	46	547	318	865	0	7,731	107
SUMMER 08	Apr-2008	6,744	106	67	173	318	491	0	6,253	87
SUMMER 08	May-2008	7,703	133	71	204	319	523	0	7,180	99
SUMMER 08	Jun-2008	8,329	159	73	231	319	550	0	7,779	107
SUMMER 08	Jul-2008	8,478	176	73	250	319	569	0	7,909	109
SUMMER 08	Aug-2008	8,642	163	74	237	319	556	0	8,086	111
SUMMER 08	Sep-2008	8,269	149	73	222	319	541	0	7,728	106
SUMMER 08	Oct-2008	7,322	94	69	163	319	482	0	6,840	95
WINTER 08/09	Nov-2008	7,749	324	48	372	320	692	0	7,057	98
WINTER 08/09	Dec-2008	9,436	714	48	762	320	1,082	0	8,354	120
WINTER 08/09	Jan-2009	11,327	681	49	729	320	1,049	0	10,278	141
WINTER 08/09	Feb-2009	10,382	594	49	643	320	963	0	9,419	129
WINTER 08/09	Mar-2009	8,705	491	49	540	320	860	0	7,845	109
SUMMER 09	Apr-2009	6,863	93	71	164	320	484	0	6,379	88
SUMMER 09	May-2009	7,839	117	74	192	321	513	0	7,326	101
SUMMER 09	Jun-2009	8,477	140	76	216	321	537	0	7,940	109
SUMMER 09	Jul-2009	8,629	156	76	232	321	553	0	8,076	111
SUMMER 09	Aug-2009	8,803	144	77	221	321	542	0	8,261	113
SUMMER 09	Sep-2009	8,415	132	76	208	321	529	0	7,886	108

FPC 124

JUNE 1999 FORECAST (S990506)
Extreme Weather
Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 09	Oct-2009	7,451	83	72	155	321	476	0	6,975	96
WINTER 09/10	Nov-2009	7,847	317	51	368	322	690	0	7,157	99
WINTER 09/10	Dec-2009	9,563	700	51	752	322	1,074	0	8,489	121

FPC 125

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

1999 SERC RATINGS, COGENERATION = 981231

JUNE 1999 FORECAST (S990506)

Bulk Power Sales Included in Demand & Energy Forecast

Hines 2 in 11/2003 : "Extreme" Weather Analysis with Capacity @ "Base" Ratings

		WINTER 99/00	WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08	WINTER 08/09
		Jan-2000	Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008	Jan-2009
Existing FPC Capacity	MW	8,351	8,351	8,689	8,706	8,706	9,121	9,121	9,121	9,688	9,688
New FPC Capacity	MW	0	338	17	0	567	0	0	567	0	0
Retired FPC Capacity	MW	0	0	0	0	152	0	0	0	0	0
Total Installed Capacity	MW	8,351	8,689	8,706	8,706	9,121	9,121	9,121	9,688	9,688	9,688
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831	831
QF Contractually-Allowed On-Peak Capacity Reduction	MW	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	9,545	9,883	9,900	9,900	10,315	10,325	10,325	10,892	10,892	10,892
Extreme Weather Demand (Before Load Control)	**MW**	**10,965**	**11,158**	**10,798**	**10,448**	**10,603**	**10,688**	**10,841**	**11,002**	**11,165**	**11,327**
Extreme Weather Reserves (Before Load Control)	MW	-1,420	-1,275	-898	-548	-288	-363	-516	-110	-273	-435
Extreme Weather Reserve Margin (Before Load Control)	**%**	**-13.0%**	**-11.4%**	**-8.3%**	**-5.2%**	**-2.7%**	**-3.4%**	**-4.8%**	**-1.0%**	**-2.4%**	**-3.8%**
Extreme Weather Load Management	MW	973	944	872	828	802	782	766	752	740	729
Extreme Weather Demand (After Load Management)	MW	9,992	10,214	9,926	9,620	9,801	9,906	10,075	10,250	10,425	10,598
Extreme Weather Reserves (After Load Management)	MW	-447	-331	-26	280	514	419	250	642	467	294
Extreme Weather Reserve Margin (After Load Management)	%	-4.5%	-3.2%	-0.3%	2.9%	5.2%	4.2%	2.5%	6.3%	4.5%	2.8%
Extreme Weather Interruptible Load	MW	326	314	311	313	310	312	314	316	318	320
Extreme Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Extreme Weather Demand (After All Load Control)	**MW**	**9,666**	**9,900**	**9,615**	**9,307**	**9,491**	**9,594**	**9,761**	**9,934**	**10,107**	**10,278**
Extreme Weather Reserves (After All Load Control)	MW	-121	-17	285	593	824	731	564	958	785	614
Extreme Weather Reserve Margin (After All Load Control)	**%**	**-1.2%**	**-0.2%**	**3.0%**	**6.4%**	**8.7%**	**7.6%**	**5.8%**	**9.6%**	**7.8%**	**6.0%**
Extreme Weather Reserves (After All Load Control) Required For 15 %	MW	1,450	1,485	1,442	1,396	1,424	1,439	1,464	1,490	1,516	1,542
Extreme Weather Reserves (After All Load Control) Above 15 %	MW	-1,571	-1,502	-1,157	-803	-600	-708	-900	-532	-731	-927
Extreme Weather "DLC" Reserve Margin Contribution	%	-1076.7%	-7488.5%	414.5%	192.4%	135.0%	149.7%	191.5%	111.5%	134.8%	170.8%

FPC 126

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

1999 SERC RATINGS, COGENERATION = 981231

JUNE 1999 FORECAST (S990506)

Bulk Power Sales Included in Demand & Energy Forecast

Hines 2 in 11/2003 : "Extreme" Weather Analysis with Capacity @ "Base" Ratings

		SUMMER 00 Aug-2000	SUMMER 01 Aug-2001	SUMMER 02 Aug-2002	SUMMER 03 Aug-2003	SUMMER 04 Aug-2004	SUMMER 05 Aug-2005	SUMMER 06 Aug-2006	SUMMER 07 Aug-2007	SUMMER 08 Aug-2008	SUMMER 09 Aug-2009
Existing FPC Capacity	MW	7,236	7,236	7,485	7,502	7,502	7,847	7,847	7,847	8,342	8,342
New FPC Capacity	MW	0	249	17	0	495	0	0	495	0	0
Retired FPC Capacity	MW	0	0	0	0	150	0	0	0	0	0
Total Installed Capacity	MW	7,236	7,485	7,502	7,502	7,847	7,847	7,847	8,342	8,342	8,342
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831	831
QF Contractually-Allowed On-Peak Capacity Reduction	MW	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	8,430	8,679	8,696	8,696	9,041	9,051	9,051	9,546	9,546	9,546
Extreme Weather Demand (Before Load Control)	MW	8,470	8,637	8,287	7,924	8,078	8,167	8,320	8,480	8,642	8,803
Extreme Weather Reserves (Before Load Control)	MW	-40	42	409	772	963	884	731	1,066	904	743
Extreme Weather Reserve Margin (Before Load Control)	%	-0.5%	0.5%	4.9%	9.7%	11.9%	10.8%	8.8%	12.6%	10.5%	8.4%
Extreme Weather Load Management	MW	513	467	406	363	331	302	277	255	237	221
Extreme Weather Demand (After Load Management)	MW	7,957	8,170	7,881	7,561	7,747	7,865	8,043	8,225	8,405	8,582
Extreme Weather Reserves (After Load Management)	MW	473	508	814	1,135	1,293	1,186	1,008	1,321	1,140	963
Extreme Weather Reserve Margin (After Load Management)	%	5.9%	6.2%	10.3%	15.0%	16.7%	15.1%	12.5%	16.1%	13.6%	11.2%
Extreme Weather Interruptible Load	MW	327	315	312	314	311	313	315	317	319	321
Extreme Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Extreme Weather Demand (After All Load Control)	MW	7,630	7,855	7,569	7,247	7,436	7,552	7,728	7,908	8,086	8,261
Extreme Weather Reserves (After All Load Control)	MW	800	823	1,126	1,449	1,604	1,499	1,323	1,638	1,459	1,284
Extreme Weather Reserve Margin (After All Load Control)	%	10.5%	10.5%	14.9%	20.0%	21.6%	19.8%	17.1%	20.7%	18.0%	15.5%
Extreme Weather Reserves (After All Load Control) Required For 20 %	MW	1,526	1,571	1,514	1,449	1,487	1,510	1,546	1,582	1,617	1,652
Extreme Weather Reserves (After All Load Control) Above 20 %	MW	-726	-748	-388	0	117	-12	-223	57	-158	-368
Extreme Weather "DLC" Reserve Margin Contribution	%	105.1%	94.9%	63.7%	46.8%	40.0%	41.0%	44.8%	34.9%	38.1%	42.2%

FPC 127

															5.5%	8.7%	Extreme Weather						
	Month	Scheduled Maintenance	Baseload Plants	Baseload Contracts	QF Contracts	Intermediate Resources	Baseload & Intermediate Resources	Peaking Resources	Total Resources	QF On-Peak Reduction	Baseload & Intermediate Resources	Peaking Resources	Operating Requirements	FPC Available Resources EFOR	FPC Available Resources EFOR	Total Peak Before DLC	Supply Variance	Supply Reserve Margin	Total DLC (including IS/CS and Volt Red.)	Firm Peak After DLC	Total Variance	Total Reserve Margin
1	Jan-00	0	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,033	2,712	341	-459	-818	10,965	-1,314	-11.99%	1,238	9,656	-15	-0.15%
2	Feb-00	-162	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,039	2,714	341	-460	-794	9,996	-507	-5.07%	1,182	8,814	675	7.66%
3	Mar-00	-1,299	3,150	469	831	2,374	6,824	2,827	9,651	-105	6,055	2,730	341	-356	-684	8,490	-138	-1.63%	1,040	7,450	902	12.11%
4	Apr-00	-1,332	3,069	469	831	2,262	6,631	2,188	8,819	-106	5,979	2,103	291	-340	-600	6,290	1,197	19.03%	671	5,619	1,868	33.25%
5	May-00	0	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,963	2,004	291	-416	-733	7,379	1,481	20.07%	753	6,626	2,234	33.72%
6	Jun-00	0	3,110	469	831	2,262	6,672	1,950	8,622	-106	5,973	1,849	291	-403	-710	8,129	493	6.06%	829	7,300	1,322	18.11%
7	Jul-00	0	3,110	469	831	2,262	6,672	1,950	8,622	-106	5,973	1,849	291	-403	-710	8,316	307	3.69%	878	7,437	1,185	15.93%
8	Aug-00	0	3,024	469	831	2,262	6,586	1,950	8,536	-106	5,891	1,850	291	-398	-702	8,470	66	0.77%	840	7,630	906	11.87%
9	Sep-00	0	3,110	469	831	2,262	6,672	2,045	8,717	-106	5,959	1,943	291	-408	-719	8,019	698	8.70%	802	7,217	1,500	20.78%
10	Oct-00	-437	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,983	2,091	291	-359	-668	6,854	1,519	22.16%	644	6,210	2,183	34.64%
11	Nov-00	-884	3,191	469	831	2,374	6,865	2,188	9,053	-106	6,185	2,094	291	-378	-658	7,589	580	7.64%	796	6,793	1,376	20.26%
12	Dec-00	-115	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,064	3,006	341	-472	-832	9,447	427	4.52%	1,311	8,136	1,735	21.37%
13	Jan-01	0	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,060	3,005	341	-478	-843	11,168	-1,168	-10.46%	1,268	9,900	89	0.90%
14	Feb-01	-167	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,066	3,007	341	-469	-827	10,191	-369	-3.62%	1,138	9,053	769	8.49%
15	Mar-01	-501	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,050	3,011	341	-460	-794	8,646	842	9.74%	996	7,650	1,838	24.03%
16	Apr-01	-1,096	3,110	469	831	2,262	6,672	2,512	9,184	-106	5,995	2,419	291	-373	-656	6,493	1,595	24.56%	834	5,659	2,229	39.05%
17	May-01	-506	3,110	469	831	2,262	6,672	2,437	9,109	-106	5,986	2,341	291	-355	-679	7,575	728	9.61%	707	6,868	1,435	20.89%
18	Jun-01	0	3,110	469	831	2,262	6,672	2,199	8,871	-106	5,963	2,096	291	-416	-734	8,235	566	7.07%	774	7,511	1,359	18.10%
19	Jul-01	0	3,110	469	831	2,262	6,672	2,199	8,871	-106	5,963	2,096	291	-416	-734	8,480	391	4.61%	817	7,663	1,207	15.76%
20	Aug-01	0	3,024	469	831	2,262	6,586	2,199	8,785	-106	5,880	2,098	291	-412	-726	8,637	148	1.71%	782	7,855	928	11.83%
21	Sep-01	0	3,110	469	831	2,262	6,672	2,294	8,966	-106	5,959	2,189	291	-422	-744	8,176	790	9.66%	744	7,432	1,534	20.63%
22	Oct-01	-625	3,110	469	831	2,262	6,672	2,437	9,109	-106	5,979	2,338	291	-395	-697	7,019	1,462	20.83%	599	6,420	2,061	32.11%
23	Nov-01	-1,467	3,191	469	831	2,374	6,865	2,437	9,302	-106	6,196	2,347	291	-359	-634	7,762	73	0.94%	755	7,007	828	11.82%
24	Dec-01	-1,152	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,107	3,020	341	-416	-731	9,610	-773	-8.04%	1,233	8,377	460	5.49%
25	Jan-02	0	3,208	469	831	2,374	6,882	3,124	10,006	-106	6,076	3,004	341	-479	-844	10,798	-792	-7.33%	1,183	9,615	391	4.07%
26	Feb-02	0	3,208	469	831	2,374	6,882	3,124	10,006	-106	6,076	3,004	341	-479	-844	9,934	72	0.72%	1,074	8,860	1,146	12.94%
27	Mar-02	-941	3,208	469	831	2,374	6,882	3,124	10,006	-106	6,115	3,017	341	-427	-753	8,404	661	7.87%	945	7,459	1,606	21.53%
28	Apr-02	-1,101	3,127	469	831	2,262	6,689	2,512	9,201	-106	6,012	2,419	291	-374	-650	6,240	1,860	29.81%	590	5,650	2,460	43.35%
29	May-02	-434	3,127	469	831	2,262	6,689	2,437	9,126	-106	5,989	2,336	291	-404	-712	7,292	1,350	18.51%	652	6,640	2,002	30.14%
30	Jun-02	0	3,127	469	831	2,262	6,689	2,199	8,888	-106	5,979	2,094	291	-417	-736	7,924	964	12.16%	708	7,216	1,671	23.16%
31	Jul-02	0	3,127	469	831	2,262	6,689	2,199	8,888	-106	5,979	2,094	291	-417	-736	8,128	760	9.35%	746	7,382	1,506	20.40%
32	Aug-02	0	3,041	469	831	2,262	6,603	2,199	8,802	-106	5,897	2,095	291	-413	-728	8,287	515	6.21%	718	7,569	1,232	16.28%
33	Sep-02	0	3,127	469	831	2,262	6,689	2,294	8,983	-106	5,975	2,188	291	-423	-745	7,817	1,166	14.92%	686	7,131	1,852	25.97%
34	Oct-02	-601	3,127	469	831	2,262	6,689	2,437	9,126	-106	5,994	2,338	291	-397	-701	6,709	1,816	27.07%	564	6,145	2,380	38.73%
35	Nov-02	-705	3,208	469	831	2,374	6,882	2,437	9,319	-106	6,183	2,336	291	-402	-709	7,521	1,090	14.49%	729	6,792	1,819	26.78%
36	Dec-02	-712	3,208	469	831	2,374	6,882	3,124	10,006	-106	6,105	3,014	341	-440	-776	9,279	15	0.16%	1,181	8,098	1,196	14.77%
37	Jan-03	0	3,208	469	831	2,374	6,882	3,124	10,006	-106	6,076	3,004	341	-479	-844	10,448	-442	-4.23%	1,141	9,307	698	7.51%
38	Feb-03		3,208	469	831	2,374	6,882	3,124	10,006	-106	6,076	3,004	341	-479	-844	9,573	433	4.52%	1,039	8,534	1,472	17.25%
39	Mar-03		3,208	469	831	2,374	6,882	3,124	10,006	-106	6,076	3,004	341	-479	-844	8,131	1,875	23.06%	918	7,213	2,793	38.72%
40	Apr-03		3,127	469	831	2,262	6,689	2,512	9,201	-106	5,966	2,403	291	-435	-765	6,224	2,977	47.83%	563	5,661	3,540	62.54%
41	May-03		3,127	469	831	2,262	6,689	2,437	9,126	-106	5,969	2,329	291	-430	-759	7,100	2,026	28.54%	618	6,482	2,644	40.79%
42	Jun-03		3,127	469	831	2,262	6,689	2,199	8,888	-106	5,979	2,094	291	-417	-736	7,675	1,213	15.80%	668	7,007	1,881	26.84%
43	Jul-03		3,127	469	831	2,262	6,689	2,199	8,888	-106	5,979	2,094	291	-417	-736	7,810	1,078	13.80%	702	7,108	1,779	25.03%
44	Aug-03	0	3,041	469	831	2,262	6,603	2,199	8,802	-106	5,897	2,095	291	-413	-728	7,924	878	11.08%	677	7,247	1,555	21.46%
45	Sep-03		3,127	469	831	2,262	6,689	2,294	8,983	-106	5,975	2,188	291	-423	-745	7,818	1,365	17.92%	851	6,967	2,015	28.93%
46	Oct-03		3,127	469	831	2,262	6,689	2,437	9,126	-106	5,969	2,329	291	-430	-759	6,751	2,375	35.18%	544	6,207	2,919	47.03%
47	Nov-03		3,208	469	831	2,789	7,297	2,437	9,734	-106	6,552	2,321	291	-464	-818	7,336	2,398	32.69%	717	6,619	3,115	47.07%
48	Dec-03		3,208	469	831	2,789	7,297	3,124	10,421	-106	6,474	2,939	341	-502	-885	8,889	1,532	17.23%	1,154	7,735	2,686	34.73%
49	Jan-04	0	3,208	469	831	2,789	7,297	3,124	10,421	-106	6,474	2,899	341	-502	-885	10,603	-182	-1.72%	1,112	9,491	930	9.79%
50	Feb-04		3,208	469	831	2,789	7,297	3,124	10,421	-106	6,474	2,939	341	-502	-885	9,722	699	7.19%	1,013	8,709	1,712	19.66%
51	Mar-04		3,208	469	831	2,789	7,297	3,124	10,421	-106	6,474	2,939	341	-502	-885	8,232	2,189	26.59%	897	7,335	3,086	42.05%
52	Apr-04		3,127	469	831	2,607	7,034	2,512	9,546	-106	6,297	2,399	291	-454	-800	6,335	3,211	50.69%	540	5,795	3,751	64.73%
53	May-04		3,127	469	831	2,607	7,034	2,437	9,471	-106	6,300	2,325	291	-449	-793	7,231	2,240	30.98%	589	6,642	2,829	42.59%
54	Jun-04		3,127	469	831	2,607	7,034	2,199	9,233	-106	6,310	2,090	291	-436	-769	7,818	1,415	18.09%	632	7,186	2,047	28.49%
55	Jul-04		3,127	469	831	2,112	6,539	2,199	8,738	-105	5,825	2,095	291	-409	-721	7,957	781	9.81%	663	7,294	1,444	19.79%
56	Aug-04	0	3,041	469	831	2,607	6,948	2,199	9,147	-106	6,227	2,091	291	-432	-761	8,078	1,069	13.23%	642	7,436	1,710	23.00%
57	Sep-04		3,127	469	831	2,607	7,034	2,294	9,328	-106	6,305	2,184	291	-442	-779	7,761	1,567	20.19%	618	7,143	2,185	30.59%
58	Oct-04		3,127	469	831	2,607	7,034	2,437	9,471	-106	6,300	2,325	291	-445	-783	6,875	2,596	37.76%	523	6,352	3,119	49.11%
59	Nov-04		3,208	469	831	2,789	7,297	2,437	9,734	-106	6,552	2,321	291	-464	-818	7,428	2,306	31.04%	705	6,723	3,011	44.78%

FPC 128

60	Dec-04		3,208	469	831	2,789	7,297	3,124	10,421	-106	6,474	2,999	341	-502	-885	8,008	1,413	15.69%	1,129	7,879	2,542	32.26%
61	Jan-05	0	3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,999	341	-502	-885	10,688	-257	-2.40%	1,894	8,594	837	8.72%
62	Feb-05		3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,999	341	-502	-885	9,796	635	6.48%	999	8,797	1,634	18.57%
63	Mar-05		3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,999	341	-502	-885	8,281	2,150	25.96%	885	7,396	3,036	41.05%
64	Apr-05		3,127	479	831	2,607	7,044	2,512	9,556	-106	6,307	2,399	291	-454	-800	6,397	3,159	49.38%	524	5,873	3,683	62.72%
65	May-05		3,127	479	831	2,607	7,044	2,437	9,481	-106	6,310	2,325	291	-449	-793	7,304	2,177	29.81%	568	6,736	2,745	40.75%
66	Jun-05		3,127	479	831	2,607	7,044	2,199	9,243	-106	6,320	2,090	291	-436	-769	7,896	1,347	17.05%	606	7,288	1,954	26.81%
67	Jul-05		3,127	479	831	2,607	7,044	2,199	9,243	-106	6,320	2,090	291	-436	-769	8,037	1,206	15.00%	604	7,433	1,839	24.85%
68	Aug-05	0	3,041	479	831	2,607	6,958	2,199	9,157	-106	6,237	2,081	291	-432	-761	8,167	990	12.12%	815	7,352	1,805	21.25%
69	Sep-05		3,127	479	831	2,607	7,044	2,294	9,338	-106	6,316	2,184	291	-442	-779	7,840	1,498	19.11%	594	7,246	2,092	28.87%
70	Oct-05		3,127	479	831	2,607	7,044	2,437	9,481	-106	6,310	2,325	291	-449	-793	6,944	2,537	36.54%	510	6,434	3,047	47.36%
71	Nov-05		3,208	479	831	2,789	7,307	2,437	9,744	-106	6,562	2,321	291	-464	-818	7,467	2,277	30.49%	700	6,767	2,977	43.99%
72	Dec-05		3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,999	341	-502	-885	9,066	1,365	15.05%	1,115	7,953	2,478	31.15%
73	Jan-06	0	3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,999	341	-502	-885	10,841	-410	-3.78%	1,090	9,751	678	6.95%
74	Feb-06		3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,999	341	-502	-885	9,937	494	4.97%	987	8,950	1,481	16.55%
75	Mar-06		3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,999	341	-502	-885	8,391	2,050	24.45%	878	7,503	2,928	39.02%
76	Apr-06		3,127	479	831	2,607	7,044	2,512	9,556	-106	6,307	2,399	291	-454	-800	6,508	3,048	46.83%	511	5,997	3,559	59.36%
77	May-06		3,127	479	831	2,607	7,044	2,437	9,481	-106	6,310	2,325	291	-449	-793	7,431	2,050	27.59%	550	6,881	2,600	37.79%
78	Jun-06		3,127	479	831	2,607	7,044	2,199	9,243	-106	6,320	2,090	291	-436	-769	8,035	1,208	15.03%	585	7,450	1,793	24.07%
79	Jul-06		3,127	479	831	2,607	7,044	2,199	9,243	-106	6,320	2,090	291	-436	-769	8,179	1,064	13.00%	609	7,570	1,672	22.09%
80	Aug-06	0	3,041	479	831	2,607	6,958	2,199	9,157	-106	6,237	2,081	291	-432	-761	8,329	837	10.05%	592	7,728	1,428	18.49%
81	Sep-06		3,127	479	831	2,607	7,044	2,294	9,338	-106	6,316	2,184	291	-442	-779	7,977	1,361	17.06%	573	7,404	1,934	26.13%
82	Oct-06		3,127	479	831	2,607	7,044	2,437	9,481	-106	6,310	2,325	291	-449	-793	7,066	2,415	34.18%	499	6,567	2,914	44.37%
83	Nov-06		3,208	479	831	3,356	7,874	2,437	10,311	-106	7,106	2,313	291	-495	-873	7,555	2,756	36.48%	695	6,858	3,462	50.32%
84	Dec-06		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	9,184	1,814	19.75%	1,102	8,082	2,916	36.06%
85	Jan-07	0	3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	11,002	-4	-0.04%	1,068	9,934	1,064	10.71%
86	Feb-07		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	10,085	913	9.05%	978	9,107	1,891	20.76%
87	Mar-07		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	8,487	2,511	29.59%	871	7,616	3,382	44.40%
88	Apr-07		3,127	479	831	3,102	7,539	2,512	10,051	-106	6,781	2,392	291	-491	-848	6,625	3,426	51.71%	500	6,125	3,926	64.11%
89	May-07		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	7,567	2,409	31.84%	535	7,032	2,944	41.87%
90	Jun-07		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,182	1,556	19.01%	566	7,616	2,122	27.87%
91	Jul-07		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,328	1,410	16.93%	587	7,741	1,997	25.79%
92	Aug-07	0	3,041	479	831	3,102	7,453	2,199	9,652	-106	6,712	2,084	291	-459	-809	8,480	1,172	13.82%	572	7,908	1,744	22.05%
93	Sep-07		3,127	479	831	3,102	7,539	2,294	9,833	-106	6,790	2,177	291	-469	-827	8,123	1,710	21.05%	556	7,567	2,266	29.94%
94	Oct-07		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	7,194	2,782	38.67%	490	6,704	3,272	48.80%
95	Nov-07		3,208	479	831	3,356	7,874	2,437	10,311	-106	7,106	2,313	291	-495	-873	7,653	2,658	34.73%	694	6,959	3,352	48.17%
96	Dec-07		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	8,311	1,687	18.12%	1,091	8,220	2,778	33.60%
97	Jan-08	0	3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	11,165	-167	-1.50%	1,056	10,107	891	8.82%
98	Feb-08		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	10,232	766	7.49%	970	9,262	1,736	18.74%
99	Mar-08		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	8,596	2,402	27.94%	865	7,731	3,267	42.26%
100	Apr-08		3,127	479	831	3,102	7,539	2,512	10,051	-106	6,781	2,392	291	-491	-848	6,744	3,307	49.04%	491	6,253	3,798	60.74%
101	May-08		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	7,703	2,273	29.51%	523	7,180	2,796	38.95%
102	Jun-08		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,329	1,409	16.91%	550	7,779	1,959	25.18%
103	Jul-08		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,478	1,260	14.86%	569	7,909	1,829	23.11%
104	Aug-08	0	3,041	479	831	3,102	7,453	2,199	9,652	-106	6,712	2,084	291	-459	-809	8,642	1,010	11.69%	556	8,086	1,565	19.36%
105	Sep-08		3,127	479	831	3,102	7,539	2,294	9,833	-106	6,790	2,177	291	-469	-827	8,269	1,564	18.91%	541	7,728	2,105	27.24%
106	Oct-08		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	7,322	2,654	36.25%	482	6,840	3,136	45.85%
107	Nov-08		3,208	479	831	3,356	7,874	2,437	10,311	-106	7,106	2,313	291	-495	-873	7,749	2,562	33.06%	692	7,057	3,254	46.10%
108	Dec-08		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	8,436	1,562	18.55%	1,082	8,354	2,644	31.65%
109	Jan-09	0	3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	11,327	-329	-2.90%	1,049	10,278	720	7.01%
110	Feb-09		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	10,382	616	5.93%	953	9,412	1,579	16.78%
111	Mar-09		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	8,705	2,293	26.34%	850	7,855	3,153	40.19%
112	Apr-09		3,127	479	831	3,102	7,539	2,512	10,051	-106	6,781	2,392	291	-491	-848	6,863	3,188	46.45%	484	6,379	3,672	57.56%
113	May-09		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	7,839	2,137	27.26%	513	7,326	2,650	36.17%
114	Jun-09		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,477	1,261	14.87%	537	7,940	1,797	22.64%
115	Jul-09		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,629	1,109	12.85%	553	8,076	1,661	20.57%
116	Aug-09	0	3,041	479	831	3,102	7,453	2,199	9,652	-106	6,712	2,084	291	-459	-809	8,803	849	9.64%	542	8,261	1,390	16.83%
117	Sep-09		3,127	479	831	3,102	7,539	2,294	9,833	-106	6,790	2,177	291	-469	-827	8,415	1,418	16.85%	529	7,886	1,947	24.69%
118	Oct-09		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	7,451	2,525	33.89%	476	6,975	3,001	43.03%
119	Nov-09		3,208	479	831	3,356	7,874	2,437	10,311	-106	7,106	2,313	291	-495	-873	7,847	2,464	31.40%	690	7,157	3,154	44.07%
120	Dec-09		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	8,563	1,435	15.01%	1,074	8,489	2,509	29.55%

FPC 129

JUNE 1999 FORECAST (S990507)

Mild Weather

Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
WINTER 99/00	Jan-2000	8,841	338	23	361	326	687	0	8,154	105
WINTER 99/00	Feb-2000	8,060	321	23	344	326	670	0	7,390	96
WINTER 99/00	Mar-2000	6,779	305	23	328	326	654	0	6,125	81
SUMMER 00	Apr-2000	6,104	286	43	329	327	656	0	5,448	76
SUMMER 00	May-2000	7,164	305	47	352	327	679	0	6,485	89
SUMMER 00	Jun-2000	7,896	405	49	454	327	781	0	7,115	97
SUMMER 00	Jul-2000	8,078	342	50	392	327	719	0	7,359	100
SUMMER 00	Aug-2000	8,229	384	50	434	327	761	0	7,468	102
SUMMER 00	Sep-2000	7,788	365	49	414	327	741	0	7,047	96
SUMMER 00	Oct-2000	6,651	225	45	270	328	598	0	6,053	84
WINTER 00/01	Nov-2000	6,073	299	24	323	328	651	0	5,422	74
WINTER 00/01	Dec-2000	7,628	331	25	356	328	684	0	6,944	94
WINTER 00/01	Jan-2001	9,035	326	26	353	314	667	0	8,368	108
WINTER 00/01	Feb-2001	8,256	307	26	333	314	647	0	7,609	98
WINTER 00/01	Mar-2001	6,935	289	26	315	314	629	0	6,306	84
SUMMER 01	Apr-2001	6,306	260	46	307	314	621	0	5,685	79
SUMMER 01	May-2001	7,360	276	50	326	314	640	0	6,720	92
SUMMER 01	Jun-2001	8,052	364	52	416	315	731	0	7,321	100
SUMMER 01	Jul-2001	8,243	307	52	359	315	674	0	7,569	103
SUMMER 01	Aug-2001	8,396	344	52	396	315	711	0	7,685	105
SUMMER 01	Sep-2001	7,944	324	52	375	315	690	0	7,254	99
SUMMER 01	Oct-2001	6,815	197	47	244	315	559	0	6,256	86
WINTER 01/02	Nov-2001	6,245	278	27	304	315	619	0	5,626	77
WINTER 01/02	Dec-2001	7,790	305	27	332	316	648	0	7,142	97
WINTER 01/02	Jan-2002	8,674	299	27	326	311	637	0	8,037	104
WINTER 01/02	Feb-2002	7,998	282	27	309	311	620	0	7,378	96
WINTER 01/02	Mar-2002	6,693	266	27	293	311	604	0	6,089	81
SUMMER 02	Apr-2002	6,054	218	49	267	311	578	0	5,476	76
SUMMER 02	May-2002	7,078	232	53	284	311	595	0	6,483	89
SUMMER 02	Jun-2002	7,691	307	54	360	311	671	0	7,020	96
SUMMER 02	Jul-2002	7,891	259	55	314	312	626	0	7,265	99
SUMMER 02	Aug-2002	8,046	291	55	346	312	658	0	7,388	101
SUMMER 02	Sep-2002	7,585	275	54	329	312	641	0	6,944	95
SUMMER 02	Oct-2002	6,506	168	50	218	312	530	0	5,976	83
WINTER 02/03	Nov-2002	6,004	259	29	289	312	601	0	5,403	74
WINTER 02/03	Dec-2002	7,459	286	30	315	313	628	0	6,831	93
WINTER 02/03	Jan-2003	8,324	281	30	311	313	624	0	7,700	100
WINTER 02/03	Feb-2003	7,637	265	30	295	313	608	0	7,029	92
WINTER 02/03	Mar-2003	6,420	251	30	281	313	594	0	5,826	78

FPC 130

JUNE 1999 FORECAST (S990507)
Mild Weather
Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 03	Apr-2003	6,038	188	52	240	313	553	0	5,485	76
SUMMER 03	May-2003	6,885	200	56	256	313	569	0	6,316	87
SUMMER 03	Jun-2003	7,443	266	57	323	314	637	0	6,806	93
SUMMER 03	Jul-2003	7,573	225	58	283	314	597	0	6,976	95
SUMMER 03	Aug-2003	7,683	253	58	312	314	626	0	7,057	97
SUMMER 03	Sep-2003	7,387	240	57	297	314	611	0	6,776	93
SUMMER 03	Oct-2003	6,548	147	53	200	314	514	0	6,034	83
WINTER 03/04	Nov-2003	5,819	247	33	280	314	594	0	5,225	72
WINTER 03/04	Dec-2003	7,069	273	33	306	315	621	0	6,448	88
WINTER 03/04	Jan-2004	8,479	269	33	302	310	612	0	7,867	102
WINTER 03/04	Feb-2004	7,786	254	33	288	310	598	0	7,188	94
WINTER 03/04	Mar-2004	6,521	241	34	274	310	584	0	5,937	79
SUMMER 04	Apr-2004	6,148	166	55	221	310	531	0	5,617	78
SUMMER 04	May-2004	7,015	177	59	236	310	546	0	6,469	89
SUMMER 04	Jun-2004	7,584	234	60	295	310	605	0	6,979	96
SUMMER 04	Jul-2004	7,719	199	61	259	311	570	0	7,149	98
SUMMER 04	Aug-2004	7,836	224	61	285	311	596	0	7,240	99
SUMMER 04	Sep-2004	7,529	212	60	272	311	583	0	6,946	95
SUMMER 04	Oct-2004	6,671	129	56	186	311	497	0	6,174	85
WINTER 04/05	Nov-2004	5,910	238	36	274	311	585	0	5,325	73
WINTER 04/05	Dec-2004	7,188	264	36	299	311	610	0	6,578	89
WINTER 04/05	Jan-2005	8,564	260	36	296	312	608	0	7,956	103
WINTER 04/05	Feb-2005	7,860	246	36	282	312	594	0	7,266	95
WINTER 04/05	Mar-2005	6,570	233	37	270	312	582	0	5,988	80
SUMMER 05	Apr-2005	6,211	147	58	205	312	517	0	5,694	79
SUMMER 05	May-2005	7,089	156	62	218	312	530	0	6,559	90
SUMMER 05	Jun-2005	7,663	207	63	270	313	583	0	7,080	97
SUMMER 05	Jul-2005	7,800	175	64	239	313	552	0	7,248	99
SUMMER 05	Aug-2005	7,926	197	64	262	313	575	0	7,351	101
SUMMER 05	Sep-2005	7,608	187	63	250	313	563	0	7,045	97
SUMMER 05	Oct-2005	6,741	114	60	174	313	487	0	6,254	86
WINTER 05/06	Nov-2005	5,950	231	39	270	313	583	0	5,367	74
WINTER 05/06	Dec-2005	7,249	256	39	295	314	609	0	6,640	90
WINTER 05/06	Jan-2006	8,717	252	39	291	314	605	0	8,112	106
WINTER 05/06	Feb-2006	8,001	239	40	278	314	592	0	7,409	97
WINTER 05/06	Mar-2006	6,670	226	40	266	314	580	0	6,090	82
SUMMER 06	Apr-2006	6,321	129	61	191	314	505	0	5,816	81
SUMMER 06	May-2006	7,216	138	65	203	314	517	0	6,699	92
SUMMER 06	Jun-2006	7,802	182	66	249	315	564	0	7,238	99

FPC 131

JUNE 1999 FORECAST (S990507)

Mild Weather

Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 06	Jul-2006	7,941	155	67	222	315	537	0	7,404	101
SUMMER 06	Aug-2006	8,079	174	67	241	315	556	0	7,523	103
SUMMER 06	Sep-2006	7,746	165	67	231	315	546	0	7,200	99
SUMMER 06	Oct-2006	6,862	101	63	163	315	478	0	6,384	88
WINTER 06/07	Nov-2006	6,038	225	42	266	315	581	0	5,457	75
WINTER 06/07	Dec-2006	7,365	248	42	291	316	607	0	6,758	92
WINTER 06/07	Jan-2007	8,879	245	42	288	316	604	0	8,275	108
WINTER 06/07	Feb-2007	8,150	232	43	275	316	591	0	7,559	99
WINTER 06/07	Mar-2007	6,777	220	43	263	316	579	0	6,198	83
SUMMER 07	Apr-2007	6,439	114	64	178	316	494	0	5,945	83
SUMMER 07	May-2007	7,352	121	68	190	316	506	0	6,846	94
SUMMER 07	Jun-2007	7,949	161	69	230	317	547	0	7,402	101
SUMMER 07	Jul-2007	8,091	136	70	207	317	524	0	7,567	104
SUMMER 07	Aug-2007	8,239	154	70	224	317	541	0	7,698	105
SUMMER 07	Sep-2007	7,891	145	70	215	317	532	0	7,359	101
SUMMER 07	Oct-2007	6,990	89	66	155	317	472	0	6,518	90
WINTER 07/08	Nov-2007	6,136	219	45	264	318	582	0	5,554	76
WINTER 07/08	Dec-2007	7,491	242	45	287	318	605	0	6,886	94
WINTER 07/08	Jan-2008	9,041	239	45	285	318	603	0	8,438	110
WINTER 07/08	Feb-2008	8,297	227	46	273	318	591	0	7,706	101
WINTER 07/08	Mar-2008	6,885	215	46	261	318	579	0	6,306	85
SUMMER 08	Apr-2008	6,557	101	67	168	318	486	0	6,071	84
SUMMER 08	May-2008	7,488	107	71	178	319	497	0	6,991	96
SUMMER 08	Jun-2008	8,095	142	73	215	319	534	0	7,561	104
SUMMER 08	Jul-2008	8,240	120	73	194	319	513	0	7,727	106
SUMMER 08	Aug-2008	8,400	135	74	209	319	528	0	7,872	108
SUMMER 08	Sep-2008	8,037	128	73	201	319	520	0	7,517	103
SUMMER 08	Oct-2008	7,118	78	69	147	319	466	0	6,652	92
WINTER 08/09	Nov-2008	6,233	213	48	261	320	581	0	5,652	78
WINTER 08/09	Dec-2008	7,617	236	48	285	320	605	0	7,012	96
WINTER 08/09	Jan-2009	9,204	234	49	282	320	602	0	8,602	113
WINTER 08/09	Feb-2009	8,447	222	49	270	320	590	0	7,857	103
WINTER 08/09	Mar-2009	6,995	210	49	259	320	579	0	6,416	86
SUMMER 09	Apr-2009	6,676	89	71	159	320	479	0	6,197	86
SUMMER 09	May-2009	7,625	95	74	169	321	490	0	7,135	98
SUMMER 09	Jun-2009	8,244	125	76	201	321	522	0	7,722	106
SUMMER 09	Jul-2009	8,392	106	76	182	321	503	0	7,889	108
SUMMER 09	Aug-2009	8,562	119	77	196	321	517	0	8,045	110
SUMMER 09	Sep-2009	8,184	113	76	189	321	510	0	7,674	105

FPC 132

JUNE 1999 FORECAST (S990507)

Mild Weather

Bulk Power Sales Included

SEASON	MONTH	TOTAL SYSTEM BEFORE LOAD CONTROL (MW)	DIRECT LOAD CONTROL PROGRAMS: RESIDENTIAL LOAD MGT. (MW)	OTHER DLC PROGRAMS (MW)	TOTAL DLC PROGRAMS (MW)	INTERR. LOAD (MW)	TOTAL LOAD CONTROL CAPABILITY (MW)	(USED) VOLTAGE REDUCTION (MW)	FIRM SYSTEM AFTER LOAD CONTROL (MW)	(AVAILABLE) VOLTAGE REDUCTION (MW)
SUMMER 09	Oct-2009	7,247	69	72	141	321	462	0	6,785	94
WINTER 09/10	Nov-2009	6,330	209	51	260	322	582	0	5,748	79
WINTER 09/10	Dec-2009	7,743	231	51	282	322	604	0	7,139	97

FPC 133

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

1999 SERC RATINGS, COGENERATION = 981231

JUNE 1999 FORECAST (S990507)

Bulk Power Sales Included in Demand & Energy Forecast

Hines 2 in 11/2003 : "Mild" Weather Analysis with Capacity @ "Base" Ratings

		WINTER 99/00	WINTER 00/01	WINTER 01/02	WINTER 02/03	WINTER 03/04	WINTER 04/05	WINTER 05/06	WINTER 06/07	WINTER 07/08	WINTER 08/09
		Jan-2000	Jan-2001	Jan-2002	Jan-2003	Jan-2004	Jan-2005	Jan-2006	Jan-2007	Jan-2008	Jan-2009
Existing FPC Capacity	MW	8,351	8,351	8,689	8,706	8,706	9,121	9,121	9,121	9,688	9,688
New FPC Capacity	MW	0	338	17	0	567	0	0	567	0	0
Retired FPC Capacity	MW	0	0	0	0	152	0	0	0	0	0
Total Installed Capacity	MW	8,351	8,689	8,706	8,706	9,121	9,121	9,121	9,688	9,688	9,688
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831	831
QF Contractually-Allowed On-Peak Capacity Reduction	MW	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	9,545	9,883	9,900	9,900	10,315	10,325	10,325	10,892	10,892	10,892
Mild Weather Demand (Before Load Control)	MW	8,841	9,035	8,674	8,324	8,479	8,564	8,717	8,879	9,041	9,204
Mild Weather Reserves (Before Load Control)	MW	704	848	1,226	1,576	1,836	1,761	1,608	2,013	1,851	1,688
Mild Weather Reserve Margin (Before Load Control)	%	8.0%	9.4%	14.1%	18.9%	21.7%	20.6%	18.4%	22.7%	20.5%	18.3%
Mild Weather Load Management	MW	361	353	326	311	302	296	291	288	285	282
Mild Weather Demand (After Load Management)	MW	8,480	8,682	8,348	8,013	8,177	8,268	8,426	8,591	8,756	8,922
Mild Weather Reserves (After Load Management)	MW	1,065	1,201	1,552	1,887	2,138	2,057	1,899	2,301	2,136	1,970
Mild Weather Reserve Margin (After Load Management)	%	12.6%	13.8%	18.6%	23.5%	26.1%	24.9%	22.5%	26.8%	24.4%	22.1%
Mild Weather Interruptible Load	MW	326	314	311	313	310	312	314	316	318	320
Mild Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Mild Weather Demand (After All Load Control)	MW	8,154	8,368	8,037	7,700	7,867	7,956	8,112	8,275	8,438	8,602
Mild Weather Reserves (After All Load Control)	MW	1,391	1,515	1,863	2,200	2,448	2,369	2,213	2,617	2,454	2,290
Mild Weather Reserve Margin (After All Load Control)	%	17.1%	18.1%	23.2%	28.6%	31.1%	29.8%	27.3%	31.6%	29.1%	26.6%
Mild Weather Reserves (After All Load Control) Required For 15 %	MW	1,223	1,255	1,206	1,155	1,180	1,193	1,217	1,241	1,266	1,290
Mild Weather Reserves (After All Load Control) Above 15 %	MW	168	259	657	1,044	1,268	1,176	997	1,375	1,188	1,000
Mild Weather "DLC" Reserve Margin Contribution	%	49.4%	44.0%	34.2%	28.3%	25.0%	25.7%	27.4%	23.1%	24.6%	26.3%

FPC 134

LOAD AND CAPACITY REPORT - SEASONAL GENERATION CAPACITY

1999 SERC RATINGS, COGENERATION = 981231

JUNE 1999 FORECAST (S990507)

Bulk Power Sales Included In Demand & Energy Forecast

Hines 2 in 11/2003 : "Mild" Weather Analysis with Capacity @ "Base" Ratings

		SUMMER 00	SUMMER 01	SUMMER 02	SUMMER 03	SUMMER 04	SUMMER 05	SUMMER 06	SUMMER 07	SUMMER 08	SUMMER 09
		Aug-2000	Aug-2001	Aug-2002	Aug-2003	Aug-2004	Aug-2005	Aug-2006	Aug-2007	Aug-2008	Aug-2009
Existing FPC Capacity	MW	7,236	7,236	7,485	7,502	7,502	7,847	7,847	7,847	8,342	8,342
New FPC Capacity	MW	0	249	17	0	495	0	0	495	0	0
Retired FPC Capacity	MW	0	0	0	0	150	0	0	0	0	0
Total Installed Capacity	MW	7,236	7,485	7,502	7,502	7,847	7,847	7,847	8,342	8,342	8,342
Firm Purchase Capacity	MW	469	469	469	469	469	479	479	479	479	479
Firm QF Purchase Capacity	MW	831	831	831	831	831	831	831	831	831	831
QF Contractually-Allowed On-Peak Capacity Reduction	MW	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)	(106)
Seasonal Purchase Capacity	MW	0	0	0	0	0	0	0	0	0	0
Capacity on Scheduled Maintenance	MW	0	0	0	0	0	0	0	0	0	0
Firm Sale of Capacity	MW	0	0	0	0	0	0	0	0	0	0
Total Available Capacity	MW	8,430	8,679	8,696	8,696	9,041	9,051	9,051	9,546	9,546	9,546
Mild Weather Demand (Before Load Control)	MW	8,229	8,396	8,046	7,683	7,836	7,926	8,079	8,239	8,400	8,562
Mild Weather Reserves (Before Load Control)	MW	201	283	650	1,013	1,205	1,125	972	1,307	1,146	984
Mild Weather Reserve Margin (Before Load Control)	%	2.4%	3.4%	8.1%	13.2%	15.4%	14.2%	12.0%	15.9%	13.6%	11.5%
Mild Weather Load Management	MW	434	396	346	312	285	262	241	224	209	196
Mild Weather Demand (After Load Management)	MW	7,795	8,000	7,700	7,371	7,551	7,664	7,838	8,015	8,191	8,366
Mild Weather Reserves (After Load Management)	MW	635	679	996	1,324	1,489	1,386	1,213	1,531	1,355	1,180
Mild Weather Reserve Margin (After Load Management)	%	8.1%	8.5%	12.9%	18.0%	19.7%	18.1%	15.5%	19.1%	16.5%	14.1%
Mild Weather Interruptible Load	MW	327	315	312	314	311	313	315	317	319	321
Mild Weather Voltage Reduction	MW	0	0	0	0	0	0	0	0	0	0
Mild Weather Demand (After All Load Control)	MW	7,468	7,685	7,388	7,057	7,240	7,351	7,523	7,698	7,872	8,045
Mild Weather Reserves (After All Load Control)	MW	962	994	1,308	1,638	1,800	1,699	1,528	1,848	1,674	1,501
Mild Weather Reserve Margin (After All Load Control)	%	12.9%	12.9%	17.7%	23.2%	24.9%	23.1%	20.3%	24.0%	21.3%	18.7%
Mild Weather Reserves (After All Load Control) Required For 20 %	MW	1,494	1,537	1,478	1,411	1,448	1,470	1,505	1,540	1,574	1,609
Mild Weather Reserves (After All Load Control) Above 20 %	MW	-531	-543	-170	227	352	229	23	308	99	-108
Mild Weather "DLC" Reserve Margin Contribution	%	79.1%	71.6%	50.3%	38.2%	33.1%	33.8%	36.4%	29.3%	31.5%	34.5%

FPC 135

Mild Weather

	Month	Scheduled Maintenance	Baseload Plants	Baseload Contracts	QF Contracts	Intermediate Resources	Baseload & Intermediate Resources	Peaking Resources	Total Resources	QF On-Peak Reduction	Baseload & Intermediate Resources	Peaking Resources	Operating Requirements	5.5% FPC Available Resources EFOR	8.7% FPC Available Resources EFOR	Total Peak Before DLC	Supply Variance	Supply Reserve Margin	Total DLC (including IS/CS and Vol. Red.)	Firm Peak After DLC	Total Variance	Total Reserve Margin
1	Jan-00	0	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,033	2,712	341	-458	-810	8,841	810	9.16%	687	8,154	1,497	18.36%
2	Feb-00	-162	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,039	2,714	341	-450	-794	8,060	1,429	17.73%	670	7,390	2,099	28.40%
3	Mar-00	-1,299	3,150	469	831	2,374	6,824	2,827	9,651	-106	6,086	2,730	341	-388	-884	6,779	1,573	23.20%	654	6,125	2,227	36.36%
4	Apr-00	-1,332	3,069	469	831	2,262	6,631	2,188	8,819	-106	5,979	2,103	291	-340	-600	6,104	1,363	22.66%	656	5,448	2,039	37.44%
5	May-00	0	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,983	2,084	291	-416	-733	7,164	1,896	23.87%	678	6,485	2,375	36.63%
6	Jun-00	0	3,110	469	831	2,262	6,672	1,950	8,622	-106	5,973	1,849	291	-403	-710	7,898	728	9.19%	781	7,115	1,507	21.18%
7	Jul-00	0	3,110	469	831	2,262	6,672	1,950	8,622	-106	5,873	1,849	291	-403	-710	8,078	544	6.73%	718	7,358	1,263	17.16%
8	Aug-00	0	3,024	469	831	2,262	6,586	1,850	8,536	-106	5,881	1,850	291	-388	-702	8,229	307	3.73%	761	7,468	1,068	14.30%
9	Sep-00	0	3,110	469	831	2,262	6,672	2,045	8,717	-106	5,969	1,943	291	-408	-718	7,788	929	11.93%	741	7,047	1,670	23.71%
10	Oct-00	-467	3,110	469	831	2,262	6,672	2,188	8,860	-106	5,983	2,081	291	-380	-686	6,651	1,722	25.89%	598	6,053	2,320	38.33%
11	Nov-00	-884	3,191	469	831	2,374	6,865	2,188	9,053	-106	6,185	2,094	291	-378	-668	6,073	2,098	34.51%	651	5,422	2,747	50.66%
12	Dec-00	-115	3,191	469	831	2,374	6,865	3,124	9,988	-106	6,064	3,006	341	-472	-832	7,628	2,248	29.44%	684	6,944	2,930	42.19%
13	Jan-01	0	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,060	3,005	341	-478	-843	8,035	854	10.56%	667	7,368	1,621	19.37%
14	Feb-01	-167	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,066	3,007	341	-468	-827	8,256	1,564	18.97%	647	7,609	2,213	29.09%
15	Mar-01	-501	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,080	3,011	341	-450	-784	6,835	2,653	38.81%	629	6,206	3,182	50.46%
16	Apr-01	-1,096	3,110	469	831	2,262	6,672	2,512	9,184	-106	5,995	2,419	291	-373	-658	6,306	1,782	28.28%	621	5,685	2,403	42.26%
17	May-01	-606	3,110	469	831	2,262	6,672	2,437	9,109	-106	5,986	2,341	291	-385	-678	7,360	843	12.81%	640	6,720	1,583	23.56%
18	Jun-01	0	3,110	469	831	2,262	6,672	2,199	8,871	-106	5,963	2,095	291	-418	-734	8,052	619	10.17%	731	7,321	1,549	21.16%
19	Jul-01	0	3,110	469	831	2,262	6,672	2,199	8,871	-106	5,963	2,095	291	-418	-734	8,243	628	7.61%	674	7,569	1,302	17.20%
20	Aug-01	0	3,024	469	831	2,262	6,586	2,199	8,785	-106	5,880	2,096	291	-412	-726	8,396	388	4.63%	711	7,685	1,100	14.31%
21	Sep-01	0	3,110	469	831	2,262	6,672	2,294	8,966	-106	5,959	2,189	291	-422	-744	7,944	1,022	12.87%	690	7,254	1,712	23.60%
22	Oct-01	-628	3,110	469	831	2,262	6,672	2,437	9,109	-106	5,979	2,338	291	-385	-687	6,815	1,666	24.45%	658	6,256	2,225	35.57%
23	Nov-01	-1,467	3,191	469	831	2,374	6,865	2,437	9,302	-106	6,186	2,347	291	-358	-634	6,245	1,500	25.46%	619	5,626	2,208	38.27%
24	Dec-01	-1,152	3,191	469	831	2,374	6,865	3,124	9,989	-106	6,107	3,020	341	-415	-731	7,790	1,047	13.44%	648	7,142	1,695	23.73%
25	Jan-02	0	3,208	469	831	2,374	6,882	3,124	10,006	-106	6,076	3,004	341	-479	-844	8,674	1,332	15.36%	637	8,037	1,969	24.49%
26	Feb-02	0	3,208	469	831	2,374	6,882	3,124	10,006	-106	6,076	3,004	341	-479	-844	7,998	2,008	25.11%	620	7,378	2,628	35.62%
27	Mar-02	-941	3,208	469	831	2,374	6,882	3,124	10,006	-106	6,115	3,017	341	-427	-753	6,693	2,372	35.44%	604	6,089	2,976	48.88%
28	Apr-02	-1,101	3,127	469	831	2,262	6,689	2,512	9,201	-106	6,012	2,419	291	-374	-660	6,054	2,048	33.80%	578	5,476	2,624	47.82%
29	May-02	-464	3,127	469	831	2,262	6,689	2,437	9,126	-106	5,988	2,338	291	-404	-712	7,078	1,564	22.10%	595	6,483	2,159	33.31%
30	Jun-02	0	3,127	469	831	2,262	6,689	2,199	8,888	-106	5,978	2,094	291	-417	-736	7,691	1,197	15.56%	671	7,020	1,868	26.61%
31	Jul-02	0	3,127	469	831	2,262	6,689	2,199	8,888	-106	5,978	2,094	291	-417	-736	7,891	987	12.63%	626	7,265	1,622	22.33%
32	Aug-02	0	3,041	469	831	2,262	6,603	2,199	8,802	-106	5,897	2,085	291	-413	-728	8,040	756	9.39%	658	7,382	1,414	19.13%
33	Sep-02	0	3,127	469	831	2,262	6,689	2,294	8,983	-106	5,975	2,188	291	-423	-745	7,685	1,308	16.43%	641	7,044	2,038	29.36%
34	Oct-02	-601	3,127	469	831	2,262	6,689	2,437	9,126	-106	5,984	2,338	291	-397	-701	6,508	2,019	31.03%	530	5,978	2,549	42.65%
35	Nov-02	-708	3,208	469	831	2,374	6,882	2,437	9,319	-106	6,163	2,336	291	-402	-709	6,004	2,607	43.42%	601	5,403	3,208	59.37%
36	Dec-02	-712	3,208	469	831	2,374	6,882	3,124	10,006	-106	6,105	3,014	341	-440	-775	7,459	1,835	24.60%	628	6,831	2,463	36.07%
37	Jan-03	0	3,208	469	831	2,374	6,882	3,124	10,006	-106	6,076	3,004	341	-479	-844	8,324	1,682	20.21%	624	7,700	2,306	29.94%
38	Feb-03		3,208	469	831	2,374	6,882	3,124	10,006	-106	6,076	3,004	341	-478	-844	7,637	2,369	31.02%	608	7,029	2,977	42.36%
39	Mar-03		3,208	469	831	2,374	6,882	3,124	10,006	-106	6,076	3,004	341	-478	-844	6,420	3,586	55.86%	594	5,826	4,180	71.75%
40	Apr-03		3,127	469	831	2,262	6,689	2,512	9,201	-106	5,968	2,403	291	-435	-766	6,038	3,163	52.38%	553	5,485	3,716	67.76%
41	May-03		3,127	469	831	2,262	6,689	2,437	9,126	-106	5,968	2,329	291	-430	-758	6,885	2,241	32.55%	569	6,316	2,810	44.49%
42	Jun-03		3,127	469	831	2,262	6,689	2,199	8,888	-106	5,978	2,094	291	-417	-736	7,443	1,445	19.41%	637	6,806	2,081	30.58%
43	Jul-03		3,127	469	831	2,262	6,689	2,199	8,888	-106	5,978	2,094	291	-417	-736	7,573	1,315	17.36%	597	6,976	1,911	27.40%
44	Aug-03	0	3,041	469	831	2,262	6,603	2,199	8,802	-106	5,897	2,085	291	-413	-728	7,683	1,119	14.56%	626	7,057	1,744	24.71%
45	Sep-03		3,127	469	831	2,262	6,689	2,294	8,983	-106	5,975	2,188	291	-423	-745	7,387	1,596	21.61%	611	6,776	2,207	32.57%
46	Oct-03		3,127	469	831	2,262	6,689	2,437	9,126	-106	5,968	2,329	291	-430	-758	6,548	2,578	39.37%	514	6,034	3,092	51.24%
47	Nov-03		3,208	469	831	2,789	7,297	2,437	9,734	-106	6,552	2,321	291	-464	-818	5,819	3,915	67.28%	594	5,225	4,509	86.30%
48	Dec-03		3,208	469	831	2,789	7,297	3,124	10,421	-106	6,474	2,999	341	-502	-885	7,069	3,352	47.42%	621	6,448	3,973	61.62%
49	Jan-04	0	3,208	469	831	2,789	7,297	3,124	10,421	-106	6,474	2,999	341	-502	-885	8,479	1,942	22.90%	612	7,867	2,554	32.47%
50	Feb-04		3,208	469	831	2,789	7,297	3,124	10,421	-106	6,474	2,999	341	-502	-885	7,786	2,635	33.84%	598	7,188	3,233	44.97%
51	Mar-04		3,208	469	831	2,789	7,297	3,124	10,421	-106	6,474	2,999	341	-502	-885	6,521	3,900	59.81%	584	5,937	4,484	75.54%
52	Apr-04		3,127	469	831	2,607	7,034	2,512	9,546	-106	6,297	2,399	291	-454	-800	6,148	3,398	55.27%	531	5,617	3,929	68.96%
53	May-04		3,127	469	831	2,607	7,034	2,437	9,471	-106	6,300	2,325	291	-449	-793	7,015	2,456	35.01%	546	6,469	3,002	46.40%
54	Jun-04		3,127	469	831	2,607	7,034	2,199	9,233	-106	6,310	2,090	291	-436	-768	7,584	1,649	21.74%	605	6,979	2,253	32.28%
55	Jul-04		3,127	469	831	2,112	6,539	2,199	8,738	-106	5,835	2,096	291	-409	-721	7,718	1,019	13.20%	570	7,148	1,589	22.23%
56	Aug-04	0	3,041	469	831	2,607	6,948	2,199	9,147	-106	6,227	2,081	291	-432	-761	7,836	1,311	16.73%	596	7,240	1,906	28.33%
57	Sep-04		3,127	469	831	2,607	7,034	2,294	9,328	-106	6,306	2,184	291	-442	-779	7,529	1,789	23.89%	583	6,946	2,382	34.29%
58	Oct-04		3,127	469	831	2,607	7,034	2,437	9,471	-106	6,300	2,325	291	-449	-793	6,671	2,800	41.97%	497	6,174	3,297	53.40%
59	Nov-04		3,208	469	831	2,789	7,297	2,437	9,734	-106	6,552	2,321	291	-464	-818	5,810	3,824	64.70%	585	5,325	4,409	82.80%

60	Dec-04		3,208	459	831	2,789	7,297	3,124	10,421	-106	6,474	2,899	341	-502	-845	7,188	3,233	44.98%	610	6,578	3,843	58.43%
61	Jan-05	0	3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,989	341	-502	-845	8,564	1,867	21.80%	608	7,958	2,476	31.11%
62	Feb-05		3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,989	341	-502	-845	7,860	2,571	32.71%	594	7,266	3,165	43.56%
63	Mar-05		3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,989	341	-502	-845	6,570	3,861	58.77%	582	5,988	4,443	74.18%
64	Apr-05		3,127	479	831	2,607	7,044	2,512	9,556	-106	6,307	2,399	291	-454	-800	6,211	3,345	53.86%	517	5,694	3,862	67.82%
65	May-05		3,127	479	831	2,607	7,044	2,437	9,481	-106	6,310	2,325	291	-448	-793	7,088	2,392	33.74%	530	6,558	2,922	44.55%
66	Jun-05		3,127	479	831	2,607	7,044	2,199	9,243	-106	6,320	2,090	291	-438	-769	7,663	1,580	20.61%	583	7,080	2,163	30.55%
67	Jul-05		3,127	479	831	2,607	7,044	2,199	9,243	-106	6,320	2,090	291	-438	-769	7,800	1,443	18.49%	552	7,248	1,995	27.52%
68	Aug-05	0	3,041	479	831	2,607	6,958	2,199	9,157	-106	6,237	2,091	291	-432	-761	7,926	1,231	15.53%	575	7,351	1,806	24.55%
69	Sep-05		3,127	479	831	2,607	7,044	2,294	9,338	-106	6,316	2,184	291	-442	-779	7,608	1,730	22.74%	563	7,045	2,293	32.55%
70	Oct-05		3,127	479	831	2,607	7,044	2,437	9,481	-106	6,310	2,325	291	-448	-793	6,741	2,740	40.65%	487	6,254	3,227	51.60%
71	Nov-05		3,208	479	831	2,789	7,307	2,437	9,744	-106	6,562	2,321	291	-464	-818	5,950	3,794	63.76%	583	5,367	4,377	81.55%
72	Dec-05		3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,989	341	-502	-845	7,248	3,182	43.90%	608	6,640	3,791	57.08%
73	Jan-06	0	3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,989	341	-502	-845	8,717	1,714	19.66%	605	8,112	2,319	28.59%
74	Feb-06		3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,989	341	-502	-845	8,001	2,430	30.37%	592	7,408	3,022	40.79%
75	Mar-06		3,208	479	831	2,789	7,307	3,124	10,431	-106	6,484	2,989	341	-502	-845	6,670	3,761	56.38%	580	6,090	4,341	71.28%
76	Apr-06		3,127	479	831	2,607	7,044	2,512	9,556	-106	6,307	2,399	291	-454	-800	6,321	3,235	51.18%	505	5,816	3,740	64.29%
77	May-06		3,127	479	831	2,607	7,044	2,437	9,481	-106	6,310	2,325	291	-448	-793	7,216	2,265	31.39%	517	6,699	2,782	41.52%
78	Jun-06		3,127	479	831	2,607	7,044	2,199	9,243	-106	6,320	2,090	291	-438	-769	7,802	1,441	18.46%	564	7,238	2,004	27.69%
79	Jul-06		3,127	479	831	2,607	7,044	2,199	9,243	-106	6,320	2,090	291	-438	-769	7,941	1,302	16.39%	537	7,404	1,838	24.83%
80	Aug-06	0	3,041	479	831	2,607	6,958	2,199	9,157	-106	6,237	2,091	291	-432	-761	8,079	1,078	13.34%	556	7,523	1,634	21.72%
81	Sep-06		3,127	479	831	2,607	7,044	2,294	9,338	-106	6,316	2,184	291	-442	-779	7,746	1,592	20.55%	546	7,200	2,138	28.70%
82	Oct-06		3,127	479	831	2,607	7,044	2,437	9,481	-106	6,310	2,325	291	-448	-793	6,862	2,619	38.17%	478	6,384	3,097	48.52%
83	Nov-06		3,208	479	831	3,356	7,874	2,437	10,311	-106	7,108	2,313	291	-495	-873	6,038	4,273	70.77%	581	5,457	4,854	88.96%
84	Dec-06		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	7,365	3,633	49.33%	607	6,758	4,240	62.73%
85	Jan-07	0	3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	8,879	2,119	23.87%	604	8,275	2,723	32.90%
86	Feb-07		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	8,150	2,848	34.94%	591	7,559	3,439	45.50%
87	Mar-07		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	6,777	4,221	62.28%	578	6,198	4,800	77.45%
88	Apr-07		3,127	479	831	3,102	7,539	2,512	10,051	-106	6,741	2,392	291	-481	-848	6,439	3,612	56.10%	494	5,945	4,106	69.08%
89	May-07		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,745	2,318	291	-477	-841	7,352	2,624	35.69%	506	6,846	3,130	45.71%
90	Jun-07		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	7,948	1,789	22.50%	547	7,402	2,336	31.56%
91	Jul-07		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,091	1,647	20.35%	524	7,567	2,170	28.68%
92	Aug-07	0	3,041	479	831	3,102	7,453	2,199	9,652	-106	6,712	2,084	291	-459	-809	8,238	1,413	17.15%	541	7,698	1,954	25.38%
93	Sep-07		3,127	479	831	3,102	7,539	2,294	9,833	-106	6,790	2,177	291	-469	-827	7,891	1,942	24.61%	532	7,359	2,474	33.62%
94	Oct-07		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	6,990	2,986	42.72%	472	6,518	3,458	53.04%
95	Nov-07		3,208	479	831	3,356	7,874	2,437	10,311	-106	7,106	2,313	291	-495	-873	6,136	4,175	68.04%	582	5,554	4,757	85.64%
96	Dec-07		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	7,491	3,507	46.82%	605	6,886	4,112	59.72%
97	Jan-08	0	3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	9,041	1,957	21.65%	603	8,438	2,560	30.34%
98	Feb-08		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	8,297	2,701	32.55%	591	7,706	3,292	42.71%
99	Mar-08		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	6,885	4,113	59.74%	579	6,306	4,692	74.41%
100	Apr-08		3,127	479	831	3,102	7,539	2,512	10,051	-106	6,781	2,392	291	-481	-848	6,557	3,494	53.29%	486	6,071	3,980	65.56%
101	May-08		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	7,488	2,488	33.23%	487	6,991	2,985	42.70%
102	Jun-08		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,095	1,643	20.29%	534	7,561	2,176	28.78%
103	Jul-08		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,240	1,498	18.17%	513	7,727	2,010	26.01%
104	Aug-08	0	3,041	479	831	3,102	7,453	2,199	9,652	-106	6,712	2,084	291	-459	-809	8,400	1,252	14.90%	528	7,872	1,780	22.61%
105	Sep-08		3,127	479	831	3,102	7,539	2,294	9,833	-106	6,790	2,177	291	-469	-827	8,037	1,796	22.35%	520	7,517	2,316	30.81%
106	Oct-08		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	7,118	2,858	40.15%	468	6,652	3,324	49.97%
107	Nov-08		3,208	479	831	3,356	7,874	2,437	10,311	-106	7,106	2,313	291	-495	-873	6,233	4,078	65.43%	581	5,652	4,659	82.45%
108	Dec-08		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	7,617	3,381	44.38%	605	7,012	3,986	56.84%
109	Jan-09	0	3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	9,204	1,794	18.48%	602	8,602	2,396	27.86%
110	Feb-09		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	8,447	2,551	30.20%	580	7,857	3,141	39.99%
111	Mar-09		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	6,995	4,003	57.23%	578	6,416	4,582	71.42%
112	Apr-09		3,127	479	831	3,102	7,539	2,512	10,051	-106	6,781	2,392	291	-481	-848	6,676	3,375	50.55%	478	6,197	3,854	62.20%
113	May-09		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	7,625	2,351	30.83%	490	7,135	2,841	39.81%
114	Jun-09		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,244	1,494	18.12%	522	7,722	2,015	26.10%
115	Jul-09		3,127	479	831	3,102	7,539	2,199	9,738	-106	6,794	2,083	291	-464	-817	8,392	1,346	16.03%	503	7,889	1,849	23.44%
116	Aug-09	0	3,041	479	831	3,102	7,453	2,199	9,652	-106	6,712	2,084	291	-459	-809	8,562	1,090	12.73%	517	8,045	1,607	19.97%
117	Sep-09		3,127	479	831	3,102	7,539	2,294	9,833	-106	6,790	2,177	291	-469	-827	8,184	1,649	20.15%	510	7,674	2,159	28.13%
118	Oct-09		3,127	479	831	3,102	7,539	2,437	9,976	-106	6,785	2,318	291	-477	-841	7,247	2,729	37.66%	462	6,785	3,191	47.03%
119	Nov-09		3,208	479	831	3,356	7,874	2,437	10,311	-106	7,106	2,313	291	-495	-873	6,330	3,981	62.89%	582	5,748	4,563	79.37%
120	Dec-09		3,208	479	831	3,356	7,874	3,124	10,998	-106	7,027	2,991	341	-533	-940	7,743	3,255	42.04%	604	7,139	3,859	54.07%

FPC 137

5.2.1.1 Financial

FPC 138

FINANCIAL ASSUMPTIONS FOR 2000 10 Year Site Plan and IRP
BASE CASE VALUES

Base year 2000

		10 Year Site Plan Values
	CER Inputs	
9	DISCOUNT RATE	8.53%
10	REAL DISCOUNT RATE	5.53%
11	FED INC TAX RATE	38.58%
12	INFLATION RATE	3.00%
13	AFUDC RATE	8.53%
14	CAPITALIZED INT DEBT RATE	7.0%
15	DEBT STRUCTURE BOOK	45.00%
16	DEBT STRUCTURE FOR TAX	100.00%
17	DESIRED RETURN ON RATE BASE	9.75%
18	ITC RATE	0.0%
19	LONG TERM DEBT INT RATE	7.0%
20	COST OF CAP ESC RATE (Coal)	2.5%
21	COST OF CAP ESC RATE (C.T.)	2.5%
22	COST OF CAP ESC RATE (C.C.)	2.5%
23	COST OF CAP ESC RATE (Transm & Substa)	2.5%
24	COST OF CAP ESC RATE (Distrib)	2.5%
26	**PRV Inputs**	
28	FUEL COST ESCALATION (Nuclear 100%	N/A
29	FUEL COST ESCALATION (Coal)	N/A
30	FUEL COST ESCALATION (Oil)	N/A
31	FUEL COST ESCALATION (Gas)	N/A
32	ENERGY COST ESCALATION	N/A
33	FIXED COST ESCALATION	2.5%
34	VARIABLE COST ESCALATION	3.0%
35	REVENUE DISCOUNT RATE	8.53%
36	SALES DISCOUNT RATE	0.00%
37	WEIGHTED COST OF CAPITAL	9.75%
38	CONSTRUCTION ESCALATION (Coal)	2.5%
39	CONSTRUCTION ESCALATION (C.T.)	2.5%
40	CONSTRUCTION ESCALATION (C.C.)	2.5%
41	LEVELIZED CHARGE RATE (Coal)	13.77%
42	LEVELIZED CHARGE RATE (C.T.)	13.88%
43	LEVELIZED CHARGE RATE (C.C.)	14.35%
45	**DSV Inputs**	
47	BASE REVENUE ESCALATION	0.0%
48	CUSTOMER COST ESCALATION	3.0%
49	DSM EXPENSE ESCALATION	3.0%
51	*Memo GENERAL INFLATION (CPI)*	3.0%
52	*Memo GDP PRICE Index*	2.5%

Base Case Cap Structure

56	Long Term Debt	**45.00%**	**7.00%**	3.15%
57	Preferred Stock	**0.00%**	**8.00%**	0.00%
58	Common Stock	**55.00%**	**12.00%**	6.60%
59	Composite			$\boxed{9.750\%}$
60	Debt Tax Deductible			1.22%
61	After-Tax Discount Rate			$\boxed{8.53\%}$
63	Federal Income Tax Rate			35.00%
64	State Income Tax Rate			5.50%

5.2.1.2 Fuel Forecast

COAL FORECAST							0001	OIL FORECAST			
	CRYSTAL 1-2 (includes 5% Pet. Coke)			CRYSTAL 4-5			#6 FUEL OIL			#2 FUEL OIL	
		$/MMBTU			$/MMBTU		$/MMBTU				
	BTU/LB	AVG.	INCRE.	BTU/LB	AVG.	INCRE.	1.0%	1.50%	2.50%	.2-.5%	
Jan-00	12500	1.630	1.550	12500	1.950	1.610	2.97	2.96	2.93	5.36	
Feb-00	12500	1.630	1.550	12500	1.950	1.610	3.10	3.09	3.06	5.71	
Mar-00	12500	1.630	1.550	12500	1.950	1.610	3.01	2.99	2.96	5.52	
Apr-00	12500	1.630	1.550	12500	1.950	1.610	2.92	2.91	2.88	5.31	
May-00	12500	1.630	1.550	12500	1.950	1.610	2.83	2.82	2.79	5.09	
Jun-00	12500	1.630	1.550	12500	1.950	1.610	2.76	2.75	2.72	4.92	
Jul-00	12500	1.630	1.550	12500	1.950	1.610	2.68	2.67	2.65	4.82	
Aug-00	12500	1.630	1.550	12500	1.950	1.610	2.62	2.61	2.59	4.76	
Sep-00	12500	1.630	1.550	12500	1.950	1.610	2.57	2.56	2.54	4.78	
Oct-00	12500	1.630	1.550	12500	1.950	1.610	2.53	2.52	2.49	4.49	
Nov-00	12500	1.630	1.550	12500	1.950	1.610	2.48	2.47	2.45	4.70	
Dec-00	12500	1.630	1.550	12500	1.950	1.610	2.44	2.43	2.41	4.83	
2001	12500	1.650	1.570	12500	1.930	1.650	2.69	2.59	2.43	4.76	
2002	12500	1.670	1.590	12500	1.920	1.680	2.65	2.56	2.40	4.74	
2003	12500	1.690	1.610	12500	1.940	1.710	2.65	2.56	2.40	4.77	
2004	12500	1.710	1.640	12500	1.960	1.740	2.67	2.58	2.42	4.81	
2005	12500	1.730	1.660	12500	1.910	1.770	2.71	2.61	2.45	4.89	
2006	12500	1.770	1.690	12500	1.930	1.800	2.77	2.67	2.50	4.99	
2007	12500	1.790	1.710	12500	1.950	1.830	2.83	2.73	2.56	5.10	
2008	12500	1.820	1.740	12500	1.990	1.860	2.89	2.79	2.61	5.21	
2009	12500	1.840	1.770	12500	2.020	1.890	2.96	2.85	2.67	5.31	

Oil Transport	$/MMBtu
Suw #6	
2.50%	0.50
1%	0.65
#2 Oil	
Anclote	0.13
Avon Park	0.21
Bartow	0.20
Bayboro	0.20
Crystal R	0.23
Debary	0.30
Higgins	0.09
Hines*	0.34
Int.City	0.11
Rio P	0.23
Suwannee	0.24
Turner	0.27

* .05%Sulfur
Add $.15/mmbtu
for any new #2 oil sites
plus transport

Escalation rates : Coal :+ 1.0%/yr after 2009
Oil : +1.0%/yr after 2009

Heat Content : #6 oil - 6.5 Mbtu/bbl
#2 oil - 5.8 Mbtu/bbl

FPC 141

NATURAL GAS SUPPLY AND VARIABLE TRANSPORTATION COST
($/MMBTU)

	REGULAR SUPPLY COST	PREMIUM SUPPLY COST	TIGER SUPPLY COST	VARIABLE FT					INTERRUPTIBLE TRANSPORTATION				
				FGT U of F	FGT IC	FGT O-FGT	GulfStr FTS	Sonat Suwan	U of F	IC	O-FGT	Gulfstr	SONAT
Jan-00	$2.35	$3.35	$2.29	$0.22	$0.22	$0.12	$0.00	$0.19	$0.39	$0.39	$0.29	$0.00	$0.70
Feb-00	$2.49	$3.49	$2.29	$0.22	$0.22	$0.12	$0.00	$0.19	$0.39	$0.39	$0.29	$0.00	$0.70
Mar-00	$2.51	$3.51	$2.29	$0.22	$0.22	$0.12	$0.00	$0.19	$0.39	$0.39	$0.29	$0.00	$0.70
Apr-00	$2.57	$3.57	$2.29	$0.22	$0.22	$0.12	$0.00	$0.19	$0.39	$0.39	$0.29	$0.00	$0.60
May-00	$2.60	$3.60	$2.29	$0.22	$0.22	$0.12	$0.00	$0.19	$0.67	$0.67	$0.57	$0.00	$0.60
Jun-00	$2.61	$3.61	$2.29	$0.22	$0.22	$0.12	$0.00	$0.19	$0.67	$0.67	$0.57	$0.00	$0.60
Jul-00	$2.62	$3.62	$2.29	$0.22	$0.22	$0.12	$0.00	$0.19	$0.67	$0.67	$0.57	$0.00	$0.60
Aug-00	$2.63	$3.63	$2.29	$0.22	$0.22	$0.12	$0.00	$0.19	$0.67	$0.67	$0.57	$0.00	$0.60
Sep-00	$2.64	$3.64	$2.29	$0.22	$0.22	$0.12	$0.00	$0.19	$0.67	$0.67	$0.57	$0.00	$0.60
Oct-00	$2.67	$3.67	$2.29	$0.22	$0.22	$0.12	$0.00	$0.19	$0.47	$0.47	$0.37	$0.00	$0.60
Nov-00	$2.78	$3.78	$2.29	$0.22	$0.22	$0.12	$0.00	$0.19	$0.47	$0.47	$0.37	$0.00	$0.70
Dec-00	$2.90	$3.90	$2.29	$0.22	$0.22	$0.12	$0.00	$0.19	$0.47	$0.47	$0.37	$0.00	$0.70
2001	$2.59	$3.59	$2.38	$0.23	$0.23	$0.13	$0.00	$0.20	$0.55	$0.55	$0.45	$0.00	$0.65
2002	$2.63	$3.63	$2.48	$0.23	$0.23	$0.13	$0.09	$0.20	$0.60	$0.60	$0.50	$0.30	$0.65
2003	$2.71	$3.71	$2.58	$0.23	$0.23	$0.13	$0.09	$0.20	$0.60	$0.60	$0.50	$0.30	$0.65
2004	$2.80	$3.80	$2.68	$0.23	$0.23	$0.13	$0.09	$0.20	$0.60	$0.60	$0.50	$0.30	$0.65
2005	$2.88	$3.88	$2.79	$0.23	$0.23	$0.13	$0.09	$0.20	$0.60	$0.60	$0.50	$0.30	$0.65
2006	$2.94	$3.94	$2.90	$0.24	$0.24	$0.14	$0.10	$0.21	$0.61	$0.61	$0.51	$0.30	$0.65
2007	$3.01	$4.01	$3.01	$0.24	$0.24	$0.14	$0.10	$0.21	$0.61	$0.61	$0.51	$0.30	$0.65
2008	$3.07	$4.07	$3.13	$0.24	$0.24	$0.14	$0.10	$0.21	$0.61	$0.61	$0.51	$0.30	$0.65
2009	$3.14	$4.14	$3.26	$0.24	$0.24	$0.14	$0.10	$0.21	$0.61	$0.61	$0.51	$0.30	$0.65

Post 2009 escalation rate for Regular and Premium Supply Costs = 1.0% per year
Post 2009 thru 12/31/10 escalation rate for Tiger Supply Costs = 4% per year

FPC 142

5.2.1.4 Generation Technology

Confidential

2000 Ten-Year Site Plan

2000 Dollars

Confidential

Plant name		Hines	Hines	Hines	Inter. City	FPC System
Option name		F Type	F Type Market	G Type	CT gas ("EA")	CT gas ("F")
Study		2000 TYSP	2000 TYSP	2000 TYSP	2000 TYSP	2000 TYSP
Alternative		CCH2	CCM	CCG	3CTE	CTF
Generation and Fuel						
New winter maximum capacity	MW	567	567	365	282	178
New summer maximum capacity	MW	495	495	323	249	151
New minimum capacity	MW	289	289	190	141	89
Number of units in capacity ratings		1	1	1	3	1
Available capacity		no limit	no limit	no limit	no limit	no limit
Full load net heat rate (x000)	(btu/kwh)	6.800	6.800	6.787	11.814	10.614
Minimum load net heat rate (x000)	(btu/kwh)	7.850	7.850	7.535	15.621	13.972
Mature forced outage rate	%	3.7	3.7	3.7	3.0	3.0
Maintenance requirement	(wks/yr)	2.3	2.3	2.3	1.5	1.5
Primary fuel type	fuel name	Firm Gas	Firm Gas	Firm Gas	IT Gas	IT Gas
Secondary fuel type	fuel name	IT Gas	IT Gas	IT Gas	Dist. Oil	Dist. Oil
Incremental Fixed O&M rate	($/kw/yr)	2.5	2.5	2.4	1.4	2.9
Incremental Fixed O&M rate	($000/yr)	1,402	1,402	865	407	519
• Fixed gas demand cost	($/kw/yr)	32	32	32	n/a	n/a
• Fixed gas demand cost	($000/yr)	18,144	18,144	11,680	n/a	n/a
• Fixed gas quantity	(mmbtu/day)	65,000	65,000	41,843		
Variable O&M cost	($/mwh)	2.10	2.10	1.96	4.35	3.77
Variable O&M Capacity Factor (check)	(CF%)	0.70	0.70	0.70	0.15	0.15
Variable O&M cost (check)	($000/yr)	6,842	6,842	4,128	1,516	815
Capital Expenditure & Recovery						
Design construction duration	years	3	3	3	2	2
Projected conversion downtime	months	NA	NA	NA	NA	NA
Generation Costs	($1000)	165,830	186,430	160,680	80,000	44,808
Construction expenditure (1st year)	%	15	15	15	30	30
Construction expenditure (2nd year)	%	60	60	60	70	70
Construction expenditure (3rd year)	%	25	25	25		
Construction expenditure (4th year)	%					
Base cost w/o AFUDC	($/kw) WTR	292	329	440	284	252
Base cost w/o AFUDC	($/kw) NOM.	312	351	467	301	272

Cost Estimate Worksheet: Impact of Staged CC Construction

Original Investigations: Hines 2 Cost Impact

For CT's Staged In-Service ($2000)

Original Power Block Cost Estimate	$166 Million
Estimated Impact on Power Block Cost *	20%
Potential Cost Impact @ 20% Project	$ 33 Million
Potential Cost Impact (Mitigated) **	$ 20 Million

Estimated Impact for a "Market" Combined Cycle

For CT's Staged In-Service ($2000)

Current Power Block Cost Estimate	$186 Million
Potential Cost Impact (Mitigated)	$ 20 Million
Resultant Total Cost of Power Block	$206 Million

* Note: Based on B&V conceptual studues for Hines 2 development.

** Note: The planning estimate for mitigation of cost impact is based on advance planning and contract development anticipating staged installation.

6.1.1 Financial

BATES NOS. FPC 148 – FPC 149
CONFIDENTIAL
PURSUANT TO FLORIDA
POWER CORPORATION'S
REQUST FOR CONFIDENTIAL
CLASSIFICATION FILED
AUGUST 7, 2000

FINANCIAL ASSUMPTIONS FOR 2000 10 Year Site Plan and IRP
BASE CASE VALUES

Base year 2000

		10 Year Site Plan Values
	CER Inputs	
9	DISCOUNT RATE	8.53%
10	REAL DISCOUNT RATE	5.53%
11	FED INC TAX RATE	38.58%
12	INFLATION RATE	3.00%
13	AFUDC RATE	8.53%
14	CAPITALIZED INT DEBT RATE	7.0%
15	DEBT STRUCTURE BOOK	45.00%
16	DEBT STRUCTURE FOR TAX	100.00%
17	DESIRED RETURN ON RATE BASE	9.75%
18	ITC RATE	0.0%
19	LONG TERM DEBT INT RATE	7.0%
20	COST OF CAP ESC RATE (Coal)	2.5%
21	COST OF CAP ESC RATE (C.T.)	2.5%
22	COST OF CAP ESC RATE (C.C.)	2.5%
23	COST OF CAP ESC RATE (Transm & Substa)	2.5%
24	COST OF CAP ESC RATE (Distrib)	2.5%
26	PRV Inputs	
28	FUEL COST ESCALATION (Nuclear 100%	N/A
29	FUEL COST ESCALATION (Coal)	N/A
30	FUEL COST ESCALATION (Oil)	N/A
31	FUEL COST ESCALATION (Gas)	N/A
32	ENERGY COST ESCALATION	N/A
33	FIXED COST ESCALATION	2.5%
34	VARIABLE COST ESCALATION	3.0%
35	REVENUE DISCOUNT RATE	8.53%
36	SALES DISCOUNT RATE	0.00%
37	WEIGHTED COST OF CAPITAL	9.75%
38	CONSTRUCTION ESCALATION (Coal)	2.5%
39	CONSTRUCTION ESCALATION (C.T.)	2.5%
40	CONSTRUCTION ESCALATION (C.C.)	2.5%
41	LEVELIZED CHARGE RATE (Coal)	13.77%
42	LEVELIZED CHARGE RATE (C.T.)	13.88%
43	LEVELIZED CHARGE RATE (C.C.)	14.35%
45	DSV Inputs	
47	BASE REVENUE ESCALATION	0.0%
48	CUSTOMER COST ESCALATION	3.0%
49	DSM EXPENSE ESCALATION	3.0%
51	*Memo GENERAL INFLATION (CPI)*	3.0%
52	*Memo GDP PRICE Index*	2.5%

Base Case Cap Structure

56	Long Term Debt	**45.00%**	**7.00%**	3.15%
57	Preferred Stock	**0.00%**	**8.00%**	0.00%
58	Common Stock	**55.00%**	**12.00%**	6.60%
59		Composite		$\boxed{9.750\%}$
60		Debt Tax Deductible		1.22%
61		After-Tax Discount Rate		$\boxed{8.53\%}$
63	Federal Income Tax Rate			35.00%
64	State Income Tax Rate			5.50%

FPC 150

Show O&M for:

20 April 00

Effective since 1/1/00

Plant	Unit	O&M Cost
Anclote	G1	[redacted]
Anclote	G2	[redacted]
Auburndale	G1	[redacted]
Avon Park	P1	[redacted]
Avon Park	P2	[redacted]
Bartow	G1	[redacted]
Bartow	G2	[redacted]
Bartow	G3	[redacted]
Bartow	P1	[redacted]
Bartow	P2	[redacted]
Bartow	P3	[redacted]
Bartow	P4	[redacted]
Bay County	G1	[redacted]
Bayboro	P1	[redacted]
Bayboro	P2	[redacted]
Bayboro	P3	[redacted]
Bayboro	P4	[redacted]
Cargill	G1	[redacted]
Crystal River	G1	[redacted]
Crystal River	G2	[redacted]
Crystal River	G3	[redacted]
Crystal River	G4	[redacted]
Crystal River	G5	[redacted]
Dade County	G1	[redacted]
Debary	P1	[redacted]
Debary	P1-P6	[redacted]
Debary	P10	[redacted]
Debary	P2	[redacted]
Debary	P3	[redacted]
Debary	P4	[redacted]
Debary	P5	[redacted]
Debary	P6	[redacted]
Debary	P7	[redacted]
Debary	P7-P10	[redacted]
Debary	P8	[redacted]
Debary	P9	[redacted]
Higgins	P1	[redacted]

Higgins	P2	[redacted]
Higgins	P3	[redacted]
Higgins	P4	[redacted]
Hines	G1	[redacted]
Intercession City	P1	[redacted]
Intercession City	P1-P6	[redacted]
Intercession City	P10	[redacted]
Intercession City	P11	[redacted]
Intercession City	P2	[redacted]
Intercession City	P3	[redacted]
Intercession City	P4	[redacted]
Intercession City	P5	[redacted]
Intercession City	P6	[redacted]
Intercession City	P7	[redacted]
Intercession City	P7-P10	[redacted]
Intercession City	P8	[redacted]
Intercession City	P9	[redacted]
Lake Cogen	G1	[redacted]
Lake County	G1	[redacted]
Mulberry	G1	[redacted]
Non Telemetered	G1	[redacted]
Orange	G1	[redacted]
Orlando	G1	[redacted]
Pasco Cogen	G1	[redacted]
Pasco County	G1	[redacted]
Pertetual Energy	G1	[redacted]
Pinellas County	G1	[redacted]
Ridge	G1	[redacted]
Rio Pinar	P1	[redacted]
Suwannee	G1	[redacted]
Suwannee	G2	[redacted]
Suwannee	G3	[redacted]
Suwannee	P1	[redacted]
Suwannee	P2	[redacted]
Suwannee	P3	[redacted]
Tiger Bay	G1	[redacted]
Timber Energy	G1	[redacted]
Turner	P1	[redacted]
Turner	P2	[redacted]
Turner	P3	[redacted]
Turner	P4	[redacted]
US Agri-Chem	G1	[redacted]
Univ. of Florida	G1	[redacted]

12/14/99

K-Factor for Standard Offer Contract and Value of Deferral

- ✓ $5 Mill contingency included. AFDAC included
- ✓ 25 years
- ✓ Property taxes included 1.7%, not escalated. no AFDAC
- ✓ Payroll taxes excluded
- ✓ 55% Eq @ 12.0% + 45% D @ 7.3% = ATWACC
- ✓ 5 year contract (standard offer)
- ✓ 2.5% escalation
- ✓ Zero capital additions
- ✓ 2004 Jan in service for first full year
- ✓ Zero O&M
- ✓ No transmission or substation

O&M
- ✓ Payroll taxes excluded
- ✓ 3.1% escalation
- ✓ Variable
- ✓ Fixed

Fuel
- ✓ 6,975 Heat Rate @ 65% average dispatch

BATES NOS. FPC 154 – FPC 155
CONFIDENTIAL
PURSUANT TO FLORIDA
POWER CORPORATION'S
REQUST FOR CONFIDENTIAL
CLASSIFICATION FILED
AUGUST 7, 2000

Northern States Power

Build Vs

Purchase Power

Paul Pender, Manager
Financial & Investment Analysis
(612) 330-7769

EEI System Planning Committee
San Francisco, California
September 25, 1991

FPC 156

Independent Power Producers (IPP's)

- Facilitated because of utility unwillingness or inability to build due to experience during last construction cycle with:
  - Prudency disallowances
  - Escalating construction costs
  - High financing costs

Entities Involved
Independent Power Producers

Generation facilities (not QF) that are frequently subsidiaries of utilities, non-utilities or independent publicly-held companies not subject to traditional regulation

Power Purchase Contract
Key Factors

- Financial leverage
  The lender will extend credit to the IPP on 85-90% of the project based on the power purchase contract
- Assignment of risk
  Credit to the IPP is granted based on credit worthiness of the utility that is purchasing power

Entities Involved
Cost of Capital
Tax Rate of 40%

	IPP		Traditional Utility	
	% of Total Capital	% Cost*	% of Total Capital	% Cost*
Debt	85	6.6	50	5.4
Preferred Stock	0	-	6	9.5
Common Equity	15	16	44	12.5
Weighted Cost of Capital		8.0		8.8

*. After Tax

Build Vs Purchase Power
Why?

- Avoid large capital outlay
- Reduce risk of not being included in rate base
- Cost advantages
- Supply diversity

Financial Impact

- Bondholder
- Equity Investor (Shareholder)

Standard & Poor's

The company's credit protection is eroded by additional fixed obligations

"While transfer of capacity ownership to third-party generators can lower costs, reduce regulatory risks, ... this supply option entails specific risks that must be accounted for in S&P's evaluation of credit quality."

Rating Agency Response
Standard & Poor's

"Take-or-pay obligations are treated by S&P as debt equivalents. With take-and-pay contracts the minimum fixed payment under the contract is reflected in S&P's calculation of the utility's fixed charge coverage: Funds from operations + interest + capacity payment / (interest + capacity payments)

Rating Agency Response
Moody's

"In our view, the practice of imputing debt obligations for purchase power contracts constitutes a better measurement of the real financial burden being undertaken by the company."

Total Cost of Purchase Contract
Step 1

Present value of future purchase contract obligations * (equity ratio/debt ratio) = equity financing required to restore original capital structure

Total Cost of Purchase Contract
Step 1 - Example

Dollars in millions

Year	PV Purchase Contract	Equity Ratio	Debt Ratio	Equity Financing Required
1	$200	60%	40%	$300
2	187	"	"	280
3	173	"	"	259
4	157	"	"	235
5	140	"	"	210
6	121	"	"	182
7	101	"	"	151
8	79	"	"	118
9	55	"	"	82
10	29	"	"	43

Equity financing required * Debt ratio = Amount normally financed with debt

Dollars in millions

Year	Equity Financing Required	Debt Ratio	Amount Normally Debt Financed
1	$300	40%	$120
2	280	"	112
3	259	"	103
4	235	"	94
5	210	"	84
6	182	"	73
7	151	"	61
8	118	"	47
9	82	"	33
10	43	"	17

Total Cost of Purchase Contract Step 3

Amount normally financed with debt * (Cost of equity - Cost of debt) = Excess return

Total Cost of Purchase Contract Step 3 - Example

Dollars in millions

Year	Amount Normally Debt Financed	Equity Cost	Debt Cost	Excess Return
1	$120	12.5%	9.0%	$4.20
2	112	"	"	3.92
3	103	"	"	3.62
4	94	"	"	3.29
5	84	"	"	2.94
6	73	"	"	2.55
7	61	"	"	2.12
8	47	"	"	1.66
9	33	"	"	1.15
10	17	"	"	0.60

Total Cost of Purchase Contract Step 4

(Amount normally debt financed * Cost of equity) * (Tax rate/1-tax rate) = Excess taxes

Total Cost of Purchase Contract Step 4 - Example

Dollars in millions

Year	Amount Normally Debt Financed	Equity Cost	Tax Rate	Excess Taxes
1	$120	12.5%	40%	$10.00
2	112	"	"	9.34
3	103	"	"	8.62
4	94	"	"	7.84
5	84	"	"	6.99
6	73	"	"	6.06
7	61	"	"	5.05
8	47	"	"	3.94
9	33	"	"	2.74
10	17	"	"	1.43

Excess return + Excess taxes =

Total PV incremental return adjustment

Step 5 - Example

Dollars in millions

Year	Excess Return	Excess Taxes	Total PV Incremental Return Adjustment
1	$4.20	$10.00	$13.03
2	3.92	9.34	11.17
3	3.62	8.62	9.46
4	3.29	7.84	7.89
5	2.94	6.99	6.45
6	2.55	6.06	5.13
7	2.12	5.05	3.92
8	1.66	3.94	2.81
9	1.15	2.74	1.79
10	0.60	1.43	0.86

Total Cost of Purchase Contract Step 6

Nominal cost + Total PV incremental return adjustment = Total contract cost

Total Cost of Purchase Contract Step 6 - Example

Dollars in millions

Year	PV Purchase Contract	Total PV Incremental Return Adjustment	Total Contract Cost
1	$200	$13.03	$262
2	187	11.17	
3	173	9.46	
4	157	7.89	
5	140	6.45	
6	121	5.13	
7	101	3.92	
8	79	2.81	
9	55	1.79	
10	29	0.86	

Bondholder Concerns Summary

Purchase Contracts = Increased Debt

Financial Impact Equity Investor

High power purchases limits the company's ability to meet shareholders' return expectations

Calculation of the True Cost of a Capacity Purchase
Method 3 - Capitalized Capacity Payments

Annual Capacity Pmt	33	Cost of Debt:	9.00%
Escalation rate:	0.0%	Debt ratio:	40.00%
Contract Term (yrs):	10	Equity return:	12.50%
Risk Factor:	100%		
Effective tax rate:	40.000%	COC - before tax	11.10%
Interest Coverage ratio	4.47	COC - after tax:	9.66%

Year	Capacity Payment	Present Value	Implicit Interest	Compensating Equity	Added Rev Requmt
1	32.549	200.000	20.000	120.000	14.200
2	32.549	187.451	18.745	112.471	13.309
3	32.549	173.647	17.365	104.188	12.329
4	32.549	158.463	15.846	95.078	11.251
5	32.549	141.760	14.176	85.056	10.065
6	32.549	123.387	12.339	74.032	8.760
7	32.549	103.176	10.318	61.906	7.326
8	32.549	80.945	8.094	48.567	5.747
9	32.549	56.490	5.649	33.894	4.011
10	32.549	29.590	2.959	17.754	2.101
NPV	202.955				61.705
			Original Contract PV:		200.000
			Total PP Contract Cost:		261.705

Percent Increase in Revenue Requirement: 30.40%

Note: NPV is calculated using the after-tax cost of capital

Of course, at least initially, this restructuring will be done largely at the expense of its investors. PNM's shareholders may absorb some of the fixed embedded costs that cannot be reduced, such as a portion of the company's $54 million lease payments associated with PV units 1&2 ($76 million of this lease is in rates).

It is important to recognize that PNM may eventually be a threat to surrounding regions. A large part of the utility's significant excess reserves are not recoverable from rate payers. Capacity out of rate base totals 365mw, including a 105mw purchased power contract. Since this investment has already been written down and represents a drag on cash flow, PNM can justify marketing it at only a small premium over marginal cost. This could present a problem for other utilities in surrounding areas.

The Arizona utilities are also vulnerable to competitive threats from surrounding areas like, Utah and New Mexico. A particularly vulnerable utility in the Southwest is Tuscon Electric Power Company. TEP also has surplus reserves, high rates and nonearning assets. Like PNM, TEP must rely heavily on wholesale interchange markets, given the large amount of surplus reserves. Furthermore, about 198mw of TEP's Springerville unit 2 coal plant is out of rate base, and a certain portion of the lease of Springerville unit 1 has been disallowed. The company also has 4?% industrial load with a 9% concentration of load in the mining industry, which could benefit from self-generation. However, unlike PNM, which is taking steps to allow it to lower rates eventually, TEP is so financially distressed that it has limited flexibility to lower rates. Like PNM, TEP has excess reserves and assets out of rate base and could also contribute to the reduction of regional market rates. Yet its long-term competitive viability under the present structure is questionable.

Public Service Co.'s (PSCO) has the lowest rate structure in its immediate area. Also, capacity needs are modest. While it will have some small rate needs over the intermediate term, its low cost rate structure should not change significantly. Industrial load and wholesale load exposure is not that significant. The only threat to Colorado would be from companies to its south that have assets out of rate base and thus may be able to sell power only slightly above margin to gain load.

Deborah Goldsmith, C.F.A.
(212) 208-1394

Figures based on Typical Residential, Commercial, and Industrial Bills: Edison Electric Institute.

BUY VERSUS BUILD DEBATE REVISITED

The debate over purchased power, or the "buy versus build" controversy, will likely continue to rage as state utility regulators grapple with the implications of the National Energy Policy Act of 1992. As part of this sweeping legislation, state regulators must consider the potential impact on utilities' cost of capital from purchasing power.

Table 1
Determining the risk factor

The risk factor chosen is a function of a subjective (not arbitrary) analysis of qualitative risks

Market	Need for power Economics
Operating	Performance standards Reliability Dispatchability Control over maintenance Flexibility and diversity
Regulatory	Preapproval Regulatory recovery mechanisms Regulatory out clause

Compared with the last baseload construction cycle, which is universally acknowledged to have been a disaster for investor-owned utilities, buying power from others appears substantially less risky than building new capacity. However, the electric utility industry's entire approach to supply-side resource additions has undergone radical transformation, to the point where it is now impossible to generalize about whether utility bondholders are better off if their utility buys or builds. The important thing is that both resource strategies have inherent risks. S&P employs a methodology for evaluating the benefits and risks of purchased power, and for adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with traditional utilities.

BENEFITS OF PURCHASING POWER

Buying power may be the best choice for a utility that faces increasing demand. Moreover purchasing may be the least risky course. The benefits of purchasing can be quite compelling. For example, utilities that purchase avoid the risks of significant construction cost overruns or that the plant might never be finished at all! They also may avoid the associated financial stress caused by regulatory lag typical in building programs.

In addition, utilities that purchase power avoid risking substantial capital. There are many examples of utilities that have failed to earn a full return on and of capital employed to build a plant. Furthermore, purchased power may contribute to fuel-supply diversity and flexibility, and may be cheaper, at least over the short run. Utilities that meet demand expectations with a portfolio of supply-side options also may be better able to adapt to future demand uncertainty, given the specter of retail transmission access.

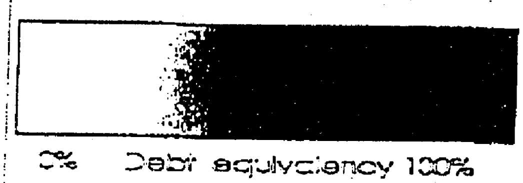
Nevertheless, in the buy-versus-build debate it is important that appropriate comparisons are made. A properly designed building program may avoid many of the risks associated with the

FPC 162

unfortunate baseload program of the 1970s and early 1980s. A utility could:

- Build a plant using a fixed-price, turnkey construction contract;
- Construct with a modular approach, adding small units incrementally as demand expectations solidify;
- Obtain regulatory preapproval;
- Receive a cash return on construction work in progress to ease financing stress; and
- Finance the asset with a large portion of equity, providing a cushion for bondholders.

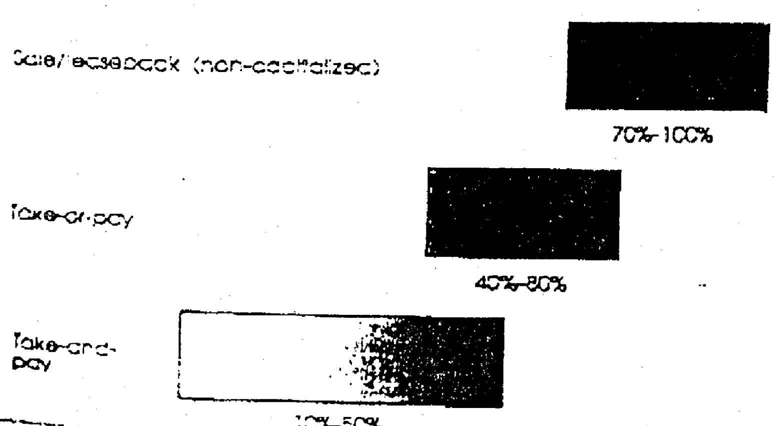
Chart 1
Risk Spectrum



PURCHASES ARE NOT RISK-FREE

Regardless of whether a utility buys or builds, adding capacity means incurring risk. To the extent that there are any risks with purchased power, bondholders are directly threatened because there is no equity layer to protect them. Utilities are not compensated for any risks they assume in purchasing power. At best, purchased power is recovered dollar-for-dollar as an operating expense, so there is no markup to reward equity holders for taking risks.

Chart 2
Risk factors for various off-balance-sheet obligations



When a utility enters into a long-term purchased power contract with a fixed-cost component, it takes on financial risk. Heavy fixed long-term contractual arrangements represent—at least in part—off-balance-sheet debt equivalents. Utilities need to take these "financial externalities" into account so that buy and build options are evaluated on a level playing field.

S&P has developed a methodology to quantify this financial risk and adjust financial statements to make traditional utilities and purchasing utilities comparable. S&P's approach is unique because it folds our qualitative analysis into our quantitative methodology. S&P begins by determining the potential off-balance-sheet obligation. This is done by calculating the present value of the capacity payments to be made over the life of the contract, discounted at 10%. The capacity payment is the fixed portion of the purchased power expense. It covers fixed costs, including debt service, depreciation, and a return on equity. S&P is concerned about the total fixed payment, not simply the debt service portion; the utility is obligated to pay the whole amount, not just a part. This means S&P is relatively indifferent to how the nonutility generator is capitalized, except in the extreme case where vast overleveraging threatens the viability of the project.

In virtually all cases, S&P has access to—and utilizes—actual capacity payments. In the rare instance where they are not available or where capacity and energy payments are not broken out—such as in an energy-only contact—S&P will estimate the capacity payment.

S&P does not stop with the potential debt equivalent. S&P recognizes that not all obligations have the same characteristics. What is true of other off-balance-sheet liabilities also is true of purchased power: some are more firm and therefore more debt-like than others.

This concept of the difference in the relative debt characteristics of purchased power obligations can be illustrated by using the concept of a risk spectrum *(see chart 1)*. A risk spectrum is simply a range from 0% to 100%. Obligations on the low end of the scale would have fewer debt-like characteristics and would be considered less firm than the obligations judged to fall on the high end of the scale. This spectrum is important because the place where an obligation falls on the scale—what S&P calls the risk factor—will determine what portion of the obligation S&P will add to a utility's reported debt. For example, if S&P determines that the risk factor for an obligation is 20%, S&P adds 20% of the potential debt equivalent to reported debt.

Different off-balance-sheet obligations have different risks *(see chart 2, which shows various types of off-balance sheet obligations and where S&P believes they might fall on the risk spectrum scale)*. Sale/leasebacks of major plants are viewed as the virtual equivalent of debt, due to the strategic importance of these major electric generating facilities and the "hell-or-high-water" nature of the lease commitments.

Obligations under take-or-pay contracts, which are unconditional as to both acceptance and availability of power, are considered quite firm. The extreme case would be a unit-specific

firm take-or-pay arrangement. Here, the risk factor might be as high as 70%-80%. Take-and-pay contracts, which require capacity payments only if power is available, are considered the least debt-like of the three types of obligations listed in chart 2 because take-and-pay capacity payments are conditional. In practice, the risk factors for take-and-pay performance contracts are generally in the 10%-20% range, although some may be as high as 50%.

DETERMINING THE RISK FACTOR

How does S&P determine the risk factor or the place where an obligation falls on the risk spectrum? S&P's assessment of the risk factor reflects our analysis of the risks a utility incurs when purchasing power under contract. This depends on a qualitative analysis of market, operating, and regulatory risks. It also depends on S&P's evaluation of the extent to which these risks are borne by the utility. The analysis is subjective, but not arbitrary *(see table 1 for some of the key factors under each broad risk category)*. Depending on circumstances, the utility may bear substantial risks, or it may have successfully shifted risks to either the ratepayers or to the nonutility generator provider of the power.

Lower risk factors would be appropriate if:

- The power is economic and needed,
- True performance standards exist,
- A project has operated reliably,
- The utility has a say in the scheduling of maintenance and retains control over dispatch,
- A contract is preapproved by regulators,
- Capacity payments are recovered through a fuel-clause type mechanism, and
- A regulatory out clause passes disallowance risk to the power seller

The absence of these qualitative risk mitigators would lead toward the higher end of the risk spectrum and a higher risk factor

Table 2
ABC Power Co. adjustment to capital structure
(Mil. $ at year-end 1992)

	Original capital structure		Adjusted capital structure		
	$	%	$	%	
Debt	1,400	54	1,400	49	} 58
Adjustment to debt	—	—	265	9	
Preferred stock	200	8	200	7	
Common equity	1,000	38	1,000	35	

Table 3
ABC Power Co. adjustment to pretax interest coverage
(Mil. $ year-end 1992)

		Orig. pretax int. cov.		Adj. pretax int. cov.
Net income	120		300	
Income taxes	65	300	+27	
Interest expense	115	115 = 2.6x	115	= 2.3x
Pretax available	300		+27	

Interest associated with adjusted debt = $265 million x 10%

ADJUSTMENTS TO FINANCIAL STATEMENTS

Once S&P has determined what the risk factor is through a qualitative evaluation, S&P then adjusts the utility's financial statements. The procedure to adjust debt is to take the present value of future capacity payments discounted at 10%. The 10% discount factor was chosen to approximate a utility's average cost of capital. The result—the potential debt equivalent—would be multiplied by the risk factor. That result would be added to the utility's reported debt. To adjust the traditional pretax interest coverage ratio, S&P would take 10% of the adjustment to debt. A typical example of the adjustment process is shown below.

ABC POWER CO. EXAMPLE

To illustrate the financial adjustments, consider the hypothetical example of ABC Power Co buying power from XYZ Cogeneration Venture. Under the terms of the purchased power contract, annual capacity payments made by ABC Power start at $115 million in 1993, rise by $5 million per year to $135 million by 1997, and remain fixed through the expiration of the purchased power contract in 2023. The net present value of these obligations over the life of the contract discounted at 10% is $1.3 billion.

In the case of XYZ, S&P chose a 20% risk factor, which, when multiplied by the potential debt equivalent, resulted in a figure of $265 million. The risk factor is chosen based on qualitative analysis of the purchased power contract itself and the extent to which market, operating, and regulatory risks are borne by the utility.

Table 2 shows the adjustment to ABC Power's capital structure. S&P takes $265 million, which is the net present value of the future capacity payments multiplied by a 20% risk factor, and adds it to ABC Power's actual debt of $1.4 billion at year-end 1992. As illustrated in table 2, ABC Power's adjusted debt leverage is 58%, up from 54%.

Table 3 illustrates that ABC Power's pretax interest coverage for 1992, without adjusting for off-balance-sheet obligations, was 2.6 times (x), which is calculated by dividing the sum of net income, income taxes, and interest expense by interest expense. To adjust for the XYZ capacity payments, the $265 million debt adjustment is multiplied by a 10% interest rate to arrive at $27 million. When this is added to both the numerator and denominator, adjusted pretax interest coverage falls to 2.3x.

EFFECT ON RATINGS

The purchased power issue is somewhat complex, but S&P strongly believes that certain purchased power contracts are less risky than others and that these subtle differences must be factored into the analysis. S&P combines qualitative analysis with the traditional present value approach. The result is an adjustment to debt that is understandable and useful, particularly in the regulatory process, since the adjusted ratios S&P derives are the ones on which S&P ratings are based.

FPC 164

Over the past few years, several ratings have been lowered due to purchased power obligations. In other cases, S&P did not raise ratings. Still others are lower than they might otherwise be owing to purchased power liabilities.

S&P anticipates some rating downgrades of electric utilities over the next couple of years. However, much will depend on how utilities and regulators respond to S&P's analysis.

Utilities can offset purchased power liabilities in several ways, including higher returns on equity or higher equity components in capital structures. Another possibility might be some type of incentive return mechanism.

As competition increases in the electric utility industry, power supply strategies will grow more complex. Consequently, a utility's purchased power obligations must be evaluated in a broader framework than the one this article addresses.

The simple truth is that a utility can build all of its own plants, finance them with a balanced mix of equity and debt, put them into rate base without a disallowance, and still find itself in trouble if its rates are not competitive. Consequently, the buy-versus-build debate must be viewed within the larger context of a utility's competitive position.

There are many benefits to purchasing power. Indeed, purchasing may be the least risky strategy, but it is not risk-free. S&P's methodology quantifies the risks by explicitly recognizing the key qualitative factors of markets, operations, and regulation. S&P analyzes contracts to determine who is taking the risk: the nonutility generator, the utility, or the ratepayer. S&P recognizes that these adjustments must be viewed within the larger context of a utility's competitive position.

Curtis Moulton
(212) 208-1651

DEMAND-SIDE MANAGEMENT GAINS MOMENTUM

Over the past year, the move to Demand-Side Management (DSM) has gathered momentum as investor-owned utilities attempt to meet the demand for power without incurring the financing stress, and subsequent regulatory scrutiny, associated with new plant construction. Moreover, regulatory pressures have motivated utilities to pursue this path for an additional attribute: environmental benefits.

DSM is the reduction of electric consumption through behavior modification. This can be achieved by inducing customers to avail themselves of energy-efficient technologies, or by curtailing/shifting energy usage from periods of high to low demand. Utilities must add resources to meet high, or peak, demand. DSM is often addressed through an Integrated Resource Planning (IRP), or Least Cost Planning (LCP), process whereby utilities and regulators jointly evaluate all available demand- and supply-side options (including purchased power).

At present, DSM plays a minor role in assessing the total credit quality of an issuer, although there have been two ratings actions where DSM was cited as a contributing factor. Georgia Power Co.'s January 1992 upgrade reflected material reductions in capital requirements achieved through IRP. Potomac Electric Power Co.'s August 1990 downgrade took note of a return on equity (ROE) penalty levied in response to what regulators deemed a subpar commitment to DSM.

Prospectively, S&P believes that utility ratings may come under pressure if DSM programs do not deliver their promised economic savings. Commonwealth Electric Co. finds itself in this position. The utility has been the focus of recent media reports alleging rate escalation due to inefficient DSM. The northeast is sprinkled with additional examples, since utilities in this part of the country embarked on aggressive DSM programs under more favorable economic conditions. Although reserve margins subsequently swelled in the aftermath of the recession, several utilities' DSM programs have become virtually impossible to halt.

S&P maintains that DSM can enhance credit strength if it is truly economic compared to other alternatives and is used as part of a balanced approach to resource planning. However, experience is beginning to raise red flags for this resource option, which had initially appeared to be a panacea for meeting incremental power needs. Recall that nuclear power, at its inception, was touted as being "too cheap to meter." Furthermore, embedded costs of unneeded DSM programs may put utilities at a competitive disadvantage in the advent of retail wheeling. The passage of the 1992 Energy Policy Act legalized wholesale wheeling; most industry participants feel that retail wheeling is inevitable. In fact, it is currently being explored in New Mexico and Michigan.

DSM AS A RESOURCE OPTION

DSM was conceived as a resource alternative to plant construction. It was to offer benefits such as:

- Reducing costs of incremental resources (either built or saved),
- Avoiding financial/regulatory risks associated with construction,
- Meeting environmental objectives,
- Offering the flexibility to match resources incrementally with load, and
- Diversifying programs to mitigate asset concentration.

However, as conservation gained broad public and political appeal, regulators embraced DSM for its noneconomic benefits. Consideration of environmental externalities has become mandatory in many jurisdictions. However, pollution mitigation may not be efficiently addressed by individual state regulators and may duplicate efforts by other agencies. Monetizing externalities raises the price of electricity to consumers. The same is true of discounting the cost of DSM programs to give them an advantage. Further-

BATES NOS. FPC 173 – FPC 177
CONFIDENTIAL
PURSUANT TO FLORIDA
POWER CORPORATION'S
REQUST FOR CONFIDENTIAL
CLASSIFICATION FILED
AUGUST 7, 2000

BATES NOS. FPC 178 – FPC 210
CONFIDENTIAL
PURSUANT TO FLORIDA
POWER CORPORATION'S
REQUST FOR CONFIDENTIAL
CLASSIFICATION FILED
AUGUST 7, 2000

6.1.4.2 Expansion Resources Financials

BATES NOS. FPC 212 – FPC 251
CONFIDENTIAL
PURSUANT TO FLORIDA
POWER CORPORATION'S
REQUST FOR CONFIDENTIAL
CLASSIFICATION FILED
AUGUST 7, 2000

TREASURY

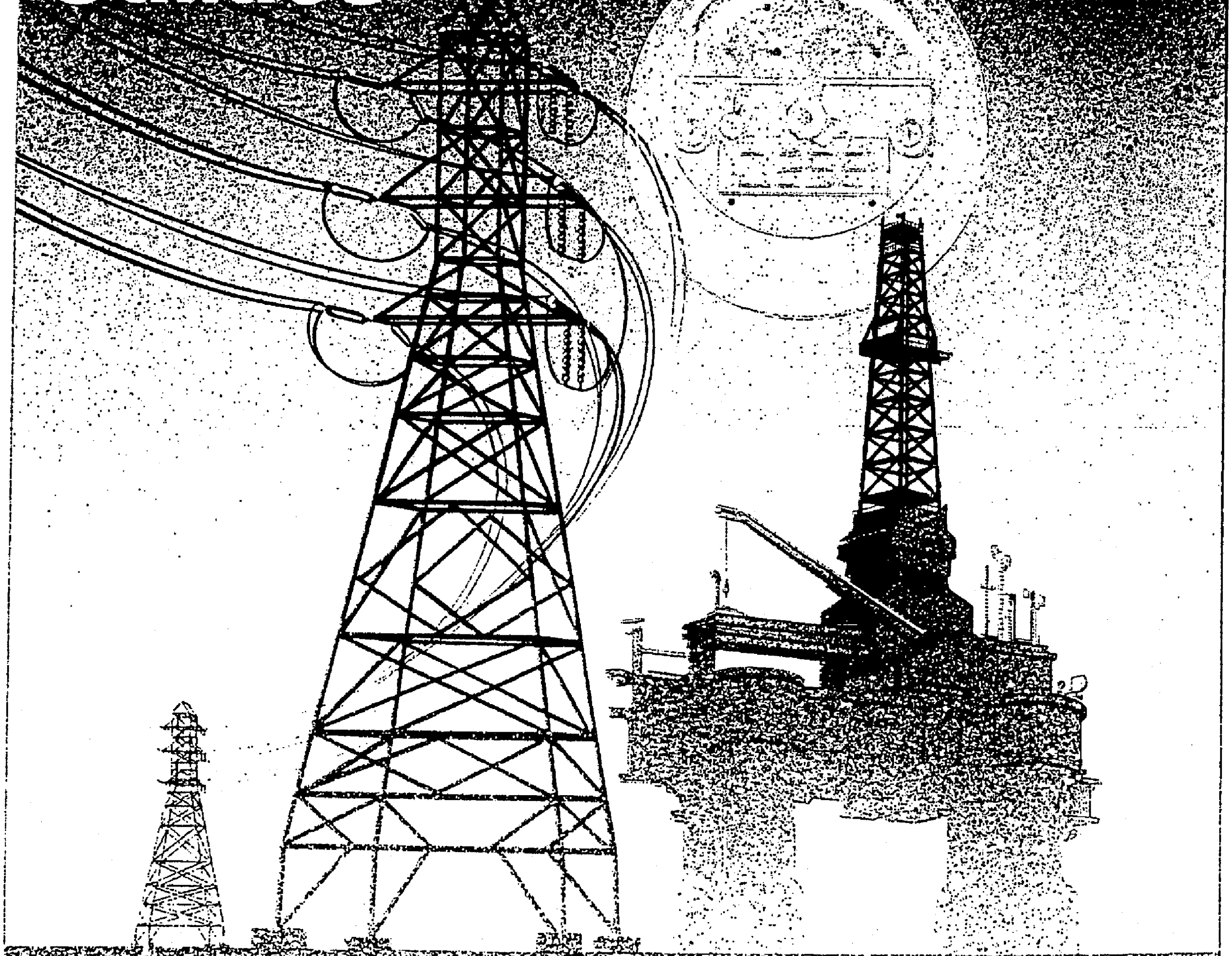
STANDARD & POOR'S

CREDITREVIEW

THE AUTHORITY ON CREDIT QUALITY

JUNE 21, 1993

Electric, Gas & Water Utilities



Commentary
Analyses
Ratings

FPC 252

Of course, at least initially, this restructuring will be done largely at the expense of its investors. PNM's shareholders may absorb some of the fixed embedded costs that cannot be reduced, such as a portion of the company's $84 million lease payments associated with PV units 1&2 ($76 million of this lease is in rates).

It is important to recognize that PNM may eventually be a threat to surrounding regions. A large part of the utility's significant excess reserves are not recoverable from rate payers. Capacity out of rate base totals 365mw, including a 105mw purchased power contract. Since this investment has already been written down and represents a drag on cash flow, PNM can justify marketing it at only a small premium over marginal cost. This could present a problem for other utilities in surrounding areas.

The Arizona utilities are also vulnerable to competitive threats from surrounding areas like, Utah and New Mexico. A particularly vulnerable utility in the Southwest is Tuscon Electric Power Company. TEP also has surplus reserves, high rates and nonearning assets. Like PNM, TEP must rely heavily on wholesale interchange markets, given the large amount of surplus reserves. Furthermore, about 198mw of TEP's Springerville unit 2 coal plant is out of rate base, and a certain portion of the lease of Springerville unit 1 has been disallowed. The company also has 34% industrial load with a 9% concentration of load in the mining industry, which could benefit from self-generation. However, unlike PNM, which is taking steps to allow it to lower rates eventually, TEP is so financially distressed that it has limited flexibility to lower rates. Like PNM, TEP has excess reserves and assets out of rate base and could also contribute to the reduction of regional market rates. Yet its long-term competitive viability under the present structure is questionable.

Public Service Co.'s (PSCO) has the lowest rate structure in its immediate area. Also, capacity needs are modest. While it will have some small rate needs over the intermediate term, its low cost rate structure should not change significantly. Industrial load and wholesale load exposure is not that significant. The only threat to Colorado would be from companies to its south that have assets out of rate base and thus may be able to sell power only slightly above margin to gain load.

Deborah Goldsmith, C.F.A.
(212) 208-1394

**Figures based on Typical Residential, Commercial, and Industrial Bills/Edison Electric Institute.*

BUY VERSUS BUILD DEBATE REVISITED

The debate over purchased power, or the "buy versus build" controversy, will likely continue to rage as state utility regulators grapple with the implications of the National Energy Policy Act of 1992. As part of this sweeping legislation, state regulators must consider the potential impact on utilities' cost of capital from purchasing power. builds. The important thing is that both resource strategies have inherent risks. S&P employs a methodology for evaluating the benefits and risks of purchased power, and for adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with traditional utilities.

Table 1
Determining the risk factor

The risk factor chosen is a function of a subjective (not arbitrary) analysis of qualitative risks.

Market	Need for power Economics
Operating	Performance standards Reliability Dispatchability Control over maintenance Flexibility and diversity
Regulatory	Preapproval Regulatory recovery mechanisms Regulatory out clause

Compared with the last baseload construction cycle, which is universally acknowledged to have been a disaster for investor-owned utilities, buying power from others appears substantially less risky than building new capacity. However, the electric utility industry's entire approach to supply-side resource additions has undergone radical transformation, to the point where it is now impossible to generalize about whether utility bondholders are better off if their utility buys or

BENEFITS OF PURCHASING POWER

Buying power may be the best choice for a utility that faces increasing demand. Moreover, purchasing may be the least risky course. The benefits of purchasing can be quite compelling. For example, utilities that purchase avoid the risks of significant construction cost overruns or that the plant might never be finished at all. They also may avoid the associated financial stress caused by regulatory lag typical in building programs.

In addition, utilities that purchase power avoid risking substantial capital. There are many examples of utilities that have failed to earn a full return on and of capital employed to build a plant. Furthermore, purchased power may contribute to fuel-supply diversity and flexibility, and may be cheaper, at least over the short run. Utilities that meet demand expectations with a portfolio of supply-side options also may be better able to adapt to future demand uncertainty, given the specter of retail transmission access.

Nevertheless, in the buy-versus-build debate it is important that appropriate comparisons are made. A properly designed building program may avoid many of the risks associated with the

unfortunate baseload program of the 1970s and early 1980s. A utility could:

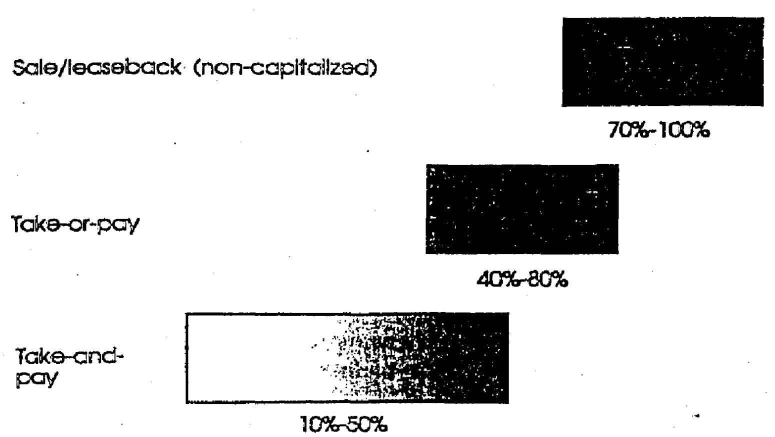
- Build a plant using a fixed-price, turnkey construction contract;
- Construct with a modular approach, adding small units incrementally as demand expectations solidify;
- Obtain regulatory preapproval;
- Receive a cash return on construction work in progress to ease financing stress; and
- Finance the asset with a large portion of equity, providing a cushion for bondholders.

Chart 1
Risk Spectrum

PURCHASES ARE NOT RISK-FREE

Regardless of whether a utility buys or builds, adding capacity means incurring risk. To the extent that there are any risks with purchased power, bondholders are directly threatened because there is no equity layer to protect them. Utilities are not compensated for any risks they assume in purchasing power. At best, purchased power is recovered dollar-for-dollar as an operating expense, so there is no markup to reward equity holders for taking risks.

Chart 2
Risk factors for various off-balance-sheet obligations



When a utility enters into a long-term purchased power contract with a fixed-cost component, it takes on financial risk. Heavy fixed charges reduce a utility's financial flexibility, and long-term contractual arrangements represent—at least in part—off-balance-sheet debt equivalents. Utilities need to take these "financial externalities" into account so that buy and build options are evaluated on a level playing field.

S&P has developed a methodology to quantify this financial risk and adjust financial statements to make traditional utilities and purchasing utilities comparable. S&P's approach is unique because it folds our qualitative analysis into our quantitative methodology. S&P begins by determining the potential off-balance-sheet obligation. This is done by calculating the present value of the capacity payments to be made over the life of the contract, discounted at 10%. The capacity payment is the fixed portion of the purchased power expense. It covers fixed costs, including debt service, depreciation, and a return on equity. S&P is concerned about the total fixed payment, not simply the debt service portion: the utility is obligated to pay the whole amount, not just a part. This means S&P is relatively indifferent to how the nonutility generator is capitalized, except in the extreme case where vast overleveraging threatens the viability of the project.

In virtually all cases, S&P has access to—and utilizes—actual capacity payments. In the rare instance where they are not available or where capacity and energy payments are not broken out—such as in an energy-only contact—S&P will estimate the capacity payment.

S&P does not stop with the potential debt equivalent. S&P recognizes that not all obligations have the same characteristics. What is true of other off-balance-sheet liabilities also is true of purchased power: some are more firm and therefore more debt-like than others.

This concept of the difference in the relative debt characteristics of purchased power obligations can be illustrated by using the concept of a risk spectrum *(see chart 1)*. A risk spectrum is simply a range from 0% to 100%. Obligations on the low end of the scale would have fewer debt-like characteristics and would be considered less firm than the obligations judged to fall on the high end of the scale. This spectrum is important because the place where an obligation falls on the scale—what S&P calls the risk factor—will determine what portion of the obligation S&P will add to a utility's reported debt. For example, if S&P determines that the risk factor for an obligation is 20%, S&P adds 20% of the potential debt equivalent to reported debt.

Different off-balance-sheet obligations have different risks *(see chart 2, which shows various types of off-balance sheet obligations and where S&P believes they might fall on the risk spectrum scale)*. Sale/leasebacks of major plants are viewed as the virtual equivalent of debt, due to the strategic importance of these major electric generating facilities and the "hell-or-high-water" nature of the lease commitments.

Obligations under take-or-pay contracts, which are unconditional as to both acceptance and availability of power, are considered quite firm. The extreme case would be a unit-specific purchase of expensive nuclear capacity under a

FPC 254

firm take-or-pay arrangement. Here, the risk factor might be as high as 70%-80%. Take-and-pay contracts, which require capacity payments only if power is available, are considered the least debt-like of the three types of obligations listed in chart 2 because take-and-pay capacity payments are conditional. In practice, the risk factors for take-and-pay performance contracts are generally in the 10%-20% range, although some may be as high as 50%.

DETERMINING THE RISK FACTOR

How does S&P determine the risk factor or the place where an obligation falls on the risk spectrum? S&P's assessment of the risk factor reflects our analysis of the risks a utility incurs when purchasing power under contract. This depends on a qualitative analysis of market, operating, and regulatory risks. It also depends on S&P's evaluation of the extent to which these risks are borne by the utility. The analysis is subjective, but not arbitrary *(see table 1 for some of the key factors under each broad risk category)*. Depending on circumstances, the utility may bear substantial risks, or it may have successfully shifted risks to either the ratepayers or to the nonutility generator provider of the power.

Lower risk factors would be appropriate if:
- The power is economic and needed,
- True performance standards exist,
- A project has operated reliably,
- The utility has a say in the scheduling of maintenance and retains control over dispatch,
- A contract is preapproved by regulators,
- Capacity payments are recovered through a fuel-clause type mechanism, and
- A regulatory out clause passes disallowance risk to the power seller.

The absence of these qualitative risk mitigators would lead toward the higher end of the risk spectrum and a higher risk factor.

Table 2
ABC Power Co. adjustment to capital structure
(Mil. $ at year-end 1992)

	Original capital structure $	Original capital structure %	Adjusted capital structure $	Adjusted capital structure %	
Debt	1,400	54	1,400	49	} 58
Adjustment to debt	—	—	265	9	
Preferred stock	200	8	200	7	
Common equity	1,000	38	1,000	35	

Table 3
ABC Power Co. adjustment to pretax interest coverage
(Mil. $ year-end 1992)

		Orig. pretax int. cov.		Adj. pretax int. cov.
Net income	120		300	
Income taxes	65	300	+27	
Interest expense	115	115 = 2.6x	115	= 2.3x
Pretax available	300		+27	

Interest associated with adjusted debt = $265 million x 10%

ADJUSTMENTS TO FINANCIAL STATEMENTS

Once S&P has determined what the risk factor is through a qualitative evaluation, S&P then adjusts the utility's financial statements. The procedure to adjust debt is to take the present value of future capacity payments discounted at 10%. The 10% discount factor was chosen to approximate a utility's average cost of capital. The result—the potential debt equivalent—would be multiplied by the risk factor. That result would be added to the utility's reported debt. To adjust the traditional pretax interest coverage ratio, S&P would take 10% of the adjustment to debt. A typical example of the adjustment process is shown below.

ABC POWER CO. EXAMPLE

To illustrate the financial adjustments, consider the hypothetical example of ABC Power Co. buying power from XYZ Cogeneration Venture. Under the terms of the purchased power contract, annual capacity payments made by ABC Power start at $115 million in 1993, rise by $5 million per year to $135 million by 1997, and remain fixed through the expiration of the purchased power contract in 2023. The net present value of these obligations over the life of the contract discounted at 10% is $1.3 billion.

In the case of XYZ, S&P chose a 20% risk factor, which, when multiplied by the potential debt equivalent, resulted in a figure of $265 million. The risk factor is chosen based on qualitative analysis of the purchased power contract itself and the extent to which market, operating, and regulatory risks are borne by the utility.

Table 2 shows the adjustment to ABC Power's capital structure. S&P takes $265 million, which is the net present value of the future capacity payments multiplied by a 20% risk factor, and adds it to ABC Power's actual debt of $1.4 billion at year-end 1992. As illustrated in table 2, ABC Power's adjusted debt leverage is 58%, up from 54%.

Table 3 illustrates that ABC Power's pretax interest coverage for 1992, without adjusting for off-balance-sheet obligations, was 2.6 times (x), which is calculated by dividing the sum of net income, income taxes, and interest expense by interest expense. To adjust for the XYZ capacity payments, the $265 million debt adjustment is multiplied by a 10% interest rate to arrive at $27 million. When this is added to both the numerator and denominator, adjusted pretax interest coverage falls to 2.3x.

EFFECT ON RATINGS

The purchased power issue is somewhat complex, but S&P strongly believes that certain purchased power contracts are less risky than others, and that these subtle differences must be factored into the analysis. S&P combines qualitative analysis with the traditional present value approach. The result is an adjustment to debt that is understandable and useful, particularly in the regulatory process, since the adjusted ratios S&P derives are the ones on which S&P ratings are based.

Over the past few years, several ratings have been lowered due to purchased power obligations. In other cases, S&P did not raise ratings. Still others are lower than they might otherwise be owing to purchased power liabilities.

S&P anticipates some rating downgrades of electric utilities over the next couple of years. However, much will depend on how utilities and regulators respond to S&P's analysis.

Utilities can offset purchased power liabilities in several ways, including higher returns on equity or higher equity components in capital structures. Another possibility might be some type of incentive return mechanism.

As competition increases in the electric utility industry, power supply strategies will grow more complex. Consequently, a utility's purchased power obligations must be evaluated in a broader framework than the one this article addresses.

The simple truth is that a utility can build all of its own plants, finance them with a balanced mix of equity and debt, put them into rate base without a disallowance, and still find itself in trouble if its rates are not competitive. Consequently, the buy-versus-build debate must be viewed within the larger context of a utility's competitive position.

There are many benefits to purchasing power. Indeed, purchasing may be the least risky strategy, but it is not risk-free. S&P's methodology quantifies the risks by explicitly recognizing the key qualitative factors of markets, operations, and regulation. S&P analyzes contracts to determine who is taking the risk: the nonutility generator, the utility, or the ratepayer. S&P recognizes that these adjustments must be viewed within the larger context of a utility's competitive position.

Curtis Moulton
(212) 208-1651

DEMAND-SIDE MANAGEMENT GAINS MOMENTUM

Over the past year, the move to Demand-Side Management (DSM) has gathered momentum as investor-owned utilities attempt to meet the demand for power without incurring the financing stress, and subsequent regulatory scrutiny, associated with new plant construction. Moreover, regulatory pressures have motivated utilities to pursue this path for an additional attribute: environmental benefits.

DSM is the reduction of electric consumption through behavior modification. This can be achieved by inducing customers to avail themselves of energy-efficient technologies, or by curtailing/shifting energy usage from periods of high to low demand. Utilities must add resources to meet high, or peak, demand. DSM is often addressed through an Integrated Resource Planning (IRP), or Least Cost Planning (LCP), process whereby utilities and regulators jointly evaluate all available demand- and supply-side options (including purchased power).

At present, DSM plays a minor role in assessing the total credit quality of an issuer, although there have been two ratings actions where DSM was cited as a contributing factor. Georgia Power Co.'s January 1992 upgrade reflected material reductions in capital requirements achieved through IRP. Potomac Electric Power Co.'s August 1990 downgrade took note of a return on equity (ROE) penalty levied in response to what regulators deemed a subpar commitment to DSM.

Prospectively, S&P believes that utility ratings may come under pressure if DSM programs do not deliver their promised economic savings. Commonwealth Electric Co. finds itself in this position. The utility has been the focus of recent media reports alleging rate escalation due to inefficient DSM. The northeast is sprinkled with additional examples, since utilities in this part of the country embarked on aggressive DSM programs under more favorable economic conditions. Although reserve margins subsequently swelled in the aftermath of the recession, several utilities' DSM programs have become virtually impossible to halt.

S&P maintains that DSM can enhance credit strength if it is truly economic compared to other alternatives and is used as part of a balanced approach to resource planning. However, experience is beginning to raise red flags for this resource option, which had initially appeared to be a panacea for meeting incremental power needs. Recall that nuclear power, at its inception, was touted as being "too cheap to meter." Furthermore, embedded costs of unneeded DSM programs may put utilities at a competitive disadvantage in the advent of retail wheeling. The passage of the 1992 Energy Policy Act legalized wholesale wheeling; most industry participants feel that retail wheeling is inevitable. In fact, it is currently being explored in New Mexico and Michigan.

DSM AS A RESOURCE OPTION

DSM was conceived as a resource alternative to plant construction. It was to offer benefits such as:

- Reducing costs of incremental resources (either built or saved),
- Avoiding financial/regulatory risks associated with construction,
- Meeting environmental objectives,
- Offering the flexibility to match resources incrementally with load, and
- Diversifying programs to mitigate asset concentration.

However, as conservation gained broad public and political appeal, regulators embraced DSM for its noneconomic benefits. Consideration of environmental externalities has become mandatory in many jurisdictions. However, pollution mitigation may not be efficiently addressed by individual state regulators and may duplicate efforts by other agencies. Monetizing externalities raises the price of electricity to consumers. The same is true of discounting the cost of DSM programs to give them an advantage. Further- ▶

STANDARD & POOR'S

CREDIT COMMENT

CREDIT ISSUES FOR UTILITY PURCHASERS

"There are indeed benefits to purchasing power, but there are also risks that are too often overlooked."

The debate over purchased power continues to rage in the utility industry, and S&P has been at the forefront of efforts to analyze the issue. What are the merits of purchasing power versus utility construction of electric generating plants? It is impossible to generalize about whether utility bondholders are better off if their utility buys or builds. The important thing is that both resource strategies have inherent risks.

Purchased power is usually touted as a virtually risk-free alternative to costly plant construction. As we shall see, there are indeed benefits to purchasing power, but there are also risks that are too often overlooked. Only by thoroughly examining the risks--as well as the benefits--can a utility choose correctly. And only by evaluating both buying and building can an investor know what he is getting into.

The "buy versus build" controversy has been around for a long time--as long as purchasing power has been an option. In the past, when utilities built new plants, they typically built more capacity than they needed and sold excess power to their neighbors. The contracts under which this power was sold were timed to expire when the selling utility needed the power to meet its growing native load.

TO BUY OR BUILD?

In this article, S&P tackles the debate over the pros and cons of utilities purchasing power rather than building their own plants. The initial focus is on the benefits associated with purchased power. But the risks will also be examined, since S&P believes that utilities are absorbing significant market, operating, regulatory, and financial risks when they enter into long-term purchased power contracts with nonutility generators. S&P will also present here its method of adjusting a utility's financial statements to capture the off-balance sheet obligations associated with purchased power.

BIRTH OF THE NUG

The enactment of the Public Utilities Regulatory Policies Act (PURPA) in 1978 gave birth to a new provider of electricity: the nonutility generator, or NUG. Congress intended to spur the development of cogeneration and small power producers by providing incentives that included exemption from utility regulation and a requirement that utilities buy electricity from qualifying facilities (QFs) at avoided cost. A QF is a cogenerator or small power producer that is certified by the Federal Energy Regulatory Commission (FERC) as meeting the operating and efficiency standards required by PURPA. Avoided cost is an estimate of the incremental costs that the utility would have incurred absent the purchase from the QF.

A second type of nonutility generator is the independent power producer (IPP), which does not have the same rights under PURPA as a QF. IPPs are not automatically granted a full avoided cost standard for rate setting and have no legislated right to sell power. Their success hinges solely on their competitiveness.

Up to 50% of generating capacity needed over the next 20 years could be built by nonutility generators, according to some estimates. These aggressive estimates assume that the Public Utility Holding Company Act of 1935 (PUHCA) will be amended to exempt IPPs from certain regulatory entanglements associated with the act. S&P's current estimate is that Congress will enact a comprehensive energy bill in 1992. It will include an exemption from PUHCA for IPPs and will also mandate open access transmission for wholesale transactions. Because of these changes, the future will be completely wide open to competition in generation.

BENEFITS OF PURCHASED POWER

Why are so many deciding to buy so much? The decision to shun new generating plant investment is not difficult to understand, in view of the politicized and occasionally recalcitrant regulatory environments with which some utilities have had to contend to recover their investment. The first benefit is avoidance of construction risk. Buying instead of building will allow the purchasing utility to avoid the risk that a plant under construction will incur significant cost overruns or might never be finished at all. A purchasing utility

"Utilities are not compensated for any risks they assume in purchasing power."

only begins paying for power once the NUG plant achieves performance hurdles outlined in the power purchase contract.

Second, utilities can avoid financial deterioration that is typical in multiyear construction programs and is caused by regulators' reluctance to allow a full cash return on construction work in progress. A third benefit to purchasing is that if timed correctly, a utility's rates will rise concurrent with or close to the time it begins making purchased power payments. Thus, an important incentive to purchase capacity is the reduction of regulatory lag. In most states, it has been easier to recover purchased power expense than to rate base a new plant.

Other benefits of purchased power are power supply flexibility and diversity. These benefits arise mainly from the fact that most NUG projects are small relative to a utility's total supply base. So there is little concentration risk. Lastly, a utility that avoids investing in generating plant while continuing to depreciate existing plants will see a shift in its asset mix over time. With ongoing new investment in transmission and distribution, the proportion of total assets in the less risky segments of the business will increase.

MARKET RISKS

To the extent that there are any risks with purchased power, bondholders are directly threatened, because there is no equity cushion to insulate them. Utilities are not compensated for any risks they assume in purchasing power. At best, purchased power is recovered dollar-for-dollar as an operating expense, so there is no markup to reward equity holders for taking risks.

S&P's methodology to evaluate the risks inherent in a purchased power strategy is divided into two basic parts: qualitative and quantitative. The two parts are closely related. In the qualitative area, S&P is interested in three key areas: market risk, operating risk, and regulatory risk. In the quantitative area, S&P addresses financial risks associated with purchased power and how these risks are incorporated into the rating process.

The market risks in purchasing power stem from the fact that a utility enters into a long-term contract to buy power without assurance that it will be able to sell the power. Even a cursory analysis of the last construction cycle demonstrates that utilities are not very good at forecasting demand for electricity. Given that regulators get very upset when a utility procures too much power, there is a major risk to utilities if demand falls short of expectations.

The utility also accepts the risk that the power may not be economic over time. In the increasingly competitive electric utility industry, a utility's cost of power is critical to its success. To the extent that contracted power becomes uneconomic relative to other sources of supply, the utility may suffer a loss of customers, sales, and earnings.

OPERATING RISKS

There are also operating risks in purchasing power. Erecting a power plant is much more difficult today than it was 10 years ago due to heightened environmental awareness. This means that a lot of contracted NUG capacity may never actually come on line. Purchasing utilities try to compensate for this by accepting more bids for power than they actually need. If a significantly greater percentage of contracted purchased power fails to materialize, the utility may be required to accelerate its own construction activities at a late date, thereby resulting in greater cost than previously anticipated and a greater risk of regulatory disallowance. The utility has an obligation to serve, but the NUG does not.

Will NUG plants operate well? The data suggest that there is not much difference in availability between utility plants and NUG plants. But there are lingering doubts. Any discrepancy in quality may not be known until plants begin to age. Another operating risk faced by the purchasing utility is loss of control over its supply sources. The utility may or may not control a NUG plant's operations and dispatch and may have no say in when the unit is taken down for routine maintenance. These factors can have an important influence on a utility's efficiency and reliability. Control over dispatch is particularly important. It is bad enough that a utility has to pay minimum capacity payments regardless of the economics of the power purchased. But it is worse if the utility cannot decline delivery of uneconomic energy.

The benefits associated with a diverse and flexible fuel supply were discussed earlier. Obviously, the opposite would be a risk. S&P pays particular attention to natural gas-fired NUGs. S&P believes that natural gas will play an increasingly important role in electric generation in the U.S., and that superior drilling and recovery technologies will keep gas prices relatively low for the foreseeable future. Moreover, natural gas combustion technologies are pretty straightforward. Nevertheless, overreliance on any one fuel is a risk, and nearly three-quarters of independent power projects in development are fired with natural gas.

FPC 258

"*The first financial risk is the potential for liquidating rate base.*"

REGULATORY RISKS

The independent power industry argues that since regulators allow the passthrough of purchased power expense to a utility's customers, there is no risk to the purchasing utility. S&P agrees that one-for-one recovery of the expense helps mitigate the risk. But there remains the chance that regulators will disallow purchased power costs--either capacity costs or energy costs, and either prospectively or retroactively.

The risk that the purchasing utility may have to absorb regulatory disallowances could be reduced by the existence of a "regulatory out" clause in the power purchase contract. Under this clause, disallowance risk is passed to the NUG. Whether or not a regulatory out provision reduces risk for the utility depends on specific language in the contract. Further, these provisions have not yet been tested in the courts.

Another important factor when considering regulatory risk is a state-by-state analysis of the mechanics of recovering purchased power expense. For example, S&P believes that disallowance risk is reduced if purchased power capacity charges are recovered from customers in a separate adjustment mechanism like a fuel clause rather than through base rates. This way, there is little or no delay in beginning to recover the charges, since no general rate filing is needed, and it is also easier to track the expense and be assured that there are adequate revenues to cover the charge.

One of the ways to mitigate disallowance risk is through a comprehensive integrated resource planning process hosted by the state regulators. In these elaborate procedures, all supply- and demand-side options are considered within a common framework to obtain a least-cost mix. Certain states like Nevada have instituted preapproval programs for resource planning that alleviate the risk of regulatory scrutiny after the fact. Legislation in Nevada precludes disallowance of future capacity once the resource plan has been approved by the commission. This does not preclude the potential for cost overrun penalties, but it is a step toward ensuring that capacity additions will not be classified as unnecessary after the investment has already been made. In the end, S&P's evaluation of regulatory risk is a state-by-state effort, encompassing the entire regulatory, legislative, and judicial arenas.

FINANCIAL RISKS

The first financial risk is the potential for liquidating rate base. Equity investors, in particular, are alarmed about this phenomenon. The idea is that since utilities are allowed a return on depreciated investment (or rate base), their earnings will decline to the extent that rate base declines. If a utility is not building new generating plant, yet continues to depreciate existing generating investment, then its depreciation will exceed new capital investment, and its rate base and earnings will erode.

But debt quality may not necessarily be affected. S&P recognizes that declining rate base will be gradual and that spending on transmission and distribution will continue, so rate base will not disappear altogether. And if depreciation exceeds new investment, that need not be alarming, since it means that cash flow is strong relative to needs. What is critical is what the utility does with its cash flow. A shrinking utility does not threaten bondholders to the extent that the utility reduces debt as its assets contract. Done in proportion, key relationships like cash flow to debt and cash flow coverage of interest will stay relatively constant.

The bigger concern with declining rate base is how management will react when faced with a scenario of slow earnings growth or declining earnings. Historically, the typical response has been nonutility diversification. S&P has never been a big fan of diversification because of concerns about management pursuing greater risk in search of greater returns.

The second and more important area of financial risk stems from the fact that in a purchased power arrangement, the purchasing utility enters into a long-term contract with a fixed-cost component. These long-term contractural arrangements are, at least in part, off-balance sheet debt equivalents. S&P is really concerned with firm long-term contracts, not spot purchases. And, as a practical matter, overall purchased power risk is usually not significant until purchased power exceeds 10%-15% of capacity.

The fixed or capacity portion of the purchased power payment covers a NUG's fixed costs, including debt service, depreciation, and a return on equity. The total fixed capacity payment is of concern, not simply the debt service portion. This is because the utility is obligated to pay the whole thing, not just a part.

By capturing the entire fixed payment in its analysis, S&P is not focused on the extent to which the NUG is leveraged. Whether a NUG is capitalized with 70% or 90% debt makes little difference in the capacity payments. There may be a difference in the NUG's financial viability.

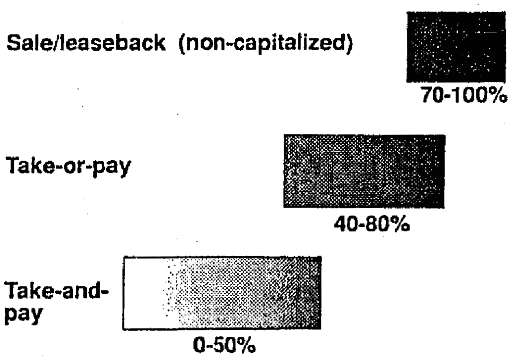
Figure 1
Risk spectrum

That is, highly leveraged NUGs are inherently less creditworthy than less leveraged NUGs. And their financial health may affect their reliability. But this is better analyzed within an overall evaluation of a utility's fuel and power supply risk.

TAKE-OR-PAY VS. TAKE-AND-PAY

There are two basic types of purchased power contracts: take-or-pay and take-and-pay. Take-or-pay contracts are unconditional as to both acceptance and availability of power. That is, the utility is obligated to make capacity payments all the time, whether or not the plant is able to produce power. Thus, if the plant cannot produce, the utility has to make the capacity payment and still go elsewhere and pay for replacement power.

Figure 2
Risk factors for various off-balance sheet obligations



Alternatively, take-and-pay contracts require capacity payments only if power is available. Virtually all NUG power is sold under take-and-pay contracts that contain conditional provisions, such as those that include a minimum performance standard measured against actual operating availability. If performance of the NUG plant falls below the contract minimums, capacity payments are lowered. If performance is chronically poor, the take-and-pay contract is usually cancellable.

As a practical matter, contract provisions vary widely, so it is not always easy to clearly distinguish between a conditional and an unconditional contract. Thus, whether capacity payments represent debt under take-or-pay or take-and-pay contracts is a murky issue. What is true of purchased power is true of other off-balance sheet obligations--that some are more firm, and therefore more debt-like, than others.

RISK SPECTRUM

The difference in the relative debt characteristics of off-balance sheet obligations can be illustrated through the concept of a risk spectrum *(see figure 1)*. Obligations on the left hand of the spectrum would have fewer debt-like characteristics and would be considered less firm than the obligations judged to fall on the right-hand side. This spectrum is important because the place where an obligation falls on the scale--the risk factor--will determine what portion of the obligation S&P will add to a utility's reported debt. For example, if S&P considers that the risk factor for any particular obligation is 50%, it will add 50% of that obligation to reported debt.

OFF-BALANCE SHEET OBLIGATIONS DIFFER

Different off-balance sheet obligations have different risks. Figure 2 shows various types of off-balance sheet obligations and where S&P believes they might fall on the scale--their risk factors. Sale/leasebacks of major plants are viewed as virtually the equivalent of debt, due to the strategic importance of these major electric generating facilities and the "hell-or-high-water" nature of the lease commitments. Take-or-pay obligations are considered quite firm, given the general unconditional nature of a utility's obligation to make capacity payments. Take-and-pay contracts are considered least debt-like of the three types of obligations listed in figure 2 because take-and-pay capacity payments are conditional. It is important to keep in mind that while all of these obligations have fixed charges associated with them that will impact a utility's day-to-day fixed charge burden, the executory nature of the lease or contractural relationship may allow S&P to view an obligation as something short of a total debt equivalent.

ATTRIBUTES DECREASING THE RISK FACTOR

Where take-and-pay contracts fall on the risk spectrum--their risk factor--depends on a qualitative analysis of the purchased power contract itself, and the extent to which market, operating, and regulatory risks are borne by the utility. What are some of the attributes of these qualitative factors that would allow S&P to arrive at a relatively low risk factor? In the area of market risk, the risk factor would be reduced to the extent that the power is economic relative to alternatives. Secondly, risk would be lower if the project's energy rate was indexed to the purchasing util-

FPC 260

"Once S&P has determined what the risk factor is through a qualitative evaluation, it then adjusts the utility's financial statments."

ity's other sources of power, so that the purchased power's economics would not decline over time.

In the area of operating risk, the risk factor would tend to be lower where a contract contains true performance standards, such as a minimum capacity factor of 80% and a total cutoff of capacity payments below a certain level of availability. If the utility retains control over the NUG's scheduling of maintenance and dispatch, risk would also be lower. Another attribute contributing to lower risk would be project diversity, since concentrations of purchased power exposure are more significant than aggregate exposure.

Lessening regulatory risk would be: a regulatory out clause, complete recovery of the capacity charge through a fuel clause type mechanism rather than base rates, and a state regulatory environment that supports and encourages utilities to purchase power. The absence of these qualitative risk mitigators would lead one toward the higher end of the risk spectrum and a higher risk factor. S&P would expect that, as a practical matter, the risk factor for take-and-pay obligations would range between 10%-50%.

ADJUSTMENTS TO FINANCIAL STATEMENTS

Once S&P has determined what the risk factor is through a qualitative evaluation, it then adjusts the utility's financial statements. The procedure to adjust debt would be to take the net present value of future capacity payments discounted at 10%. The 10% discount factor was chosen to approximate a utility's average cost of capital. The result--the potential debt equivalent--would be multiplied by the risk factor. That result would be added to the utility's reported debt. To adjust the traditional interest coverage ratio, S&P would take 10% of the adjustment to debt. A typical example of the adjustment process is shown below.

CONSUMERS POWER EXAMPLE

Table 1 shows the annual capacity payments that Consumers Power Co. is scheduled to make to the Midland Cogeneration Venture (MCV). Based on 90% availability, they rise to $369 million in 1995, where they remain for the duration of the 35-year contract. The net present value of these obligations over the life of the contract discounted at 10% is $3.383 billion.

In the case of MCV, S&P chose a 30% risk factor, which, when multiplied by the potential debt equivalent, resulted in a figure of $1.015 billion. The risk factor is chosen based on qualitative

Table 1
Consumers Power adjustment to debt
(Mil. $ Year-end 1990)

	Off-balance sheet obligation payments		
1991	$284		
1992	$299	Net present value of obligations at 10% =	$3,383
1993	$328	Multiplied by risk factor	X 30%
1994	$355	Adjustment to debt	$1,015
1995-2025	$369 per year		

analysis of the purchased power contract itself and the extent to which market, operating, and regulatory risks are borne by the utility. In the Consumers Power example, S&P chose the 30% risk factor for several reasons. First, there is some

Table 2
Consumers Power adjustment to capital structure
(Mil. $ Year-end 1990)

	Original capital structure $	Original capital structure %	Adjusted capital structure $	Adjusted capital structure %	
Debt	3,435	65	3435	54	} 70
Adjustment to debt	--	--	1,015	16	
Preferred stock	170	3	170	3	
Common stock	1,720	32	1,720	27	

risk because of concentration–MCV will represent 15% of Consumers' capacity. In addition, while regulatory peace is beginning to emerge, it it too early to say that Michigan utility regulators are fully supportive of MCV. Consumers Power is not currently recovering the full capacity payment, because Michigan regulators are allowing recovery based on deliverability rather that availability.

On the other hand, the MCV capacity payments are not viewed as total debt equivalents, because there is a fuel clause in Michigan for the energy payments and a regulatory out clause covering the energy portion of the contract. In addition, S&P is comfortable with the Michigan pool controlling dispatch and believes that the performance standards in the contract render it truly conditional.

Table 2 shows the adjustment to Consumers' capital structure. We take $1.015 billion, which is the net present value of the future capacity payments multiplied by a 30% risk factor, and add it to Consumers' actual debt of $3.435 billion at 1990 year end. As is evident to the table, Consumers' adjusted debt leverage is 70%, up from 65%.

Table 3 illustrates that Consumers' pretax inter-

Table 3
Consumers Power adjustment to pretax interest coverage
(Mil. $ Year-end 1990)

		Original pretax interest coverage	adjusted pretax interest coverage
Net income	$34		700
Income taxes	403	$\frac{700}{263}$ =2.66x	$\frac{+101}{263}$ =2.20x
Interest expense	263		
Pretax available	700		+101

est coverage for 1990, without adjusting for off-balance sheet obligations, was 2.66 times (x), which is calculated by dividing the sum of net income, income taxes, and interest expense by interest expense. To adjust for the MCV capacity payments, the $1.015 billion debt adjustment is multiplied by a 10% interest rate to arrive at $101 million. When this is added to both the numerator and denominator, adjusted pretax interest coverage falls to 2.2x.

S&P can make similar adjustments to two other traditionally important ratios--funds from operations interest coverage and funds from operations to average total debt. The results of these adjustments are shown in Table 4.

EFFECT ON RATINGS

Will S&P lower bond ratings to reflect its focus on the risks in purchased power? Going forward, S&P would expect some rating downgrades over the next couple of years. However, where purchases represent less than 10%-15% of a utility's capacity, the quantitative adjustments will not make much difference to the ratios, and the incremental financial risk may be offset by the qualitative benefits of purchasing power.

Even where purchases are more significant, downgrades may or may not be appropriate, depending on the response to S&P's analysis by utilities and their regulators. It is not S&P's role to simply sit in judgment. Rather, it intends to work closely with both utilities and regulators to help identify the appropriate risk factor to apply to a utility's off-balance sheet obligations. Moreover, S&P will work with interested parties to design ways to offset purchased power risks. These offsets could take several forms, including higher returns on equity, higher equity components in capital structures, incentive return mechanisms for purchasing, or laws or regulations that would eliminate disallowance risk.

Table 4
Consumers Power summary of adjusted ratios

	1990 original	1990 adjusted
Total debt/total capital	65%	70%
Pretax interest coverage	2.66x	2.20x
Funds from operations interest coverage	2.71x	2.23x
Funds from operations/total debt	13%	10%

Curtis Moulton
(212) 208-1651

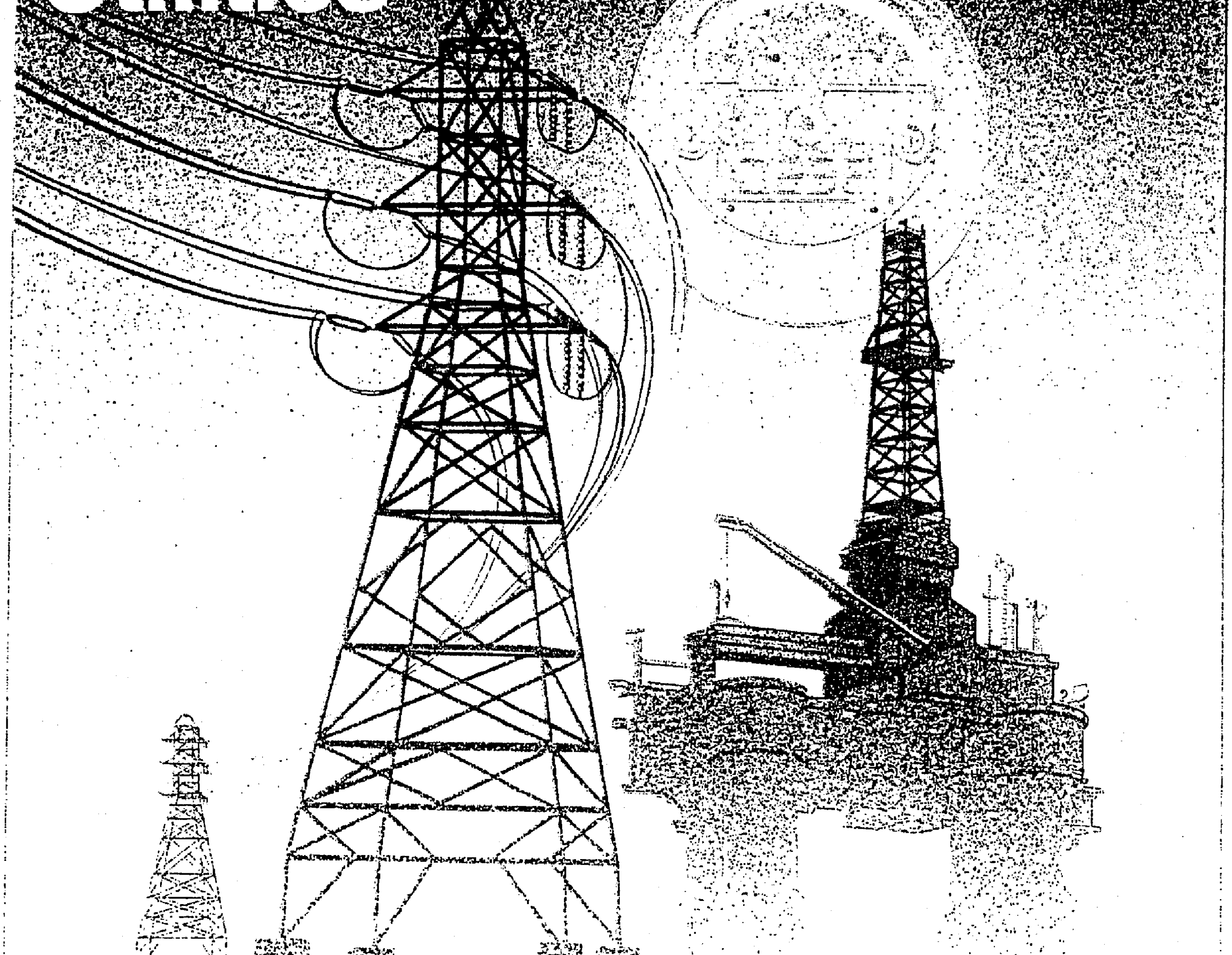
STANDARD & POOR'S

CREDITREVIEW

THE AUTHORITY ON CREDIT QUALITY

JUNE 21, 1993

Electric, Gas & Water Utilities



Commentary
Analyses
Ratings

FPC 263

Of course, at least initially, this restructuring will be done largely at the expense of its investors. PNM's shareholders may absorb some of the fixed embedded costs that cannot be reduced, such as a portion of the company's $84 million lease payments associated with PV units 1&2 ($76 million of this lease is in rates).

It is important to recognize that PNM may eventually be a threat to surrounding regions. A large part of the utility's significant excess reserves are not recoverable from rate payers. Capacity out of rate base totals 365mw, including a 105mw purchased power contract. Since this investment has already been written down and represents a drag on cash flow, PNM can justify marketing it at only a small premium over marginal cost. This could present a problem for other utilities in surrounding areas.

The Arizona utilities are also vulnerable to competitive threats from surrounding areas like, Utah and New Mexico. A particularly vulnerable utility in the Southwest is Tuscon Electric Power Company. TEP also has surplus reserves, high rates and nonearning assets. Like PNM, TEP must rely heavily on wholesale interchange markets, given the large amount of surplus reserves. Furthermore, about 198mw of TEP's Springerville unit 2 coal plant is out of rate base, and a certain portion of the lease of Springerville unit 1 has been disallowed. The company also has 34% industrial load with a 9% concentration of load in the mining industry, which could benefit from self-generation. However, unlike PNM, which is taking steps to allow it to lower rates eventually, TEP is so financially distressed that it has limited flexibility to lower rates. Like PNM, TEP has excess reserves and assets out of rate base and could also contribute to the reduction of regional market rates. Yet its long-term competitive viability under the present structure is questionable.

Public Service Co.'s (PSCO) has the lowest rate structure in its immediate area. Also, capacity needs are modest. While it will have some small rate needs over the intermediate term, its low cost rate structure should not change significantly. Industrial load and wholesale load exposure is not that significant. The only threat to Colorado would be from companies to its south that have assets out of rate base and thus may be able to sell power only slightly above margin to gain load.

Deborah Goldsmith, C.F.A.
(212) 208-1394

**Figures based on Typical Residential, Commercial, and Industrial Bills/Edison Electric Institute.*

BUY VERSUS BUILD DEBATE REVISITED

The debate over purchased power, or the "buy versus build" controversy, will likely continue to rage as state utility regulators grapple with the implications of the National Energy Policy Act of 1992. As part of this sweeping legislation, state regulators must consider the potential impact on utilities' cost of capital from purchasing power.

Table 1
Determining the risk factor

The risk factor chosen is a function of a subjective (not arbitrary) analysis of qualitative risks.

Market	Need for power Economics
Operating	Performance standards Reliability Dispatchability Control over maintenance Flexibility and diversity
Regulatory	Preapproval Regulatory recovery mechanisms Regulatory out clause

Compared with the last baseload construction cycle, which is universally acknowledged to have been a disaster for investor-owned utilities, buying power from others appears substantially less risky than building new capacity. However, the electric utility industry's entire approach to supply-side resource additions has undergone radical transformation, to the point where it is now impossible to generalize about whether utility bondholders are better off if their utility buys or builds. The important thing is that both resource strategies have inherent risks. S&P employs a methodology for evaluating the benefits and risks of purchased power, and for adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with traditional utilities.

BENEFITS OF PURCHASING POWER

Buying power may be the best choice for a utility that faces increasing demand. Moreover, purchasing may be the least risky course. The benefits of purchasing can be quite compelling. For example, utilities that purchase avoid the risks of significant construction cost overruns or that the plant might never be finished at all. They also may avoid the associated financial stress caused by regulatory lag typical in building programs.

In addition, utilities that purchase power avoid risking substantial capital. There are many examples of utilities that have failed to earn a full return on and of capital employed to build a plant. Furthermore, purchased power may contribute to fuel-supply diversity and flexibility, and may be cheaper, at least over the short run. Utilities that meet demand expectations with a portfolio of supply-side options also may be better able to adapt to future demand uncertainty, given the specter of retail transmission access.

Nevertheless, in the buy-versus-build debate it is important that appropriate comparisons are made. A properly designed building program may avoid many of the risks associated with the

FPC 264

firm take-or-pay arrangement. Here, the risk factor might be as high as 70%-80%. Take-and-pay contracts, which require capacity payments only if power is available, are considered the least debt-like of the three types of obligations listed in chart 2 because take-and-pay capacity payments are conditional. In practice, the risk factors for take-and-pay performance contracts are generally in the 10%-20% range, although some may be as high as 50%.

DETERMINING THE RISK FACTOR

How does S&P determine the risk factor or the place where an obligation falls on the risk spectrum? S&P's assessment of the risk factor reflects our analysis of the risks a utility incurs when purchasing power under contract. This depends on a qualitative analysis of market, operating, and regulatory risks. It also depends on S&P's evaluation of the extent to which these risks are borne by the utility. The analysis is subjective, but not arbitrary *(see table 1 for some of the key factors under each broad risk category)*. Depending on circumstances, the utility may bear substantial risks, or it may have successfully shifted risks to either the ratepayers or to the nonutility generator provider of the power.

Lower risk factors would be appropriate if:

- The power is economic and needed,
- True performance standards exist,
- A project has operated reliably,
- The utility has a say in the scheduling of maintenance and retains control over dispatch,
- A contract is preapproved by regulators,
- Capacity payments are recovered through a fuel-clause type mechanism, and
- A regulatory out clause passes disallowance risk to the power seller.

The absence of these qualitative risk mitigators would lead toward the higher end of the risk spectrum and a higher risk factor.

Table 2
ABC Power Co. adjustment to capital structure
(Mil. $ at year-end 1992)

	Original capital structure		Adjusted capital structure		
	$	%	$	%	
Debt	1,400	54	1,400	49	} 58
Adjustment to debt	—	—	265	9	
Preferred stock	200	8	200	7	
Common equity	1,000	38	1,000	35	

Table 3
ABC Power Co. adjustment to pretax interest coverage
(Mil. $ year-end 1992)

	Orig. pretax int. cov.			Adj. pretax int. cov.	
Net income	120			300	
Income taxes	65	300		+27	
Interest expense	115	115	= 2.6x	115	= 2.3x
Pretax available	300			+27	

Interest associated with adjusted debt = $265 million x 10%

ADJUSTMENTS TO FINANCIAL STATEMENTS

Once S&P has determined what the risk factor is through a qualitative evaluation, S&P then adjusts the utility's financial statements. The procedure to adjust debt is to take the present value of future capacity payments discounted at 10%. The 10% discount factor was chosen to approximate a utility's average cost of capital. The result—the potential debt equivalent—would be multiplied by the risk factor. That result would be added to the utility's reported debt. To adjust the traditional pretax interest coverage ratio, S&P would take 10% of the adjustment to debt. A typical example of the adjustment process is shown below.

ABC POWER CO. EXAMPLE

To illustrate the financial adjustments, consider the hypothetical example of ABC Power Co. buying power from XYZ Cogeneration Venture. Under the terms of the purchased power contract, annual capacity payments made by ABC Power start at $115 million in 1993, rise by $5 million per year to $135 million by 1997, and remain fixed through the expiration of the purchased power contract in 2023. The net present value of these obligations over the life of the contract discounted at 10% is $1.3 billion.

In the case of XYZ, S&P chose a 20% risk factor, which, when multiplied by the potential debt equivalent, resulted in a figure of $265 million. The risk factor is chosen based on qualitative analysis of the purchased power contract itself and the extent to which market, operating, and regulatory risks are borne by the utility.

Table 2 shows the adjustment to ABC Power's capital structure. S&P takes $265 million, which is the net present value of the future capacity payments multiplied by a 20% risk factor, and adds it to ABC Power's actual debt of $1.4 billion at year-end 1992. As illustrated in table 2, ABC Power's adjusted debt leverage is 58%, up from 54%.

Table 3 illustrates that ABC Power's pretax interest coverage for 1992, without adjusting for off-balance-sheet obligations, was 2.6 times (x), which is calculated by dividing the sum of net income, income taxes, and interest expense by interest expense. To adjust for the XYZ capacity payments, the $265 million debt adjustment is multiplied by a 10% interest rate to arrive at $27 million. When this is added to both the numerator and denominator, adjusted pretax interest coverage falls to 2.3x.

EFFECT ON RATINGS

The purchased power issue is somewhat complex, but S&P strongly believes that certain purchased power contracts are less risky than others, and that these subtle differences must be factored into the analysis. S&P combines qualitative analysis with the traditional present value approach. The result is an adjustment to debt that is understandable and useful, particularly in the regulatory process, since the adjusted ratios S&P derives are the ones on which S&P ratings are based.

unfortunate baseload program of the 1970s and early 1980s. A utility could:

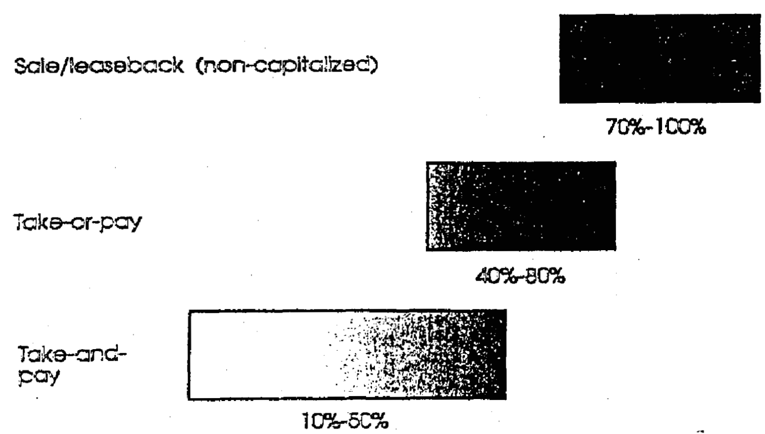
- Build a plant using a fixed-price, turnkey construction contract;
- Construct with a modular approach, adding small units incrementally as demand expectations solidify;
- Obtain regulatory preapproval;
- Receive a cash return on construction work in progress to ease financing stress; and
- Finance the asset with a large portion of equity, providing a cushion for bondholders.

Chart 1
Risk Spectrum

PURCHASES ARE NOT RISK-FREE

Regardless of whether a utility buys or builds, adding capacity means incurring risk. To the extent that there are any risks with purchased power, bondholders are directly threatened because there is no equity layer to protect them. Utilities are not compensated for any risks they assume in purchasing power. At best, purchased power is recovered dollar-for-dollar as an operating expense, so there is no markup to reward equity holders for taking risks.

Chart 2
Risk factors for various off-balance-sheet obligations



When a utility enters into a long-term purchased power contract with a fixed-cost component, it takes on financial risk. Heavy fixed charges reduce a utility's financial flexibility, and long-term contractual arrangements represent—at least in part—off-balance-sheet debt equivalents. Utilities need to take these "financial externalities" into account so that buy and build options are evaluated on a level playing field.

S&P has developed a methodology to quantify this financial risk and adjust financial statements to make traditional utilities and purchasing utilities comparable. S&P's approach is unique because it folds our qualitative analysis into our quantitative methodology. S&P begins by determining the potential off-balance-sheet obligation. This is done by calculating the present value of the capacity payments to be made over the life of the contract, discounted at 10%. The capacity payment is the fixed portion of the purchased power expense. It covers fixed costs, including debt service, depreciation, and a return on equity. S&P is concerned about the total fixed payment, not simply the debt service portion: the utility is obligated to pay the whole amount, not just a part. This means S&P is relatively indifferent to how the nonutility generator is capitalized, except in the extreme case where vast overleveraging threatens the viability of the project.

In virtually all cases, S&P has access to—and utilizes—actual capacity payments. In the rare instance where they are not available or where capacity and energy payments are not broken out—such as in an energy-only contact—S&P will estimate the capacity payment.

S&P does not stop with the potential debt equivalent. S&P recognizes that not all obligations have the same characteristics. What is true of other off-balance-sheet liabilities also is true of purchased power: some are more firm and therefore more debt-like than others.

This concept of the difference in the relative debt characteristics of purchased power obligations can be illustrated by using the concept of a risk spectrum *(see chart 1)*. A risk spectrum is simply a range from 0% to 100%. Obligations on the low end of the scale would have fewer debt-like characteristics and would be considered less firm than the obligations judged to fall on the high end of the scale. This spectrum is important because the place where an obligation falls on the scale—what S&P calls the risk factor—will determine what portion of the obligation S&P will add to a utility's reported debt. For example, if S&P determines that the risk factor for an obligation is 20%, S&P adds 20% of the potential debt equivalent to reported debt.

Different off-balance-sheet obligations have different risks *(see chart 2, which shows various types of off-balance sheet obligations and where S&P believes they might fall on the risk spectrum scale)*. Sale/leasebacks of major plants are viewed as the virtual equivalent of debt, due to the strategic importance of these major electric generating facilities and the "hell-or-high-water" nature of the lease commitments.

Obligations under take-or-pay contracts, which are unconditional as to both acceptance and availability of power, are considered quite firm. The extreme case would be a unit-specific purchase of expensive nuclear capacity under a

FPC 266

Over the past few years, several ratings have been lowered due to purchased power obligations. In other cases, S&P did not raise ratings. Still others are lower than they might otherwise be owing to purchased power liabilities.

S&P anticipates some rating downgrades of electric utilities over the next couple of years. However, much will depend on how utilities and regulators respond to S&P's analysis.

Utilities can offset purchased power liabilities in several ways, including higher returns on equity or higher equity components in capital structures. Another possibility might be some type of incentive return mechanism.

As competition increases in the electric utility industry, power supply strategies will grow more complex. Consequently, a utility's purchased power obligations must be evaluated in a broader framework than the one this article addresses.

The simple truth is that a utility can build all of its own plants, finance them with a balanced mix of equity and debt, put them into rate base without a disallowance, and still find itself in trouble if its rates are not competitive. Consequently, the buy-versus-build debate must be viewed within the larger context of a utility's competitive position.

There are many benefits to purchasing power. Indeed, purchasing may be the least risky strategy, but it is not risk-free. S&P's methodology quantifies the risks by explicitly recognizing the key qualitative factors of markets, operations, and regulation. S&P analyzes contracts to determine who is taking the risk: the nonutility generator, the utility, or the ratepayer. S&P recognizes that these adjustments must be viewed within the larger context of a utility's competitive position.

Curtis Moulton
(212) 208-1651

DEMAND-SIDE MANAGEMENT GAINS MOMENTUM

Over the past year, the move to Demand-Side Management (DSM) has gathered momentum as investor-owned utilities attempt to meet the demand for power without incurring the financing stress, and subsequent regulatory scrutiny, associated with new plant construction. Moreover, regulatory pressures have motivated utilities to pursue this path for an additional attribute: environmental benefits.

DSM is the reduction of electric consumption through behavior modification. This can be achieved by inducing customers to avail themselves of energy-efficient technologies, or by curtailing/shifting energy usage from periods of high to low demand. Utilities must add resources to meet high, or peak, demand. DSM is often addressed through an Integrated Resource Planning (IRP), or Least Cost Planning (LCP), process whereby utilities and regulators jointly evaluate all available demand- and supply-side options (including purchased power).

At present, DSM plays a minor role in assessing the total credit quality of an issuer, although there have been two ratings actions where DSM was cited as a contributing factor. Georgia Power Co.'s January 1992 upgrade reflected material reductions in capital requirements achieved through IRP. Potomac Electric Power Co.'s August 1990 downgrade took note of a return on equity (ROE) penalty levied in response to what regulators deemed a subpar commitment to DSM.

Prospectively, S&P believes that utility ratings may come under pressure if DSM programs do not deliver their promised economic savings. Commonwealth Electric Co. finds itself in this position. The utility has been the focus of recent media reports alleging rate escalation due to inefficient DSM. The northeast is sprinkled with additional examples, since utilities in this part of the country embarked on aggressive DSM programs under more favorable economic conditions. Although reserve margins subsequently swelled in the aftermath of the recession, several utilities' DSM programs have become virtually impossible to halt.

S&P maintains that DSM can enhance credit strength if it is truly economic compared to other alternatives and is used as part of a balanced approach to resource planning. However, experience is beginning to raise red flags for this resource option, which had initially appeared to be a panacea for meeting incremental power needs. Recall that nuclear power, at its inception, was touted as being "too cheap to meter." Furthermore, embedded costs of unneeded DSM programs may put utilities at a competitive disadvantage in the advent of retail wheeling. The passage of the 1992 Energy Policy Act legalized wholesale wheeling; most industry participants feel that retail wheeling is inevitable. In fact, it is currently being explored in New Mexico and Michigan.

DSM AS A RESOURCE OPTION

DSM was conceived as a resource alternative to plant construction. It was to offer benefits such as:

- Reducing costs of incremental resources (either built or saved),
- Avoiding financial/regulatory risks associated with construction,
- Meeting environmental objectives,
- Offering the flexibility to match resources incrementally with load, and
- Diversifying programs to mitigate asset concentration.

However, as conservation gained broad public and political appeal, regulators embraced DSM for its noneconomic benefits. Consideration of environmental externalities has become mandatory in many jurisdictions. However, pollution mitigation may not be efficiently addressed by individual state regulators and may duplicate efforts by other agencies. Monetizing externalities raises the price of electricity to consumers. The same is true of discounting the cost of DSM programs to give them an advantage. Further- ▶

FPC 267

THE

U.S. ECONOMY

Knowledge for Smarter Decisions

1999 | II

REWRITING HISTORY

THE NEW NIPAS

METAL MERGERS

LAGS IN CONTRACTING

STANDARD
&POOR'S
DRI

FPC 268

[illegible] RR3H

TABLE 9
Interest Rates, Money Flows, and Other Financial Variables

	1999:2	1999:3	1999:4	2000:1	2000:2	2000:3	1998	1999	2000	2001	2002	2003	2004
Interest Rates (Percent, NSA)													
Federal Funds Rate	4.75	5.08	5.37	5.50	5.60	5.50	5.35	4.89	5.50	5.50	5.60	5.50	5.50
Discount Rate	4.50	4.80	4.87	5.00	5.00	5.00	4.82	4.62	5.00	5.00	5.00	5.00	5.00
U.S. Treasury Yield Curve													
3-Month	4.57	4.77	5.11	5.15	5.14	5.15	4.90	4.74	5.15	5.14	5.13	5.13	5.13
6-Month	4.76	4.96	5.34	5.43	5.43	5.44	5.02	4.81	5.43	5.42	5.41	5.42	5.41
1-Year	4.88	5.16	5.40	5.47	5.47	5.48	5.05	5.03	5.47	5.46	5.44	5.44	5.44
2-Year	5.28	5.63	5.64	5.70	5.61	5.58	5.13	5.36	5.61	5.51	5.51	5.52	5.51
3-Year	5.35	5.71	5.76	5.81	5.69	5.64	5.14	5.42	5.68	5.54	5.55	5.56	5.56
5-Year	5.44	5.77	5.90	5.94	5.81	5.72	5.15	5.50	5.77	5.58	5.61	5.59	5.68
10-Year	5.54	5.88	5.93	5.95	5.82	5.71	5.26	5.56	5.77	5.80	5.68	5.68	5.71
30-Year	5.80	6.04	6.17	6.17	6.05	5.92	5.58	5.84	5.98	5.78	5.87	5.87	5.89
Short-Term Rates on:													
3-Month Treasury Bills	4.45	4.65	4.98	5.01	5.01	5.02	4.78	4.62	5.01	5.00	4.99	5.00	4.99
6-Month Treasury Bills	4.58	4.78	5.13	5.21	5.21	5.22	4.83	4.73	5.21	5.20	5.20	5.20	5.20
3-Month Large CDs	4.98	5.38	5.59	5.59	5.60	5.56	5.47	5.21	5.57	5.63	5.58	5.58	5.58
3-Month LIBOR	5.05	5.44	5.65	5.66	5.67	5.63	5.53	5.28	5.64	5.70	5.65	5.65	5.66
3-Month Prime Comm. Paper	4.86	5.23	5.46	5.50	5.53	5.49	5.34	5.08	5.50	5.56	5.51	5.51	5.52
Prime Commercial Loans	7.75	8.10	8.37	8.50	8.50	8.60	8.35	7.99	8.50	8.50	8.60	8.50	8.50
Auto Instal. Lns. @ Comm. Banks	8.30	8.44	8.50	8.63	8.75	8.82	8.54	8.40	8.76	8.92	9.01	9.04	9.08
Long-Term Rates													
Seasoned AAA Corporate Bonds	6.93	7.33	7.18	7.20	6.94	6.70	6.63	6.97	6.84	6.46	6.43	6.44	6.53
Seasoned BAA Corporate Bonds	7.74	8.10	7.97	7.91	7.66	7.41	7.22	7.80	7.55	7.11	7.11	7.08	7.18
AA Utilities	7.39	7.76	7.79	7.76	7.40	7.13	6.91	7.48	7.30	6.84	6.80	6.73	6.80
G.O. AAA Municipals	5.05	5.41	5.45	5.51	5.43	5.28	4.92	5.20	5.34	5.00	5.07	5.07	5.09
Bond Index of 20 G.O. Munis.	5.21	5.56	5.72	5.78	5.68	5.54	5.09	5.39	5.58	5.23	5.32	5.31	5.33
Mortgage Rates													
Conventional Mort. Commit (a)	7.21	7.81	7.92	7.82	7.66	7.44	6.95	7.45	7.53	6.94	6.87	6.92	6.95
Eff. Mort. Rate on Loans Closed													
New Homes	6.92	7.16	7.72	7.86	7.82	7.68	7.08	7.18	7.72	7.21	7.05	7.09	7.12
Existing Homes	7.13	7.58	7.73	7.87	7.82	7.66	7.10	7.35	7.72	7.19	7.02	7.06	7.09
11th-District Cost of Funds	4.49	4.56	4.66	4.77	4.87	4.95	4.86	4.57	4.90	5.16	5.31	5.39	5.44
Reserve Aggregates (Billions of dollars)													
Total Reserves	43.74	42.05	40.96	40.69	40.50	40.43	44.60	40.96	40.44	40.94	41.99	43.47	45.16
Annual Percent Change	-6.4	-14.5	-10.0	-2.6	-1.9	-0.7	-4.1	-5.6	-5.3	0.5	2.1	3.2	3.8
Nonborrowed Reserves	43.58	41.77	40.57	40.32	40.25	40.04	44.48	40.57	40.12	40.70	41.81	43.29	45.00
Borrowed Reserves	0.15	0.28	0.40	0.37	0.26	0.39	0.12	0.40	0.33	0.24	0.19	0.17	0.16
Required Reserves	42.51	40.92	39.87	39.61	39.43	39.36	43.01	39.87	39.38	39.89	40.95	42.42	44.11
Excess Reserves	1.23	1.13	1.09	1.08	1.07	1.07	1.59	1.09	1.06	1.05	1.05	1.05	1.05
Free Reserves	1.08	0.85	0.70	0.71	0.82	0.68	1.47	0.70	0.74	0.81	0.86	0.88	0.89
Monetary Aggregates (Billions of dollars) (b)													
M1	1104.8	1098.4	1101.5	1101.8	1106.0	1113.1	1087.6	1101.5	1121.5	1160.1	1208.8	1267.5	1332.2
Annual Percent Change	3.5	-2.3	1.1	0.1	1.5	2.6	1.8	1.3	1.8	3.4	4.2	4.6	5.1
Currency and Travelers' Checks	488.4	499.6	505.9	510.1	517.0	525.0	464.3	505.9	533.2	564.2	597.1	633.8	673.2
Checkable Deposits	616.3	598.9	595.6	591.7	589.0	588.0	623.3	595.6	588.3	595.9	611.7	633.7	658.9
M2	4504.8	4561.1	4615.2	4669.1	4723.6	4778.4	4303.5	4615.2	4836.2	5088.3	5313.3	5574.4	5850.5
Annual Percent Change	5.8	5.1	4.8	4.8	4.8	4.8	8.5	5.8	4.8	4.8	4.8	4.9	5.0
M3	6133.2	6218.0	6305.4	6388.3	6470.5	6554.0	5834.8	6305.4	6638.9	6986.6	7328.6	7694.7	8065.2
Annual Percent Change	5.8	5.6	5.7	5.4	5.2	5.3	10.9	6.2	5.3	5.2	4.9	5.0	5.1
M1 Velocity (GDP/M1)	8.28	8.45	8.55	8.62	8.68	8.74	8.11	8.39	8.71	8.87	8.95	9.00	9.02
Annual Percent Change	-0.3	8.3	4.9	3.2	3.3	2.7	4.6	3.4	3.8	1.8	0.9	0.6	0.1
M2 Velocity (GDP/M2)	2.03	2.03	2.04	2.03	2.03	2.04	2.08	2.04	2.04	2.04	2.04	2.05	2.05
Annual Percent Change	-2.4	0.7	1.2	-1.4	0.1	0.5	-1.7	-1.9	-0.1	0.2	0.0	0.4	0.2
Outstanding Credit													
C & I Loans at Commercial Banks	959.0	971.3	987.7	1002.3	1014.3	1025.2	949.5	987.7	1036.9	1097.8	1160.3	1229.1	1298.2
Annual Percent Change	2.4	5.2	6.8	6.1	4.9	4.4	11.8	4.0	5.0	5.8	5.7	5.9	5.6
Consumer Credit Outstanding	1347.8	1369.7	1394.8	1419.9	1439.7	1457.0	1274.0	1361.1	1447.2	1512.7	1567.8	1633.5	1716.5
Annual Percent Change	4.8	6.7	7.5	7.4	5.7	4.9	5.4	7.3	5.5	4.2	3.4	4.7	5.4
Mortgage Loans - All Issuers	5883.4	6010.3	6120.6	6247.2	6363.3	6478.2	5589.2	6129.6	6581.2	7060.3	7534.4	7986.1	8418.1
Annual Percent Change	10.6	8.9	8.2	7.9	7.6	7.4	10.0	9.7	7.5	7.1	6.7	6.0	5.4
Stock Market (NSA)													
S&P Index of 500 Common Stocks	1329.8	1342.2	1315.0	1341.4	1366.5	1420.2	1084.3	1311.5	1408.9	1503.5	1617.6	1805.1	1959.2
Dividend-Price Ratio - S&P 500	1.24	1.24	1.57	1.58	1.60	1.57	1.49	1.34	1.57	1.62	1.62	1.54	1.49
Earnings per Share - S&P 500 ($)	12.59	12.93	11.81	11.70	13.08	13.85	37.71	40.29	52.88	58.34	62.16	64.58	65.58
Price-Earnings Ratio	34.6	32.7	29.2	27.8	27.9	28.9	27.8	32.5	28.6	26.7	27.1	28.6	30.2

a. Commitment rate is for 30-year 80% mortgage loan.
b. Annual numbers are fourth-quarter numbers.

FPC 269

TABLE 1
Prices, Wages, and Productivity

	1999:2	1999:3	1999:4	2000:1	2000:2	2000:3	1998	1999	2000	2001	2002	2003	2004
Chain-Weighted Price Indexes (Percent change, SAAR)													
GDP (implicit price deflator)	1.4	0.9	1.2	1.6	1.4	1.5	1.2	1.4	1.4	1.5	1.7	2.0	2.1
GDP (Chain-wt. index)	1.3	1.0	1.1	1.6	1.4	1.6	1.2	1.3	1.4	1.6	1.8	2.0	2.1
Domestic Demand	1.9	1.6	1.6	1.8	1.3	1.2	0.7	1.4	1.8	1.4	1.8	2.0	2.0
Consumption	2.2	1.9	1.8	1.8	1.5	1.5	0.9	1.6	1.7	1.7	2.2	2.4	2.4
Durables	-1.9	-2.0	-3.6	-1.7	-1.2	-1.1	-2.4	-2.7	-1.9	-0.9	-0.3	0.0	0.0
Motor Vehicles and Parts	0.3	2.5	-3.6	0.4	0.4	0.0	-0.6	-0.1	-0.2	-0.1	0.4	0.9	0.9
Light Vehicles	-0.2	-0.9	-0.2	0.6	0.5	0.0	-0.7	-0.3	0.0	-0.3	0.2	0.8	0.8
Cars	-1.3	-1.3	-0.5	0.3	0.3	-0.1	-0.7	-0.8	-0.3	-0.4	0.0	0.5	0.6
New Trucks	0.9	-0.6	0.1	0.8	0.8	0.1	-0.7	0.4	0.4	0.0	0.5	1.1	1.1
Other	1.3	9.3	-8.5	0.1	0.1	0.0	-0.7	0.2	-0.4	0.1	0.5	0.7	0.8
Furniture and Appliances	-5.8	-6.6	-4.6	-4.4	-3.8	-3.2	-5.1	-5.9	-4.3	-2.9	-2.0	-1.8	-1.7
Computers	-12.7	-19.5	-17.9	-23.4	-25.0	-22.0	-30.2	-25.2	-21.2	-20.5	-16.3	-14.8	-14.3
Other	-4.6	-3.8	-2.9	-1.8	-0.9	-0.6	-1.5	-3.2	-2.1	-0.5	-0.1	0.1	0.1
Other Durables	1.2	-4.1	-2.2	-0.6	0.7	0.9	-0.7	-1.7	-0.7	1.3	1.8	1.7	1.6
Nondurables	5.1	2.9	3.0	1.8	1.1	1.0	0.1	2.3	2.1	1.7	2.5	2.5	2.4
Food and Beverages	1.2	2.1	2.3	2.5	2.3	2.1	1.7	2.1	2.2	2.3	2.6	2.7	2.6
Clothing and Shoes	3.8	-4.2	-4.4	-2.2	-0.7	0.3	-2.1	-2.2	-1.7	1.0	1.7	1.6	1.4
Gasoline and Oil	68.3	24.8	21.8	4.7	-6.5	-9.2	-11.5	9.1	8.0	-3.7	-0.2	0.4	0.6
Fuel Oil and Coal	14.0	24.5	3.4	7.6	-3.8	-5.8	-9.2	-0.6	4.4	-0.8	2.5	3.1	3.2
Other Nondurables	1.3	3.0	4.3	2.2	2.2	2.4	2.0	4.1	2.7	2.6	3.3	3.3	3.1
Services	1.7	2.2	2.3	2.6	2.2	2.2	2.1	2.1	2.3	2.3	2.6	2.8	2.8
Housing	3.0	2.0	2.4	2.6	2.6	3.0	3.2	2.8	2.6	2.6	2.6	3.0	3.1
Household Operation	-0.8	1.0	2.1	1.5	0.6	0.3	-1.0	0.0	1.0	0.7	1.5	1.7	1.6
Electricity	0.6	1.1	1.5	2.6	3.3	2.7	-3.8	-0.5	2.1	1.3	1.3	1.6	1.4
Natural Gas	-1.4	18.5	21.3	8.6	-4.6	-9.0	-2.1	1.7	5.2	-3.6	2.0	2.1	0.2
Other	-1.2	-0.7	-0.3	-0.1	0.4	0.9	0.5	0.1	0.0	1.1	1.5	1.8	1.9
Transportation	2.3	0.0	1.0	1.8	1.3	2.5	1.1	1.0	1.5	2.7	2.9	3.1	3.1
Medical	1.6	2.2	2.2	2.6	2.3	2.6	2.3	2.5	2.4	2.7	3.1	3.4	3.4
Other Services	1.3	2.8	2.5	3.0	2.5	1.9	2.2	2.0	2.5	2.1	2.5	2.7	2.7
Fixed Investment	-0.1	-0.5	0.4	0.3	0.2	0.0	-0.8	-0.1	0.1	-0.5	-0.3	0.0	-0.1
Nonresidential	-1.4	-1.7	-0.7	-0.7	-0.5	-0.6	-1.8	-1.4	-0.8	-1.1	-1.0	-0.7	-0.8
Equipment	-2.5	-3.1	-1.7	-1.8	-1.8	-2.0	-3.4	-2.6	-2.1	-2.2	-1.8	-1.6	-1.7
Automobiles	-4.5	-1.4	0.2	1.2	0.7	-0.4	0.5	-0.5	-0.1	-0.6	0.2	0.6	0.5
New Cars	-1.2	-1.3	-0.5	0.3	0.3	-0.1	-0.7	-0.9	-0.3	-0.4	0.0	0.5	0.6
Net Used Cars	3.4	-1.2	-1.4	-1.0	-0.4	0.2	-2.3	-1.3	-0.5	-0.2	-0.2	0.4	0.7
Computing Equipment & Software	-8.1	-8.0	-7.2	-8.4	-8.8	-9.2	-12.8	-10.4	-8.3	-10.1	-10.3	-9.9	-9.6
Other	0.0	0.0	0.5	0.8	1.0	0.9	0.0	0.6	0.6	1.0	1.6	1.6	1.4
Structures	2.2	2.9	2.6	3.2	3.8	4.3	3.1	2.5	3.3	2.7	1.8	2.6	2.3
Buildings and Other	3.7	3.3	3.1	2.9	2.7	2.7	3.3	3.7	2.9	2.4	2.6	2.7	2.5
Mining and Petroleum	-4.9	-0.3	-0.2	0.7	13.1	16.7	4.1	-2.5	6.5	5.5	-3.7	2.6	1.6
Public Utilities	0.2	2.3	2.0	1.9	1.7	1.6	1.0	0.0	1.7	1.5	1.9	2.0	2.0
Residential	3.6	3.2	3.5	3.3	2.4	1.6	2.6	3.9	2.8	1.5	2.1	2.2	2.1
Equipment	-2.9	0.4	-0.1	-0.2	-0.4	-0.1	-0.4	-1.5	-0.3	0.0	0.5	0.7	0.7
Structures	3.7	3.3	3.6	3.3	2.5	1.7	2.6	4.0	2.9	1.5	2.1	2.2	2.1
Gov't Cons. and Investment	2.9	3.0	2.2	3.3	1.7	1.7	1.5	2.6	2.5	2.1	2.3	2.4	2.4
Federal	0.9	1.3	1.5	5.1	1.2	1.1	1.1	2.9	2.2	2.2	2.4	2.4	2.5
Defense	1.0	1.3	1.3	5.0	1.1	0.8	0.8	2.6	2.1	2.0	2.2	2.3	2.3
Consumption	1.5	1.6	1.6	5.9	1.2	0.9	1.2	2.8	2.4	2.2	2.5	2.6	2.6
Employee Compensation	0.5	0.2	1.4	12.2	1.4	1.5	2.4	4.3	3.8	4.1	4.0	3.9	4.0
Cons. of Fixed Capital	0.0	1.4	0.8	1.1	1.3	0.4	-0.9	1.4	1.0	0.8	1.0	1.3	1.3
Other	3.3	3.5	2.2	1.5	0.9	0.6	0.7	2.0	1.7	0.9	1.5	1.5	1.5
Investment	-1.5	-0.3	-0.2	-0.2	0.0	0.1	-1.7	1.3	-0.2	0.2	0.6	0.7	0.7
Nondefense	0.7	1.2	1.7	5.3	1.5	1.5	1.6	3.4	2.4	2.5	2.7	2.6	2.7
Consumption	1.3	1.8	2.1	6.7	1.9	1.9	2.2	4.0	3.1	3.1	3.2	3.1	3.2
Employee Compensation	1.6	2.3	2.9	11.5	3.0	3.0	3.6	6.8	4.9	5.1	5.1	4.7	4.8
Cons. of Fixed Capital	-0.8	-0.4	0.7	0.8	0.4	0.6	-1.0	0.8	0.4	0.2	0.1	0.3	0.3
Other	1.8	2.1	1.5	1.3	0.5	0.3	1.6	2.0	1.1	0.8	1.3	1.4	1.4
Investment	-1.4	-0.6	-0.2	-0.1	-0.1	0.1	-1.0	1.2	-0.2	-0.3	-0.3	-0.1	-0.1
State and Local	4.0	4.0	2.7	2.4	2.0	2.0	1.8	2.5	2.6	2.1	2.2	2.4	2.4
Consumption	4.2	4.6	2.9	2.7	2.2	2.2	2.0	2.7	2.9	2.4	2.6	2.7	2.8
Employee Compensation	2.5	3.2	3.3	3.6	3.5	3.6	3.5	2.9	3.4	3.7	3.7	3.8	3.8
Cons. of Fixed Capital	2.6	1.2	1.2	1.0	0.9	0.8	0.3	1.3	1.1	0.5	0.3	0.6	0.6
Other	12.7	11.9	2.3	0.2	-2.0	-2.5	-2.9	2.0	1.8	-1.6	-0.8	-0.7	-0.7
Investment	3.1	1.5	1.4	1.2	1.1	1.0	0.9	1.7	1.3	0.7	0.6	0.9	0.9
Equipment	-2.0	-2.3	-1.9	-2.1	-2.2	-2.3	-3.8	-2.7	-2.2	-2.4	-2.0	-1.0	-1.9
Structures	4.9	3.0	2.6	2.4	2.3	2.2	2.6	3.3	2.6	1.8	1.5	1.8	1.8
Exports	0.7	1.0	1.0	0.1	-0.8	-1.2	-2.3	-0.5	0.0	-0.4	0.2	0.2	0.1
Merch., excl. Bus. Machines	-0.1	1.2	1.2	0.1	-0.7	-1.2	-2.4	-0.7	0.0	-0.4	0.1	0.1	0.1
Imports	5.2	5.9	5.0	1.9	-0.9	-2.8	-5.3	0.3	1.7	-0.9	0.9	0.4	-0.2
Merch., excl. Oil & Bus. Mach.	-1.0	0.6	0.6	2.1	1.0	-0.5	-2.6	-0.4	0.6	0.4	1.8	1.2	0.5

FPC 270

TABLE 1 (Continued)
Prices, Wages, and Productivity

	1999:2	1999:3	1999:4	2000:1	2000:2	2000:3	1998	1999	2000	2001	2002	2003	2004
Consumer Price Indexes (Percent change, SAAR)													
All Urban Consumers	3.5	2.6	2.5	2.4	1.9	1.9	1.6	2.2	2.3	2.1	2.6	2.8	2.8
Food	0.9	2.1	2.5	2.8	2.6	2.3	2.1	2.2	2.4	2.6	2.0	2.0	2.9
Energy	25.5	13.8	13.7	4.8	-2.9	-6.3	-7.9	3.8	5.2	-1.9	0.8	1.2	0.9
Commodities	66.2	25.3	19.8	5.0	-6.2	-8.9	-13.0	8.6	7.9	-3.4	0.0	0.7	0.8
Services	0.1	4.2	7.7	4.6	0.5	-1.4	-3.2	0.0	2.9	-0.4	1.5	1.7	1.0
Excl. Food & Energy	2.4	1.7	1.7	2.1	2.1	2.5	2.3	2.0	2.1	2.4	2.7	2.9	2.9
Commodities	0.6	0.7	-0.5	0.4	0.8	1.0	0.6	0.6	0.5	1.1	1.6	1.7	1.6
Services	3.1	2.1	2.6	2.8	2.8	3.2	3.1	2.7	2.8	3.0	3.1	3.4	3.5
Urban Wage & Clerical Workers	3.3	2.9	2.6	2.4	1.8	1.8	1.3	2.2	2.4	2.1	2.6	2.6	2.8
Wages and Productivity in the Nonfarm Business Sector (Percent change, SAAR)													
ECI for Compensation (a)	4.6	3.4	3.3	3.6	3.6	3.9	3.5	3.1	3.6	3.7	3.6	3.7	3.7
ECI for Wages & Salaries (a)	5.0	3.2	3.4	3.7	4.1	4.2	4.0	3.4	3.8	3.8	3.7	3.8	3.7
ECI for Benefits (a)	3.9	3.6	3.8	3.4	2.4	3.0	2.5	2.6	3.3	3.4	3.5	3.6	3.7
Compensation per Hour (b)	5.0	4.6	3.5	3.7	3.6	4.0	4.2	4.3	3.9	3.9	3.8	3.9	3.9
Output per Hour	0.6	3.8	2.7	0.2	2.1	2.5	2.2	2.8	1.9	2.1	2.1	2.3	2.1
Cyclically Adjusted	2.3	3.2	2.7	3.2	2.7	2.6	2.4	3.3	2.8	2.2	2.0	2.0	2.0
Unit Labor Costs	4.4	0.7	0.8	3.4	1.4	1.4	2.0	1.4	2.0	1.8	1.6	1.6	1.8
Cyc. Adj. Unit Labor Costs (c)	1.3	0.0	0.0	0.8	0.6	1.1	1.5	0.1	0.6	1.3	1.6	1.6	1.7
Manufacturing Output per Hour	4.8	5.3	5.8	1.3	3.7	4.7	4.1	5.3	3.9	4.6	4.7	4.6	4.5
Factors Affecting Inflation and Productivity													
Civilian Unemployment Rate (%)	4.3	4.2	4.1	4.1	4.1	4.1	4.5	4.2	4.1	4.1	4.3	4.4	4.5
GDP Gap (%)	-4.2	-4.6	-5.0	-4.5	-4.5	-4.5	-3.6	-4.6	-4.5	-4.4	-4.2	-4.3	-4.3
Minimum Wage ($/hour)	5.15	5.15	5.15	5.15	5.15	5.60	5.15	5.15	5.38	5.76	5.95	6.16	6.36
U.S. Dollar, Trade-Weighted Ex. Rate - OECD (1990=1.000)	1.100	1.084	1.063	1.040	1.033	1.046	1.105	1.078	1.047	1.040	1.008	0.987	0.973
Man. Capacity Utilization (%)	79.5	79.5	79.7	78.7	78.4	78.3	80.8	79.5	78.4	78.7	78.5	78.0	78.9

a. Private Industry, fixed weights.
b. Nonfarm business sector, wages and salaries of employees, plus employers' contributions for social insurance and private benefit plans, plus estimate of total self-employed, variable weights.
c. Defined as employment cost index for compensation divided by a four-quarter moving average of cyclically adjusted output per hour.

FPC 271

TABLE 2
Producer Prices

	1999:2	1999:3	1999:4	2000:1	2000:2	2000:3	1998	1999	2000	2001	2002	2003	2004
Producer Price Indexes - Stage of Processing (Percent change, SAAR)													
Finished Goods	2.7	3.8	4.9	2.5	0.8	-0.1	-0.9	1.9	2.3	0.7	1.4	1.6	1.5
Excl. Food & Energy	0.2	0.6	1.8	1.4	1.4	0.9	0.9	1.6	1.2	1.2	1.5	1.6	1.7
Consumer Finished Goods	3.7	5.2	6.3	3.2	0.8	-0.2	-1.0	2.5	3.0	0.7	1.6	1.7	1.6
Food	-2.1	0.3	3.4	2.8	2.3	1.6	-0.2	0.8	2.0	1.5	1.4	1.8	1.8
Energy	27.3	27.8	22.6	6.9	-4.0	-6.9	-9.9	5.5	8.3	-2.3	0.9	1.3	0.7
Other	0.3	1.5	2.7	2.0	1.7	1.2	1.8	2.6	1.8	1.4	1.9	1.9	2.0
Producers' Finished Goods	0.1	-0.7	0.5	0.5	0.7	0.6	-0.5	0.0	0.4	0.7	1.0	1.1	1.1
Intermediate Materials, Supplies, and Components	4.4	6.1	5.0	2.6	0.2	-0.5	-2.1	0.2	2.6	0.6	1.2	1.5	1.5
Crude Materials for Further Processing	26.7	30.1	20.7	8.0	-6.3	-5.9	-13.0	1.5	7.7	-0.8	1.5	1.8	1.2
Producer Price Indexes - Commodity Groupings (Percent change, SAAR)													
Total	5.6	7.4	5.8	2.5	0.0	-0.7	-2.5	1.0	2.9	0.6	1.4	1.6	1.5
Industrial Commodities	7.4	8.3	6.2	2.4	-0.5	-1.2	-2.3	1.5	2.9	0.4	1.4	1.6	1.5
Fuels, Related Prod., Power	50.7	40.3	29.4	6.4	-7.4	-9.9	-12.6	8.1	10.1	-3.1	1.2	1.5	0.6
Coal	1.4	-15.6	4.7	10.2	2.9	9.6	-2.8	-3.6	2.9	2.6	1.8	1.7	1.8
Natural Gas	188.1	132.8	48.7	-7.0	-15.2	-20.7	-19.6	15.7	15.2	-3.7	6.5	5.3	1.1
Electricity	-3.0	0.7	1.5	3.6	3.8	2.5	-1.2	-1.3	2.1	1.5	1.6	1.6	1.5
Utility Natural Gas	5.0	22.3	21.3	7.1	-5.7	-8.9	-3.4	1.6	5.5	-3.2	2.1	2.1	0.2
Domestic Crude Oil (NSA)	453.0	127.9	57.3	14.5	-22.2	-22.0	-37.8	41.4	23.1	-8.2	-2.0	-0.9	-0.8
Petroleum Products	150.8	89.9	61.7	14.6	-12.1	-17.0	-24.6	21.2	20.9	-7.7	-1.7	-0.6	-0.4
Residual Fuels	221.3	155.8	58.1	3.7	-17.9	-15.9	-26.2	18.0	21.3	-6.1	2.8	3.5	1.7
Non-Energy Ind. Commodities	1.0	2.6	2.1	1.6	1.0	0.7	-0.1	0.2	1.5	1.2	1.6	1.6	1.7
Textile Products and Apparel	-1.9	-2.2	-1.1	-0.4	-0.3	-0.3	0.2	-1.7	-0.8	0.2	0.8	1.0	0.9
Chemicals and Allied Products	2.2	6.1	3.0	1.6	0.4	-0.1	0.2	-0.1	2.0	1.4	2.2	2.6	2.7
Rubber and Plastic Products	0.3	1.9	1.3	1.7	1.3	0.5	-0.5	-0.2	1.3	1.1	1.2	1.0	1.2
Lumber and Wood Products	6.6	11.8	7.5	2.5	1.2	1.0	-2.6	3.7	4.3	1.5	1.1	1.4	1.1
Pulp, Paper, and Products	4.2	7.4	3.0	3.6	2.8	1.7	2.3	1.3	3.4	1.7	2.5	2.6	2.7
Metals and Metal Products	0.0	5.3	3.1	3.3	1.2	0.8	-3.0	-2.7	2.6	2.0	1.5	1.9	2.0
Machinery and Equipment	-0.6	-0.1	-0.1	-0.2	0.2	0.1	-0.8	-0.5	-0.1	0.3	0.5	0.5	0.6
Furniture & Household Equip.	0.6	0.9	0.8	0.8	0.7	0.4	0.3	0.3	0.7	0.1	0.2	0.3	0.5
Transportation Equipment	0.1	-0.6	0.0	0.7	0.8	0.7	-0.3	0.1	0.4	0.8	1.2	1.4	1.4
Passenger Cars	-0.6	-1.4	-1.4	-0.1	-0.3	-1.0	-1.3	-1.3	-0.8	-0.7	-0.1	0.2	0.1
Other Industrial Commodities	0.4	2.7	5.9	2.2	1.3	1.3	2.4	6.2	2.5	1.8	2.3	2.3	2.2
Agricultural Commod. and Food													
Farm Products	-3.9	0.6	6.0	4.4	5.2	3.4	-7.4	-6.3	3.6	2.3	1.3	1.8	1.6
Processed Foods	-4.3	2.9	3.2	2.7	2.2	1.5	-1.7	-0.1	2.0	1.5	1.5	1.6	1.6
Factors Affecting Producer Prices													
Unit Lab. Costs - Nonfarm (% ch)	4.4	0.7	0.8	3.4	1.4	1.4	2.0	1.4	2.0	1.8	1.6	1.6	1.6
Social Insurance Contributions as Percent of Wages and Salaries	14.7	14.7	14.6	14.7	14.6	14.5	14.9	14.7	14.6	14.6	14.5	14.5	14.4
U.S. Dollar Exch. Rate - OECD (a)	1.100	1.084	1.053	1.040	1.033	1.046	1.105	1.078	1.047	1.040	1.008	0.987	0.973
Annual Percent Change	9.6	-5.5	-11.1	-4.8	-2.9	5.2	5.0	-2.4	-2.9	-0.6	-3.1	-2.1	-1.4
WPI - OECD U.S. Trad. Part. (a)	1.065	1.066	1.071	1.077	1.081	1.084	1.076	1.065	1.082	1.098	1.117	1.137	1.156
Annual Percent Change	2.2	0.2	2.1	2.0	1.5	1.3	-0.6	-0.9	1.6	1.5	1.7	1.8	1.6
Man. Capacity Utilization (%)	78.5	79.5	79.7	78.7	78.4	78.3	80.8	79.5	78.4	78.7	78.5	79.0	78.9
Vendor Performance (b)	51.5	53.7	54.8	51.7	50.4	49.8	51.1	52.8	50.4	51.2	50.9	52.0	51.2

a. 1990=1.000.
b. Percent of purchasing agents reporting slower deliveries.

FPC 272

TABLE 5
Energy

	1999:2	1999:3	1999:4	2000:1	2000:2	2000:3	1998	1999	2000	2001	2002	2003	2004
Demand for All Fuels													
Total Energy Demand (Quad. Btu)	91.9	94.2	94.4	94.4	95.0	95.7	91.1	92.8	95.4	97.8	99.5	101.4	103.0
Annual Percent Change	5.3	10.2	0.7	-0.1	2.7	3.0	0.5	1.9	2.7	2.5	1.8	1.8	1.7
Real GDP (% change)	1.9	4.8	4.8	1.7	3.4	3.6	4.3	3.8	3.4	3.5	3.0	3.2	3.0
Wgtd. Ind. - Eng. Dem. (1996=1.0)	1.1	1.1	1.1	1.1	1.2	1.2	1.1	1.1	1.2	1.2	1.2	1.2	1.3
Electricity (Quad. Btu)	11.2	11.3	11.6	11.6	11.7	11.8	11.0	11.2	11.7	12.0	12.3	12.6	12.8
Coal (Quad. Btu)	2.0	2.0	1.9	1.9	1.9	1.9	2.0	1.9	1.9	1.8	1.8	1.7	1.7
Natural Gas (Quad. Btu)	17.3	18.3	18.1	18.1	18.2	18.2	17.1	17.7	18.2	18.5	18.8	19.0	19.2
Petroleum (Quad. Btu)	36.3	36.4	36.4	36.4	36.7	37.1	35.9	36.4	36.9	38.0	38.6	39.2	39.9
Energy-Use Ratios													
Million Btu per Capita	337.2	344.8	344.7	343.9	346.5	347.4	336.7	340.1	346.5	352.4	355.8	359.4	362.4
Thous. Btu / Chnd. 1996 $ GDP	10.5	10.6	10.5	10.5	10.4	10.4	10.7	10.5	10.4	10.3	10.2	10.1	9.9
Prices (Dollars per barrel)													
U.S. Refiners' Acquisition Price													
for Crude Oil - Composite	15.85	19.62	22.64	22.90	21.50	20.16	12.58	17.25	21.03	18.93	18.48	18.31	18.17
Annual Percent Change	293.0	147.3	77.3	4.7	-22.3	-22.6	-34.2	37.2	21.9	-10.0	-2.4	-0.9	-0.8
Domestic	15.98	19.75	22.97	23.59	22.04	20.84	13.19	17.53	21.57	19.38	18.92	18.74	18.60
Annual Percent Change	283.5	133.4	83.2	11.3	-23.9	-23.0	-33.0	32.9	23.1	-10.2	-2.4	-0.9	-0.8
Foreign	15.44	19.51	22.38	22.44	21.14	19.85	12.14	17.06	20.87	18.63	18.19	18.02	17.88
Annual Percent Change	304.4	154.7	73.3	0.9	-21.2	-22.3	-34.8	40.5	21.2	-9.8	-2.4	-0.9	-0.8
Foreign (Chained 1996 $)	13.60	17.14	19.61	19.58	18.39	17.19	10.83	14.98	17.94	15.92	15.28	14.83	14.41
Annual Percent Change	298.2	152.3	71.4	-0.7	-22.2	-23.5	-35.8	38.5	19.7	-11.3	-4.1	-2.9	-2.8
Prices (Percent change)													
PPI - Fuel and Power	50.7	40.3	29.4	6.4	-7.4	-9.9	-12.5	8.1	10.1	-3.1	1.2	1.5	0.6
Coal	1.4	-15.6	4.7	10.2	2.0	9.8	-2.8	-3.6	2.9	2.6	1.9	1.7	1.6
Natural Gas	188.1	132.6	49.7	-7.0	-15.2	-20.7	-19.8	15.7	15.2	-3.7	6.5	6.3	1.1
Electricity	-3.0	0.7	1.5	3.6	3.8	2.5	-1.2	-1.3	2.1	1.5	1.6	1.8	1.5
Utility Natural Gas	5.0	22.3	21.3	7.1	-5.7	-8.9	-3.4	1.8	5.6	-3.2	2.1	2.1	0.2
Domestic Crude Oil (NSA)	453.0	127.9	57.3	14.5	-22.2	-22.0	-37.8	41.4	23.1	-8.2	-2.0	-0.8	-0.8
Refined Petroleum Products	150.8	89.9	61.7	14.6	-12.1	-17.0	-24.8	21.2	20.9	-7.7	-1.7	-0.8	-0.4
Residual Fuels	221.3	155.8	58.1	3.7	-17.9	-15.9	-28.2	18.0	21.3	-5.1	2.8	3.5	1.7
Producer Price Index - Industrial	7.4	8.3	6.2	2.4	-0.5	-1.2	-2.3	1.5	2.9	0.4	1.4	1.6	1.5
Pers. Cons. Chained Index - Energy	26.9	15.0	13.3	4.6	-2.9	-5.1	-6.3	3.4	6.3	-1.8	0.7	1.1	0.9
Gasoline	68.3	24.8	21.9	4.7	-6.6	-9.2	-11.5	9.1	8.0	-3.7	-0.2	0.4	0.6
Fuel Oil and Coal	14.0	24.6	3.4	7.6	-3.8	-5.8	-9.2	-0.8	4.4	-0.8	2.6	3.1	3.2
Electricity	0.6	1.1	1.6	2.8	3.3	2.7	-3.8	-0.5	2.1	1.3	1.3	1.5	1.4
Natural Gas	-1.4	18.5	21.3	8.6	-4.6	-9.0	-2.1	1.7	5.2	-3.6	2.0	2.1	0.2
Pers. Cons. Chain Type Index	2.2	1.9	1.8	1.8	1.5	1.6	0.9	1.6	1.7	1.7	2.2	2.4	2.4
Gasoline Tax (Cents per gallon)	38.6	38.6	38.7	38.7	38.8	38.8	38.7	38.6	38.8	39.0	38.3	39.7	40.1
Federal	18.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	19.5	18.5	18.5	19.5
State and Local	19.1	19.1	19.2	19.2	19.3	19.3	19.2	19.1	19.3	19.5	19.8	20.2	20.8
Real Personal Consumption (Percent change)													
Total Consumption	5.1	4.3	5.1	2.5	3.8	3.9	4.9	5.2	3.9	3.5	2.8	3.0	3.1
Gasoline	1.3	7.1	0.1	-1.2	3.3	5.5	1.2	0.7	2.3	3.8	1.2	1.6	1.9
Fuel Oil and Coal	16.1	-7.1	-11.0	1.3	1.1	0.8	-4.1	10.6	-1.5	0.4	0.0	0.1	0.0
Electricity	-3.9	11.5	-10.2	1.9	1.3	1.2	5.7	1.8	0.0	1.2	0.9	0.8	1.0
Natural Gas	28.8	2.3	0.8	1.9	1.8	1.0	-8.8	4.1	3.0	1.1	0.7	0.4	1.1
Energy Share of Consumption (%)													
Chained 1996 Dollars	4.9	4.9	4.8	4.8	4.7	4.7	5.0	4.9	4.7	4.7	4.8	4.6	4.4
Current Dollars	4.3	4.4	4.5	4.5	4.4	4.3	4.4	4.3	4.4	4.2	4.0	3.9	3.8
Average Miles per Gallon	19.0	19.1	19.1	19.1	19.1	19.1	19.0	19.0	19.1	19.1	19.2	19.3	19.4
Imports of Petroleum and Products													
Million Barrels per Day	13.2	12.8	12.1	11.9	12.8	13.6	12.6	12.8	12.8	13.6	14.2	14.8	15.3
Billions of Chained 1996 Dollars	85.1	82.6	77.7	76.7	82.7	87.5	81.2	81.4	82.3	87.9	91.5	95.1	98.6
Billions of Current Dollars	63.7	77.7	86.7	87.8	90.3	89.8	50.9	67.6	87.2	83.6	84.3	87.4	90.1
Import Bill as Percent of GNP	0.70	0.84	0.92	0.93	0.94	0.92	0.58	0.73	0.80	0.82	0.80	0.78	0.77
Industrial Production													
Coal Mining (% change)	-1.0	13.5	3.1	3.2	-0.2	0.9	1.7	-1.1	3.1	1.4	1.2	1.4	1.0
Oil and Gas Extraction (% change)	0.8	10.3	7.6	12.8	9.3	-1.4	-3.3	-5.8	7.0	-2.5	1.6	1.2	0.3
Piped Gas and Elec. Util. (%ch)	7.9	5.3	6.2	-1.5	0.8	2.5	1.8	2.0	2.5	2.1	1.7	1.8	1.5
Dom. Energy Supply (Quad. Btu)													
Oil and Natural Gas	34.3	34.7	36.1	35.3	35.5	35.8	35.0	34.5	36.5	35.8	35.9	36.2	36.4
Nuclear, Hydro and Other	33.2	34.4	34.6	34.8	34.8	34.9	34.1	34.2	34.9	36.1	36.1	35.3	35.4
Energy Imports (Quad. Btu)	27.0	26.6	27.2	27.2	27.7	28.3	26.9	27.0	28.0	30.1	31.5	32.9	34.2
Net Exp. & Inv. Ch. (Quad. Btu)	2.6	1.5	2.5	3.0	3.0	3.0	4.9	2.9	3.0	3.0	3.0	3.0	3.0

Wieland, Karl H. /goc,openmail

From:	Lynch, Edward V. /goc,openmail
Sent:	Thursday, March 09, 2000 2:55 PM
To:	Wieland, Karl H. /goc,openmail
Subject:	Data Request

Karl,

This is from DRI's The U.S. Economy 25-Year Focus - Winter '99 (TREND25YR0299)
Ther was no Utility AA Bond series so I'm giving you the 30YR T-Bond and the 30YR Mortgage rate.

Summary of Long Term Projections:

CPI

Trend	Optimistic	Pessimistic
2.5%	1.7%	3.5%

30 YR Treas Bond

Trend	Optimistic	Pessimistic
5.56%	5.39%	6.07%
	-.2	+.5

30 YR Mortgage Rate

Trend	Optimistic	Pessimistic
6.91%	6.55%	7.42%
	-.4	+.5

Inflation

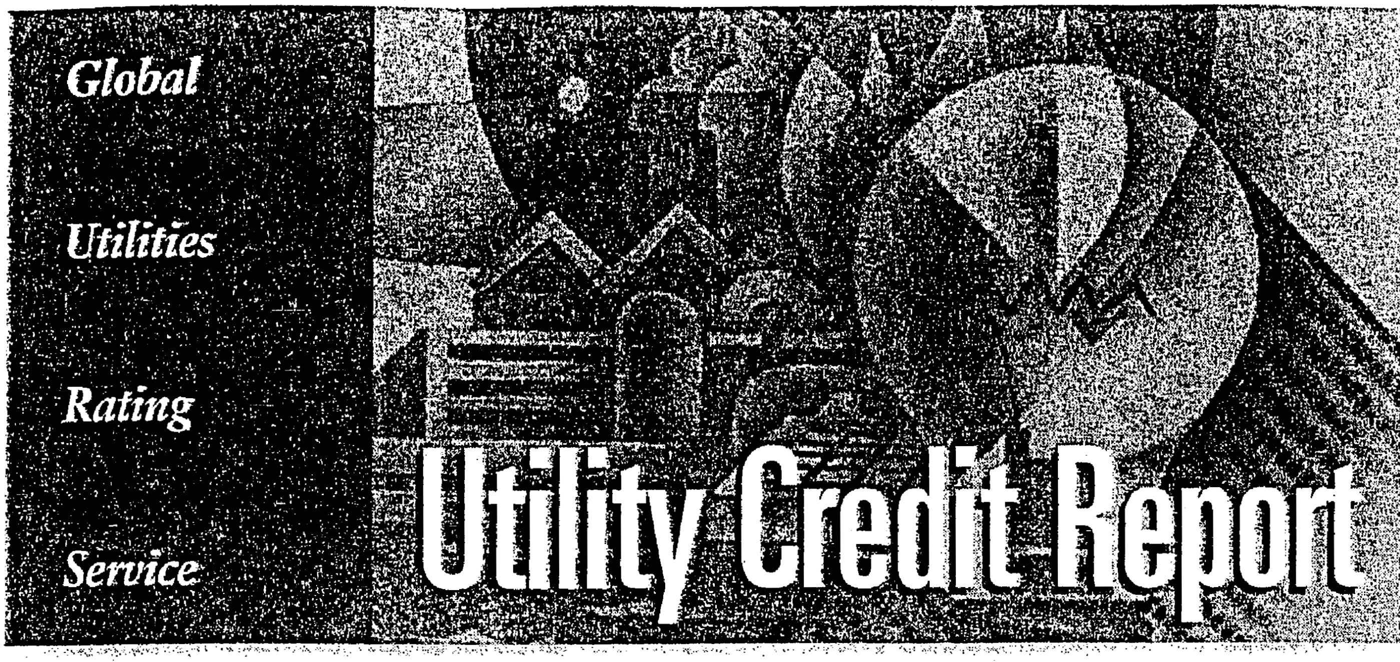
O	P
-0.8	+1%

Cost of Capital

O	P
-0.3	+0.5

used 3% for CPI 10 in
2.5% for Construction

FPC 274



FLORIDA POWER CORP.

Analyst: John W. Whitlock, New York (1) 212-438-7678

Corporate Credit Rating

AA-/Watch Neg/A-1+

Business Profile

1 2 3 **[4]** 5 6 7 8 9
strong — weak

Outstanding Rating(s)

Florida Power Corp.	
Sr unsecd debt	
Local currency	A+/Watch Neg
Sr secd debt	
Local currency	AA-/Watch Neg
CP	
Local currency	Watch Neg/A-1+
Pfd stk	
Local currency	A/Watch Neg
Florida Progress Corp.	
Corp credit rating	A/Watch Neg/A-1
Sr unsecd debt	
Local currency	A/Watch Neg
CP	
Local currency	Watch Neg/A-1
Pfd stk	
Local currency	BBB+/Watch Neg

Corporate Credit Rating History

Oct. 23, 1986	A+/A-1+
June 26, 1990	AA-/A-1+

Company Contact

Pam Saari (1) 727-820-5871

RATIONALE

The ratings of Florida Power Corp. and affiliates are on CreditWatch with negative implications, reflecting Carolina Power & Light Co.'s (CP&L) offer to acquire parent Florida Progress Corp. for $5.3 billion plus the assumption of $42.7 billion in debt. Florida Progress' credit quality is supported by solid cash flow from its utility subsidiary, Florida Power, partly offset by a weaker financial profile for its nonregulated subsidiary, Electric Fuels Corp.

Florida Power's ratings reflect an above average business position buoyed by demand growth, which is spurred by Florida's vibrant economy, growing population, and diversified fuel mix. These positive credit factors are slightly offset by less supportive regulation and the growing threat of widespread competition in the state. Also, the uncharacteristically high amount of debt used to finance nonregulated activities adversely affects the consolidated entity's financial profile.

The utility's financials have rebounded to previous levels after being held back during the outage at the Crystal River Unit 3 nuclear plant, which returned to service in early 1998. Debt leverage is temporarily higher than normal because of the buyout of the Tiger Bay purchased-power contract and the related 220MW facility. However, the lower capacity charges resulting from the buyout are a long-term credit positive.

Electric Fuels' primary holdings are in the nonregulated rail services, inland marine, and energy and related services units, which are vertically integrated and contribute to Florida Progress' profit picture. Still, the risk profile of these units is greater than the traditional regulated utility business, requiring greater cash flows commensurate with the higher risk.

The cash flow generated from nonregulated investments may allow the parent to reduce the financial leverage and improve the consolidated financial profile. A return to 1997 levels of adjusted funds flow to total debt of more than 25% and adjusted funds flow interest coverage of 4.5 times (x) is possible during the forecast period. However, the consolidated enterprise's credit quality may be affected by Electric Fuels' expansion plans, which will require even greater improvement in credit protection measures.

Financial Summary (Mil. $)

	1998	1997	1996	1995	1994
Gross revenues	2,648.2	2,448.4	2,393.6	2,271.7	2,080.5
Net income from continuing operations	250.1	135.9	238.4	227.0	200.8
Funds from operations (FFO)	659.6	459.5	529.8	524.3	502.0
Net cash flow	503.2	265.6	352.7	333.9	316.2
Capital expenditures	310.2	387.2	217.3	283.4	319.5
Total capital	3,547.6	3,727.7	3,180.8	3,202.2	3,265.4
Adjusted ratios					
Pretax interest coverage (x)	2.79	2.93	3.56	3.33	3.02
Total debt/total capital (%)	56.9	59.7	48.8	48.2	50.9
FFO interest coverage (x)	4.01	3.30	4.64	4.47	4.28
FFO/avg. total debt (%)	25.8	20.7	30.0	28.8	30.1

STANDARD & POOR'S

Rating Methodology

Florida Power's corporate credit rating is based on the financial and business risk profile analysis of the consolidated enterprise. Florida Power's first mortgage bonds are rated the same as the firm's corporate credit rating. While these bonds are collateralized by utility property, Standard & Poor's ultimate recovery analysis does not project the value of such collateral to exceed substantially the maximum amount of first mortgage bonds that could be outstanding under the terms of the indenture. Therefore, Standard & Poor's does not have the necessary confidence that first mortgage bondholders would receive their principal in a bankruptcy scenario to consider higher secured ratings. Stress cases consider varying percentages of book value for the different utility asset classes based on the quality of each asset class. Nuclear assets are presumed to have no collateral value.

The utility's senior unsecured debt is rated one notch lower than the corporate credit rating because unsecured bondholders are disadvantaged by the presence of first mortgage bonds currently outstanding. In Florida Power's case, less than 35% of total debt outstanding is secured and assets are considered encumbered only up to the amount needed to satisfy the corresponding secured debt actually outstanding.

Business Description

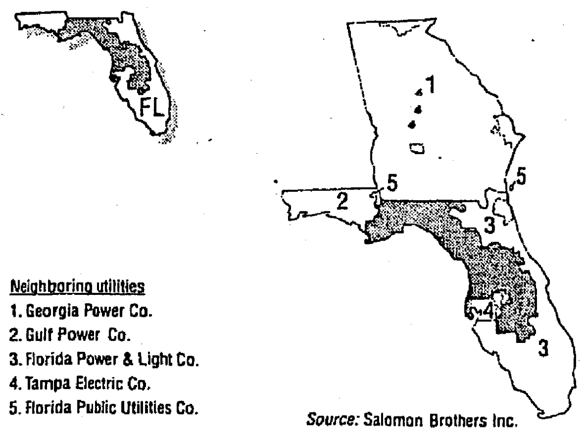
Florida Power, the regulated subsidiary of Florida Progress (*see November 1999 Utility Credit Report*), provides electric service to 1.3 million customers in central and northern Florida. The utility accounted for 80% of assets, 88% of earnings, and 73% of revenues for Florida Progress in 1998. Financing of the nonutility businesses is done at Progress Capital Holdings, which was formed to consolidate Florida Progress' diversified operations into one entity. The principal nonregulated operating subsidiary is Electric Fuels, which engages in coal mining, procurement and transportation, rail car services, and bulk commodities transportation. Progress Capital Holdings' ratings reflect a guarantee by parent Florida Progress.

Business Profile

Regulation. Florida Power's retail rates are regulated by the Florida Public Service Commission (PSC), which allows recovery of fuel-adjustment and purchased-power capacity costs, ratemaking incentives for operational efficiency, and accelerated cost recovery. The PSC has been generally supportive of Florida Power, as evidenced by the substantial recovery allowed for the buyout of the Tiger Bay purchased-power contract and acquisition of the facility. Still, the 1999 ruling allowing Duke Energy Corp. to build a merchant power plant serving the town of New Smyrna Beach (pending appeal and Florida Power Plant Siting Board approval) is a credit concern.

Previously, Florida's peninsular geography and transmission constraints helped to isolate the

FLORIDA POWER CORP.



Source: Salomon Brothers Inc.

Standard & Poor's

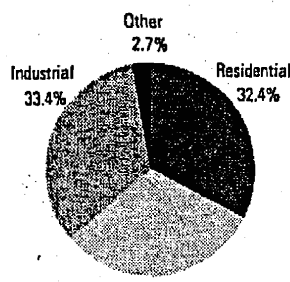
A Division of The McGraw-Hill Companies

Published monthly by Standard & Poor's, A Division of The McGraw-Hill Companies, Inc. Executive offices: 1221 Avenue of the Americas, New York, N.Y. 10020. Editorial offices: 55 Water Street, New York, NY 10041. U.S. subscription rate: $3,465 per year. Please write for rates in other countries. Subscriber services: (212) 438-7280.

Regulation		
Regulatory agency	Florida Public Service Commission	
State	Florida	
Case period	Eight months.	
Interim procedures	Selectively.	
Authorized returns (past 12 to 18 months)		
Return on equity (electric)	11.75%	
Return on equity (gas)	11.3%	
Return on equity (telephone)	13.2%	
Rate base	Average original cost.	
Test period	Forecast.	
CWIP	Some CWIP included in rate base for a partial cash return.	
Adjustment mechanisms	Fuel and purchased-power adjustment clauses (semiautomatic), both the capacity and energy components of purchased power are reflected through the fuel ajustment clause; demand-side management related expenses can be recovered without filing a base rate case; an oil backout cost adjustment allows accelerated recovery of investments in projects designed to displace oil-generated capacity.	
Incentive ratemaking	Demand-side management; plant performance; rate of return and price cap/index; oil backout cost recovery factor rule.	
Commissioners	Party	Term
Julia Johnson, Chair	Democrat	January 2001
Susan F. Clark	Democrat	January 2003
E. Leon Jacobs, Jr.	Democrat	January 2002
Joe Garcia	Independent	January 2002
J. Terry Deason	Democrat	January 2003

Source: Regulatory Research Associates Inc.

Industry Retail Sales (MWh)
1997



Source: Edison Electric Institute.

state's investor-owned utilities from competition. However, several other companies are seeking to build plants similar to the Duke/New Smyrna project, which could be the impetus for widespread competition throughout Florida. Still, there has been no grassroots support for electric restructuring legislation in past legislative sessions, given the small industrial base and temperate residential and commercial rates in the state. However, in Standard & Poor's view, additional merchant plant approvals, as well as new proposals, may be a catalyst for comprehensive legislation in Florida during 2000 to 2001.

Florida Power, which does not plan to seek base rate relief for the foreseeable future, is currently authorized a regulatory return on equity (ROE) of 12%, with an allowed range between 11% and 13%. However, the allowed rate of returns for the Florida investor-owned utilities have been under greater PSC scrutiny recently, which could affect the utility in the future. Still, Florida Power is protected by a rate stipulation that does not expire until 2001.

Markets. Florida Power serves about half of Florida's 67 counties, with a population of almost 5 million residing in the service territory. Service is provided in portions of central and north-central Florida and along the west coast of the state, including St. Petersburg and Clearwater, as well as the areas surrounding Walt Disney World, Orlando, Ocala, and Tallahassee. Some of the municipalities in the franchise area have exerted some pressure on the company when negotiating franchise renewal agreements by threatening to exit the system and team up with an independent power producer (IPP). Yet, the company is protected to some degree by the high cost of the distribution plant that would have to be purchased from Florida Power before a municipality could leave.

Florida Power's industrial customers accounted for about 9% of retail electric revenues and 13% of retail kWh sales, lessening its future exposure to potential electric restructuring in Florida. The company's heavy reliance on residential customers (60% of retail electric revenues and 50% of retail kWh sales) helps to guard against fluctuations in economic activity among the diverse customer base. Continued economic growth will likely fuel customer growth of 2% per year and retail kWh sales increases of 3% per year for 2000 and 2001.

Environmental concerns in Florida have limited Florida Power's transmission network, and no new high-voltage lines are likely in the foreseeable future. Combined with capacity constraints at the transmission interface with Georgia Power Co. outside of Florida, the utility has little transmission flexibility. Standard & Poor's is concerned that the lack of transmission could cause bottlenecks during high demand periods, which could lead to price spikes.

Operations. To meet its future firm load projected demand, Florida Power could build an additional 1,000MW of gas-fired, combined-cycle generation at its Hines facility (a 500MW unit went into service in 1998). The ability to build and place in service gas-fired, combined-cycle plants in a short time gives the company increased flexibility in planning its long-range capacity needs.

Service Area Economics (% chg.)

	1996	1997	1998	1999-2001*	1999-2009*
Population					
Florida	1.7	1.6	1.5	1.5	1.5
Southeast region	1.3	1.2	1.1	1.0	0.9
National	0.9	0.9	0.9	0.8	0.8
Real per capita income (1992 $)					
Florida	21,894	22,484	23,139	23,526	24,891
Southeast region	19,319	19,848	20,401	20,765	22,008
National	22,183	22,872	23,477	23,791	25,013
Total employment					
Florida	3.2	4.2	3.3	1.7	1.9
Southeast region	2.2	2.7	2.4	1.0	1.2
National	2.2	2.6	2.3	1.0	1.1
Unemployment rate					
Florida	5.0	4.7	4.7	5.4	5.4
Southeast region	5.1	4.6	4.4	5.5	5.6
National	5.3	4.8	4.7	5.4	5.4

*Population and total employment estimates represent average annual growth rates for the period. Real per capita income and unemployment rate estimates represent forecasts for the last year in the period. *Source:* DRI/McGraw-Hill.

Market Segments

	1998	1997	1996	1995	1994
Sales					
Total retail (GWh)	33,387	30,850	30,785	29,499	27,675
Residential (%)	49.5	48.9	50.3	50.6	50.1
Commercial (%)	30.0	30.0	28.7	29.2	29.8
Industrial (%)	13.1	13.6	13.7	13.1	12.9
Other (%)	7.4	7.5	7.2	7.1	7.2
Wholesale (GWh)	3,864	2,440	2,708	2,903	2,339
Total sales (GWh)	37,251	33,290	33,493	32,403	30,015
Revenue					
Total retail (mil. $)	2,390	2,203	2,169	2,074	1,908
Residential (%)	59.6	58.7	59.9	60.4	59.9
Commercial (%)	25.5	25.8	24.8	24.8	25.4
Industrial (%)	9.0	9.4	9.5	9.1	9.1
Other (%)	6.0	6.1	5.8	5.6	5.7
Wholesale (mil. $)	206	151	159	153	125
Total revenue (mil. $)	2,596	2,358	2,328	2,227	2,033
Annual sales growth (%)					
Residential	9.6	(2.6)	3.6	7.8	3.7
Commercial	8.0	4.6	2.7	4.4	4.7
Industrial	4.5	(0.9)	9.3	8.0	5.9
Total retail	8.2	0.2	4.4	6.6	4.3
Standard & Poor's retail avg.	2.0	0.6	3.0	3.1	2.6
Wholesale	58.4	(9.9)	(6.7)	24.1	10.4
Total sales growth	11.9	(0.6)	3.4	8.0	4.8
Retail customer growth	2.0	1.7	1.6	2.2	2.4

Source: Navigant Consulting Inc.

Florida Power's construction needs for 2000 and 2001 will be about $550 million, with the majority of the expense targeted for transmission and distribution activity. Free cash flow is expected to cover amply this level of expenditure.

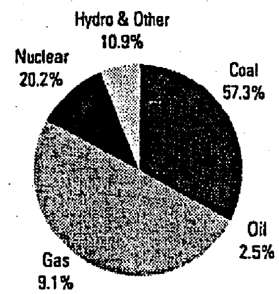
Florida Power's fuel mix is coal 38%, nuclear 15%, gas 7%, oil 20%, and purchased power 20%. The company's coal-fired plants mainly use Appalachian coal delivered by rail and barge and supplied by Florida Progress' subsidiary, Electric Fuels, pursuant to long-term contracts between Florida Power and Electric Fuels. The company's oil needs and gas supply are purchased under contracts and in the spot market from several suppliers with existing contracts sufficient to cover requirements.

A sizable portion of Florida Power's energy needs are provided by purchased-power contracts with other utilities and qualifying facilities (QF), including a large contract with Southern Co. and several QFs totaling 946MW of capacity, 831MW of which is currently available. The PSC allows recovery of QF contract costs in rates, but the company has attempted to buy out several QF contracts to minimize future capacity payments. The elimination of these uneconomical contracts helps to reduce Florida Power's potential exposure to stranded investment.

For credit protection measures, Standard & Poor's adjusts the debt component of utilities with purchased-power contracts to fully realize the financial impact. The net present value of future annual capacity payments for each contract is discounted by 10% (the estimated cost of capital) to identify the potential debt equivalent that a utility incurs when it enters into a long-term purchased-power contract. A risk factor for each contract is then determined on the basis of a qualitative analysis of the contract's terms and conditions, the ability to recover costs through regulatory means, and operating risks. The potential debt equivalent is multiplied by the risk factor to determine the amount of off-balance-sheet obligations added, which was $350 million for Florida Power in 1999.

Florida Power meets environmental standards by burning low-sulfur coal and installing low-nitrogen burners at Crystal River Units 1, 2, 4, and 5. Standard & Poor's believes that more stringent guidelines for nitrogen oxide and mercury emissions are likely to be implemented, which could adversely affect coal-burning

Industry Fuel Mix
1997



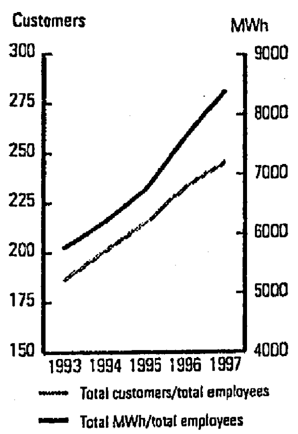
Source: Edison Electric Institute.

Fuel and Power Supply

	1998	1997	1996	1995	1994
Generating capacity					
Owned (MW)	7,727	6,755	7,347	6,526	7,207
Firm purchased (MW)	1,286	1,523	1,495	457	250
Peak demand (MW-summer)	7,444	8,066	8,807	7,128	6,955
Reserve margin (%)	21.1	2.6	0.4	(2.0)	7.2
Peak growth (%)	(7.7)	(8.4)	23.6	2.5	3.4
Annual load factor (%)	N.A.	N.A.	N.A.	49.8	51.2
FRCC regional reserve margin (%-summer)	7.7	N.A.	N.A.	N.A.	N.A.
Generation by fuel source (%)					
Coal	37.9	45.3	60.1	39.2	44.0
Oil	19.6	17.8	22.5	12.2	16.1
Gas	6.5	6.5	4.2	3.9	0.0
Nuclear	14.9	0.0	8.6	18.8	18.0
Purchased	21.0	30.5	4.7	26.0	21.9

FRCC—Florida Reliability Coordinating Council. N.A.—Not available.

Industry Efficiency Measures

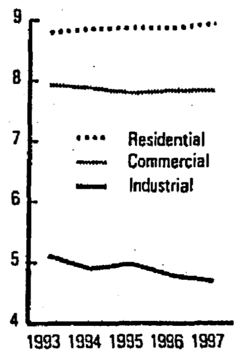


Efficiency Statistics
Operating Efficiency (electric-retail)

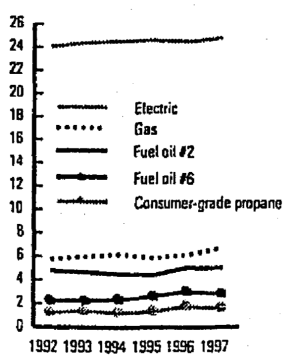
	1998	1997	1996	1995	1994
Total customers/employee	283	239	279	241	225
Industry avg.	259	247	233	215	204
Total MWh/total employee	7,044	5,601	6,650	5,600	5,005
Industry avg.	6,781	6,364	6,061	5,558	5,148
Total revenue/total kWh (cents)	7.16	7.14	7.05	7.03	6.89
Industry avg.	7.00	7.14	7.13	7.16	7.19

Source: Navigant Consulting Inc.

Industry Rates
(cents/kWh)



Average Residential Fuel Cost
($/MMBtu)



Source: American Gas Association.

Nuclear Operating Statistics (1998)

Unit	% owned	Lifetime forced outage rate (%)
Crystal River 3	90.4	21.3

Unit	Book value (mil. $)	Decomm. basis	Est. decomm. cost (mil. $)	Date of estimate	Total amt. funded (mil. $)	Annual amt. funded (mil. $)	Funding sufficiency (%)
Crystal River 3	335.5	Greenfield	420.2	12/98	235.3	21.7	105.4

electric utilities. However, Florida Power's ability to pass along environmental costs to ratepayers in a regulated energy market and its use of natural gas at new plant sites help to mitigate this potential risk.

The Crystal River Unit 3 nuclear plant has performed well since its return to service in early 1998. The plant ran at 100% capacity for 20 consecutive months before beginning a 45-day scheduled refueling outage at the end of September 1999. The turnaround is largely attributable to the new management team that has been running the facility since 1997.

Florida Power's 90.4% share of Crystal River Unit 3 had a net book value of $384 million at year-end 1998. Florida Power is licensed to operate the nuclear plant through December 2016 when decommissioning would likely begin. The PSC has determined future decommissioning costs for Crystal River Unit 3 to be about $2 billion, which is equivalent to $465 million in 1998 dollars. As of June 1999, Florida Power funded about $354 million of its estimated decommissioning expense.

Florida Power and Dynegy Inc. have a power marketing alliance that leverages the utility's physical assets and minimizes its risk exposure through Dynegy's expertise in energy marketing, power trading, and risk management. Florida Power's excess physical capacity is sold on a short-term forward (less than three months) basis and spot basis after its native load requirements are met, and the utility has the right to veto any transaction. Any increase in margins resulting from on-system energy trading is credited back to the utility's ratepayers under the fuel-adjustment clause, which reduces the overall energy costs for its customers. Standard & Poor's views Florida Power's decision to use a successful power marketer (Dynegy) and use only excess capacity backed by physical assets to be a sensible lower-risk strategy, which is favorable to credit quality.

Competitive position. Florida Power's competitive position is enhanced by the small size of its industrial customer class. The primary groups are the phosphate and citrus industries, which reduce the threat of relocation and political opposition. Also, the industrial customers benefit from the current interruptible rate of 4 cents per MWh, which creates a disincentive to seek open competition. Still, the looming presence of planned IPPs could affect the utility's position.

One area that the company has focused on is improving overall system reliability. Residential and commercial customers throughout Florida demand that the service outages be limited in frequency and duration. The company has beefed up its resources dedicated to improving its distribution system, which will position the company favorably when the market transitions from regulation to competition.

Florida Power's biggest investment is the Crystal River Unit 3 nuclear station, with a book value of about $384 million (excluding nuclear fuel). It represents about 20% of common equity and 10% of net electric plant in service and total capitalization. Crystal River Unit 3 is Florida Power's single largest base load facility, and it represented 8% of 1998's total winter capacity (including purchased power).

Energy Costs and Rates (1998)
(cents/kWh)

Utility	Fuel	Total variable production	Total fixed production	Purchased power	Production and purchased power	Total energy cost	Residential rate	Commercial rate	Industrial rate
Florida Power Corp.	**N.A.**	**N.A.**	**N.A.**	**N.A.**	**N.A.**	**N.A.**	**8.62**	**6.09**	**4.90**
Florida Power & Light Co.	N.A.	N.A.	N.A.	N.A.	N.A.	N.A.	7.87	6.47	4.99
Gulf Power Co.	1.74	2.33	0.37	3.75	2.80	4.01	6.22	5.17	3.81
Tampa Electric Co.	2.23	2.88	1.42	4.10	4.27	5.52	7.99	6.48	4.48
FRCC region average	**1.99**	**2.60**	**0.90**	**3.93**	**3.54**	**4.76**	**7.68**	**6.05**	**4.54**
Standard & Poor's average	**1.50**	**2.39**	**1.79**	**3.95**	**3.96**	**5.57**	**8.67**	**7.35**	**5.10**

FRCC—Florida Reliability Coordinating Council. N.A.—Not available.

Financial Profile

Financial policy: Average
Florida Power's debt leverage is high, but the company continues to make strides to reduce debt to 45% of capitalization. The roll off in 2000 of a portion of the debt associated with the buyout of the Tiger Bay contract and sufficient internal funding for planned capital expenditures provide a platform for the company to achieve its goal. Florida Progress' dividend payout for 1999 is expected to be about 70% of earnings.

Profitability. Through the first three quarters of 1999, retail sales were up slightly from the same period in 1998. Solid customer growth was offset by bad weather in 1999, compared with 1998; a heat wave prevailed in Florida during most of June 1999. Full-year earnings will probably be slightly more than in 1998. Still, the utility's ROE is expected to be about 13% for 1999.

Adjusted pretax interest coverage is expected to be about 4.5x. Robust cash flow, cost-containment initiatives, and strong customer sales growth are the expected catalysts.

Cash flow protection. The utility's modest capital budget of about $300 million per year should be ably funded from internal cash generation. Capital spending will be concentrated in large part on transmission and distribution projects.

Cash flow protection measures are expected to remain healthy during the 2000-2001 period. Standard & Poor's expects a return to prior levels, with funds from operations (adjusted for off-balance-sheet purchased-power obligations) interest coverage of 4.5x and adjusted funds from operations to total average debt of 25% possible.

Capital structure. Debt leverage for the utility is high, but the company is committed to improving this measure. The roll off in 2000 of a portion of the debt associated with the buyout of the Tiger Bay contract will help Florida Power meet its goal as will robust regulated cash flow.

The average remaining life of Florida Power's long-term debt is 12.9 years, with an embedded cost of 6.8%. The PSC's approval of accelerated depreciation has reduced the amount of regulatory assets that could have been stranded in a deregulated energy market.

Financial flexibility. Florida Progress' stock is trading at 230% of its book value, in reaction to CP&L's offer to purchase the company. Florida Power has a $200 million 364-day and a $200 million five-year revolving credit facility, which are used to back up its $400 million commercial paper program.

Florida Power has $585 million in first mortgage bonds outstanding, with maturities through 2023. The utility has registered $370 million in additional first mortgage bonds but has no plans to issue new first mortgage bonds at this time. The company also has a remaining shelf filing of $250 million in medium-term notes.

Financing Flexibility

Common equity characteristics as of June 30, 1999	
Ticker symbol	FPC
Stock price ($)	41.3125
PE ratio (x)	13.7
Dividend yield (%)	5.3
Market to book (%)	209.7
Dividend to book (%)	11.0

Debt characteristics at fiscal year ended 1998	
Secured debt (%)	35
Unsecured debt (%)	65
Subordinated debt (%)	0
Fixed-rate debt (%)	100
Variable-rate debt (%)	0
Avg. life of long-term debt (years)	14
Embedded cost of long-term debt (%)	6.6
Debt maturing in five years (mil. $)	1,284.1

Short-term Financing As of Dec. 31, 1998

Short-term debt (mil. $)	Arranged	Outstanding	Expiration date	Same-day availability	MAC clause
Commercial paper	400.0	0.0			
Bank lines					
Contracted committed lines	400.0	0.0	11/99	N.A.	N.A.
Avg. cost of short-term debt (%)	N.A.				

MAC—Material adverse change. N.A.—Not available.

FPC 281

Financial Statistics—Florida Power Corp.

	—Year ended Dec. 31—				
	1998	1997	1996	1995	1994
Income statement (mil. $)					
Gross revenues	2,648.2	2,446.4	2,393.6	2,271.7	2,080.5
Operating expenses (excl. DD&A)	1,784.3	1,631.6	1,600.9	1,523.4	1,399.5
Depreciation and amortization	347.1	325.9	324.2	23.7	261.5
Pretax operating income	516.8	490.9	468.5	454.6	419.5
Gross interest expense	136.5	117.3	98.4	104.5	108.4
Pretax income	390.4	205.8	374.2	356.5	315.5
AFUDC and deferrals	16.9	9.7	7.5	9.0	10.9
Income taxes	140.3	69.9	135.8	129.5	114.7
Net income from continuing operations	250.1	135.9	238.4	227.0	200.8
Earnings protection					
Pretax interest coverage (x)	3.77	4.15	4.73	4.33	3.81
Adjusted pretax interest coverage (x)	2.79	2.93	3.56	3.33	3.02
Preferred dividend coverage (x)	3.71	4.07	4.34	3.80	3.34
EBITDA interest coverage (x)	6.32	6.93	8.02	7.14	6.22
AFUDC and deferred income/earnings (%)	6.8	7.1	3.1	4.0	5.4
Return on common equity (nominal) (%)	12.9	6.9	12.6	12.2	10.8
Common dividend payout (%)	62.3	143.2	73.6	83.2	92.1
Annual O&M growth (%)	12.7	2.8	0.7	(7.6)	N.A.
Annual expense growth (excl. DD&A) (%)	9.4	1.9	5.1	8.9	N.A.
O&M/revenues (%)	20.8	20.0	19.9	20.8	24.6
Total operating expenses (excl. DD&A)/revenues (%)	67.4	66.6	66.9	67.1	67.3
Balance sheet (mil. $)					
Cash and equivalents	0.0	0.0	0.0	0.8	0.0
Gross plant	6,732.0	6,869.4	6,522.5	6,403.1	6,201.2
Net plant	3,630.5	3,649.5	3,517.1	3,605.1	3,669.2
Total assets	4,928.1	4,900.8	4,264.0	4,284.9	4,284.5
Short-term debt	138.9	181.3	25.4	30.6	90.7
Long-term debt	1,555.1	1,745.4	1,296.4	1,279.1	1,363.8
Preferred stock	33.5	33.5	33.5	138.5	143.5
Common equity	1,820.1	1,767.5	1,825.5	1,754.0	1,667.4
Total capitalization	3,547.6	3,727.7	3,180.8	3,202.2	3,265.4
Total off-balance-sheet obligations	748.8	744.4	450.6	448.7	426.0
Balance sheet ratios (%)					
Short-term debt/total capital	3.9	4.9	0.8	1.0	2.8
Long-term debt/total capital	43.8	46.8	40.8	39.9	41.8
Preferred stock/total capital	0.9	0.9	1.1	4.3	4.4
Common equity/total capital	51.3	47.4	57.4	54.8	51.1
Adjusted total debt/total capital	56.9	59.7	48.8	48.2	50.9
Debt/EBITDA (x)	2.0	2.4	1.7	1.8	2.2
Cash flow (mil. $)					
Net income	250.1	135.9	238.4	227.0	200.8
Depreciation	361.0	305.7	313.0	309.2	282.9
Deferred taxes and ITC	36.5	(15.2)	(32.8)	(29.3)	(0.9)
AFUDC and deferrals	(16.9)	(9.7)	(7.5)	(7.3)	(10.9)
Other funds from operations (FFO) adjustments	28.9	42.8	18.7	24.7	30.1
FFO	659.6	459.5	529.8	524.3	502.0
Preferred dividends	(1.5)	(1.5)	(5.8)	(9.7)	(10.1)
Common dividends	(154.9)	(192.4)	(171.3)	(180.7)	(175.7)
Net cash flow (NCF)	503.2	265.6	352.7	333.9	316.2
Working capital changes	89.8	(57.6)	(57.3)	32.8	(10.3)
Capital expenditures (capex)	(310.2)	(387.2)	(217.3)	(283.4)	(319.5)
Discretionary cash flow	282.8	(179.2)	78.1	83.3	(13.6)
Cash flow adequacy					
Capex/avg. total capital (%)	8.5	11.2	6.8	8.8	9.8
NCF/capex (%)	162.2	68.6	162.3	117.8	99.0
FFO/avg. total debt (%)	36.4	28.3	40.3	37.9	34.5
Adjusted FFO/avg. total debt (%)	25.8	20.7	30.0	28.8	30.1
FFO interest coverage (x)	5.66	4.76	6.31	5.95	5.57
Adjusted FFO interest coverage (x)	4.01	3.30	4.64	4.47	4.28

AFUDC—Allowance for funds used during construction. O&M—Operations and maintenance. ITC—Investment tax credits. DD&A—Depreciation, depletion, and amortization. EBITDA—Earnings before interest, taxes, depreciation, and amortization. N.A.—Not available. *Source:* Financial data from EKS™ software by Navigant Consulting Inc.

Florida Power Corp.

John W. Whitlock, New York (1) 212-438-7678

Florida Power Corp.

Corporate Credit Rating

AA-/Watch Neg/A-1+

RATIONALE The ratings of Florida Power Corp. are on CreditWatch with negative implications, reflecting Carolina Power & Light Co.'s offer to acquire parent Florida Progress Corp. for $5.3 billion plus the assumption of $42.7 billion in debt. Florida Progress' credit quality is supported by solid cash flow from its utility subsidiary, Florida Power, partly offset by a weaker financial profile for its nonregulated subsidiary, Electric Fuels Corp.

Florida Power's ratings reflect an above-average business position buoyed by demand growth, which is spurred by Florida's vibrant economy, growing population, and diversified fuel mix. These positive credit factors are slightly offset by less supportive regulation and the growing threat of widespread competition in the state. Also, the high amount of debt used to finance nonregulated activities adversely affects the consolidated entity's financial profile.

The utility's financials have rebounded to previous levels after being held back during the outage at the Crystal River Unit 3 nuclear plant, which returned to service in early 1998. Debt leverage is temporarily higher than normal because of the buyout of the Tiger Bay purchased-power contract and the related 220 megawatts facility. However, the lower capacity charges resulting from the buyout are a long-term credit positive.

Electric Fuels' primary holdings are in the nonregulated rail services, inland marine, and energy and related services units, which are vertically integrated and contribute to Florida Progress' profit picture. Still, these units are riskier than the traditional regulated utility business, requiring greater cash flows commensurate with the higher risk.

The cash flow generated from nonregulated investments may allow the parent to reduce the financial leverage. A return to 1997 levels of adjusted funds flow to total debt of more than 25% and adjusted funds flow interest coverage of 4.5 times (x) is possible during the forecast period. However, the consolidated enterprise's credit quality may be affected by Electric Fuels' expansion plans, which will require even greater improvement in credit protection measures.

Florida Power Corp. Financial Statistics

	—Year ended Dec. 31—				
(Mil. $)	1998	1997	1996	1995	1994
Gross revenues	2,648.2	2,448.4	2,393.6	2,271.7	2,080.5
Net income from cont. operations	250.1	135.9	238.4	227.0	200.8
Funds from operations (FFO)	659.6	459.5	529.8	524.3	502.0
Net cash flow (NCF)	503.2	265.6	352.7	333.9	316.2
Capital expenditures	310.2	387.2	217.3	283.4	319.5
EBIT interest coverage (x)	3.77	4.15	4.73	4.33	3.81
Preferred dividend coverage (x)	3.71	4.07	4.34	3.80	3.34
FFO interest coverage (x)	5.66	4.76	6.31	5.95	5.57
Capital expend./avg. total capital (%)	8.5	11.2	6.8	8.8	9.8
NCF/capital expenditures (%)	162.2	68.6	162.3	117.8	99.0
FFO/avg. total debt (%)	36.4	28.3	40.3	37.9	34.5
Return on common equity (nominal) (%)	13.9	7.5	13.0	12.7	11.4
Total capitalization	3,547.6	3,727.7	3,180.8	3,202.2	3,265.4
Short-term debt (%)	3.9	4.9	0.8	1.0	2.8
Long-term debt (%)	43.8	46.8	40.8	39.9	41.8
Preferred stock (%)	0.9	0.9	1.1	4.3	4.4
Common equity (%)	51.3	47.4	57.4	54.8	51.1

Florida Power Corp. Operating Statistics

	—Year ended Dec. 31—				
	1998	1997	1996	1995	1994
Total sales (GWh)	37,251	33,290	33,493	32,403	30,015
Residential (%)	44.4	45.3	46.2	46.1	46.2
Commercial (%)	26.8	27.8	26.4	26.6	27.5
Industrial (%)	11.7	12.6	12.6	11.9	11.9
Wholesale (%)	10.4	7.3	8.1	9.0	7.8
Other (%)	6.7	7.0	6.7	6.4	6.6
Avg. retail revenue (cents/kWh)	0.07	0.07	0.07	0.07	0.07
Retail sales growth (%)	8.22	0.21	4.36	6.59	4.32
Capacity at time of peak (MW)	9,013	8,278	8,842	6,983	7,457
Reserve margin (%)	21.1	2.6	0.4	1.4	9.1

GWh—Gigawatt hours. kWh—Kilowatt hours. MW—Megawatts.

FPC 283

Balance Sheet Statistics for Electric Utilities

For 12 months ended Dec. 31, 1999
(Mil. $)

Company Name	Gross plant	Net plant	Current assets	Total assets	Short-term debt	Long-term debt	OBS debt	Pref. stock	Comm. stock	Total cap.
Wisconsin Public Service Corp.	2,053.6	850.8	186.4	1,409.9	50.4	373.1	0.0	51.2	525.1	999.9
Average AA+	2,053.6	850.8	186.4	1,409.9	50.4	373.1	0.0	51.2	525.1	999.9
Madison Gas & Electric Co.	782.2	297.8	71.1	495.5	27.0	148.6	5.7	0.0	185.7	361.2
Northern States Power Wisconsin	1,240.3	752.8	86.7	907.1	80.8	232.0	0.0	0.0	357.0	669.8
Southern Indiana Gas & Electric Co.	1,362.5	738.9	104.0	894.8	76.6	238.3	0.0	19.3	334.6	668.7
Tampa Electric Co.	4,563.7	2,745.0	306.3	3,322.5	356.0	690.3	32.6	0.0	1,043.1	2,089.4
Average AA	1,987.2	1,133.6	142.0	1,405.0	135.1	327.3	9.6	4.8	480.1	947.3
Central Illinois Public Service Co.	2,733.3	1,472.8	249.6	1,781.8	167.9	493.6	0.0	80.0	534.4	1,275.9
Florida Power & Light Co.	18,005.0	7,821.0	893.0	10,608.0	219.0	2,079.0	1,236.6	226.0	4,793.0	7,317.0
Florida Power Corp.	6,993.2	3,651.9	520.7	5,002.5	229.9	1,478.8	781.2	33.5	1,885.0	3,627.2
Indianapolis Power & Light Co.	3,049.5	1,750.4	176.6	2,048.8	49.0	628.0	50.0	59.1	780.5	1,516.6
Northern States Power Co.	9,783.9	4,451.5	1,033.8	9,767.7	1,094.0	3,453.4	198.2	305.3	2,557.5	7,410.2
Otter Tail Power Co.	889.6	503.0	119.9	680.8	5.9	176.4	32.9	33.5	245.7	461.6
San Diego Gas & Electric Co.	4,483.0	2,157.0	843.0	4,366.0	66.0	892.0	260.1	104.0	1,314.0	2,376.0
TECO Energy Inc.	6,064.4	3,627.8	531.8	4,690.1	969.5	1,207.8	32.6	0.0	1,472.5	3,649.8
Union Electric Co.	9,652.7	5,331.8	707.8	7,043.6	11.4	1,816.6	42.7	221.2	2,433.7	4,482.9
Wisconsin Electric Power Co.	6,395.2	3,205.3	645.9	5,052.6	295.5	1,677.6	0.0	30.5	1,880.9	3,884.4
Wisconsin Power & Light Co.	2,508.0	1,241.6	121.5	1,766.1	182.7	414.7	36.5	60.0	599.1	1,256.5
Average AA-	6,414.4	3,201.3	531.3	4,800.7	299.2	1,301.6	242.8	104.8	1,681.5	3,387.1
Alabama Power Co.	12,605.2	7,703.8	848.3	9,648.7	197.8	3,190.4	101.5	664.5	2,988.9	7,041.5
Allegheny Energy Inc.	8,839.7	5,207.2	709.3	6,852.4	830.8	1,499.0	75.8	229.5	1,695.3	4,254.6
Allegheny Generating Co.	828.9	601.7	7.3	620.9	52.5	148.9	0.0	0.0	154.5	355.9
Alliant Energy Corp.	6,205.7	3,128.3	486.0	6,075.7	492.8	1,512.8	211.9	113.6	2,155.6	4,274.8
Ameren Corp.	13,056.5	7,165.2	879.0	9,177.6	209.0	2,382.9	52.5	300.7	3,089.7	5,982.4
Baltimore Gas & Electric Co.	8,976.2	5,510.1	655.0	7,272.6	652.9	1,956.0	248.5	440.0	2,355.4	5,404.3
Consolidated Edison Co. of New York Inc.	14,991.7	10,606.9	1,378.1	13,682.2	770.4	4,243.1	698.5	249.6	4,393.8	9,656.8
Duke Energy Corp.	30,436.0	20,995.0	6,717.0	33,409.0	782.0	8,683.0	233.7	1,450.0	10,198.0	21,113.0
FPL Group Inc.	19,397.0	9,107.0	1,373.0	13,441.0	464.0	3,478.0	1,236.6	226.0	5,370.0	9,538.0
Georgia Power Co.	16,343.3	9,804.7	1,028.6	12,276.9	792.0	2,688.4	473.3	804.2	3,938.2	8,222.8
Gulf Power Co.	1,887.8	1,065.9	158.2	1,308.5	55.0	367.4	12.8	89.2	422.3	934.0

Source: Financial data from EKS™ software by Navigant Consulting Inc.

FPC 284

Standard & Poor's RatingsDirect

Analysis

Publication Date: 26-Apr-2000

Summary: Florida Power Corp.

Analyst: John W Whitlock, New York (1) 212-438-7678

Contents

Credit Rating: **AA-/Watch Neg/A-1+**

Rationale

The ratings on Florida Power Corp. are on CreditWatch with negative implications, reflecting Carolina Power & Light Co.'s offer to acquire parent Florida Progress Corp. for $5.3 billion plus the assumption of $4.7 billion in debt. Florida Progress' credit quality is supported by solid cash flow from its utility subsidiary, Florida Power, partly offset by a weaker financial profile for its nonregulated subsidiary, Electric Fuels Corp.

The ratings on Florida Power reflect an above average business position buoyed by demand growth, which is spurred by Florida's vibrant economy, growing population, and diversified fuel mix. These positive credit factors are slightly offset by the changing regulatory and political environment in Florida, which may adversely impact the consolidated business profile of the utility. Also, the uncharacteristically high amount of debt used to finance nonregulated activities adversely affects the consolidated entity's financial profile.

Debt leverage for Florida Power is temporarily higher than normal because of the buyout of the Tiger Bay purchased-power contract and the related 220MW facility. However, the lower capacity charges resulting from the buyout are a long-term credit positive. Still, the high amount of debt leverage pressures consolidated credit protection measures.

Electric Fuels' primary holdings are in the nonregulated rail services, inland marine, and energy and related services units, which are vertically integrated and contribute to Florida Progress' profit picture. Still, the risk profile of these units is greater than the traditional regulated utility business, requiring greater cash flows commensurate with the higher risk.

The cash flow generated from nonregulated investments may allow the parent to reduce the financial leverage and improve the consolidated financial profile. A return to 1997 levels of adjusted funds flow to total debt of more than 25% and adjusted funds flow interest coverage of 4.5 times is possible during the forecast period. However, the consolidated enterprise's credit quality may be affected by Electric Fuels' expansion plans, which will require even greater improvement in credit protection measures.

Moody's Investors Service
Global Credit Research

Florida Power Corporation

September 1999

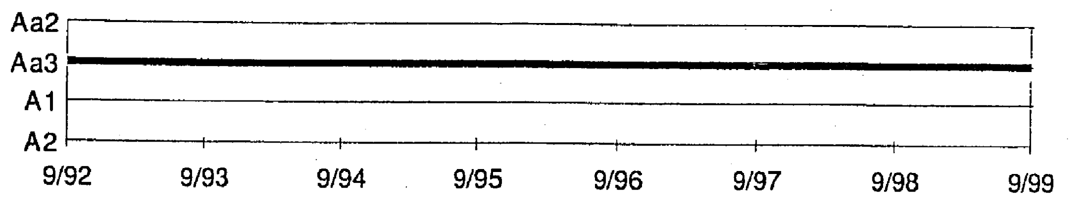
Ratings and Contacts

Category	Moody's Rating
Issuer Rating	A1*
First Mortgage Bonds	Aa3*
Senior Unsecured	A1*
Preferred Stock	"a1"*
Commercial Paper	P-1*
Ult Parent: Carolina Power & Light Company	
Issuer Rating	A3
First Mortgage Bonds	A2
Senior Unsecured Shelf	(P)A3
Subordinate	Baa1

* Placed under review for possible downgrade on August 23, 1999

Analyst	Phone
A. Tucker Hackett/New York	1.212.553.1653
Scott Solomon/New York	
Susan D. Abbott/New York	

Rating History — Senior Secured



Operating Statistics

Florida Power Corporation (Statistics in bold type)[1]
Peer Group Median (Statistics in light type)

	[2]1999	1998		1997		1996		1995		[3]5-Yr.Avg	
Revenue (US$ bil.)	**2.7**	1.2	**2.6**	1.1	**2.4**	1.1	**2.4**	1.0	**2.3**	[4]4.5	**[4]6.2**
Assets (US$ bil.)	**5.0**	2.9	**4.9**	2.8	**4.9**	2.7	**4.3**	2.8	**4.3**	[4]2.5	**[4]3.0**
Com. Equity (US$ bil.)	**1.8**	0.9	**1.8**	0.9	**1.8**	0.9	**1.8**	0.9	**1.8**	[4]2.2	**[4]3.6**
Op. Margin (%)	**14.2**	14.8	**14.0**	15.5	**10.1**	16.4	**13.9**	16.1	**14.4**	15.7	**13.4**
ROA(%)	**5.3**	3.7	**5.0**	3.6	**2.7**	3.7	**5.5**	3.8	**5.1**	3.7	**4.6**
ROE(%)	**14.2**	12.2	**13.7**	11.8	**7.6**	12.0	**12.7**	12.5	**12.4**	12.0	**11.6**
Div. Payout (%)	**133.6**	82.8	**61.7**	85.2	**142.0**	81.9	**71.2**	79.0	**83.2**	82.3	**90.0**
Pretax Int. Cov. (X)	**4.1**	3.5	**3.7**	3.4	**2.7**	3.5	**4.7**	3.4	**4.3**	3.4	**3.9**
Fxd. Chg. Cov. (X)	**4.0**	3.0	**3.7**	2.9	**2.6**	2.9	**4.3**	2.9	**3.8**	2.9	**3.6**
FFO Int. Cov. (X)	**6.5**	4.5	**6.0**	4.5	**5.2**	4.6	**6.6**	4.4	**6.1**	4.4	**5.9**
FFO % Total Debt	**41.6**	25.7	**40.7**	26.2	**25.5**	26.4	**42.0**	25.3	**40.9**	25.3	**36.9**
RCF % Gross CAPEX	**97.3**	114.0	**172.2**	124.6	**77.0**	128.8	**176.6**	113.5	**121.6**	113.8	**129.7**
Total Cap. (US$ bil.)	**3.6**	2.0	**3.5**	2.0	**3.7**	2.0	**3.2**	1.9	**3.2**	[4]1.7	**[4]1.8**
TD % Cap.	**47.4**	49.2	**47.8**	49.5	**51.7**	48.8	**41.6**	49.5	**40.9**	49.4	**45.3**
Pfd. Stk. % Cap.	**0.9**	5.8	**0.9**	6.0	**0.9**	5.8	**1.1**	4.6	**0.8**	5.4	**0.9**
Common % Cap.	**51.7**	44.9	**51.3**	44.9	**47.4**	45.4	**57.4**	45.1	**54.8**	44.9	**52.4**

Electric Utility Operating Statistics

Customer Segmentation	Residential	Commercial	Industrial	Wholesale	Total
Revenue (US$ mil.)	**1,424.6**	**608.9**	**214.4**	**207.9**	**2,648.2**
Kwh(mil.)	**16526**	**9999**	**4375**	**3864**	**37251**
¢/Kwh	**8.6**	**6.1**	**4.9**	**5.4**	**7.1**
Regional Average	**7.9**	**6.5**	**4.7**	**4.3**	**7.6**

Competitive Position	Fuel	Non-Fuel	Investment	Total Cost	Regional Cost
$ per Mwhr.	**22.03**	**3.29**	**9.15**	**34.47**	**34.76**

[1] Competivie Position reflects 1997 figures. [2] For the 12 months ended June 30; Balance sheet items are as of June 30. [3] Five year average 1998-1994. [4] Five year compound annual growth rate.

Opinion

Rating Rationale

Florida Power Corporation (FPC) has retained a Aa3 senior secured rating for a number of years by virtue of its capable management, cost-cutting initiatives, supportive regulation, competitive rates, the state's vibrant economy, and limited in-state competition. However, the utility is exposed to nuclear risk through its 90% ownership of the Crystal River nuclear plant and to potential stranded costs from expensive power-purchase contracts and regulatory assets. In addition, ratings pressure originates in acquisition leverage issued by a new holding company created to purchase FPC.

Recent Events

Management announced in August the company will be sold to Carolina Power & Light Company (CP&L, rated A2 sr. sec.) to create the nation's 9th largest utility in terms of generating capacity. The new super regional utility will be headquartered in North Carolina.

New management expects merger-related synergies, driven by cost savings, to exceed $100 million per annum. Savings will result primarily from elimination of duplicate corporate and administrative programs and operating efficiencies. A substantial portion of these savings will be extracted from FPC.

In addition, revenue enhancements are likely from generation expansion and wholesale marketing opportunities. CP&L intends to use the FPC platform to build gas-fired generating plants in Florida.

Rating Outlook

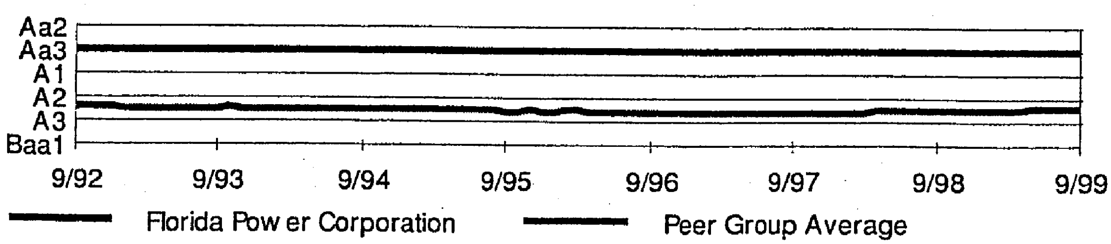
Concern that financial pressure will result from the obligation to service up to $3.5 billion of acquisition leverage to be issued by a new holding company led Moody's to place the securities on review for potential downgrade.

F

FPC 286

Coupon	Type of Debt	Maturity	Moody's Rating
Florida Power Corporation			
—	Issuer Rating	—	A1
—	MTN Program	—	A1
—	4% Cum. Pfd. Stk.	—	"a1"
—	4.60% Cum. Pfd. Stk.	—	"a1"
—	4.40% Cum. Pfd. Stk.	—	"a1"
—	4.58% Cum. Pfd. Stk.	—	"a1"
—	7.40% Cum. Pfd. Stk.	—	"a1"
—	7.76% Cum. Pfd. Stk.	—	"a1"
—	$7.08 Cum. Pfd. Stk.	—	"a1"
—	4.75% Pfd. Stk.	—	"a1"
7.000%	First Mortgage Bonds	2023	Aa3
8.000%	First Mortgage Bonds	2022	Aa3
8.625%	First Mortgage Bonds	2021	Aa3
6.875%	First Mortgage Bonds	2008	Aa3
6.000%	First Mortgage Bonds	2003	Aa3
6.125%	First Mortgage Bonds	2003	Aa3
7.250%	First Mortgage Bonds	2002	Aa3
7.375%	First Mortgage Bonds	2002	Aa3
6.500%	First Mortgage Bonds	1999	Aa3
6.750%	Medium Term Notes	2028	A1
6.810%	Medium Term Notes	2007	A1
6.770%	Medium Term Notes	2006	A1
6.720%	Medium Term Notes	2005	A1
6.690%	Medium Term Notes	2004	A1
6.620%	Medium Term Notes	2003	A1
6.540%	Medium Term Notes	2002	A1
6.470%	Medium Term Notes	2001	A1
6.330%	Medium Term Notes	2000	A1
—	Commercial Paper	—	P-1
—	415 Shelf Registration	—	(P)Aa3

Rating History Peer — Senior Secured



Authors
A. Tucker Hackett
Edward Ip

Editor
David Veasey

Production Associate
John Tzanos

FPC 287

Risks/Weaknesses

- Financial pressure from acquisition debt issued to finance its acquisition by Carolina Power and Light (CPL).
- Exposure to nuclear risk through Crystal River and CPL's nuclear units.
- Above-market purchased-power contracts constrain the company's ability to reduce production costs.
- Merchant plant sponsors continue attempts at inroads in FPC's service territory.
- Potential stranded costs are high for the rating category, but average for investor owned utilities in Florida.
- Significant risks inherent in expanding unregulated activities of parent.
- Parent guarantee of non-regulated subsidiary debt issued by Progress Capital Holdings, a downstream holding company that finances the parent's non-regulated businesses.

Opportunities/Strengths

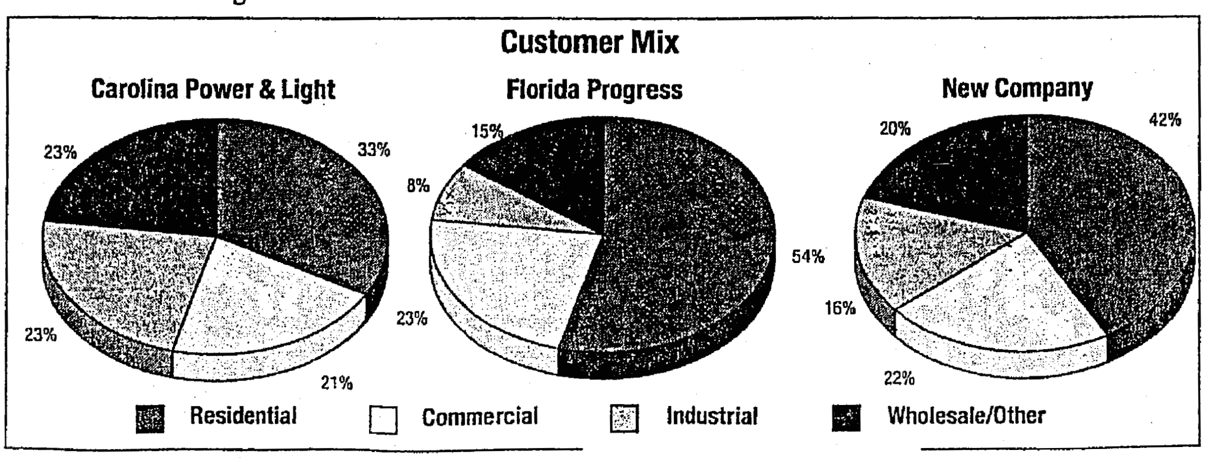
- Acquisition by CPL creates critical mass and cost savings opportunities.
- An economically vibrant service territory.
- The lack of political or regulatory support for deregulation in Florida.
- A growing residential customer base drives steady revenue growth.
- Competitive rates within Florida.

Company Fundamentals

On August 23, 1999, Carolina Power & Light Company announced plans to acquire the parent company of Florida Power Corporation (FPC), Florida Progress, in a cash and stock transaction valued at $8 billion, including the assumption of $2.7 billion in FPC debt and preferred stock. Under terms of the agreement, Florida Progress shareholders will receive $54 per share in a combination of cash and a new CPL holding company's common stock (See Management Strategy and Competitive Position for details). Acquisition debt of $3.5 billion will be issued by a new holding company to finance the acquisition.

Florida Power Corporation is the principal operating subsidiary of Florida Progress Corporation, a diversified energy-related holding company based in St. Petersburg, Florida. As the state's second largest investor-owned utility, FPC provides electric service to more than 1.3 million customers in a 20,000 square-mile service territory encompassing substantial portions of west-central and northern Florida, including the fast growing region around Orlando. Electric Fuels Corporation, an energy and transportation company is Florida Progress' other major subsidiary. Progress Capital Holdings, Inc. (PCH), a downstream holding company finances the parent's non-utility businesses. In 1997, the company wrote off its investment in Mid-Continent Life Insurance Company without impacting ratings.

At year-end 1998, FPC comprised approximately 80% of Florida Progress' assets, 73% of its consolidated revenue, and 89% of its net income. Residential and commercial customers contributed 54% and 23% to total electric revenues, respectively, while industrial and wholesale customers each supplied 8%. As demonstrated in the pie chart below, the predominantly residential base of FPC will make a strong complement to CPL's higher mix of commercial and industrial customers. This strategic fit will enhance CPL's plans to expand its electric generation capacity and build a powerful presence in the Southeastern electric and natural gas markets.



Centered on its growing trade and services industries, while further influenced by tourism and agriculture, Florida's economy continues to be among the fastest growing in the nation. During the 1990s, the state's population has grown by nearly 20% and continues to outperform the region and the nation in employment and income growth. As a result, this vibrant service territory appeals to outside utilities, who are interested in constructing merchant plants to serve it.

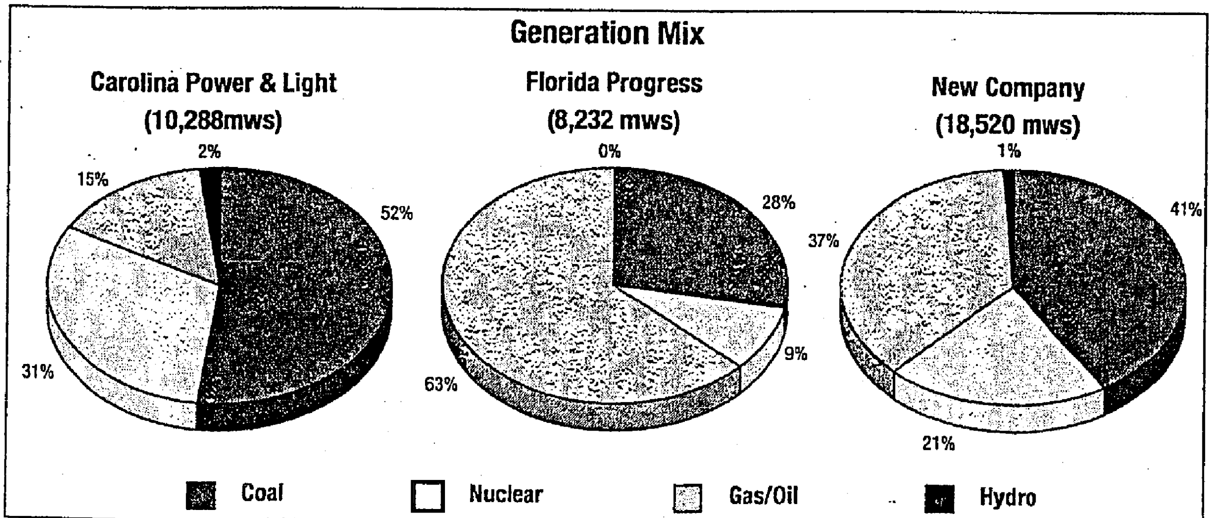
To date, neither the legislature nor the Florida Public Service Commission (FPSC) has been a forceful advocate for deregulation of electricity markets. Despite political disinterest, FPC's management has taken certain steps in anticipation of eventual electric deregulation and created a national retail energy strategy to position itself for a more competitive marketplace. When competition finally arrives, FPC will be relatively well positioned due to its strong customer base and transmission bottlenecks limiting other utilities access to the state. In addition, CPL will construct new plants in the area to serve load growth.

In an attempt to capitalize on increased wholesale demand, several companies, including Duke Energy Power Services (a subsidiary of Duke Energy), are planning to build cogeneration merchant plants to service wholesale customers within Florida, primarily municipalities. However, the plans of these companies have met significant opposition from the three investor-owned utilities in Florida, who have argued that merchant plants are illegal under the state's complex laws governing power projects, specifically the Florida Power Plant Siting (PPSA) Act.

The PPSA governs the building of new generation involving steam capacity of 75 megawatts or more. Other companies, such as Constellation Power (a subsidiary of Baltimore Gas & Electric), have circumvented the PPSA by proposing to build a combustion turbine plant rather than a combined cycle facility.

On March 5, 1999, the Florida Public Service Commission (FPSC) voted 4 to 1 in favor of allowing Duke Energy Power Services to build a 514 megawatt combined cycle merchant plant in New Smyrna Beach, Florida, thereby setting an important precedent for the development of merchant plants, and indirectly increasing the IOU's competition within Florida. Given the decision by the FPSC to allow Duke Energy Power Services to build a merchant plant in New Smyrna Beach, Moody's anticipates other merchant plants will be built, therefore, further increasing in-state competition for wholesale customers. However, Moody's believes the anticipated increase in wholesale competition is partially mitigated by the growth in demand for wholesale energy. All three Florida utilities have appealed the FPSC's decision to the Florida Supreme Court.

At year-end 1998, FPC's resources for serving load consisted of 9,013 mw of electric power, with 7,727 mw generated by owned facilities and 1,286 mw obtained through purchased power contracts. The pie chart below highlights the combined company's post-merger generation mix, which is more balanced, but retains a higher exposure to nuclear assets.



Power purchased under contract from other utilities and non-utility generators comprise a significant portion of total energy sold by the company. These long-term contracts are above market and constrain the company's ability to reduce production costs and become more competitive. FPC is obligated to purchase approximately 871 mw of power (831 mw is currently available) from qualifying facilities with expiration dates ranging from 2002 to 2025. From other utilities, FPC purchases 455 mw of power, primarily from Southern Company with whom it has a contract to purchase approximately 400 mw through 2010.

FPC 289

Over the past few years, management has made progress in renegotiating these contracts, notably the July 1997 buyout of the 220 mw Tiger Bay cogeneration facility, which is now run as a gas-fired combined cycle generating plant. The FPSC recently approved an amended contract between FPC and El Paso Energy to allow two units to operate at times as merchant plants. The utility will retain first call on the power produced by Mulberry and Orange facilities, which will lose their qualifying facility status. El Paso Energy agreed to reduced capacity payments for the facilities in exchange for the ability to operate them by their power marketing subsidiary.

As the majority owner and operator of the Crystal River Nuclear Plant, FPC continues to retain a significant exposure to nuclear assets. Subsequent to restarting in early February 1998, after an extended outage, Crystal River achieved a capacity factor of 90% vs. an industry average of 76.7%. Because the Nuclear Regulatory Commission is currently designing a new system for evaluating safety of nuclear plants, recent scores for Crystal River are not available.

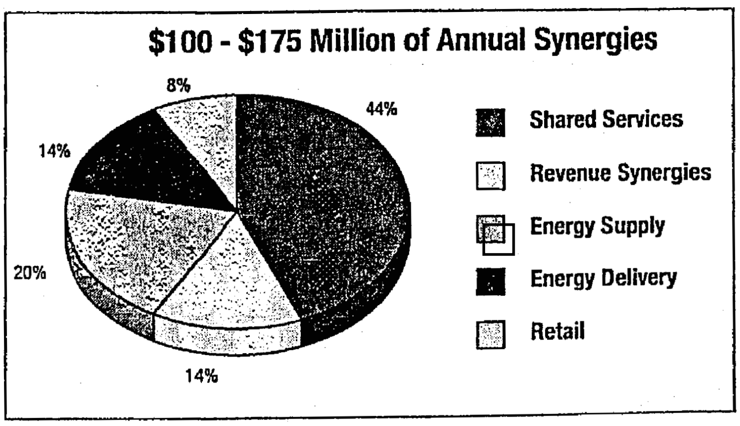
Management Strategy and Competitive Position

Acquisition by Carolina Power & Light

Because size will be important to achieve economies of scale and expand the customer base in a deregulating market, FPC agreed to be acquired by CPL to create the nation's ninth largest electric utility based on generating capacity. The super regional utility will serve nearly 2.7 million customers in a 50,000 square-mile service territory across three states and will have generating capacity of approximately 18,520 megawatts. Combined assets will total $15.2 billion, while total revenue reaches $6.7 billion. For a discussion of CPL, please refer to the Global Credit Report published in February 1999.

The new company will be operated out of Raleigh, NC, the headquarters of CP&L. A local office will likely remain open in St. Petersburg, Florida. Richard Korpan will retire as chairman, president, and chief executive officer of Florida Progress and will join CP&L's board of directors. The board will consist of 14 members, 10 from CP&L and 4 from FPC.

According to the pie chart below, new management expects merger-related synergies to range from $100 to $175 million on an annual basis, driven primarily by cost savings instead of revenue enhancements. These synergies result primarily from the elimination of duplicate corporate and administrative programs, and from operating efficiencies, including integration of the Crystal River nuclear site with CP&L's three existing nuclear sites. Revenue enhancements are also possible from generation expansion and wholesale marketing opportunities.



After the integration is completed, it is anticipated the company will have a combined workforce of approximately 16,000 employees, reflecting a reduction of about seven percent. The company will use a combination of attrition and moderation in hiring to reduce the need for employee separations. At this early stage in the merger process many of these synergies have not been definitively identified; however, a significant portion of these savings will likely be extracted from FPC.

Strategy Prior to Acquisition May Change

Prior to the acquisition, FPC's strategy was to capitalize on strengths in its core business, pursue growth opportunities through Electric Fuels, and develop a national retail energy business. It remains to be seen how new management will alter FPC's stated strategy.

As part of a national retail strategy, FPC planned to offer commodity-related products and services, as well as their transportation to the retail customer. Through its marketing and service joint venture with Cinergy and New Century Energies, management targets large national companies in diverse locations and offers energy management services. In addition, its power marketing alliance with Houston-based Dynegy, Inc. (formerly NGC Corporation) enables the company to better market its power supply to utilities and large energy users in Florida and other regions. Dynegy's energy marketing, trading, and risk management skills also help FPC optimize the value of its generation portfolio, while reducing energy costs.

Management's focus on cost controls allows FPC to maintain competitive retail prices by limiting O&M increases to less than inflation, and reducing costs associated with expensive purchased-power contracts. In particular, the Tiger Bay buy-out reduced purchased power commitments by 220 mw or 20%, while saving customers approximately $2 billion during the period 2008 through 2025. The Pasco Cogen buy-out is expected to save customers $183 million beginning in 2002. Additional savings come from formation of strategic business units in 1996, and a corporate-wide work process-reengineering program instituted in 1997.

Management continues to grow its non-regulated businesses at Electric Fuels through acquisitions and business expansion. At year-end 1998, Electric Fuels represented approximately 11% of Florida Progress' equity investment and 27% of consolidated revenue. Its business units are energy- related services, inland marine transportation, and rail services. Medium term notes issued by PCH fund business unit operations. Non-regulated businesses include:

- Energy and Related Services – This business unit supplies coal to FPC and other utilities and industrial customers through its network of operations. Abnormal weather in 1998 increased the volume of coal transported to FPC and resulted in higher earnings. Continued growth will be driven largely from the expansion of its river terminal operations and related activities.
- Inland Marine Transportation – This business unit transports coal, agricultural, and other dry bulk commodities through the Ohio and Mississippi rivers. Weak export shipments caused by a strong U.S. dollar and warmer winter weather have negatively impacted 1998 earnings. Growth is expected to be driven by barge fleet expansion.
- Rail Services – This business unit serves the country's major railroads by providing various services. In 1998, the company spent approximately $200 million for acquisitions and will continue to expand its operations into new markets serving other Class 1 and shortline railroads, as well as private fleet owners.

Year 2000—Company Expects to be Ready

Since mid-1997, FPC has been actively preparing for Year 2000 (Y2K) through the replacement and upgrade of computer systems and technologies. Total costs for this program have been estimated between $15 and $20 million, $9.5 million has been incurred and expensed to date. Management plans to complete its Y2K program by the third quarter of 1999 for FPC, and by the fourth quarter of 1999 for Electric Fuels.

Regulation, Rates, and Restructuring

New management will obtain regulatory approvals for the acquisition in two steps. In early 2000, management expects to receive approval for formation of the new holding company from the SEC, FERC, NRC, NCUC, and SCPSC. By next summer, management expects merger approval from CPL and FPC shareholders, the SEC, FERC, the NRC, and the Department of Justice. Approvals from the FPSC and state commissions in North Carolina and South Carolina are not required, but discussions will be held with these state regulators. CPL will register as a holding company under the Public Utilities Holding Company Act of 1935.

Neither legislators nor regulators are moving quickly to implement retail competition in Florida due to the state's competitive electric rates, small number of industrial customers, and relative physical isolation. The 1999 legislative session in Florida adjourned in April without considering restructuring legislation. The Florida legislature has been monitoring restructuring activities in other states via a working group established in 1997. A comprehensive restructuring bill was introduced in the 1998 session, but was not passed.

During 1997, the FPSC approved a settlement agreement allowing FPC to recover a portion of replacement fuel costs incurred during Crystal River's extended outage. While Crystal River was out of service, the company spent $100 million in additional nuclear O&M expenses and approximately $173 million in fuel replacement costs. Under the settlement agreement, FPC agreed not to seek a change in base rates or the authorized range of its equity return for a four year period ending in 2001. The company has not filed for rate relief since 1992 when the FPSC approved a 12% regulatory return on equity with an allowed ranged between 11% and 13%.

Financial Analysis

The acquisition will be treated as a purchase for accounting purposes. This creates goodwill of $3.3 billion to be housed at the new holding company. Despite goodwill amortization of $83 million per year, management expects earnings per share growth of 7-8%. The new entity will continue CPL's dividend policy. The remainder of this report discusses FPC's financial performance and goals as disclosed before the merger.

For the six-month period ended June 30, 1999, Florida Progress' net income increased approximately 12% over the same period in 1998, driven by improved earnings at the utility. FPC earnings increased due to lower amortization of regulatory assets and lower interest expenses for debt refinancings in late 1998. At Electric Fuels, earnings increased due to sales of a coal-based synthetic fuel by the Energy and Related Services group. In addition, the Rail Services and Inland Marine Transportation business units experienced improved operating results during the second quarter of 1999.

Florida Progress' net income increased to $282 million in 1998, up from $54 million in 1997, as the company recovered from the extended outage at Crystal River and rebounded from the $87 million write-off of Mid-Continent. In addition, strong customer growth at the utility and enhanced earnings from diversified operations bolstered results. At the utility, however, accelerated amortization of regulatory assets, expenditures to increase reliability, and a lump-sum pay increase offset increased revenues attributed to hotter-than-normal weather. These accelerations increased utility operation and maintenance expenses beyond the increases already anticipated because of costs related to operating Tiger Bay. Despite higher operating expenses, pre-tax interest coverage strengthened to 3.7 times from 2.6 times. It had been depressed in 1997 due to expenses related to the Crystal River outage.

Funds from operations interest coverage increased from 5.2 times to 6.20 times as income rebounded from depressed levels in 1997, and accelerated amortization increased in amounts sufficient to offset higher interest expense.

On December 31, 1998, FPC's capital structure improved to approximately 48% debt, 1% preferred stock, and 51% common equity, from 52% debt, 1% preferred, and 47% equity at year-end 1997 as debt declined by $233 million. However, these figures do not reflect off-balance sheet obligations from above market power- purchase contracts. Prior to the acquisition by CPL, management intended to repay debt in order to achieve its capital structure target of 55% equity. Whether this goal remains is uncertain. At June 30th, the capital structure remained essentially unchanged.

Construction expenditures (excluding the allowance for funds used during construction) totaled approximately $315 million in 1998, compared to $387 million in 1997. These expenditures covered distribution lines and the construction of the Hines Energy Complex, a 500 mw gas-fired power plant that began operations in April, 1999. Going forward, the company estimates construction expenditures to total approximately $885 million from 1999 to 2001, over half of which relate to transmission and distribution expenditures. Production expenditures total $254 million, including three 100 mw Intercession City peakers scheduled for completion in December 2000. Internally generated funds will finance the capital expenditure program.

Florida Power Corporation

	1998	1997	1996	1995	1994
INCOME STATEMENT ($ millions)					
Revenue	2,648	2,448	2,394	2,272	2,080
Operating Expense	2,136	2,131	1,925	1,815	1,661
Earnings Before Interest, Taxes, Depr. & Amort.	859	644	793	750	681
Depreciation and Amortization	347	326	324	294	262
Earnings Before Interest & Taxes	512	318	468	456	420
Other Income	6	1	1	1	-0
Gross Interest Expense	136	117	98	104	108
Pretax Income	250	136	238	227	201
Income Taxes	140	70	136	130	115
Preferred Dividends	2	2	6	10	10
Net Income Available for Common Stock	249	134	233	217	191
Coverage Analysis					
EBITDA Interest Coverage	6.3	5.5	8.1	7.2	6.3
EBIT Interest Coverage	3.7	2.7	4.8	4.4	3.9
Pretax Interest Coverage	3.7	2.7	4.7	4.3	3.8
FFO Interest Coverage	6.0	5.2	6.6	6.1	5.7
(FFO-Gross Capital Expenditures) Interest Coverage	2.8	0.9	3.4	2.4	1.8
Fixed Charge Coverage	3.7	2.6	4.3	3.8	3.3
Earnings Analysis					
Operating Margin	14.0	10.1	13.9	14.4	14.7
Return on Equity	13.7	7.6	12.7	12.4	11.4
Return on Asset	5.0	2.7	5.5	5.1	4.5
Return on Capital	10.6	6.6	10.3	9.9	9.0
AFUDC % Net Income	6.8	7.2	3.2	3.4	5.7
BALANCE SHEET ($ millions)					
Cash and Equivalents	0	0	0	1	0
Net Plant and Equipment	3,630	3,650	3,517	3,609	3,669
Total Assets	4,928	4,901	4,264	4,285	4,284
Current Portion of LT Debt, Leases & Pref.	92	2	21	31	35
Short-Term Debt	47	180	4	0	55
Long-Term Debt	1,555	1,745	1,296	1,279	1,364
Total Debt	1,694	1,927	1,322	1,310	1,454
Preferred Equity	34	34	34	138	144
Common Equity	1,820	1,768	1,826	1,754	1,667
Total Capitalization	3,548	3,728	3,181	3,202	3,265
Tangible Capitalization (net worth)	3,548	3,728	3,181	3,202	3,265
Capital Structure					
Retained Earnings	816	763	821	761	724
Total Debt - Cash and Equivalents	1,694	1,927	1,322	1,309	1,454
Deferred Charges % Common Equity	45.2	42.6	16.0	6.4	6.0
STD + Curr. Portion of LTD, Leases & Pref. % Capitalization	3.9	4.9	0.8	1.0	2.8
Total Debt % Capitalization	47.8	51.7	41.6	40.9	44.5
Asset Composition					
Net Plant and Equipment % Total Assets	73.7	74.5	82.5	84.2	85.6
Investments % Total Assets	0.2	0.7	0.3	4.3	3.4
Current Assets % Total Assets	9.4	9.5	10.4	8.9	8.6
Deferred Charges % Total Assets	16.7	15.4	6.8	2.6	2.4

Florida Power Corporation

	1998	1997	1996	1995	1994
CASH FLOW STATEMENT ($ millions)					
Funds From Operations	689	490	555	535	514
Preferred Dividends	2	2	6	10	10
Common Dividends	153	191	166	181	176
Retained Cash Flow	534	298	384	345	328
Gross Capital Expenditures	310	387	217	283	324
Free Cash Flow	224	-89	166	61	4
Issuance of Long-Term Debt	144	448	0	0	0
Retirement of Long-Term Debt	-259	-21	-47	0	0
Net Change in Long-Term Debt	-115	426	-47	0	0
Retirement of Preferred Equity	0	0	-106	0	0
Net Change in Preferred Equity	0	0	-106	0	0
Change in Working Capital	-73	67	64	-34	17
Cash Flow Analysis					
FFO % Gross Capital Expenditures	172.2	77.0	176.6	121.6	101.3
FFO % Total Debt	40.7	25.5	42.0	40.9	35.3
Total Debt / FFO	245.8	392.9	238.2	244.8	282.9
Total Debt / (FFO - Gross Capital Expenditures)	447.0	1,867.0	391.4	520.5	765.9
RCF % Gross Capital Expenditures	172.2	77.0	176.6	121.6	101.3
RCF % Total Debt	31.5	15.5	29.0	26.3	22.6
Construction Analysis					
Gross Capital Expenditures % Capitalization	8.7	10.4	6.8	8.9	9.9
CWIP % Common Equity	20.8	15.8	7.7	7.5	13.3
OPERATING STATISTICS					
Market Analysis					
Electric % Total Revenue	100.0	100.0	100.0	100.0	100.0
Residential % Electric Revenue	53.8	52.8	54.3	55.1	54.9
Commercial % Electric Revenue	23.0	23.2	22.4	22.7	23.3
Industrial % Electric Revenue	8.1	8.5	8.6	8.3	8.3
Wholesale % Electric Revenue	7.9	6.3	6.7	6.8	6.0
Residential % Kwh Sales	44.4	45.3	46.2	46.1	46.2
Commercial % Kwh Sales	26.8	27.8	26.4	26.6	27.5
Industrial % Kwh Sales	11.7	12.6	12.6	11.9	11.9
Wholesale % Kwh Sales	10.4	7.3	8.1	9.0	7.8
Residential Price per Kwh	8.6	8.6	8.4	8.4	8.2
Commercial Price per Kwh	6.1	6.1	6.1	6.0	5.9
Industrial Price per Kwh	4.9	5.0	4.9	4.9	4.8
Wholesale Price per Kwh	5.4	6.3	5.9	5.3	5.3
Total Price per Kwh	7.1	7.4	7.1	7.0	6.9
Competitive Position					
Fuel Per Mwhr	22.0	22.0	0.0	0.0	0.0
Non-Fuel Per Mwhr	3.3	3.3	0.0	0.0	0.0
Investment Per Mwhr	9.2	9.2	0.0	0.0	0.0
Total Cost Per Mwhr	34.5	34.5	0.0	0.0	0.0

Florida Power Corporation

St. Petersburg, Florida, United States October 1, 1999

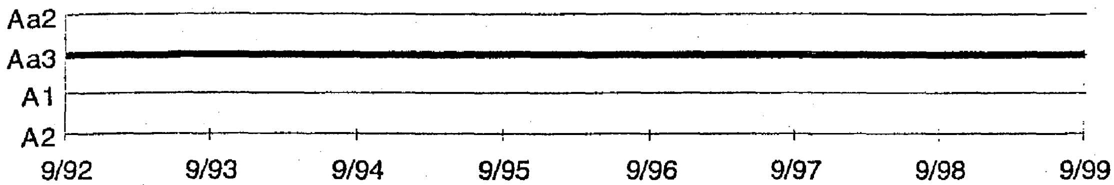
Ratings and Contacts

Category	Moody's Rating
Issuer Rating	A1*
First Mortgage Bonds	Aa3*
Senior Unsecured	A1*
Preferred Stock	"a1"*
Commercial Paper	P-1*

• Placed under review for possible downgrade on August 23, 1999

Analyst	Phone
A. Tucker Hackett/New York	1.212.553.1653
Scott Solomon/New York	
Susan D. Abbott/New York	

Rating History — Senior Secured



Operating Statistics

Florida Power Corporation (Statistics in bold type)[1]

Peer Group Median (Statistics in light type)

	[2]1999	1998		1997		1996		1995		[3]5-Yr.Avg	
Revenue (US$ bil.)	**2.7**	1.2	**2.6**	1.1	**2.4**	1.1	**2.4**	1.0	**2.3**	[4]4.5	**[4]6.2**
Assets (US$ bil.)	**5.0**	2.9	**4.9**	2.8	**4.9**	2.7	**4.3**	2.8	**4.3**	[4]2.5	**[4]3.0**
Com. Equity (US$ bil.)	**1.8**	0.9	**1.8**	0.9	**1.8**	0.9	**1.8**	0.9	**1.8**	[4]2.3	**[4]3.6**
Op. Margin (%)	**14.2**	14.8	**14.0**	15.5	**10.1**	16.4	**13.9**	16.1	**14.4**	15.7	**13.4**
ROA(%)	**5.3**	3.7	**5.0**	3.6	**2.7**	3.7	**5.5**	3.8	**5.1**	3.7	**4.6**
ROE(%)	**14.2**	12.2	**13.7**	11.7	**7.6**	12.0	**12.7**	12.5	**12.4**	12.0	**11.6**
Div. Payout (%)	**133.6**	82.8	**61.7**	85.2	**142.0**	81.9	**71.2**	79.0	**83.2**	82.3	**90.0**
Pretax Int. Cov. (X)	**4.1**	3.5	**3.7**	3.4	**2.7**	3.5	**4.7**	3.4	**4.3**	3.4	**3.9**
Fxd. Chg. Cov. (X)	**4.0**	3.0	**3.7**	2.9	**2.6**	2.9	**4.3**	2.9	**3.8**	2.9	**3.6**
FFO Int. Cov. (X)	**6.5**	4.5	**6.0**	4.5	**5.2**	4.6	**6.6**	4.4	**6.1**	4.4	**5.9**
FFO % Total Debt	**41.6**	25.7	**40.7**	26.2	**25.5**	26.4	**42.0**	25.3	**40.9**	25.3	**36.9**
RCF % Gross CAPEX	**97.3**	114.0	**172.2**	124.6	**77.0**	128.8	**176.6**	113.5	**121.6**	113.8	**129.7**
Total Cap. (US$ bil.)	**3.6**	2.1	**3.5**	2.0	**3.7**	2.0	**3.2**	1.9	**3.2**	[4]2.3	**[4]1.8**
TD % Cap.	**47.4**	49.2	**47.8**	49.5	**51.7**	48.8	**41.6**	49.5	**40.9**	49.4	**45.3**
Pfd. Stk. % Cap.	**0.9**	5.5	**0.9**	6.0	**0.9**	5.7	**1.1**	4.6	**0.8**	5.3	**0.9**
Common % Cap.	**51.7**	45.0	**51.3**	44.9	**47.4**	45.4	**57.4**	45.1	**54.8**	45.0	**52.4**

Electric Utility Operating Statistics

Customer Segmentation	Residential	Commercial	Industrial	Wholesale	Total
Revenue (US$ mil.)	**1,424.6**	**608.9**	**214.4**	**207.9**	**2,648.2**
Kwh(mil.)	**16526**	**9999**	**4375**	**3864**	**37251**
¢/Kwh	**8.6**	**6.1**	**4.9**	**5.4**	7.1
Regional Average	7.9	6.5	4.7	4.3	7.6

Competitive Position	Fuel	Non-Fuel	Investment	Total Cost	Regional Cost
$ per Mwhr.	**22.03**	**3.29**	**9.15**	**34.47**	**34.76**

[1] Competivie Position reflects 1997 figures. [2] For the 12 months ended June 30; Balance sheet items are as of June 30. [3] Five year average 1998-1994. [4] Five year compound annual growth rate.

Opinion

Rating Rationale

Florida Power Corporation (FPC) has retained a Aa3 senior secured rating for a number of years by virtue of its capable management, cost-cutting initiatives, supportive regulation, competitive rates, the state's vibrant economy, and limited in-state competition. However, the utility is exposed to nuclear risk through its 90% ownership of the Crystal River nuclear plant and to potential stranded costs from expensive power-purchase contracts and regulatory assets. In addition, ratings pressure originates in acquisition leverage issued by a new holding company created to purchase FPC.

Recent Events

Management announced in August the company will be sold to Carolina Power & Light Company (CP&L, rated A2 sr. sec.) to create the nation's 9th largest utility in terms of generating capacity. The new super regional utility will be headquartered in North Carolina.

New management expects merger-related synergies, driven by cost savings, to exceed $100 million per annum. Savings will result primarily from elimination of duplicate corporate and administrative programs and operating efficiencies. A substantial portion of these savings will be extracted from FPC.

In addition, revenue enhancements are likely from generation expansion and wholesale marketing opportunities. CP&L intends to use the FPC platform to build gas-fired generating plants in Florida.

Rating Outlook

Concern that financial pressure will result from the obligation to service up to $3.5 billion of acquisition leverage to be issued by a new holding company led Moody's to place the securities on review for potential downgrade.

BATES NOS. FPC 296 - FPC 299
CONFIDENTIAL
PURSUANT TO FLORIDA
POWER CORPORATION'S
REQUST FOR CONFIDENTIAL
CLASSIFICATION FILED
AUGUST 7, 2000

- Steam turbine annual, minor, and major inspection costs are estimated based on Black & Veatch data. Annual inspections occur every 8,000 hours of operation, minor overhauls occur every 24,000 hours of operation, and major overhauls occur every 48,000 hours of operation.
- The costs for demineralized cycle makeup water and cooling tower raw water are included.
- The variable O&M analysis is based on a repeating maintenance schedule for the CTG and includes replacement and refurbishment costs. The annual average cost is the estimated average cost over the 25 year cycle life.
- O&M costs for the simple cycle 7EA and 7FA are based on a 17.1 percent capacity factor.
- O&M costs for the combined cycle plants a 85 percent capacity factor.

6.3 Simple Cycle Combustion Turbine

The simple cycle combustion turbine is a packaged (pre-assembled by vendors) machine consisting of an air compressor, combustor, gas turbine, and electric generator. Figure 6-4 presents a plant flow diagram for a combustion turbine simple cycle unit. Filtered air is drawn through the compressor end of the machine and compressed by the multistage axial compressor. Fuel is mixed with the compressed air and burned in the combustor section. The hot gases then expand through the turbine and are exhausted to the atmosphere. The shaft power produced by the turbine drives the compressor and an electric generator.

Four simple cycle combustion turbines were selected as generating unit alternatives:

- General Electric 7EA (Tables 24 & 25)
- General Electric 7FA (Tables 26 & 27)

The 7EA, and 7FA combustion turbines are heavy-duty industrial combustion turbines. The combustion turbines are dual fueled with specifications for performance and operating costs give for both natural gas and distillate.

6.4 Combined Cycle

A combustion turbine combined cycle unit includes a combustion turbine (air compressor, combustor, gas turbine, and generator), a heat recovery steam generator (HRSG), and a steam turbine. Major components included in the steam cycle are the air-cooled condenser, condensate pumps, deaerator, and boiler feed pumps. Figure 6-3 presents a plant flow diagram for a combustion turbine combined cycle generating unit. The combined cycle is arranged so that hot exhaust gas from the combustion turbine is ducted to the HRSG, where it passes over heat exchanger tubes. Heat from the exhaust gas is transferred to water flowing in the tubes, generating steam. The superheater section of the HRSG provides superheated steam to the steam turbine. Both the steam turbine and combustion turbine drive electric generators, thus the name combines cycle.

A combined cycle unit may be configured in a number of different ways. A typical configuration would include either one or two combustion turbines exhausting to individual HRSGs that provide steam to a single steam turbine.

Four combined cycle units were selected as generating unit alternatives:

- 2 x 1 Westinghouse 501FC (Hines #2) (Tables 28 & 29)
- 2 x 1 Westinghouse 501F (Hines #2 market price) (Tables 30 & 31)
- 1 x 1 Westinghouse 501G (Tables 32)

The combined cycles all utilize conventional, heavy-duty industrial type combustion turbines. The combined cycles would be dual fueled. Specifications for performance and operating costs are based on baseload operation. The combined cycles assume dry low NO_x combustors. The units would be located at the Hines Energy Center and would utilize existing common facilities to the extent possible. Adequate natural gas pressure is assumed. Therefore, natural gas compressors are not included.

Notice that two different prices are given for the Westinghouse 501F 2 x 1 combined cycle alternative at Hines (Hines #2). The first price is based on an agreement that was entered when Hines #1 was procured. This agreement was established before the recent increase in combustion turbine prices. The non-market based price is therefore lower than the market based price. The market price typifies the capital cost of a Westinghouse 501F 2 x 1 combined cycle installation without the cost savings associated with the established Hines #2 agreement.

6.5 Pulverized Coal

A conventional pulverized coal steam-generating unit receives raw coal that has been pulverized and dried so that about 70 percent would pass through a 200-mesh screen (0.074 millimeter particle size). As shown on the flow diagram on Figure 6-1, the dry pulverized coal is carried on a hot air stream through coal piping to the furnace, where it is ignited and burned in suspension. Waterwalls in the furnace absorb the radiant energy obtained from the combustion process.

Downstream from the furnace, the flue gas flows through steam- and water-cooled convective heat transfer surfaces and then through a regenerative air heater. From the air heater, the flue gas flows through particulate removal and desulfurization equipment before entering the stack and being exhausted to the atmosphere. The superheated steam is delivered to the steam turbine generator. Steam from the turbine exhaust is condensed, heated by steam from turbine extractions, and pumped back to the steam-generating unit.

A 800 MW pulverized coal unit with dry scrubber, electrostatic precipitator, and selective catalytic reduction (SCR) was selected as a solid fueled alternative. The unit is assumed to be the first unit at a site. It is assumed that coal is delivered by rail and cooling is achieved with

Table 28 Estimated Cost and Performance for Hines Unit #2, 2x1 501FC on Natural Gas				
Total Capital Cost, 1999 $1,000	160,700			
Total Capital Cost, 1999 $/kW	302			
O&M Cost-Peaking Duty (17.1% CF)				
Fixed O&M Cost, 1999 $/kW-y	2.44			
Variable O&M Cost, 1999 $/MWh	2.04			
Equivalent Availability, %	92			
Equivalent Forced Outage Rate, %	3.7			
Planned Maintenance Outage, days/year	16			
Startup Fuel (cold start), Mbtu	4296			
Construction Cash Flows (1st/2nd/.../nth year, %)	15/60/25			
Construction Period, months	30			
Net Plant Output and Net Plant Heat Rate (HHV)	NPO (MW)		NPHR (Btu/kWh)	
	40° F	90° F	40° F	90° F
100 Percent of Full Load	567.2	495.5	6,785	6,823
75 Percent of Full Load	448.9	394.0	7,111	7,354
50 Percent of Full Load	308.5	267.7	7,799	7,894
35 Percent of Full Load	206.3	176.5	9,334	9,586

Table 29 Estimated Cost and Performance for Hines Unit #2, 2x1 501FC on Distillate				
Total Capital Cost, 1999 $1,000	160,700			
Total Capital Cost, 1999 $/kW	316			
O&M Cost-Peaking Duty (17.1% CF)				
Fixed O&M Cost, 1999 $/kW-y	2.44			
Variable O&M Cost, 1999 $/MWh	2.25			
Equivalent Availability, %	92			
Equivalent Forced Outage Rate, %	3.7			
Planned Maintenance Outage, days/year	16			
Startup Fuel (cold start), Mbtu	4120			
Construction Cash Flows (1st/2nd/.../nth year, %)	15/60/25			
Construction Period, months	30			
Net Plant Output and Net Plant Heat Rate (HHV)	NPO (MW)		NPHR (Btu/kWh)	
	40° F	90° F	40° F	90° F
100 Percent of Full Load	545.3	473.3	6,553	6,635
75 Percent of Full Load	402.3	347.9	7,019	7,135
50 Percent of Full Load	289.0	249.0	7,633	7,786
35 Percent of Full Load	193.1	164.7	8,947	9,223

- Steam turbine annual, minor, and major inspection costs are estimated based on Black & Veatch data. Annual inspections occur every 8,000 hours of operation, minor overhauls occur every 24,000 hours of operation, and major overhauls occur every 48,000 hours of operation.
- The costs for demineralized cycle makeup water and cooling tower raw water are included.
- The variable O&M analysis is based on a repeating maintenance schedule for the CTG and includes replacement and refurbishment costs. The annual average cost is the estimated average cost over the 25 year cycle life.
- O&M costs for the simple cycle 7EA and 7FA are based on a 17.1 percent capacity factor.
- O&M costs for the combined cycle plants a 85 percent capacity factor.

6.3 Simple Cycle Combustion Turbine

The simple cycle combustion turbine is a packaged (pre-assembled by vendors) machine consisting of an air compressor, combustor, gas turbine, and electric generator. Figure 6-4 presents a plant flow diagram for a combustion turbine simple cycle unit. Filtered air is drawn through the compressor end of the machine and compressed by the multistage axial compressor. Fuel is mixed with the compressed air and burned in the combustor section. The hot gases then expand through the turbine and are exhausted to the atmosphere. The shaft power produced by the turbine drives the compressor and an electric generator.

Four simple cycle combustion turbines were selected as generating unit alternatives:

- General Electric 7EA (Tables 24 & 25)
- General Electric 7FA (Tables 26 & 27)

The 7EA, and 7FA combustion turbines are heavy-duty industrial combustion turbines. The combustion turbines are dual fueled with specifications for performance and operating costs give for both natural gas and distillate.

6.4 Combined Cycle

A combustion turbine combined cycle unit includes a combustion turbine (air compressor, combustor, gas turbine, and generator), a heat recovery steam generator (HRSG), and a steam turbine. Major components included in the steam cycle are the air-cooled condenser, condensate pumps, deaerator, and boiler feed pumps. Figure 6-3 presents a plant flow diagram for a combustion turbine combined cycle generating unit. The combined cycle is arranged so that hot exhaust gas from the combustion turbine is ducted to the HRSG, where it passes over heat exchanger tubes. Heat from the exhaust gas is transferred to water flowing in the tubes, generating steam. The superheater section of the HRSG provides superheated steam to the steam turbine. Both the steam turbine and combustion turbine drive electric generators, thus the name combines cycle.

A combined cycle unit may be configured in a number of different ways. A typical configuration would include either one or two combustion turbines exhausting to individual HRSGs that provide steam to a single steam turbine.

Four combined cycle units were selected as generating unit alternatives:

- 2 x 1 Westinghouse 501FC (Hines #2) (Tables 28 & 29)
- 2 x 1 Westinghouse 501F (Hines #2 market price) (Tables 30 & 31)
- 1 x 1 Westinghouse 501G (Tables 32)

The combined cycles all utilize conventional, heavy-duty industrial type combustion turbines. The combined cycles would be dual fueled. Specifications for performance and operating costs are based on baseload operation. The combined cycles assume dry low NO_x combustors. The units would be located at the Hines Energy Center and would utilize existing common facilities to the extent possible. Adequate natural gas pressure is assumed. Therefore, natural gas compressors are not included.

Notice that two different prices are given for the Westinghouse 501F 2 x 1 combined cycle alternative at Hines (Hines #2). The first price is based on an agreement that was entered when Hines #1 was procured. This agreement was established before the recent increase in combustion turbine prices. The non-market based price is therefore lower than the market based price. The market price typifies the capital cost of a Westinghouse 501F 2 x 1 combined cycle installation without the cost savings associated with the established Hines #2 agreement.

6.5 Pulverized Coal

A conventional pulverized coal steam-generating unit receives raw coal that has been pulverized and dried so that about 70 percent would pass through a 200-mesh screen (0.074 millimeter particle size). As shown on the flow diagram on Figure 6-1, the dry pulverized coal is carried on a hot air stream through coal piping to the furnace, where it is ignited and burned in suspension. Waterwalls in the furnace absorb the radiant energy obtained from the combustion process.

Downstream from the furnace, the flue gas flows through steam- and water-cooled convective heat transfer surfaces and then through a regenerative air heater. From the air heater, the flue gas flows through particulate removal and desulfurization equipment before entering the stack and being exhausted to the atmosphere. The superheated steam is delivered to the steam turbine generator. Steam from the turbine exhaust is condensed, heated by steam from turbine extractions, and pumped back to the steam-generating unit.

A 800 MW pulverized coal unit with dry scrubber, electrostatic precipitator, and selective catalytic reduction (SCR) was selected as a solid fueled alternative. The unit is assumed to be the first unit at a site. It is assumed that coal is delivered by rail and cooling is achieved with

Table 28 Estimated Cost and Performance for Hines Unit #2, 2x1 501FC on Natural Gas				
Total Capital Cost, 1999 $1,000	160,700			
Total Capital Cost, 1999 $/kW	302			
O&M Cost-Peaking Duty (17.1% CF)				
Fixed O&M Cost, 1999 $/kW-y	2.44			
Variable O&M Cost, 1999 $/MWh	2.04			
Equivalent Availability, %	92			
Equivalent Forced Outage Rate, %	3.7			
Planned Maintenance Outage, days/year	16			
Startup Fuel (cold start), Mbtu	4296			
Construction Cash Flows ($1^{st}/2^{nd}/.../n^{th}$ year, %)	15/60/25			
Construction Period, months	30			
Net Plant Output and Net Plant Heat Rate (HHV)	NPO (MW)		NPHR (Btu/kWh)	
	40° F	90° F	40° F	90° F
100 Percent of Full Load	567.2	495.5	6,785	6,823
75 Percent of Full Load	448.9	394.0	7,111	7,354
50 Percent of Full Load	308.5	267.7	7,799	7,894
35 Percent of Full Load	206.3	176.5	9,334	9,586

Table 29 Estimated Cost and Performance for Hines Unit #2, 2x1 501FC on Distillate				
Total Capital Cost, 1999 $1,000	160,700			
Total Capital Cost, 1999 $/kW	316			
O&M Cost-Peaking Duty (17.1% CF)				
Fixed O&M Cost, 1999 $/kW-y	2.44			
Variable O&M Cost, 1999 $/MWh	2.25			
Equivalent Availability, %	92			
Equivalent Forced Outage Rate, %	3.7			
Planned Maintenance Outage, days/year	16			
Startup Fuel (cold start), Mbtu	4120			
Construction Cash Flows ($1^{st}/2^{nd}/.../n^{th}$ year, %)	15/60/25			
Construction Period, months	30			
Net Plant Output and Net Plant Heat Rate (HHV)	NPO (MW)		NPHR (Btu/kWh)	
	40° F	90° F	40° F	90° F
100 Percent of Full Load	545.3	473.3	6,553	6,635
75 Percent of Full Load	402.3	347.9	7,019	7,135
50 Percent of Full Load	289.0	249.0	7,633	7,786
35 Percent of Full Load	193.1	164.7	8,947	9,223

Table 30
Estimated Cost and Performance a 2x1 501FC on Natural Gas

Total Capital Cost, 1999 $1,000	181,200			
Total Capital Cost, 1999 $/kW	341			
O&M Cost-Peaking Duty (17.1% CF)				
Fixed O&M Cost, 1999 $/kW-y	2.44			
Variable O&M Cost, 1999 $/MWh	2.04			
Equivalent Availability, %	92			
Equivalent Forced Outage Rate, %	3.7			
Planned Maintenance Outage, days/year	16			
Startup Fuel (cold start), Mbtu	4296			
Construction Cash Flows (1st/2nd/.../nth year, %)	15/60/25			
Construction Period, months	30			
Net Plant Output and Net Plant Heat Rate (HHV)	NPO (MW)		NPHR (Btu/kWh)	
	40° F	90° F	40° F	90° F
100 Percent of Full Load	567.2	495.5	6,785	6,823
75 Percent of Full Load	448.9	394.0	7,111	7,354
50 Percent of Full Load	308.5	267.7	7,799	7,894
35 Percent of Full Load	206.3	176.5	9,334	9,586

Table 31
Estimated Cost and Performance for a 2x1 501FC on Distillate

Total Capital Cost, 1999 $1,000	181,200			
Total Capital Cost, 1999 $/kW	356			
O&M Cost-Peaking Duty (17.1% CF)				
Fixed O&M Cost, 1999 $/kW-y	2.44			
Variable O&M Cost, 1999 $/MWh	2.25			
Equivalent Availability, %	92			
Equivalent Forced Outage Rate, %	3.7			
Planned Maintenance Outage, days/year	16			
Startup Fuel (cold start), Mbtu	4120			
Construction Cash Flows (1st/2nd/.../nth year, %)	15/60/25			
Construction Period, months	30			
Net Plant Output and Net Plant Heat Rate (HHV)	NPO (MW)		NPHR (Btu/kWh)	
	40° F	90° F	40° F	90° F
100 Percent of Full Load	545.3	473.3	6,553	6,635
75 Percent of Full Load	402.3	347.9	7,019	7,135
50 Percent of Full Load	289.0	249.0	7,633	7,786
35 Percent of Full Load	193.1	164.7	8,947	9,223

Table 41
Estimated Capital Cost Range for Alternatives

	Fuel	Capacity			Capital Cost		Capital Cost Range			
		Winter	Summer	Average			Low	High	Low	High
	Type	MW	MW	MW	$1,000	$/kw	$1,000	$1,000	$/kw	$/kw
GE 7EA Simple Cycle	N. Gas	88.9	74.2	81.6	30,700	376	28,600	33,300	351	408
GE 7EA Simple Cycle	Distillate	92.0	76.4	84.2	30,700	365	28,600	33,300	340	396
GE 7FA Simple Cycle	N. Gas	178	151	164	49,800	303	45,100	51,700	275	315
GE 7FA Simple Cycle	Distillate	185	161	173	49,800	288	45,100	51,700	261	299
Hines Unit #2	N. Gas	567	496	531	160,700	302	159,000	170,000	299	320
Hines Unit #2	Distillate	545	473	509	160,700	316	159,000	170,000	312	334
West. 501FC 2x1 CC	N. Gas	567	496	531	181,200	341	178,000	205,000	335	386
West. 501FC 2x1 CC	Distillate	545	473	509	181,200	356	178,000	205,000	349	403
West 501G 1x1 CC	N. Gas	366	323	345	156,100	453	148,000	169,000	430	491
Pulverized Coal	Coal	800	800	800	687,040	859	620,000	756,000	775	945
Fluidized Bed	Coal	500	500	500	477,100	954	425,000	512,500	850	1,025
IGCC	Coal	577	494	536	697,900	1303	560,000	725,000	1,046	1,354
Bartow #3 Repower	N. Gas	574	536	555	171,000	308	150,000	195,000	270	351
Bartow #1or #2 Repower	N. Gas	274	248	261	103,000	394	81,000	107,000	310	410
Higgins Repower	N. Gas	127	118	122	56,000	459	51,000	62,000	418	508
Turner Repower	N. Gas	248	230	239	88,000	368	80,000	102,000	335	427

Table 30 Estimated Cost and Performance a 2x1 501FC on Natural Gas				
Total Capital Cost, 1999 $1,000	181,200			
Total Capital Cost, 1999 $/kW	341			
O&M Cost-Peaking Duty (17.1% CF)				
Fixed O&M Cost, 1999 $/kW-y	2.44			
Variable O&M Cost, 1999 $/MWh	2.04			
Equivalent Availability, %	92			
Equivalent Forced Outage Rate, %	3.7			
Planned Maintenance Outage, days/year	16			
Startup Fuel (cold start), Mbtu	4296			
Construction Cash Flows (1st/2nd/../nth year, %)	15/60/25			
Construction Period, months	30			
Net Plant Output and Net Plant Heat Rate (HHV)	NPO (MW)		NPHR (Btu/kWh)	
	40° F	90° F	40° F	90° F
100 Percent of Full Load	567.2	495.5	6,785	6,823
75 Percent of Full Load	448.9	394.0	7,111	7,354
50 Percent of Full Load	308.5	267.7	7,799	7,894
35 Percent of Full Load	206.3	176.5	9,334	9,586

Table 31 Estimated Cost and Performance for a 2x1 501FC on Distillate				
Total Capital Cost, 1999 $1,000	181,200			
Total Capital Cost, 1999 $/kW	356			
O&M Cost-Peaking Duty (17.1% CF)				
Fixed O&M Cost, 1999 $/kW-y	2.44			
Variable O&M Cost, 1999 $/MWh	2.25			
Equivalent Availability, %	92			
Equivalent Forced Outage Rate, %	3.7			
Planned Maintenance Outage, days/year	16			
Startup Fuel (cold start), Mbtu	4120			
Construction Cash Flows (1st/2nd/.../nth year, %)	15/60/25			
Construction Period, months	30			
Net Plant Output and Net Plant Heat Rate (HHV)	NPO (MW)		NPHR (Btu/kWh)	
	40° F	90° F	40° F	90° F
100 Percent of Full Load	545.3	473.3	6,553	6,635
75 Percent of Full Load	402.3	347.9	7,019	7,135
50 Percent of Full Load	289.0	249.0	7,633	7,786
35 Percent of Full Load	193.1	164.7	8,947	9,223