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RECORDS AND REPORTING

September 13, 1999
VIA Hand Delivery

Blanca S. Bayo, Director
Division of Records and Reporting
Betty Easley Conference Center
4075 Esplanade Way
Tallahassee, Florida 32399-0870

Re: Docket No.981890-EU

Dear Ms. Bayo:

Enclosed for filing and distribution are the original and15 copies of the testimony and exhibits of James A. Ross filed on behalf of the Florida Industrial Power Users Group in the above docket.

Please acknowledge receipt of the above on the extra copy enclosed herein and return it to me. Thank you for your assistance.

Yours truly,

Vicki Gordon Kaufman

Vicki Gordon Kaufman

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FPSC-RECORDS/REPORTING

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Generic investigation into the aggregate electric utility reserve margins planned for Peninsular Florida.)	Docket No. 981890-EU Filed: September 13, 1999

REBUTTAL TESTIMONY AND EXHIBITS
OF
JAMES A. ROSS

ON BEHALF OF THE
FLORIDA INDUSTRIAL POWER USERS GROUP

REGULATORY & COGENERATION SERVICES, INC.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Generic investigation into the	)	
aggregate electric utility reserve margins	)	Docket No. 981890-EU
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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

REBUTTAL TESTIMONY OF JAMES A. ROSS

ON BEHALF OF THE

FLORIDA INDUSTRIAL POWER USERS GROUP

DOCKET NO. 981890-EU

I INTRODUCTION AND SUMMARY OF CONCLUSIONS

Q PLEASE STATE YOUR NAME, OCCUPATION AND BUSINESS ADDRESS.

A My name is James A. Ross. I am a member of the consulting firm of Regulatory & Cogeneration Services, Inc. ("RCS"), a utility rate and economic consulting firm. My business address is 500 Chesterfield Center, Suite 320, Chesterfield, Missouri, 63017. A statement of my qualifications is attached as Appendix A to my rebuttal testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A This testimony is presented on behalf of the Florida Industrial Power Users Group ("FIPUG"). FIPUG is a group of large electric consumers. The cost of electricity represents the largest variable cost of doing business for FIPUG members and often impacts their ability to compete in the marketplace as well as expand current operations.

Q WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A The purpose of this testimony is to rebut a number of contentions made by the parties in their direct testimony.

Q PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS.

A My conclusions are:

1. The characteristics of the FRCC are significantly different from those of the SPP and ERCOT. Accordingly, it is inappropriate to rely on the 15% reserve margin experience of either the SPP or ERCOT as support for the adequacy of FRCC's 15% reserve margin standard.

2. The characteristic differences among the FRCC, SPP and ERCOT suggest that the FRCC may require a reserve margin standard greater than 15%.

3. The Commission should consider the potential impact that short-term wholesale sales may have on reliability and consider establishing a policy that places a higher priority on service to a utility's retail customer load vis-a-vis short-term wholesale transactions. Additionally, as a matter of policy, the Commission should require the utilities to make available to the public wholesale power transaction contracts that are subject to regulatory approval. Such a policy could serve to assure independent verification of the appropriateness of these transactions.

4. The Commission should adopt a policy to encourage the development of merchant plants. Capacity from merchant plants would be available to

enhance the reliability of peninsular Florida (without placing long-term revenue requirement obligations on Florida ratepayers as is the case with utility generating assets). Furthermore, these plants complement non-firm load programs and enhance the development of a competitive wholesale power market. Additionally, merchant plants provide an "insurance policy" for operational contingencies, such as the 1989 winter power shortfall.

II RESERVE MARGIN STANDARD

Q WHO IS RESPONSIBLE FOR ANALYZING THE RELIABILITY OF PENINSULAR FLORIDA?

A The Florida Reliability Coordination Council ("FRCC") is responsible for analyzing and reporting the reliability of the electric system for peninsular Florida. The FRCC is one of the 10 regional reliability organizations that comprise the North American Reliability Council ("NERC").

Q HAS THE FRCC FILED TESTIMONY IN THIS PROCEEDING?

A Yes, Mr. Mario Villar filed testimony on behalf of the FRCC. Furthermore, Mr. Villar concludes in his testimony (p. 25, l. 6) that the electric system of peninsular Florida is projected to be reliable whether one judges the system from a reserve margin perspective or an LOLP perspective.

Q WHAT RESERVE MARGIN STANDARD DOES THE FRCC PROPOSE?

A The FRCC does not see a need for the Commission to adopt a reserve margin standard for peninsular Florida. However, Mr. Villar (p. 22, l. 6) states that " ...

if the Commission does adopt a reserve margin standard, it should accept the FRCC's 15% reserve margin standard."

Q WHAT DOES MR. VILLAR STATE IS THE BEST WAY TO JUDGE THE FRCC'S PROPOSED 15% PLANNING STANDARD?

A Mr. Villar states in his testimony (p. 20, l. 20) that "...the 15% planning standard has been proven to be suitable by years of utility experience which is the best way to judge the standard."

Q DOES THE FRCC HAVE SIGNIFICANT EXPERIENCE WITH PLANNING RESERVE MARGINS AT OR NEAR 15%?

A Staff witness, Mr. Ballinger, addresses this issue on page 4 of his direct testimony. Mr. Ballinger testifies that, although the FRCC has used a 15% reserve margin planning criterion, the FRCC does not have sustained experience with planning reserve margins as low as 15%. If this is the case, the FRCC cannot satisfy the criteria that Mr. Villar advocates in his testimony as the "best way to judge" the 15% reserve margin standard that he recommends this Commission adopt.

Q DOES MR. VILLAR'S TESTIMONY IDENTIFY ANOTHER RELIABILITY REGION THAT EMPLOYS A PLANNING RESERVE MARGIN STANDARD SIMILAR TO THE FRCC PROPOSAL?

A Yes, Mr. Villar draws similarities between the FRCC proposal and the planning criteria employed by the Southwest Power Pool ("SPP"). With respect to the SPP, his testimony (p. 21, l. 3) states: "It is of interest to note that the SPP region's capacity margin of 12% translates in to a reserve margin of 15%."

Q IS THERE A DIFFERENCE BETWEEN A CAPACITY MARGIN CRITERIA AND A RESERVE MARGIN CRITERIA?

A Yes. The "capacity margin" reliability criteria reflects the ratio of the "reserve" (i.e., capacity minus demand) to the capacity. The "reserve margin" criteria, on the other hand, reflects the ratio of the "reserve" to the demand. This means that a capacity margin reliability criteria of 15% (the reliability criteria employed by the Southeastern Electric Reliability Council) requires more MW of "reserve" than a 15% reserve margin criteria. For example, assume capacity resources equal 39,100 MW and demand equals 34,000 MW. The reserve is 5,100 MW (39,100 - 34,000 = 5,100). The "reserve margin" is calculated to be 15% (5,100 ÷ 34,000 x 100 = 15.0). However, the "capacity margin" is only 13% (5,100 ÷ 39,100 x 100 = 13.0). In order to satisfy a 15% capacity margin criteria, the reserve must be 5,865 MW (39,100 x .15 = 5,865). In this illustrative example, a 15% capacity margin criteria requires capacity resources that are 765 MW (5,865 - 5,100 = 765) greater than the capacity resources required to satisfy a 15% reserve margin criteria.

Q WHAT WOULD BE THE EFFECT ON FRCC'S RESERVES IF A 15% CAPACITY MARGIN WAS EMPLOYED RATHER THAN A 15% RESERVE MARGIN CRITERIA?

A All other things being equal, the employment of a 15% "capacity margin" criteria would require an increase of approximately 400 MW in the available summer capacity for the FRCC region for the year 2000.

Q IS THERE ANOTHER RELIABILITY REGION ADDRESSED IN MR. VILLAR'S TESTIMONY?

A Yes. Mr. Villar states that the Electric Reliability Council of Texas ("ERCOT") uses the same 15% reserve margin standard as proposed by the FRCC. Mr. Villar testifies (p. 21, l. 11) that "...the FRCC standard of 15% ... exactly matches that of ERCOT...".

Q ARE THERE DIFFERENCES AMONG THE FRCC, SPP AND ERCOT THAT WERE NOT ADDRESSED IN MR. VILLAR'S TESTIMONY?

A Yes. Mr. Villar identifies similarities between the FRCC, SPP and ERCOT in his testimony (p. 21). However, the system characteristics of the SPP and ERCOT differ significantly from the FRCC. With respect to the SPP, this region has about 2,800 MW of installed hydro capacity while the FRCC's installed hydro capacity is about 11 MW. All other thing being equal, the greater the amount of hydro capacity installed in a region, the lower the planning reserve margin necessary to maintain the same level of reliability. This is because typically the availability of hydro units is higher than fossil-fueled generating units.

Another difference of the FRCC that is common to both the SPP and ERCOT is the relation between the regional seasonal peak demands. Data from the NERC 1998/99 Winter Assessment and NERC 1999 Summer Assessment reports shows that the FRCC winter projected net firm internal peak demand was 35,666 MW and the 1999 summer projected net firm internal peak demand was 34,295 MW. Thus, the difference between the seasonal peak demands is only 1, 371 MW (35,666 - 34,295 = 1, 371) or about 4% of the regional peak demand (1,371 ÷ 35,66 x 100 = 3.8). In contrast, the difference between the SPP seasonal projected net internal peak demands is 8, 755 MW or about 24% of the regional peak demand. The ERCOT seasonal peak demand difference is 12, 009 MW or about 24% of the regional peak demand.

Q **ARE THERE OTHER CHARACTERISTIC DIFFERENCES AMONG THE FRCC, SPP AND ERCOT?**

A Yes. There are significant differences in Operable Capacity Margin within the FRCC, ERCOT and SPP (i.e., the amount the region's operable capacity exceeds the region's total internal peak demand). The table presented in Schedule 1 of Exhibit JAR-1 ( ) shows at Line 3 that the NERC 1999 Summer Assessment projected that the Operable Capacity Margin for ERCOT and SPP would be about 4,100 MW and 4,600 MW, respectively. On the other hand, the Operable Capacity Margin for the FRCC was only 1,000 MW.

Q **HOW DOES THE FRCC WINTER OPERABLE CAPACITY MARGIN COMPARE WITH THAT OF ERCOT AND SPP?**

A The FRCC's winter Operable Capacity Margin is significantly less than that of either ERCOT or SPP. The table in Schedule 2 of Exhibit JAR-1 ( ) shows at

Line 3 that the NERC 1998/99 Winter Assessment projected the Operable Capacity Margin for ERCOT and SPP to be about 14,000 MW. The FRCC Operable Capacity Margin is projected to be significantly lower, only 827 MW. In other words, the winter 1998/99 Operable Capacity Margins of ERCOT and SPP are over 16 times greater than the FRCC's winter Operable Capacity Margin.

Q HOW DOES THE FRCC OPERABLE CAPACITY MARGIN COMPARE WITH THE OPERABLE CAPACITY MARGINS OF THE OTHER RELIABILITY REGIONS?

A Schedule 3 of Exhibit JAR-1 ( ) presents a tabulation of the Operable Capacity Margins (at Column 3) for the ten NERC regions based on data from the NERC 1999 Summer Assessment report. As shown in Schedule 3, the FRCC 1999 summer Operable Capacity Margin is the lowest among all of the NERC regions.

Q DOES THE FRCC'S OPERABLE CAPACITY MARGIN RANKING AMONG THE OTHER RELIABILITY COUNCILS IMPROVE IN THE WINTER?

A No. Schedule 4 of Exhibit JAR-1 ( ) shows that based on information from the NERC 1998/99 Winter Assessment, the FRCC has the lowest winter Operable Capacity Margin among all the NERC regions. In fact, the FRCC 1998/99 Winter Operable Capacity Margin of 827 MW is an order of magnitude lower than all of the other region's winter margins (i.e., the next lowest winter Operable Capacity Margin is 9,760 MW as shown at Line 4, Column 3 of Schedule 4).

Q WHAT DOES THE OPERABLE CAPACITY MARGIN MEASURE?

A The "Operable Capacity Margin" measures the amount of generating capacity that is installed within the region (including capacity located outside the region but owned by member utilities) and available to serve the projected total (i.e., firm and non-firm) internal peak demand. For example, a region exhibiting a low Operable Capacity Margin is relying more heavily upon external imported purchase power and interruptible/load management programs to reliably serve regional peak demand than a region with a higher Operable Capacity Margin.

Q WHAT ARE THE RELIABILITY IMPLICATIONS FOR A REGION THAT RELIES ON EXTERNAL PURCHASE POWER TO SERVE INTERNAL DEMAND?

A Power purchased from resources external to a region must be imported into the region over transmission lines that are subject to outages and transfer capability limitations. Accordingly, all other thing being equal, the less a region relies on imported purchase power to serve internal demand, the lower the reserve margin necessary to maintain the same level of reliability.

Q WITH RESPECT TO RELIANCE ON PURCHASE POWER TO SERVE INTERNAL DEMAND, HOW DOES THE FRCC COMPARE TO THE SPP AND ERCOT?

A The NERC 1998/99 Winter Assessment shows that the FRCC projected to rely on 1,939 MW of purchase power to serve the regional peak internal demand (i.e., purchase power comprised about 4.6% of the FRCC's projected total net capacity resources). On the other hand, the comparable NERC data shows that the projected purchase power for the SPP and ERCOT was 161 MW (i.e., 0.4% of the total net capacity resources) and 161 MW (i.e., 0.3% of the total net capacity resources), respectively.

Q **ARE THERE OTHER DIFFERENCES BETWEEN THE FRCC AND ERCOT?**

A Yes. With respect to 1999 summer non-firm load, the FRCC relies more heavily on direct control load management (56% of the total non-firm load is load management) than does ERCOT (only 7% of the total non-firm load is load management). This has reliability implications because Florida residential load management tariffs allow customers to return to firm service on only a few days notice while interruptible tariffs require a five-year notice. This means that if residential curtailments become unacceptability high, there is less assurance that the planned load reduction from these load management programs will be available to the system.

Q **DO THE FRCC AND ERCOT RESERVE MARGINS EXHIBIT THE SAME SENSITIVITY TO CHANGES IN LOAD MANAGEMENT DEMAND?**

A No. Schedule 5 of Exhibit JAR-1 ( ) illustrates the sensitivity of the FRCC and ERCOT reserve margins to changes in load management demand. Column 1 of

. Schedule 5 presents the FRCC net reserve margin calculation based upon data provided in the NERC 1999 Summer Assessment. A similar calculation is shown in Column 2 of Schedule 5 for ERCOT. Line 8, Column 1, shows that the FRCC net reserve margin is 15.8%. The corresponding reserve margin for ERCOT is shown at Line 8, Column 2 as 14.6%.

The sensitivity of the FRCC and ERCOT summer reserve margins to changes in load management demand is shown in Schedule 5 at Columns 3 and 4, respectively. Note that the FRCC reserve margin would be reduced to 10.8% (Line 8, Column 3) if load management demand were eliminated due to customers exercising their option to return to firm service. This reflects a full five percentage point reduction in the reserve margin. On the other hand, the ERCOT reserve margin would only be reduced to 14.2% (shown at Line 1, Column 4 of Schedule 3) if load management demand were to be eliminated. This represents only a 0.4% reduction in the ERCOT reserve margin.

Q **HAVE YOU PREPARED A SIMILAR SENSITIVITY FOR THE WINTER?**

A Yes. Schedule 6 of Exhibit JAR-1 (   ) presents a similar sensitivity analysis based upon data contained in the NERC 1998/99 Winter Assessment. The results of the sensitivity are shown at Line 8 of Schedule 6. Without load management demand, the FRCC winter reserve margin is reduced from 18.4% to 10.3%, while the ERCOT winter reserve margin is only reduced by 0.1% (44.0 - 43.9 = 0.1).

Q WHAT DO YOU CONCLUDE FROM A COMPARISON OF THE FRCC WITH THE SPP AND ERCOT?

A The characteristics of the FRCC are significantly different from those of the SPP and ERCOT. Accordingly, it is inappropriate to rely on the 15% reserve margin experience of either the SPP or ERCOT as support for the adequacy of the FRCC's 15% reserve margin standard. In fact, the characteristic differences among the FRCC, SPP and ERCOT suggest that the FRCC may require a reserve margin standard greater than 15%.

III ADDITIONAL CAPACITY RESOURCES

Q IS IT POSSIBLE THAT MORE INSTALLED CAPACITY MAY BE NEEDED WITHIN THE FRCC?

A Yes. The reliability of a utility system is impacted by the characteristics of installed capacity and system load, including the notice and curtailment characteristics of the non-firm load. Accordingly, it may be necessary to require the load serving utilities to implement measures to increase the amount of capacity installed within the region to assure an adequate level of reliability.

Q WHAT ARE THE POTENTIAL RAMIFICATIONS OF NOT INCREASING CAPACITY RESOURCES?

A If additional capacity resources are needed and not installed, the state runs the risk of increasing the potential for electric power shortfalls, such as that experienced in the winter of 1989.

Q MIGHT A UTILITY BE RELUCTANT TO INSTALL ADDITIONAL CAPACITY WITHIN ITS SERVICE TERRITORY?

A Possibly. The electric utility industry is currently confronted with the prospect of deregulation of the generating function that historically was solely provided by a vertically integrated utility. One of the major issues in the deregulation process is the debate over the recovery of the cost of utility generation assets. Accordingly, a utility can reduce its exposure to possible non-recovery of generation assets by refraining from installing any new generating capacity. Additionally, there may be financial considerations based upon the particular regulatory rules under which a utility operates.

Q ARE THERE OTHER REASONS A UTILITY MIGHT NOT WANT TO BUILD GENERATION?

A Yes. If a utility has in place a non-firm program where any credit provided to a non-firm customer is collected from its firm customers as a surcharge, such as TECO, FPC and FP&L, the end result of such a program is that the utility can continue to add load to non-firm programs with no obligation to build capacity to serve that load. However, the surcharge allows the utility to collect the same revenue as would be collected from a firm customer. This circumstance could give a utility a strong incentive not to build generation and to more heavily rely upon non-generating resources.

Q ARE THERE ALTERNATIVES TO REQUIRING THE UTILITIES TO

BUILD NEW PLANT?

A Yes. An alternative to requiring the utilities to build capacity is to provide customers with choice in the marketplace, so they may select their own electric supplier.

Q CAN SHORT-TERM WHOLESALE POWER SALES BY LOAD SERVING UTILITIES HAVE A DETRIMENTAL IMPACT ON RELIABILITY?

A Yes. The execution of short-term wholesale power transactions are typically undertaken based solely upon the utility's discretion with little or no regulatory oversight. Excessive short-term wholesale power transactions that increase the frequency of curtailment of non-firm demand may result in increased defections of customers from residential load management programs. This could result in reduced reliability, depending upon the notice provisions governing the customers' ability to switch to firm service and the amount of load returned to firm service. Accordingly, the Commission should consider establishing a policy that places a higher priority on service to a utility's retail customer load vis-a-vis short-term wholesale transactions.

As a matter of policy, the Commission should require the utilities to make available to the public wholesale power transaction contracts that are subject to regulatory approval. Such a policy could serve to assure independent verification of the appropriateness of these transactions.

Q HOW CAN THE COMMISSION INCREASE THE AMOUNT OF INSTALLED CAPACITY WITHIN PENINSULAR FLORIDA AND MITIGATE THE IMPACT OF WEATHER EXTREMES AND OTHER UNCERTAINTIES ON THE ABILITY OF FLORIDA UTILITIES TO SERVE LOAD?

A The Commission should adopt a policy to encourage the development of merchant plants. Capacity from merchant plants would be available to enhance the reliability of peninsular Florida (without placing long-term revenue requirement obligations on Florida ratepayers as is the case with utility generating assets). Furthermore, these plants complement non-firm load programs and enhance the development of a competitive wholesale power market. Additionally, merchant plants provide an "insurance policy" for operational contingencies such as the 1989 winter power shortfall.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

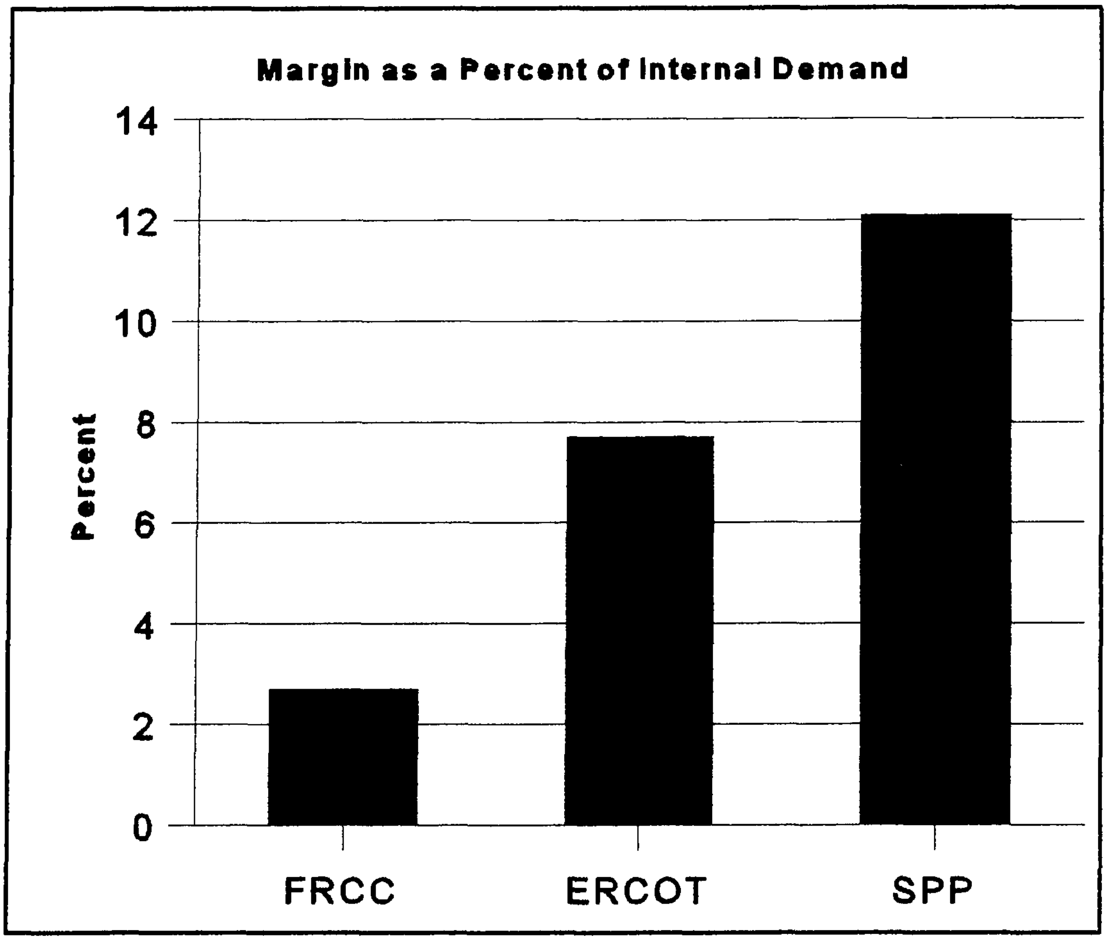
QUALIFICATIONS OF JAMES A. ROSS

Mr. Ross is a graduate of the University of Missouri, with the degrees of Bachelor of Science in Electrical Engineering and Master of Science in Engineering Management. After graduation in 1971, he was employed by Union Electric Company, a utility which provides service to Metropolitan St. Louis, Missouri, and surrounding areas. While assigned to the Power Operation Function, Mr. Ross was responsible for system operation-related engineering evaluations which included long-range and intermediate planning studies, various economic studies and computer simulation of system operations. In 1977 he was assigned to the Corporate Planning Function with responsibilities in capacity planning coordination activities and special studies.

Mr. Ross served on Edison Electric Institute committees and task forces, and participated in reliability, capacity planning, power plant siting and contract negotiation activities.

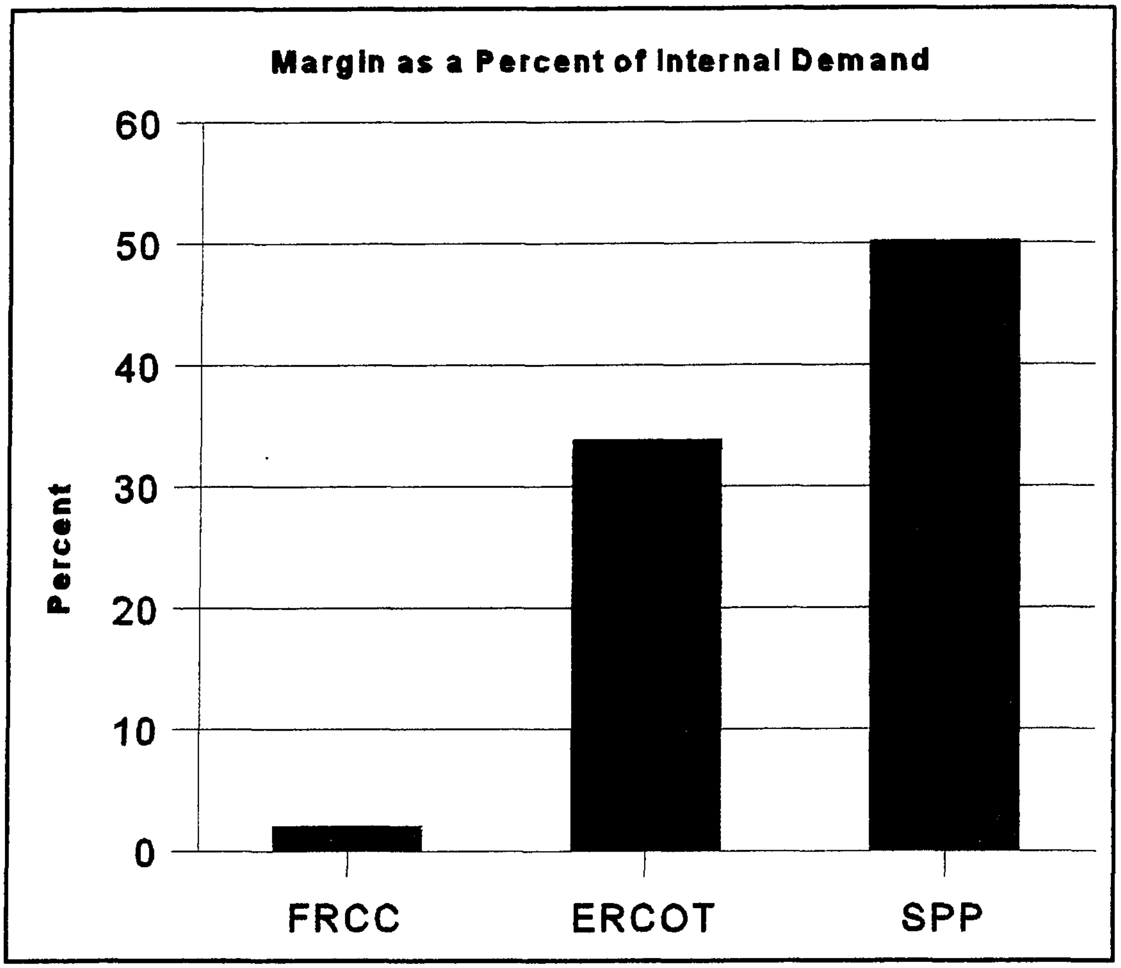
Subsequent to his approximate ten-year employment with Union Electric Company, Mr. Ross entered the field of utility rate and economic consulting. His experience includes evaluations related to various aspects of utility ratemaking, utility operation, utility planning, rate forecasting, contract negotiations and cogeneration activities. Mr. Ross is a member of Regulatory & Cogeneration Services, Inc. ("RCS"), utility rate and economic consultants. Through its offices in Chesterfield, Missouri and Vancouver, Washington, RCS provides a wide range of utility rate and economic consulting services. The members of RCS have extensive utility operation, planning, and rate-related experience and have for several years been engaged in providing electric and gas utility-related consulting services to some of the largest corporations in the United States.

Mr. Ross has testified as an expert witness on utility rates, planning, contract negotiations and related matters before the regulatory commissions of Alabama, Arizona, California, Colorado, Florida, Idaho, Illinois, Kansas, Kentucky, Louisiana, Massachusetts, Michigan, Nevada, New York, Pennsylvania, South Carolina, Texas, Utah and Wyoming.

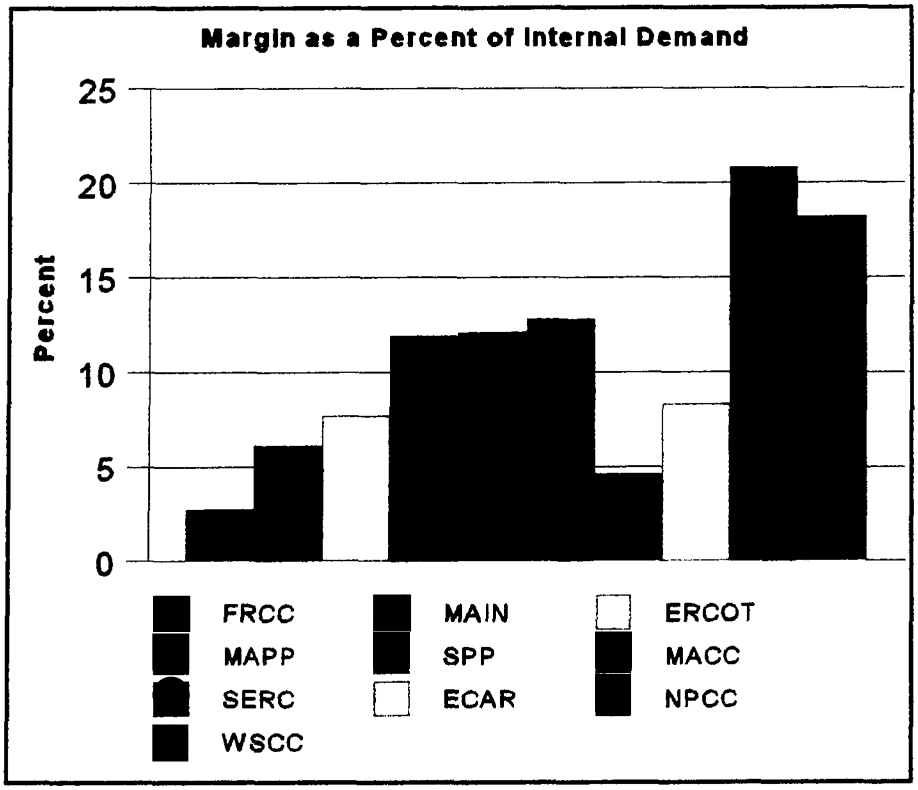


Comparison of Operable Capacity Margin
Summer 1999

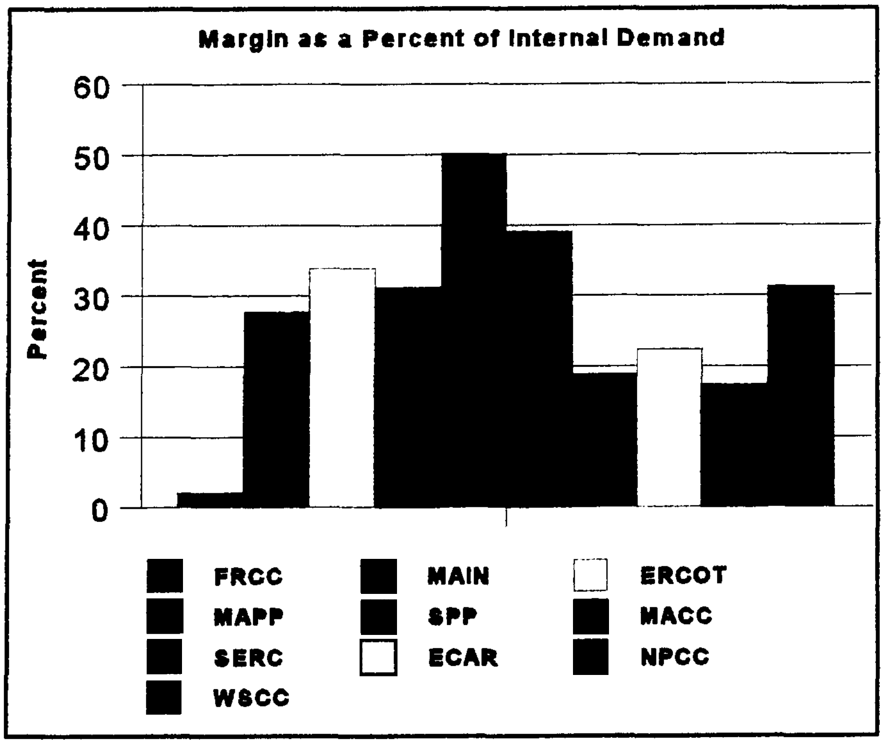
Line	Description	FRCC (1)	ERCOT (2)	SPP (3)
1	Net Operable Capacity & IPPs (MW)	38,068	57,699	42,393
2	Projected Total Internal Demand (MW)	37,060	53,569	37,803
3	Operable Capacity Margin in MW (Line 1 - Line 2)	1,008	4,139	4,590
4	Margin as a Percent of Internal Demand (Line 3 ÷ Line 2 x 100)	2.7%	7.7%	12.1%



Comparison of Operable Capacity Margin Winter 1998/99				
Line	Description	FRCC (1)	ERCOT (2)	SPP (3)
1	Net Operable Capacity & IPPs (MW)	40,277	55,384	41,780
2	Projected Total Internal Demand (MW)	39,450	41,364	27,824
3	Operable Capacity Margin in MW (Line 1 - Line 2)	827	14,020	13,956
4	Margin as a Percent of Internal Demand (Line 3 ÷ Line 2 x 100)	2.1%	33.9%	50.2%



NERC Region Operable Capacity Margin Summer 1999					
Line	Description	Net Operable Capacity & IPPs (MW) (1)	Projected Total Internal Demand (MW) (2)	Operable Capacity Margin (MW) (3)	Margin as a Percent of Internal Demand (%) (4)
1	FRCC	38,068	37,060	1,008	2.7%
2	MAIN	51,078	48,157	2,921	6.1%
3	ERCOT	57,699	53,569	4,130	7.7%
4	MAPP	41,154	36,779	4,375	11.9%
5	SPP	42,393	37,803	4,590	12.1%
6	MACC	56,188	49,807	6,381	12.8%
7	SERC	149,667	143,058	6,609	4.6%
8	ECAR	101,760	93,991	7,769	8.3%
9	NPCC	114,436	94,744	19,692	20.8%
10	WSCC	156,396	132,261	24,135	18.2%
11	Total	808,839	727,229	81,610	11.2%



NERC Region Operable Capacity Margin Winter 1998/99					
Line	Description	Net Operable Capacity & IPPs (MW) (1)	Winter Projected Total Internal Demand (MW) (2)	Operable Capacity Margin (MW) (3)	Margin as a Percent of Internal Demand (%) (4)
1	FRCC	40,277	39,450	827	2.1%
2	MAIN	48,315	37,845	10,470	27.7%
3	ERCOT	55,384	41,364	14,020	33.9%
4	MAPP	41,142	31,382	9,760	31.1%
5	SPP	41,780	27,824	13,956	50.2%
6	MACC	59,062	42,455	16,607	39.1%
7	SERC	155,105	130,470	24,635	18.9%
8	ECAR	104,729	85,536	19,193	22.4%
9	NPCC	122,073	104,055	18,018	17.3%
10	WSCC	156,218	118,958	37,260	31.3%
11	Total	824,085	659,339	164,746	25.0%

Resources, Demands and Margins Summer 1999					
		NERC Summer 1999 Assessment		Load Management Sensitivity	
Line	Description	FRCC (1)	ERCOT (2)	FRCC (3)	ERCOT (4)
1	Projected Total Internal Demand (MW)	37,060	53,569	37,060	53,569
2	Load Management Demand (MW)	1,540	193	0	0
3	Interruptible Demand (MW)	1,225	2,897	1,225	2,897
4	Projected Net Internal Demand in MW (Line 1 - Line 2 - Line 3)	34,295	50,479	35,835	50,672
5	Net Operable Capacity & IPPs (MW)	38,068	57,699	38,068	57,699
6	Projected Net Purchases (MW)	1,640	161	1,640	161
7	Net Capacity Resources in MW (Line 5 + Line 6)	39,708	57,860	39,708	57,860
8	Net Reserve Margin as a Percentage	15.8%	14.6%	10.8%	14.2%

Resources, Demands and Margins Winter 1998/99					
		NERC Winter 1998/99 Assessment		Load Management Sensitivity	
Line	Description	FRCC (1)	ERCOT (2)	FRCC (3)	ERCOT (4)
1	Projected Total Internal Demand (MW)	39,450	41,364	39,450	41,364
2	Load Management Demand (MW)	2,602	12	0	0
3	Interruptible Demand (MW)	1,182	2,882	1,182	2,882
4	Projected Net Internal Demand in MW (Line 1 - Line 2 - Line 3)	35,666	38,470	38,268	38,482
5	Net Operable Capacity & IPPs (MW)	40,277	55,384	40,277	55,384
6	Projected Net Purchases (MW)	1,939	0	1,939	0
7	Net Capacity Resources in MW (Line 5 + Line 6)	42,215	55,384	42,215	55,384
8	Net Reserve Margin as a Percentage	18.4%	44.0%	10.3%	43.9%

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing Testimony and Exhibits of James A. Ross on behalf of the Florida Industrial Power Users Group has been furnished by U.S. mail and or hand-delivery (*) on this 13th day of September, 1999 to the following:

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