INVESTIGATION OF BULK POWER MARKETS

SOUTHEAST REGION

November 1, 2000

The analyses and conclusions are those of the study team and do not necessarily reflect the views of other staff members of the Federal Energy Regulatory Commission, any individual Commissioner, or the Commission itself.

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1. Introduction

The traditional vertically integrated utility model has largely persisted in the southeastern United States. Relatively low energy costs in the region have discouraged the state restructuring initiatives seen elsewhere in the country and almost none of the utilities in the Southeast have divested themselves of generation resources. This continued control of assets in the Southeast has vastly reduced the economic incentives to utilities to facilitate activities by independent power producers (IPPs) that the Commission contemplated in Order No. 888. In many cases, utilities have damped IPP involvement without violating specific Commission regulations because, as a general matter, the Commission's regulations provide a lot of flexibility to allow for varying operating circumstances across the country.

IPPs face significant difficulties in obtaining access to transmission facilities in the Southeast. During our investigation, IPPs have told staff, among other things, that utilities' delays in performing needed studies have jeopardized the viability of proposed merchant plant projects, that utilities are able to hoard transmission capacity in the name of serving native load growth in their respective service territories, and utilities are able to manipulate ATC to their advantage.

Increased numbers of curtailments, or Transmission Loading Reliefs (TLRs), were declared in the Southeast in the summer of 2000. IPPs asserted that the ascending number of TLRs have damaged spot markets, which are most useful for short-term trading. In addition, they pointed out that because transmission customers often must pay for transmission that is curtailed, utilities have a reduced incentive to construct transmission improvements and to take other steps, such as redispatch, to avoid TLRs. Utilities have shown little inclination to improve transmission access or reduce the incidence of TLRs largely because the financial impetus for such reforms has been lacking.

A lack of market information has also helped to stymie the development of markets in the Southeast. There is no clearinghouse for electric power prices in the Southeast. Traders continue to learn prices by using telephones. In addition, price transparency is reduced because the markets have a limited number of hubs for forwards and futures contracts. Further, IPPs have reported that ATC postings seem to change constantly, which contributes to uncertainty in the execution of transmission transactions.

The Tennessee Valley Authority (TVA), despite having taken steps to participate in reformed markets, has acted as a bulwark against the development of competitive energy markets in the Southeast. This is significant because of TVA's substantial presence in the Southeast. It has 30,000 megawatts (MW) of generation, 29,000 MW of peak load, 2,500 miles of transmission facilities and is critically situated between southern and midwest markets. TVA has acted differently than other utilities in part because of federal laws that restrict its activities. One significant constraint is that sellers other than TVA cannot sell power at wholesale to distributors in TVA's service territory. Aside from constraints such as this one, IPPs have reported that TVA has discouraged the siting of new generation in its service territory by a variety of means, including rejecting requests to perform interconnection studies, taking excessive time to perform studies and charging excessive fees to complete studies.

A final situation significantly impedes the development of competitive energy markets in peninsular Florida. According to a recent decision of the Florida Supreme Court, the Florida PSC may not authorize a merchant without retail customers in Florida to construct a combined cycle plant in excess of 75 MW in the state. This ruling frustrates the development in Florida of a competitive market for the sale of electric power.

2. Supply and Demand Conditions

A. Background

The Southeast region consists of Southeastern Electric Reliability Council (SERC) and Florida Regional Coordinating Council (FRCC). SERC covers 464,000 square miles in parts of 13 states; it is the largest NERC region, both in load and peak demand. It includes 20 investor-owned utilities, eight cooperatives, seven municipals, four federal/state systems, four independent producers and 30 power marketers, and is divided into four subregions: Entergy, Southern, Tennessee Valley Authority (TVA) and Virginia Carolinas (VACAR).[1] FRCC covers peninsular Florida, a total of 62,000 square miles. It includes four investor-owned utilities. Despite a combined load of 190,000 MW in 1999, SERC and FRCC constitute only 5.2 percent of the wholesale power trades nationwide. Table 3-1 sets forth the geographic areas of the four subregions of SERC and for FRCC region.

Table 3-1. Subregions in the Southeast

Region	States Comprised	Peaking Season
Entergy	Most of Louisiana, Arkansas, Missouri, northeastern Oklahoma, Southwestern Mississippi, Southeastern Texas, and three counties of Iowa	Summer
Southern	Alabama, Georgia, Florida, Mississippi and Louisiana	Summer
TVA	Most of Tennessee, northern Alabama, northeastern Mississippi, southwestern Kentucky, and small portions of Georgia, North Carolina, and Virginia	Summer
VACAR	Virginia, North Carolina and South Carolina	Summer
FRCC	Florida	Winter

Source: NERC ES&D 2000 database.

Table 3-2 presents additional data regarding SERC and FRCC. The respective number of control areas (CAs) and security coordinators (SCs) in each of these regions suggests their relative size.

Table 3-2. Size of the Regions in the Southeast

[1] SERC has experienced two major changes in membership in recent years. On October 16, 1996, members of FRCC dropped out of SERC forming their own reliability council. In 1997, Entergy and four other systems dropped their memberships in SPP and joined SERC. We have reported data pertaining to Entergy in SERC.

Region	No. of Members	Square Miles	CAs	SCs
SERC	73	464,000	17	5
FRCC	33	62,000	12	1
Total	106	526,000	29	6

Source: SERC Reliability Review Subcommittee 2000 Report and FRCC home page.

Table 3-3 sets forth the number and type of major market participants in SERC and FRCC.

Table 3-3. Ownership Classification

Owner Classification	SERC	FRCC	Total
IOUs	20	4	24
Cooperatives	8	1	9
Municipals	7	15	22
Federal/State	4	2	6
IPPs	4	1	5
Power Marketers	30	10	40
Total	73	33	106

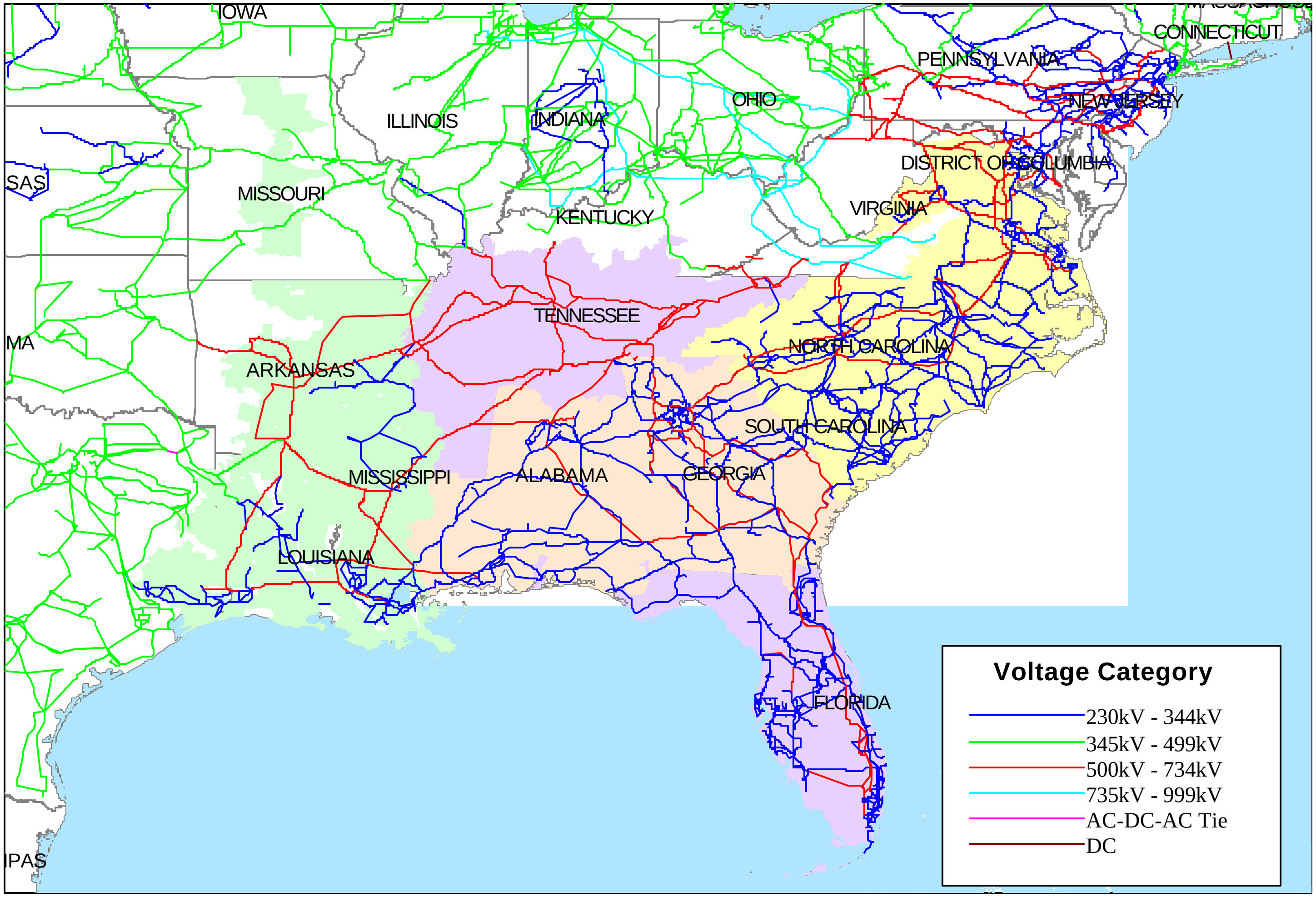
Source: SERC Reliability Review Subcommittee (RRS) 2000 Report and FRCC home page. The Appendix lists the members of SERC and FRCC.

1. Physical Transmission System

The transmission resources in both NERC regions in the Southeast are substantial. Figure 3-1 is a map that depicts major transmission lines in the Southeast. In SERC, there are 20,558 miles of 230 kV transmission lines, 753 miles of 345 kV transmission lines, and 9,230 miles of 500 kV transmission lines. In FRCC, there are 5,267 miles of transmission lines. The utilities in these regions plan to add approximately seven percent or another 2,500 miles of transmission lines to these totals in the period ending in 2009.[2] These data are captured in Table 3-4.

[2]NERC ES&D 2000 database and SERC's Reliability Review Subcommittee (RRS) 2000 Report.

Figure 3-1. Southeast Transmission System



Source: RDI Powermap, August 2000

Table 3-4. Existing and Planned Transmission Capacity, by Subregion

Subregion	Existing				Planned (2000-2009)			
	230kV	**345kV**	**500kV**	**Total**	**230kV**	**345kV**	**500kV**	**Total**
Entergy	2,336	751	2,110	5,197	280	-	64	344
Southern	8,322	-	2,724	11,046	1,129	-	86	1,215
TVA	97	2	2,405	2,504	33	-	-	-
VACAR	9,803	-	1,991	11,794	387	-	118	505
Total SERC	20,558	753	9,230	30,541	1,829	-	268	2,097
FRCC	NA	-	NA	5,267	NA	-	NA	416
Total Southeast				35,808				2,513

Source: NERC ES&D 2000 database.

2. Generation Capacity

Installed generating capacity in the Southeast region totaled approximately 214,000 MW on January 1, 2000. Of this amount, approximately 39,000 MW or 18 percent is jointly owned by several utilities. Of the installed generation capacity in the Southeast, 41 percent is coal, 21 percent is gas and 18 percent is nuclear. Table 3-5 sets forth these data in greater detail. This table indicates the region's relatively heavy reliance on coal-fired and nuclear generation.

Table 3-5. Installed Generating Capacity, by Fuel Type
(Percent)

Subregion	Coal	Gas	Hydro	Nuclear	Oil	Other
Entergy	25	58	0	16	1	0
Southern	62	10	11	14	3	0
TVA	49	4	21	22	3	1
VACAR	45	9	13	25	7	1
FRCC	25	24	0	10	33	8
Total	41	21	9	18	9	2

Source: NERC ES&D 2000.

Ownership of Generating Resources by Investor-Owned Utilities

Investor-owned utilities continue to own the majority of generating capacity in the region. Table 3-6 sets forth the existing capacity in the Southeast for IOUs, IPPs and public power entities. In the Southern subregion, Southern owns 70 percent of the generation. In the Entergy subregion, Entergy owns 71 percent of the generation. In the entire Southeast region, IOUs own 61 percent, public power entities (including TVA) own 29 percent and IPPs own 10 percent.

Table 3-6. Existing Capacity, by Type of Ownership, 2000
(Megawatts)

Subregion	IOU	Non-IOU	Public Power	Other	Total
Entergy	22,869	4,049	4,992	177	32,087
Southern	33,926	4,639	10,247	110	48,922
TVA	-	3,226	29,359	-	32,585
VACAR	46,726	5,643	7,967	78	60,414
FRCC	27,071	3,968	8,772	249	40,060
Total Southeast region	130,592	21,525	61,337	614	214,068

Source: Powerdat, August 2000.

Table 3-7 sets forth existing capacity by subregion in the southeast for the years 1998 through 2000. The table shows that a significant amount of capacity has been added since 1998, with the exception of FRCC.

Table 3-7. Existing Capacity, by Subregion, 1998, 1999, 2000

Subregion	1998	1999	% change over 1998	2000	% change over 1999
Entergy	30,161	30,875	2.4%	31,867	3.2%
Southern	44,933	45,566	1.4%	48,702	6.9%
TVA	29,966	31,402	4.8%	32,585	3.8%
VACAR	57,324	57,539	0.4%	60,258	4.7%
FRCC	38,646	38,929	0.7%	39,562	1.6%
Total Southeast region	201,030	204,311	1.6%	212,974	4.2%

Source: August 2000 RDI database compiled from FERC Form 1, EIA-412, RUS7, RUS12.

Planned Generation Capacity Increases

Table 3-8 summarizes planned generation capacity by subregion for the period 2001 to 2002. In sum, total planned generation in the Southeast in 2001 is 15,000 MW and for 2002 the amount is 26,000 MW. This new capacity is needed to meet anticipated load growth. Without this planned generation, the regional committed capacity reserve margin would drop below 10 percent in 2002. SERC's August 2000 RRS report forecasts that the capacity reserve margin will equal or exceed 10 percent in the years 2001 and 2002. According to FRCC's August 2000 Reliability Assessment, FRCC's planning reserve margin is 15 percent in 2001 and 2002.

The need for new generating capacity suggests that a viable market exists to site merchant plants. In fact, merchants plan to build a significant portion of this new capacity. In 2000, according to a SERC survey, merchants plan to build 5,340 MW in generating capacity. This figures decreases to 4,360 MW in 2001 and 3,800 MW in 2002.[3] This survey data suggests that merchants have ambitious plans to increase their presence in the Southeast.[4] Whether merchants will realize these plans is unknown at this time.

Table 3-8. Planned Generation Capacity, by Subregion, 2001-2002
(Megawatts)

Subregion	Utility	Non-Utility	Total
Entergy	423	13,461	13,884
Southern	4,187	3,977	8,164
TVA	2,340	2,620	4,960
VACAR	4,100	491	4,591
FRCC	5,566	3,749	9,315
Total Southeast Region	16,616	24,298	40,914

Source: August 2000 RDI database compiled from FERC Form 1, EIA-412, RUS7, RUS12.

[3] SERC RRS 2000 Report.

[4] Current reporting requirements do not adequately capture merchant plant activity in the region. Developers are only required to complete FERC Form 867, which is specific to existing plants or facilities that have a very high probability of coming on line.

3. Demand

The actual peak demand for 2000 in the Southeast is 192,000 MW, a slight increase over the region's 1999 summer peak of nearly 187,000 MW. In 1998, the peak demand was 182,000 MW. Annual electric energy usage in 1999 of 957,000 GWH was 2.2 percent greater than the 936,000 GWh of energy usage in 1998. These recent growth figures are consistent with SERC's 2000-2008 forecast of 2.4 percent for average annual growth in summer peak demand. The rise in annual peak demand provides further evidence that new generation must be sited in the near-term to keep pace with demand growth.

Table 3-9 contains actual peak load figures for 1998 through 2000. In 2000, Entergy witnessed the largest increase in its load while FRCC saw the lowest. The load growth for the entire Southeast was 2.8 percent in 1999 and 2000.

Table 3-9. Actual Peak Load

Subregion	1998	1999	% change over 1998	2000	% change over 1999
Entergy	26,162	26,558	1.5%	27,987	5.4%
Southern	39,855	42,196	5.9%	43,736	3.6%
TVA	27,343	28,397	3.8%	29,442	3.7%
VACAR	50,057	52,534	4.9%	53,476	1.8%
FRCC	38,730	37,493	-3.2%	37,728*	0.6%
Total Southeast region	182,147	187,178	2.8%	192,369	2.8%

Source: SERC home page, NERC Summer 2000 Assessments and ES&D Database.
* FRCC 2000 demand is projected.

B. Summer 2000

Peak prices were moderate in the Southeast in the summer of 2000. The highest price reached was $165 per MWh. In contrast, peak prices exceeded $2,000 per MWh in 1998 and 1999. Moderate peak prices in 2000 occurred, even though temperatures in the Southeast were slightly above normal this summer, in part because relatively mild summer temperatures in the Midwest permitted power to be transmitted into the

Southeast from the Midwest at reasonable prices. The transmission of power into the Southeast during the summer contributed to a significant increase in TLRs.

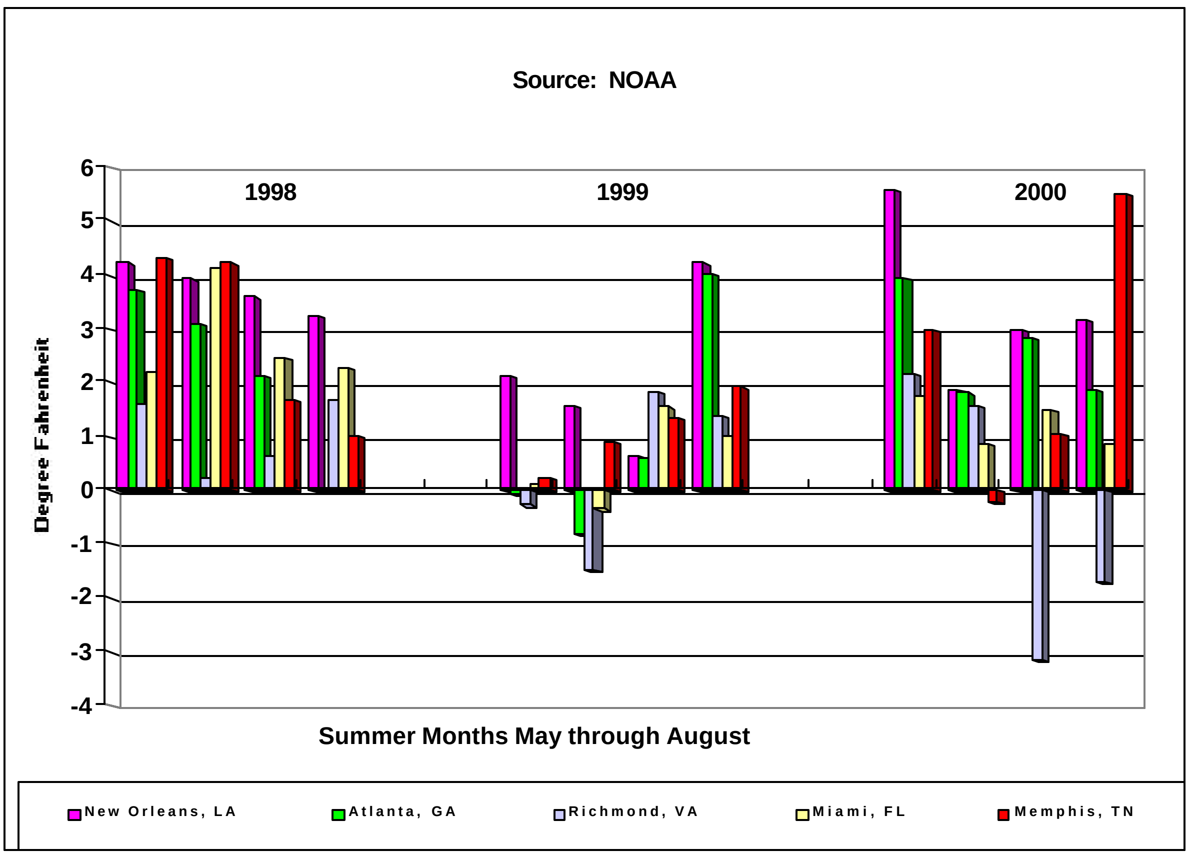
1. Temperatures

Temperatures averaged approximately 1.4 degrees above normal for the Southeast as a whole from May through August 2000. Temperatures were 3.2 degrees above normal in May, in particular, straining local generation resources and causing power to be transmitted into the Southeast from outside the region. In June, July and August, Southeast temperatures averaged 0.9, 0.5 and 1.1 degrees above normal.

Figure 3-2 depicts temperatures relative to average temperatures in five selected cities in the Southeast for May, June, July and August in each of the past three summers.[5] As Figure 3-2 shows, a majority of the selected cities experienced temperatures somewhat below average in the months on May and June in 1999, while, with few exceptions, temperatures across the Southeast exceeded the average in May and June 2000. The months of July and August in 2000 saw greater regional variation in temperatures, with Richmond, Virginia, experiencing cooler than normal weather and Memphis spiking to more than five degrees above normal.

[5] The cities selected to represent the various subregions in the Southeast are Memphis (TVA), Richmond (VACAR), New Orleans (Entergy), Atlanta (Southern), and Miami (FRCC).

Figure 3-2. Historical Temperature Departure from Norm for the Southeast



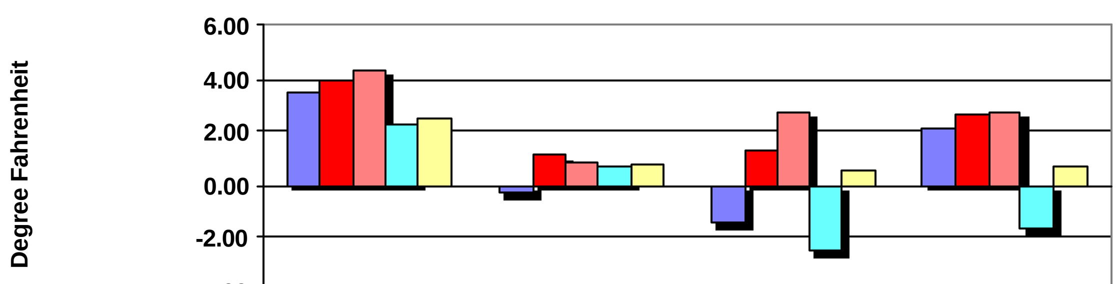
2. The Weather Effect on the Transmission System

Figure 3-3 depicts temperatures relative to the norm in four subregions in the Southeast and in the Midwest for the four summer months of 2000.[6] As the figure indicates, after being 3.3 degrees above normal in May, temperatures in the Midwest fell to slightly below normal levels in June and July, before rising again in August to 2.1 degrees above normal. VACAR, the subregion in the Southeast that covers Virginia and North and South Carolina, experienced lower temperatures than the other subregions in the Southeast for each of the summer months, dropping to 2.5 degrees below normal in July and 1.6 degrees below normal in August. The Entergy and Southern subregions witnessed temperatures at the other extreme; they averaged 2.7 degrees above normal for the four summer months. TVA and to a lesser extent, FRCC, experienced above normal temperatures throughout the summer.

As can be see from Figure 3-3, average temperatures in the Midwest were higher than normal in May and August 2000. Generation was nonetheless available in the Midwest during these months to supply markets in the Southeast because the regions did not experience peak temperatures on the same days. In fact, temperatures were

Figure 3-3. Average Temperature Departure from Norm for Midwest and Southeast Cities

Source: NOAA



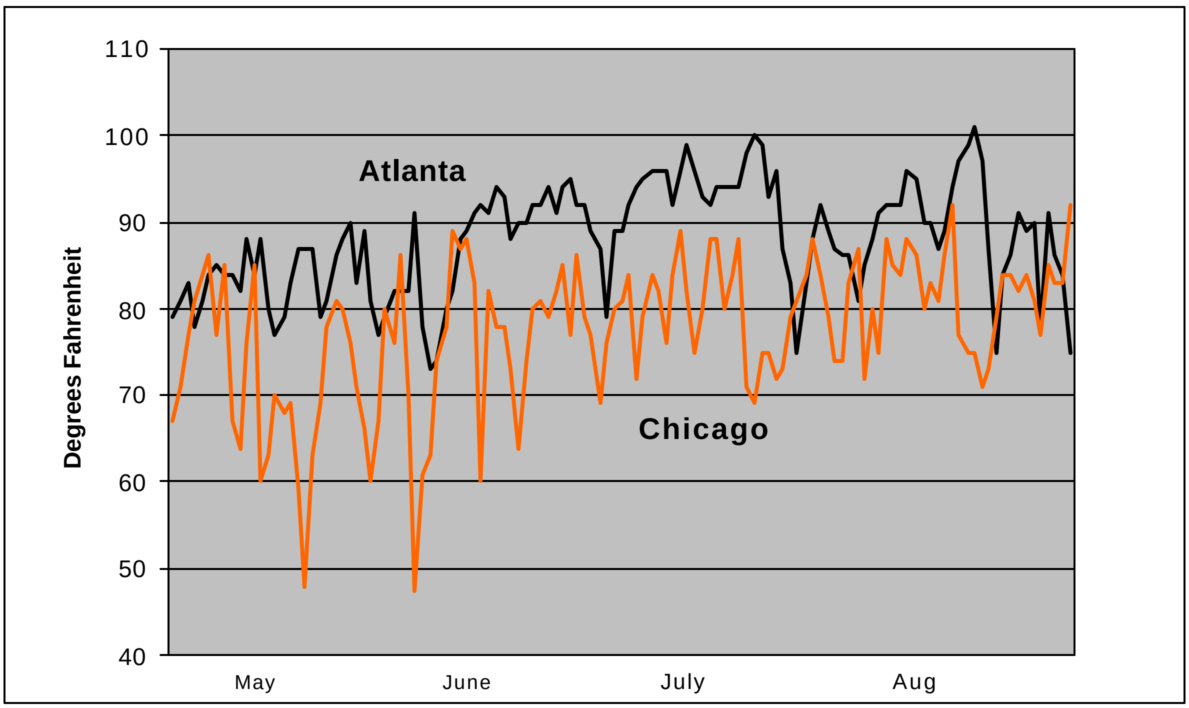
	May	Jun	Jul	Aug
MidWest	3.50	-0.30	-1.40	2.10
TVA	3.99	1.12	1.31	2.65
Entergy/Southern	4.29	0.91	2.76	2.78
VACAR	2.28	0.74	-2.49	-1.64
FRCC	2.49	0.81	0.55	0.73

Summer 2000

[6]The Midwest is defined as the NERC regions of ECAR, MAIN, MAPP and SPP.

considerably lower throughout the Midwest on many days when the Southeast was experiencing hotter than normal weather. Figure 3-4 illustrates that for two selected cities, one in each region, maximum daily temperatures varied by 20 degrees or more on many days this summer.

Figure 3-4. Daily Maximum Temperature for Atlanta and Chicago, May-August, 2000

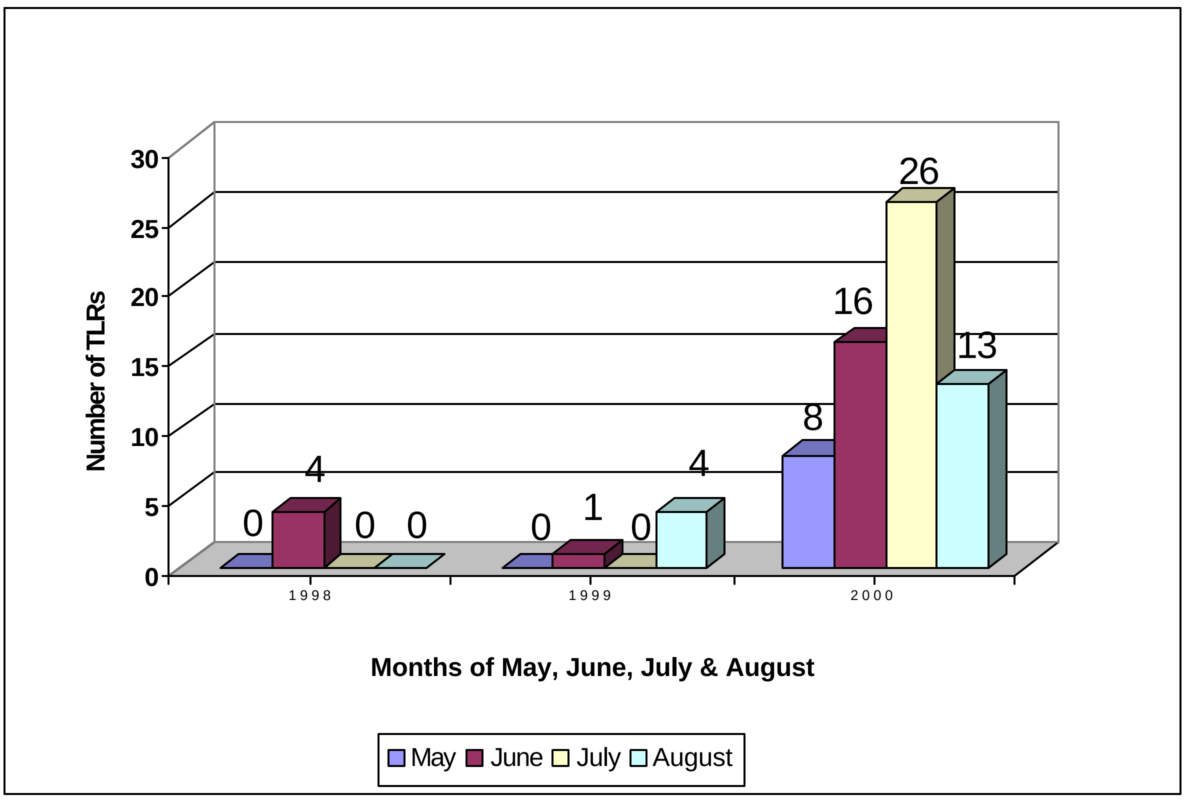


In SERC, four TLR Level 3s and higher were called during the summer of 1998 and five such TLRs were called in the summer of 1999. TLR Level 3s and higher jumped to 63 in the summer of 2000 in SERC. No TLRs were called in FRCC in 1998, 1999 and 2000. Figure 3-5 depicts the TLR Level 3 and higher activity in SERC during these summers.

TLR Level 3 and above activity was concentrated this summer in TVA, with security coordinators in TVA's service territory calling 44, or 70 percent, of all such TLRs in the Southeast. Figure 3-6 (TLR Map) sets forth the flowgates, direction of flow and distribution of these TLRs for the period May through August.

Table 3-10 shows the paths on which TLR Level 3s or higher were implemented this summer. The table indicates that 63 such TLRs were called. The table also indicates that power flowed into the Southeast.[7]

Figure 3-5. Summer TLR Events, Level 3 and Above



[7]Trade press articles also reported this phenomenon. *E.g.*, *Megawatt Daily*, July 21, 2000, at 7.

Figure 3-6. SERC TLR Level 3 and Above, Summer 2000

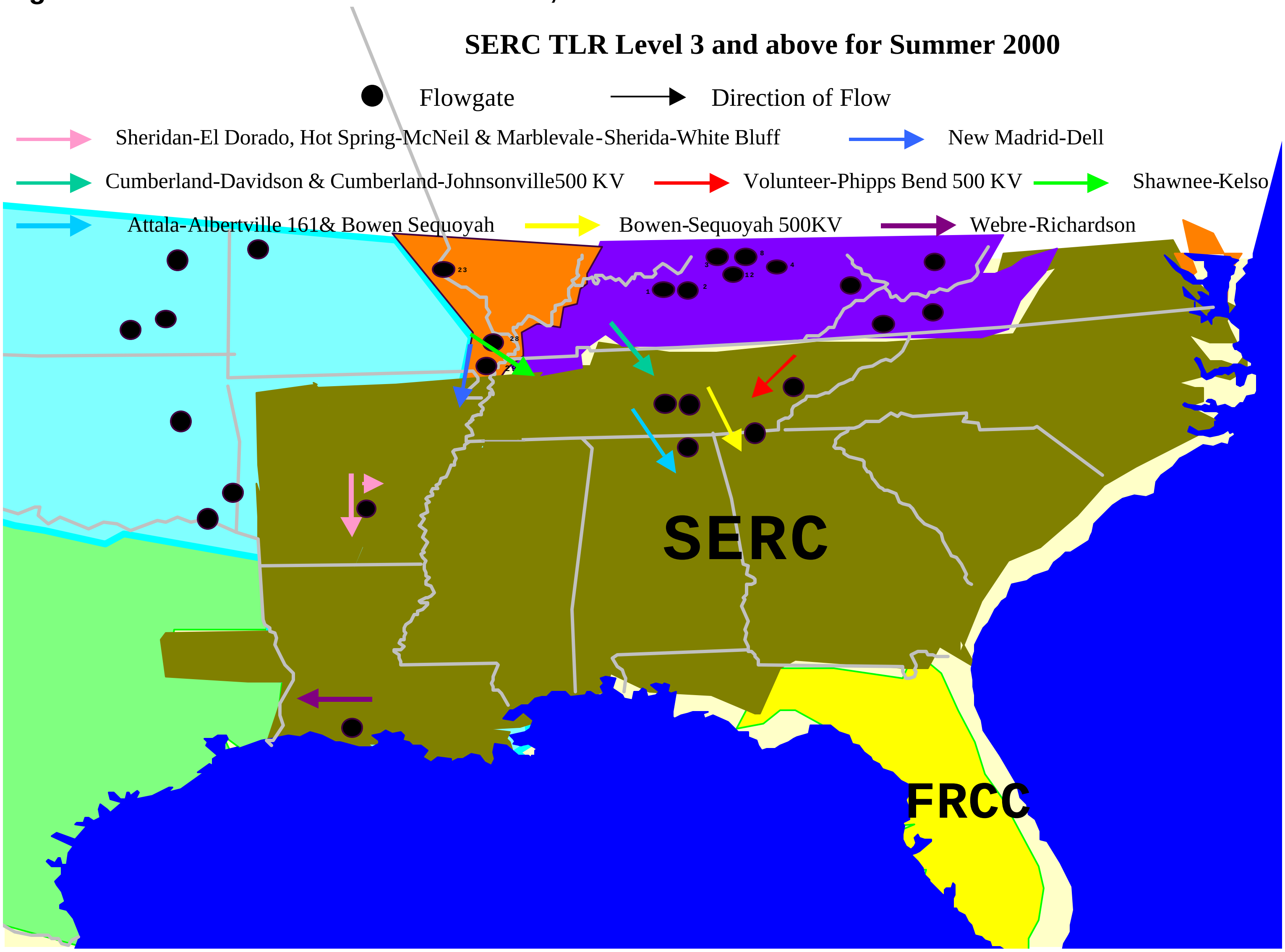


Table 3-10. Flowgates Where TLR Level 3s and Above were Called, May-August 2000

Flowgate					Number of TLRs called *(MW curtailed)*					Total
ID	**Name**	**Direction**	**SC**	**CA**	**May**	**Jun**	**Jul**	**Aug**	**TLR**	**Curtailed**
SERC										
1501	Bowen-Sequoyah 500	NW-SE	TVA	TVA	0	2	8	1	11	*
1613	Volunteer-Phipps Bend 500	NE-SW	TVA	TVA	0	8	13	5	26	738 MW
1620	Cumberland-Davidson/ Cumberland-Johnsonville	NW-SE	TVA	TVA	0	1	3	0	4	*
9139	TVA-EES	S	TVA	TVA	0	1	0	0	1	*
1353	Webre-Richard	E-W	EES	EES	5	0	0	7	12	840 MW
10139	Hot Springs-McNeil 500	S	EES	EES	0	3	0	0	3	521 MW
1351	New Madrid-Dell	S	EES	AECI	2	0	0	0	2	*
1342	Sheridan-El dorado	S	EES	EES	1	0	0	0	1	*
1326	Marblevale-Sheridan-White Bluff	S	EES	EES	0	1	0	0	1	*
1507	Attala-Albertville 161/ Bowen-Sequoyah	S-SE	SOC/ TVA	SOC/ TVA	0	0	2	0	2	*
Total all Southeast Regions					**8**	**16**	**26**	**13**	**63**	**2,099 MW**

*No curtailment amount listed.

As discussed above, hotter-than-normal weather in the Southeast was combined with average or below average temperatures in the Midwest this summer. This caused increased transfers of power into the Southeast relative to the summer of 1999. Transfers of power into SERC exceeding 10,000 MW occurred on days when temperature differentials were 20 degrees or more. Staff has been informed the TVA's planning studies indicated that transfers into SERC exceeding 6,000 MW would create transmission constraints on TVA's system.

To illustrate our point that the weather pattern triggered imports into the Southeast that burdened the transmission system, on August 17, 2000, TVA and Southern experienced their 2000 summer peak. TVA's peak load was 29,344 MW.[8] Its generation at peak was 26,599 MW with net import of 2,478 MW.[9] Southern's peak load was 40,436 MW, generation at peak was 37,155 with net import of 3,281 MW. The large import of power triggered a Level 4 TLR called by the TVA security coordinator.

In addition to the weather pattern, higher natural gas prices contributed to transmission congestion. As Figure 3-7 indicates, the peak price for natural gas at the Henry Hub was $2.99/MMBtu in the summer of 1999, and it rose to $4.79/MMBtu in the summer of 2000. Fewer gas-fired peaking units were used on days of high demand this summer in the Southeast because the higher cost of natural gas made it cheaper to purchase electricity generated from coal-fired units in the Midwest. In particular, the rise in natural gas prices strongly affected Entergy due to its high reliance on gas-fired generation units.

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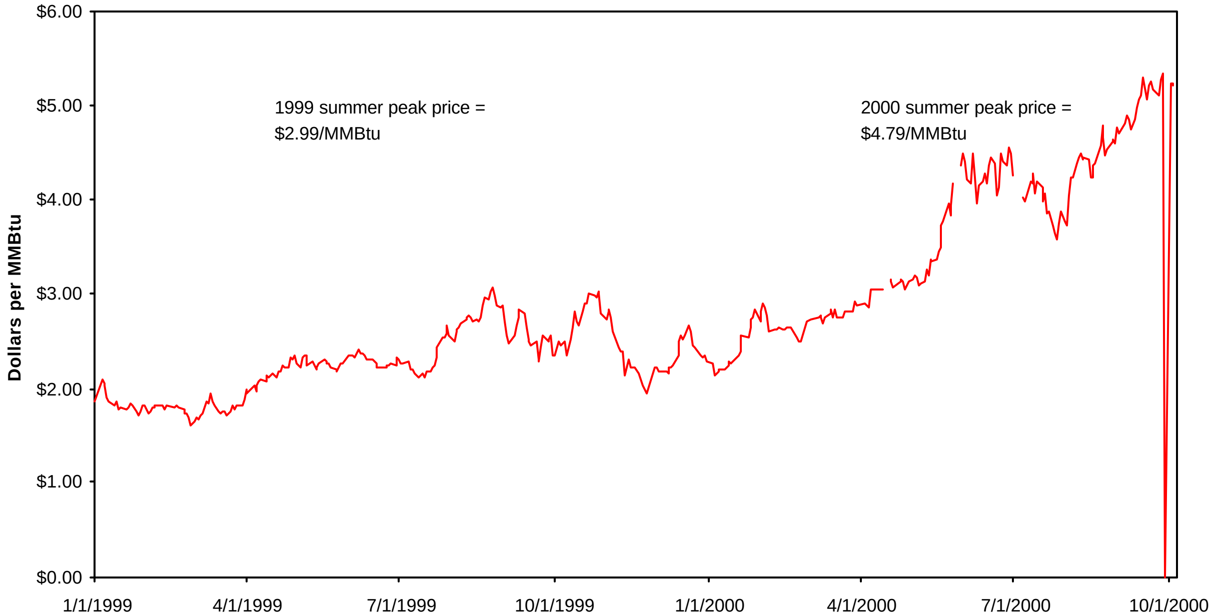
[8] The summer peak in TVA was almost 3,000 MW above the projected peak of 26,467 MW. As a result the reserve margin was as low as 3 percent at peak demand.

[9] Six other Level 4 TLRs were called in the Southeast this summer. On those dates, TVA also imported large quantities of power.

Figure 3-7. Daily Spot Price for Natural Gas at Henry Hub



Source: *Gas Daily*. Data through September 29, 2000.

3. Prices in Summer 2000

Peak prices were radically lower in the summer of 2000 than they were in the past two summers. Figure 3-8 shows that the peak price in the region in 1998 was $2,386 per MWh. In 1999 it was $2,057 per MWh, but it was only $165 per MWh in 2000. This figure depicts daily prices at four hubs in the Southeast from 1998 through August 2000.

The lower peak experienced this summer was due mainly to relatively lower temperatures for much of the summer in the Midwest. Lower temperatures in the VACAR subregion relative to other regions in the Southeast increased the availability of generation to serve customers elsewhere in the Southeast. In addition, utilities appear to have been better prepared for peak events in the summer of 2000. According to utility interviews with the Commission staff, superior preparation took the form of increased hedging through the use of forward contracts, increased generation capacity on line and a reduced number of forced outages.[10]

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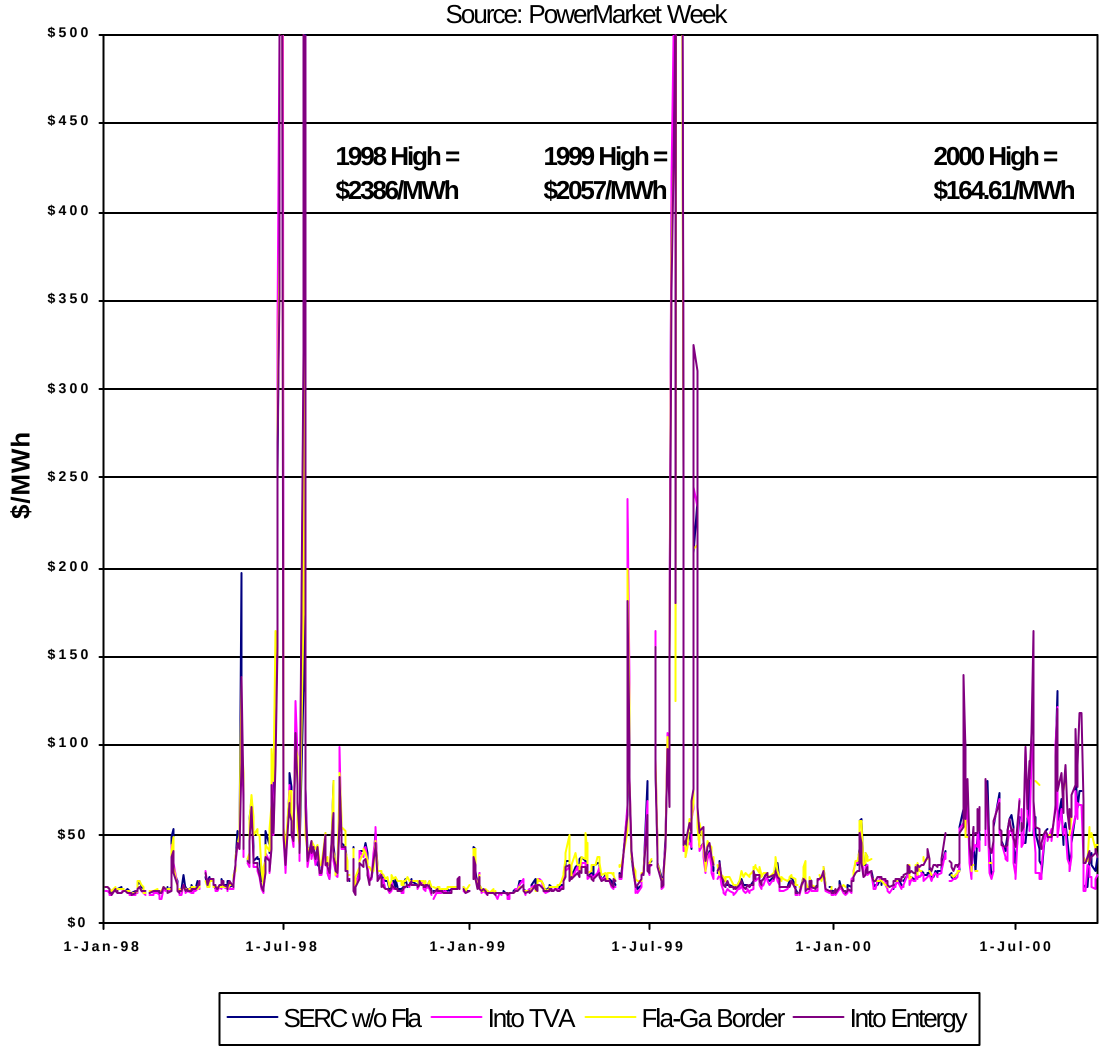
10 *See also*, *Power Markets Week*, July 24, 2000, p. 13; *Megawatt Daily*, August 25, 2000, p. 7; *Power Markets Week,* September 4, 2000, p. 1.

Figure 3-8. Daily Price Indices: Southern Market Hubs, 1998-2000



3. Market Structure in the Southeast Region

A. Principal Geographic Markets and Products

The Southeast may be divided into five subregional markets: Entergy, Southern, TVA, VACAR and FRCC. Two periodicals, *Megawatt Daily* and *Power Marketers Week*, report five trading hubs that essentially match these subregions: Into Entergy, Southern, Into TVA, Florida-Georgia border and Florida In-state. These periodicals reported trades for a standard 16-hour daily product at all the five hubs.

Responses to staff's data requests indicate that the investor-owned utilities (IOUs) offer the transmission and ancillary service required by the Order No. 888, such as point-to-point and network transmission services. However, the types of wholesale trading activities and the respective products being traded at the hubs varies considerably.

The IOU's and power marketers learn about prevailing market prices at the market hubs by consulting with brokers, customers and other market participants, reviewing trade publications, such as *Megawatt Daily, Electric Power Daily, Power Marketers Week*. The IOU's and power marketers indicate that monitoring web sites and using electric brokerage services such as Enron OnLine, Altrade, Bloomberg Power Line are useful. However, for both IOU's and power marketers the primary means for gathering price information is through telephone contacts to the various market participants. This is typical in a purely bilateral market.

B. Market-Based versus Cost-Based Sales

Wholesale sales comprise a smaller portion of total electric power sales in the Southeast than in other regions of the country. On the basis of data responses received from five utilities, wholesale sales comprise 13 percent of their total sales.[11] Wholesale sales in other regions in the country comprise between 20 and 30 percent of total sales in those sections.[12] In addition, of the total wholesale sales reported by the five utilities, 83 percent occurred under cost-based rate authority. This means that only 2.2 percent of the total sales of the reporting utilities were at wholesale at market-based rates. These facts suggest that utilities have not used market-based rates extensively to increase sales.

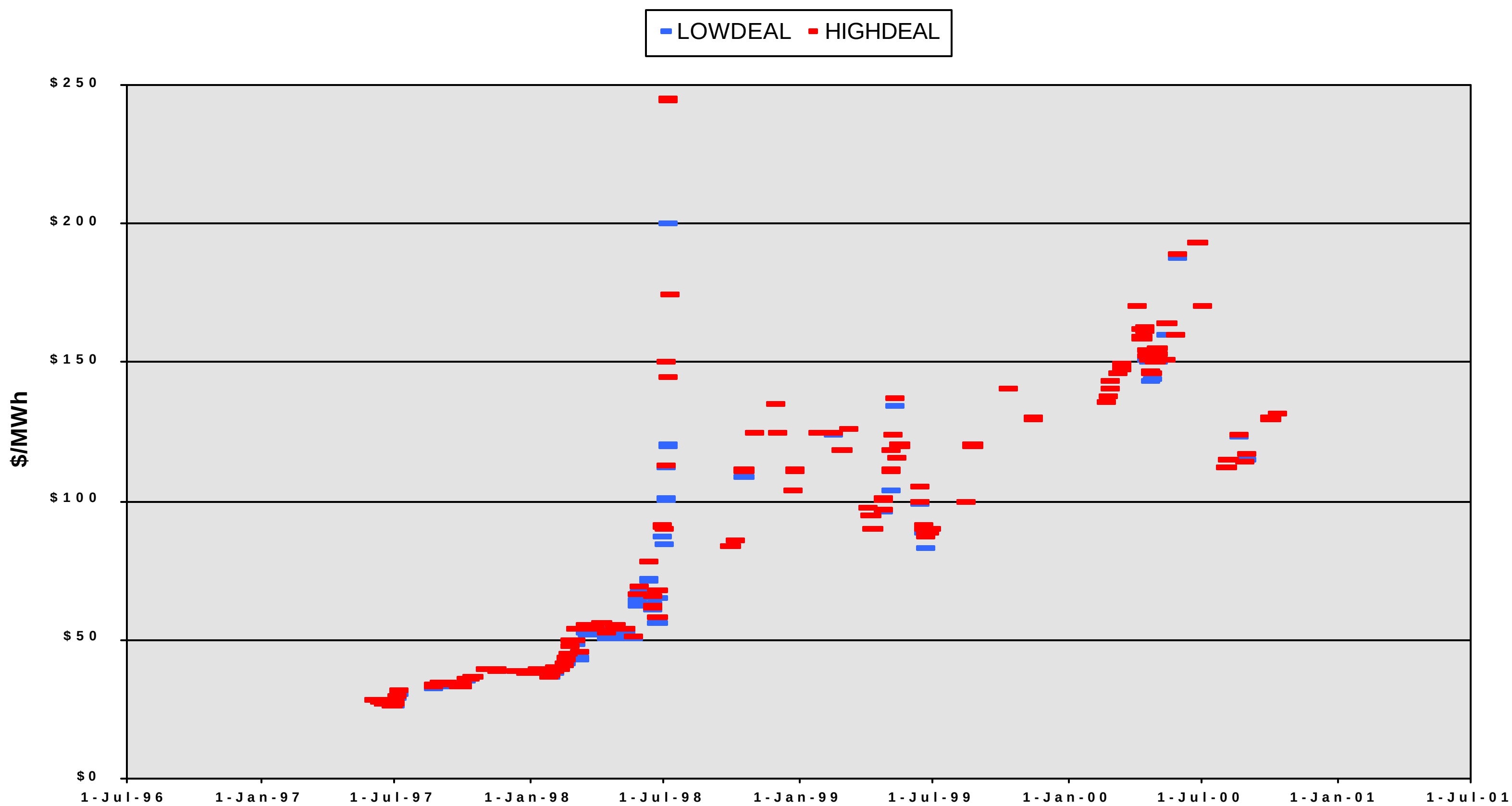
C. Forwards and Futures Contracts

[11] Dominion Resources, Duke Energy, Florida Power, Southern Company, and Tampa Electric.

[12] Estimate based on Form-1 data for 1999.

Staff reviewed data for forwards contracts that are traded in two hubs in the Southeast, Into Entergy and Into TVA, and examined futures contracts that are only traded at the Entergy hub. For the forwards contracts, there has been a general upward trend in the prices. For example, in July 1997 forwards contracts traded at the $26 per MWh to $32 per MWh range compared with July 2000 which ranged from $100 per MWh to $193 MWh at the Entergy hub. The forwards contracts prices appear to be good indicators of spot market prices. For example, the forwards contracts for July 2000 traded in the $100 per MWh to $193 per MWh range, as compared with the peak spot market price of $165 per MWh on July 18th at the Entergy hub. Figure 3-9 shows onpeak July-August forwards contract prices for each year from 1997 through 2000 at the Into Entergy hub. The figure graphically depicts the rise in prices observed above.

Figure 3-9. Into Entergy Onpeak Forwards, July-August Contracts

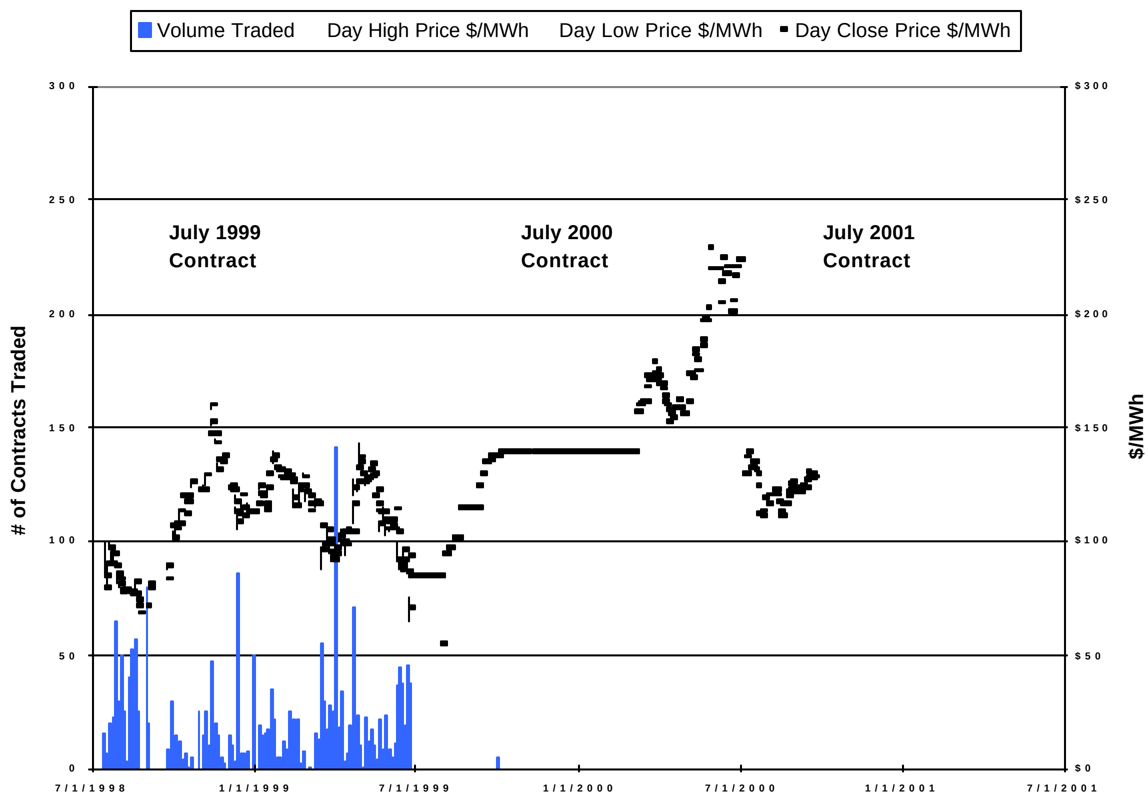


Jul-Aug 97 Contract Range: $26-32	Jul-Aug 98 Contract Range: $33-245	Jul-Aug 99 Contract Range: $83-137	Jul-Aug 00 Contract Range: $100-193	Jul-Aug 01 Contract Range: $112-131

Source: Power Markets Week

For the futures contracts, there is a less consistent pattern of price growth during the summer months. However, futures prices rose substantially in the summer of 2000, which suggests that market participants took a greater interest in futures contracts activity. Figure 3-10 shows July futures contract prices for each year from 1998 through 2000. The figure indicates that the futures contract price peaked at $235 per MWh in June 2000.

Figure 3-10. Entergy Futures, July Contract



D. Divestiture and Merger Activities

Investor-owned utilities have engaged in significant divestitures of generation assets in many areas of the country. However, the only divestiture in the Southeast in recent years occurred when Orlando Utilities Commission sold a 639 MW Indian River Power Plant to Reliant Energy on September 30, 1999.

The Southeast has witnessed five mergers in as many years: (1) Duke Power Company and PanEnergy Corporation; (2) Duke Energy Corporation and Nantahala Power and Light Company; (3) Dominion Resources, Inc. and Consolidate Natural Gas Company; (4) Florida Progress Corporation and CP&L Energy, Inc. and (5) NiSource Inc. and Columbia Energy Group.[13] The Commission has conditionally approved these mergers. One other merger between Entergy Power Marketing Corporation and Koch Energy Trading is pending before the Commission. Recently, Entergy Corporation and Florida Power and Light have announced their intention to merge.

Most of the mergers noted above were convergence mergers involving electric and natural gas resources. Non-divestiture of generation resources and rapid merger activity may tend to increase the domination of IOUs in the Southeast.

4. Regulatory and Institutional Environment

A. Federal Responsibilities, Statutes, and Provisions

The first part of this section focuses on federal responsibilities and laws that are unique to, or uniquely impact, the Southeast Region. Chief among these are those federal laws that govern the Tennessee Valley Authority and the Southeastern Power Administration. This section then discusses federal environmental regulations and the status of RTO development in the Southeast.

[13] While Nisource, Inc. has assets in the ECAR region, Columbia has operations in VACAR, which is in the Southeast.

1. Tennessee Valley Authority

The Tennessee Valley Authority (TVA)[14] was created by, and operates pursuant to, the Tennessee Valley Authority Act of 1933, as amended.[15] TVA's service area includes Tennessee and parts of Alabama, Georgia, Kentucky, Mississippi, North Carolina, and Virginia. TVA's Board of Directors is composed of three persons appointed for 9-year staggered terms, with one term expiring at each 3-year interval. TVA's rates are set exclusively by TVA's Board and are not subject to state public service commission or Commission oversight; nor is TVA responsible to shareholders. However, TVA maintains ties with electrical distributors, state and local governments, and direct customers. TVA was initially charged with the planning for the proper use, conservation, and development of the natural resources of the Tennessee River drainage basin and its adjoining territory.

As part of the 1959 self-financing amendment to the TVA Act, a “fence” was placed around TVA, so that TVA and its distributors cannot directly or indirectly be a source of power supply outside the area supplied with TVA power.[16] In addition, TVA is only permitted to enter into exchange power arrangements with the 14 generating organizations having such arrangements with TVA on that date. Further, a provision of the Energy Policy Act prevents other wholesalers from selling inside the TVA area to distributors. Thus, any energy sold within the fence must be sold to TVA for the beneficial use of all customers. With regard to its financing, TVA may borrow up to $30 billion to finance the construction of power facilities, but principal and interest on such loans are payable solely from TVA's net power proceeds. TVA must make payments to the United States Treasury to repay $1 billion of the appropriations that were invested in the TVA power systems, plus an annual return on the outstanding investment. Separate federal appropriations are made to support TVA's non-power activities.

Because TVA is a federal agency, all significant decisions must be made using the National Environmental Policy Act (NEPA) guidelines. TVA is also subject to the 1990 Clean Air Act Amendments.

The Tennessee Valley Public Power Association (TVPPA) is a major market participant in the Tennessee Valley. TVPPA is a non-profit regional service organization representing the interests of the 109 municipal utilities and 50 electric cooperatives in the TVA service area. All but one TVPPA member utility buy wholesale electric power from TVA and distribute it to eight and one half million customers in seven southeastern states.

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[14] Most of the information for this section comes from “Tennessee Valley Authority Case Study” by Mary Sharpe Hayes, as appearing in *Regulating Regional Power Systems*, edited by Clinton J. Andrews, IEEE Press, 1995.

[15] 16 U.S.C. § 831-831ee (1994 and Supp. III 1997).

[16] Order No. 2000, III FERC Stats. & Regs. ¶ 31,089 at 31,200 (1999).

The Commission has the authority under section 211 of the Federal Power Act to require TVA to provide transmission service, if requested to do so by an electric utility.[17] In addition, TVA has stated that while it is not required to file an open access transmission tariff with the Commission, under its Transmission Service Guidelines, which TVA views as modeled after the Commission's pro forma tariff, TVA provides comparable transmission service across its system for others.[18] TVA also recently has introduced a "5 Percent Plan" under which distributors in its service area may purchase up to 5 percent of their power from outside sources, if the price of that power is less than a "point of indifference" price projected by TVA. Customers must purchase a "5 x 16" product (i.e., purchase power for 5 days, 16 hours a day) and specify unalterable points of receipt and delivery. So far, small volumes (e.g., 250 MW for 1 week) have been purchased under the program. With regard to RTO formation, TVA has been working on a RTG proposal involving public power entities in the Tennessee Valley and adjoining areas.[19]

Federal legislation has been introduced that would give the Commission the same jurisdiction over TVA's transmission of electric power in interstate commerce as the Commission has over other utilities under the Federal Power Act.[20] The proposed legislation would also remove the fence around TVA limiting the movement of power in and out of TVA, provide for recovery of stranded costs, and allow TVA distributors individually to terminate their existing contracts to purchase wholesale electric energy from TVA three years after giving TVA notice of their intent to do so. This consensus legislation, which is supported by TVA, TVPPA, and other major players in the Tennessee Valley market, was included in the Barton electric restructuring bill.

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17 16 U.S.C.A. §§ 824j-824k (West 1985 and Supp. 1994) The Commission exercised this jurisdiction in AES Power, Inc., 69 FERC ¶ 61,345 (1994), final order, 74 FERC ¶ 61,220 (1996), order on reh'g, 76 FERC ¶ 61,165 (1996).

18 TVA's April 12, 2000, motion to intervene in Entergy Services, Inc., Docket No. ER00-1933-000, at 2.

19 *Electric Utility Week*, October 16, 2000, p. 16.

20 *See* Title VI, Substitute A to H.R. 2944 (July 12, 2000).

2. The Southeastern Power Administration

The Southeastern Power Administration (SEPA),[21] headquartered in Elberton, Georgia, has the responsibility to market electric power and energy generated at reservoirs operated by the U.S. Army Corps of Engineers. SEPA was created in 1950 by the Secretary of the Interior to carry out the functions assigned to him by the Flood Control Act of 1944. In 1977, SEPA was transferred to the Department of Energy. SEPA is organized into four systems: the Cumberland System located primarily in Tennessee and Kentucky, but also serving parts of Illinois, Mississippi, Alabama, and Georgia (9 dams); the Kerr-Philpott System serving Virginia, West Virginia, and a large part of North Carolina (2 dams); the GA-AL-SC System serving South Carolina, most of Alabama and Georgia, and parts of North Carolina, Mississippi, and Florida (11 dams); and the Woodruff System serving part of Florida (1 dam). SEPA markets power to customers (primarily electric cooperatives and public entities, referred to as preference customers) in all of these states. SEPA does not own transmission lines and must contract with other utilities to obtain transmission service.

SEPA's responsibilities include the negotiation, preparation, execution, and administration of contracts for sale of electric power; the preparation of wholesale rates and repayment studies; the provision, by construction, contract or otherwise, of transmission and related facilities to interconnect reservoir projects and to contractual loads; and activities pertaining to the operation of power facilities to ensure and maintain continuity of electric service to its customers.

3. Federal Environmental Regulation of Electric Utilities

The Commission is the primary agency involved in the environmental review of licensing and construction of jurisdictional hydroelectric facilities. In the Southeast, a significant amount of the hydroelectric resources are from federally run projects that are not subject to the Commission's jurisdiction. These are subject to federal environmental laws, and their power output can be significantly affected by their need to comply with environmental requirements. Economic and safety review of proposed nuclear power plants (including site safety matters and disposition of hazardous waste) is vested in the Nuclear Regulatory Commission and DOE, respectively, with most other environmental and land use issues reserved to the states or local jurisdictions. Utility operations are also governed by minimum federal standards for clean air under Title V of the Clean Air Act. Regional air quality plans are developed under EPA supervision and administered by the states. Most important among the standards are ozone, sulfur, particulate, and nitrogen dioxide (NOx), and carbon dioxide emissions.

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[21] See SEPA home page at http://sepa.fed.us.

There are 11 ozone non-attainment areas in the Southeast: Jacksonville/Duval County, Miami and Tampa in Florida; Charlotte/Gastonia, Greensboro/Winston-Salem/High Point, and Raleigh/Durham in North Carolina; Knox County, Memphis/Shelby County, and Nashville in Tennessee; Cherokee County in South Carolina; and Hampton Roads in Virginia.[22]

Currently, EPA's ozone transport rule affects most of the fossil fuel plants in the Southeast. Only the states of Arkansas, Florida, and Mississippi, and those portions of Texas in SERC, are exempted from this ruling. The rule requires compliance with a statewide NOx budget during the ozone season of May through September. This budget is based on 85 percent reduction in electric utility emissions and other reduction levels for other sources. Currently, compliance with this rule is required by the ozone season of 2003.

The reductions in emissions are based on fossil units with generating capacity of 25 MW or greater, emitting at a level of 0.15 lbs/MMBtu for NOx. There are provisions in the rules for an allowance system and use of allowances for compliance. This could allow some over compliance at some units and use of the excess allowances at others. In general, most units in the SERC region would likely have to install Selective Catalytic Reduction (SCR) systems to make the required reductions if they do not burn Western Powder River Basin coal or gas. SCR systems are estimated to require outages from 8 to 12 weeks for installation. With a compliance date of 2003 and the engineering and equipment procurement times required, the majority of these unit retrofits in the SERC region would have to occur in 2001 and 2002.

There are provisions in EPA's rule that would allow an extension for compliance to 2005 based on reliability issues but they are rather limited. Some states in SERC have already issued their draft plans and other states are drafting plans to comply with the rules. The entry of new generation that is more efficient than older generation will make it easier for entities operating in SERC to meet EPA's requirements.

B. RTOs

Aside from the TVRTG described above, there are three RTOs that would be located wholly within the Southeast: GridSouth, the SeTrans Grid Company and the GridFlorida, all of which made RTO filings on October 16, 2000. In addition, two RTOs located primarily in the Midwest would contain utilities located in the Southeast: the Alliance RTO contains Virginia Power, and the Southwest Power Pool RTO is proposed to include Entergy.

GridSouth

[22] CPL-FPC merger application, Ex. CF-445 at 1-2.

GridSouth is proposed to be a for-profit TRANSCO (transmission company) that would serve most of North and South Carolina. The transmission owners in GridSouth would include Duke, Carolina Power & Light, and South Carolina Electric and Gas, but would exclude the large transmission owning municipal in South Carolina, Santee-Cooper, whose potential inclusion is complicated by restrictions on its ability to turn over operation of its assets to a for-profit entity.

The SeTrans Grid Company

The Southern Companies have proposed the SeTrans Grid Company, which would be a for-profit TRANSCO that would operate but not own the Southern Companies' transmission facilities in Alabama, Georgia, and Mississippi, and Northern Florida. It would have a system wide transmission tariff and would be the sole provider of wholesale transmission service. The RTO would be the single site administrator for an OASIS for scheduling transmission and calculating TTC and ATC, and would be responsible for planning and expansion of the system, and for coordinating with neighboring RTOs concerning “seams” issues.

The GridFlorida

The Florida RTO is proposed to be a for-profit TRANSCO that would cover peninsular Florida, which is isolated electrically from the rest of the Eastern Interconnect because of the transmission constraint in northern Florida. All four public utilities will participate in the RTO. Non-jurisdictional utilities may participate in the Florida RTO but none of them have indicated to date whether they will do so.

C. State Responsibilities, Statutes and Provisions

State Restructuring and Retail Access

The states of the Southeast generally have been slower than states in other sections of the country to require restructuring of the electric industry at the state level.[23] The following section describes the status of state restructuring in the Southeast. As explained in more detail below, Arkansas and Virginia have required substantial restructuring, Alabama and Mississippi have decided not to require restructuring for the time being, and other states continue to study restructuring issues.

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[23] Unless otherwise noted, the information in this section is from DOE/EIA website, August 9, 2000, Status of State Electric Industry Restructuring Activity as of August 2000.

In Arkansas, restructuring legislation has been enacted that allows for the recovery of stranded costs, establishes rate freezes, allows for forced divestiture, requires functional unbundling, and sets retail competition to begin by January 1, 2002. Similarly, in Virginia, the Virginia Electric Utility Restructuring Act requires: deregulation of generation by January 1, 2002; the phase-in of consumer choice between January 1, 2002 and January 1, 2004, including pilot programs; rates capped through July 2007 for those who remain with their incumbent utility; the recovery of stranded costs through capped rates for customers staying with incumbent utility and through a wires charge for those who switch to competitive suppliers; and consumer protections such as universal service, education programs, fuel and emission disclosure requirements, and the allowance of aggregation for small consumers.

However, the Alabama Public Service Commission voted on October 2, 2000, to temporarily suspend the generic investigation of restructuring it had opened in April 1998 until there are wholesale markets in the region.[24] The PSC concurred with its staff recommendation that the burden of proof had not been met that retail competition in electricity service and restructuring the industry was in the public interest. Accordingly, Alabama Power Company is to continue as a monopoly provider of retail electric service until there is a viable wholesale market. Similarly, in Mississippi, the Public Service Commission concluded that a competitive electric power industry would not be beneficial to the state's consumers at this time, and suspended the 1996 docket opened to investigate electric power restructuring. Prices in Mississippi are below the national average, and studies conducted by the PSC indicate that prices for the residential and small consumers could rise in a competitive environment.

Other states continue to study these issues. The Florida Governor has appointed a commission to study restructuring in Florida. The commission is to report to the Governor by December 1, 2001, on their investigation of current and future electric reliability, energy conservation, environmental impacts, supply and delivery options, electric industry competition, and the financial consequences of restructuring. In January 1998, the Georgia Public Service Commission issued a staff report on electric industry restructuring. Recommendations included market-based rates, unbundled services, and stranded cost recovery. A docket was established for comments from stakeholders. A slow approach to restructuring was recommended.

In March 1999, the Louisiana Public Service Commission issued an order stating that deliberate and cautious approach was warranted for restructuring the electric utility industry. A schedule was established through August 2000 to study issues concerning consumer education, stranded costs, regional planning and reliability, market power, rate unbundling, functional unbundling, independent system operators, and transition mechanisms. In Tennessee, as of January 1999, the Tennessee Regulatory Authority released a report on the deregulation of the industry which identifies 10 issues: rates and

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[24] See Alabama Public Service Commission home page at http://www.psc.state.al.us.

prices; stranded costs; reliability; market power; universal service; environmental concerns; taxes; local rate setting; consumer education; and regulatory and legal issues. Recommendations for restructuring including any proposed legislation must be made by February 28, 2001.

In North Carolina, the Study Commission on the Future of Electric Service in North Carolina has issued its final report with recommendations to open retail electricity markets to half of the consumers by January 2005, and the other half by January 2006. The study also recommends a rate freeze until January 2005 to allow utilities to pay down stranded costs and implementation of a public benefit fund for low-income, renewable energy, and energy efficiency programs. Issues concerning the stranded costs of municipals were not addressed. The Study Commission has also announced its intention to hold a series of meetings and public hearings on deregulation in cities around the state. Issues concerning the stranded costs of municipals must be resolved before legislation can be drafted for the 2000 legislative session.

In South Carolina, as of March 2000, restructuring legislation (SB 1168) was introduced and referred to the Committee on Judiciary. The bill would allow retail direct access within three years. Debate and discussions continue in the House and Senate, but few expect passage of the bill this session. Also, a report by the Senate Task Force is due to be released soon.

State Siting Matters

In Florida, independent power producers may not construct combined cycle plants with a capacity greater than 75 MW. The Florida Supreme Court recently reached this conclusion in a case in which the state's major utilities challenged the Florida PSC's authority to permit Duke Power Company and the City of New Smyrna Beach to build a large combined cycle plant.[25] Hence, Florida law severely limits the ability of independent power producers to site merchant plants.

Florida appears to be an exception with respect to siting in the Southeast region. Market participants have reported favorable experience with siting in the state of Mississippi. They report that for several years, Mississippi has been actively "recruiting" new merchant plants by providing information on the state's infrastructure and resources. In Mississippi, approximately 6400 MW of new generation is in some phase of construction or has been installed, and several thousand MW of additional new generation is planned or recently announced. To date, no permit requests have been denied by the Mississippi Public Service Commission. Arkansas is also reported to have an expeditious siting process.

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[25] Tampa Electric Co. et al., v. Joe Garcia, et al., Nos. SC95444, et al., April 20, 2000, 25 Fla. L. Weekly S 730 (Fla. 2000), revised opinion issued September 28, 2000.

In North Carolina, a certificate of public convenience and necessity (PCN Certificate) granted by the North Carolina Utilities Commission (NCUC) is required for the construction of a generating facility for the provision of public utility service. Such certificates are granted, only if the applicant's estimated construction costs are approved and such construction is consistent with the NCUC's plan for the long-range expansion of electric generating capacity. This requirement applies to all projects involving the construction of electric generating capacity, except for generation that would be used to serve the load of the generation owner. The NCUC has issued an order requesting comments as to whether it should initiate a generic proceeding to determine how it should handle future applications to build generating plants in the state that will serve non-native load.

In South Carolina, a PCN Certificate issued by the South Carolina Public Service Commission (SCPSC) is required for the construction of a major utility facility by any person. A "major utility facility" is defined as an electric generating plant with a capacity greater than 75 MW or a transmission line with an operating voltage of 125 kV or higher. The SCPSC is required to make a finding and determination as to, among other things, the basis of the need for the facility, the nature of the probable environmental impact, whether the environmental impact is justified, and that the facilities will serve the interest of system economy and reliability.[26]

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[26] CPL-FPC merger application, Ex CF-445 at 5-8.

5. Discussion of Inefficiencies in the Southeast

Like the Midwest, the Southeast is dominated by vertically integrated utilities that maintain substantial generation resources to serve their respective native loads. These utilities have weak economic incentives to provide transmission access to non-affiliated merchants on the same basis as they do to their affiliated merchants. As part of its investigation of bulk power markets in the Southeast, the Commission's staff met with representatives of various market participants, including IOUs, IPPs, public power entities and electric power traders to explore transmission access and related issues. Market participants also provided responses to staff's data and documents requests.[27]

In general, market participants identified several inefficiencies that are frustrating the development of the bulk power markets in the Southeast. Chief among these are uncertain transmission access, the inconsistent and apparently aberrant posting of ATC and concerns that ATC is sometimes withheld, and the lack of transparency regarding implementation of TLRs. A central theme pervading these concerns is that there is a lack of current, reliable information available to the market. In addition, the role of TVA as a major transmission provider that, due to its status as a federal entity not subject to the full panoply of Commission regulation, has not fully embraced the reforms set forth in the Commission's Order No. 888, and the restrictive siting law in Florida contribute to pressures that undermine competitive wholesale energy markets in the Southeast. As noted in Section 2 above, the significant amount of IOU-owned generation within vertically integrated transmission systems is larger than anywhere else in the country. This situation adds to pressures on the wholesale market and may be a matter of concern.

Staff has not verified the accuracy of all the complaints it has received regarding transmission access, ATC postings and TLRs. The lack of precise, readily available information, the real time nature of transactions, the resources required to investigate individual complaints and the operational discretion accorded IOUs retards the staff's ability to discern the truth in the substantial number of complaints that were brought to it. Nonetheless, market participants appear to have less confidence in the Southeast market, in terms of the ability to conduct wholesale transactions without discrimination, than market participants have in other regions of the country. This lower degree of confidence appears to be justified based on investigations that the staff has undertaken and its evaluation of other complaints. Market participants' reduced confidence weighs heavily on the maturation of markets into competitive zones of enterprise because it discourages the investment and participation needed to spur this development. The widespread perception

[27] Market participants provided responses to data and document requests with requests for confidential treatment pursuant to section 388.112 of the Commission's regulations, 18 C.F.R. § 388.112 (2000). Accordingly, this report discusses information provided in these responses in general or aggregate terms. Staff is evaluating whether action is appropriate to address specific allegations contained in the data responses.

that non-IOU entities do not receive treatment equal to that of IOU-affiliated entities frustrates the Commission's open access goals.

The reforms presaged in the Commission's Order No. 2000—the encouragement of RTOs—may successfully address many of the discrimination issues that arise from the present market structure. The Commission may need to be more prescriptive in terms of how transmission is allocated, depending on whether traditional load allocations persist. Some market participants have expressed concerns that existing owners of transmission capacity would continue to dominate transmission system operations under RTOs. The formation of RTOs, then, could provide the Commission with an opportunity to take a structural approach to reduce discrimination but the timing for the creation and operation of RTOs is uncertain.

Specific inefficiencies in the Southeast are discussed below.

A. Transmission Access

Staff's investigation of interconnection issues revealed that procedures governing utilities' performance of interconnection studies are often unclear. Adherence to schedules that are established early in the interconnection request process would reduce the increasingly adversarial climate in which interconnection requests are evaluated. The time periods chosen to evaluate requests should reflect a reasoned approach to the technical challenges posed by the request and respect for the IPP's often pressing need for promptness and certainty.

In one case, typical of other complaints staff received, an IPP reported that a utility quoted a period of 11 months to complete the first of several anticipated system impact studies. In the absence of an explanation that cites the technical reasons why such a period is required, 11 months to perform a system impact study appears excessive. Studies that are not promptly commenced and linger over many months cease to be commercially reasonable.[28] Utilities that claim to have insufficient human resources to execute interconnection studies should adjust staffing levels, or out-source assignments, where their experience demonstrates that existing staffing and procedures result in significant delays.

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[28] Pursuant to the *pro forma* tariff, the utility should work diligently to complete studies in less than 60 days. However, the Commission has explained that a utility "may take more time as long as it explains to the applicant the reason that it needs additional time." American Electric Power Service Corporation, 91 FERC ¶ 61,308, at 62,049 (2000). The Commission has acknowledged that a study regarding the interconnection of new generation may often take more than 60 days, PJM Interconnection, L.L.C., 87 FERC ¶ 61, 299, at 62,198 (1999), but in such a case, the utility must nonetheless provide a justification for the extended period required to complete the study.

Charges assessed for interconnection studies must reflect costs that the utility performing the study actually incurs.[29] Information from market participants that standard charges of $10,000 for studies of varying complexity and of charges, as in the case of one charge in the amount of $50,000, that are reduced when, upon inquiry, the utility cannot support it, indicate that utilities' approach to charges for interconnection studies is too often arbitrary. The failure to adhere to the Commission's requirements and to commercially reasonable standards for administering studies discourages the participation in the wholesale market that the Commission has sought to encourage.

The Commission has expressed its sympathy for the difficulties IPPs face when they seek to site a generation plant amid the uncertainty of transmission access.[30] The staff investigation found evidence that the right of vertically integrated utilities to reserve transmission capacity has been used to deter merchants from siting plants in their respective service territories. Utilities have reserved transmission capacity in the name of serving load growth many years out, effectively deterring IPPs from siting plants in affected areas. In this connection, several IPPs complained that a utility reserved transmission capacity shortly after each IPP approached the utility with plans to site generation. According to these complainants, the utility's reservations enormously complicated, or precluded the IPPs from reserving point-to-point transmission service necessary to permit the planned project to go forward. The utility reservations were for network service designed to accommodate projects in early stages of planning. Such first-in-time reservations receive a priority because of the extended length of the terms associated with serving network loads. Because the transmission queue was lengthening, one of the IPPs was forced to get into the transmission queue and had to designate a delivery point that represented a guess on its part. The IPP made transmission reservation requests for its proposed site in advance of several probable study phases. It reported to staff that it is unlikely the project will ever be built because of the numerous requests for network service ahead of it in the queue.

A recent Commission decision suggests some of the problems associated with transmission reservations that IPPs face when seeking to site new generation.[31] SkyGen Energy, an IPP, executed an interconnection agreement with Southern. Southern later reserved transmission capacity, followed by SkyGen Energy's request for long-term firm transmission. After conducting a system impact study, Southern denied SkyGen's transmission request because granting the request would cause an area wide stability problem. Southern concluded that the only option available for meeting SkyGen's request would be the construction of a new 80-mile, 500 kV transmission line, and related

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29 *E.g.,* Carolina Power & Light Company, 93 FERC ¶ 61,032 (2000).

30 Entergy Services, Inc., 91 FERC ¶ 61,149 at 61,561 (2000).

31 SkyGen Energy LLC v. Southern Company Services, Inc., 92 FERC ¶ 61,120 (2000).

construction that would require approximately 8 years to complete. SkyGen contended that because the interconnection study agreement pre-dated Southern's OASIS transmission postings, SkyGen's request for transmission service should be given priority. The Commission ruled that Southern's transmission request queue is governed by the date that SkyGen submitted its transmission request and denied SkyGen's request for relief.

Tactics that exploit plant-siting information that IPPs provide to utilities comprise a further potential hurdle for IPPs seeking to develop generation resources in the Southeast. Possible reforms to address opportunistic load growth reservations by incumbent utilities could include allowing network requests for transmission service by generators and limiting self-built capacity in the incumbent utility's service territory. The depth of the problem posed by reconciling reservation activity by utilities with the expectation of fair play by IPPs seeking to site new generation plants underlines the importance of RTO reforms that restore confidence in the fairness of the marketplace.

B. ATC Issues

As the Midwest report points out, uniform rules do not exist for calculating and posting ATC. Inconsistent and aberrant ATC postings have posed difficulties to market participants in other regions in the country and the Southeast is no different in this respect. A particularly troubling pattern occurs when a marketer enters a request for transmission service on OASIS based on the ATC posted there; the request is denied, followed by a large reduction in the posted ATC.[32] Because the reason provided for denial of a transmission request is often less helpful than the Commission envisioned when it established the requirement to post a reason,[33] the marketer is often left to wonder what happened, as it scrambles to secure an alternate arrangement. In sum, ATC postings that are not fairly representative of actual transmission capacity and that fluctuate for no apparent reason discourage, and raise the costs of, buying and transmitting power in the bulk power market.

Several utilities in the Southeast indicated that they are active at the regional council level to coordinate a standardized ATC calculation methodology. This is a long process by its nature; it may not be resolved soon without direction from the Commission. An improved method to calculate ATC across service areas is needed. Such an effort, however, will not address the type of ATC posting deficiency, like the one described above. Improved communication by utilities to market participants regarding changes in ATC postings could allay suspicions that utilities manipulate ATC for competitive gain.

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32 During its recent audit of OASIS sites, staff observed this phenomenon. This audit, which is referenced in the Midwest report, determined compliance with the OASIS posting requirements of section 37.6 of the Commission's regulations.

33 *See* 18 C.F.R. § 37.6(e)(2) (2000).

C. TLR Issues

The Southeast experienced a 354-percent increase in TLRs in the summer of 2000 over the summer of 1999. As noted above, the substantial increase in TLRs did not cause any system-wide price spikes or any area-wide supply disruptions. However, as stated in the Midwest report, the TLR procedure is an inefficient instrument to use in mitigating transmission constraints. The Midwest report addresses TLR issues in greater detail.

The fact that a total of 184 TLRs were declared this summer suggests that the use of TLRs has been extended from the original purpose of implementing them to address extreme constrained situations. In fact, the increasing incidence of TLRs since 1999 has raised the issue of whether curtailment of transmission transactions has become an impediment to the competitive operation of the market in the Southeast. The high incidence of TLRs reduces certainty in the market because it frustrates the expectations of bulk power sellers and their customers. The following discussion addresses specific concerns regarding TLRs as they bear on the Southeast.

Whether security coordinators are truly independent and do not favor their employer-utility has been questioned. As in the case of interconnection access, the built-in incentive to favor use of the incumbent utility's assets colors the perception of impartiality of security coordinators in the implementation of NERC's TLR criteria. Staff has not confirmed that any bias that may exist has been exercised in any specific instance to the detriment of a market participant, but it cannot discount the possibility that the force of economic incentives may play a role in TLR implementation.

TLRs are not always implemented according to the criteria established by NERC. For example, Ameren Operating Companies' security coordinator implemented a Level 2B TLR on September 22, 2000. The TLR curtailed a firm transaction, Tag Code 0011194, at flowgate ID number 3102 (Bland-Franks 345 kV). The sink for the transaction was in TVA's service territory. Under NERC criteria, firm transmission can only be curtailed by a Level 5 TLR. Further, the NERC TLR Procedure Log, a historical account of TLR activity, that provided details regarding this TLR event, failed to disclose that the firm transaction at issue had been curtailed.

The increased incidence of TLRs may suggest that some transmission capacity is being oversold. Market participants have attributed a tendency to implement a greater number of TLRs to the commercial reality that transmission providers do not have to refund transmission reservation fees for service curtailed because a TLR is called. The extent to which commercial motives influence TLR implementation, if at all, evades easy verification. Increased Commission oversight in the future in this area may provide insight to a situation that exists because of the present market structure in the Southeast. Development of RTOs may also address these concerns because of the separation of the operation of transmission and generation resources. Further, the broader geographic reach that RTOs are intended to have will internalize an increased number of parallel path flows and hence reduce the incidence of TLRs. TLRs may also decline because RTOs will adopt pricing mechanisms to address congestion that will obviate recourse to TLRs. These developments would be consistent with the experience of the Northeast ISOs. However, as noted in the Midwest report, RTOs may not necessarily address this problem. To the extent that control areas are maintained, vertically integrated entities which are members of an RTO may retain mixed incentives.

Another way to reduce the incidence of TLRs would be to augment transmission capabilities. However, regulatory uncertainty, the expense of such an undertaking relative to financial return to constructing utilities and the prospect of distributed generation discourage this remedy.

D. Lack of Information

A major problem for the markets in the Southeast is lack of information. As the Commission discussed in Order Nos. 888, 889 and elsewhere, efficient markets require the free flow of useful information. In the Southeast, it is difficult for market participants to get key information. As in the Midwest, part of the problem lies in non-compliance with OASIS requirements. In a staff audit of OASIS sites a number of problems were found. First, for both constrained and unconstrained transmission paths, ATC and TTC are often posted late, if at all. And even if the general methodology of ATC calculation was described, which is all OASIS requires, market participants seldom have sufficient information concerning the precise calculation of ATC and TTC to determine whether particular postings are fair and accurate, and what ATC may be posted in the future. In addition, curtailments and the reasons for curtailing or for denying transmission service were not always posted as OASIS requries. There also were problems obtaining or downloading information concerning transmission service schedules, transmission requests and services, products and pricing, and tariffs. Moreover, several OASIS audit logs, which are used to record data and activity on the OASIS site, are not operating correctly and erase historical data so that it is impossible to audit the sites.

Beyond OASIS, providing greater access to load and transmission line outage data would increase the certainty of transactions in regional markets in the Southeast. There is merit in market participants' suggestions that transmission providers should have to post: sufficient information concerning their transactions with affiliates involving the purchase and sale of ancillary services and generation imbalance payments to ensure that their affiliates do not receive preferential treatment; additional ATC that will be available due to system upgrades that may be made in conjunction with interconnection agreements; imbalance clearing prices and transmission losses for each control area in real time.

For a number of reasons, certain information for this study was difficult to obtain for the Southeast region. Summer 2000 demand data were not readily available. The lack of Commission transmission jurisdiction over TVA made it difficult to obtain transmission access information concerning TVA. As in the case of the Midwest where such allegations also are common, allegations that transmission providers unjustifiably limited access to transmission were difficult to verify because individual events often involve complicated factual situations which require substantial time and resources to examine thoroughly.

Section 5 of the Midwest report discusses information needs of regulators and market participants. The Commission should refer to this discussion when considering action to revise reporting requirements. As noted in that section, however, the manner in which load is calculated weighs heavily on the value of this information. This is an issue that the formation of RTOs may not resolve. Eliminating native load exemptions—i.e., treating all load equally—and placing all transactions under the same tariff may be an option that provides the right incentives for the provision of transparent and standardized information. (See section 6 of the Midwest Report.)

E. TVA Issues

For a number of reasons, the TVA service area is a problem area for the Eastern Interconnect grid. While they resulted in part from factors beyond TVA's control, the many TLRs called during the summer of 2000 in the TVA service area indicate that TVA has become a transmission bottleneck in the Eastern grid. A primary impediment to the development of deep and robust power markets in this area is the existing federal law which prevents the free sale of power into and out of TVA because of the TVA fence. Behind that fence is TVA's generation capacity of 30,203 MW and the TVA service area load of 29,344 MW on a peak basis.[34] Another important factor is that TVA is not subject to the complete extent of the Commission's jurisdiction over interstate transmission service. In the absence of such jurisdiction, TVA simply does not have a strong incentive to provide effective and efficient open access transmission service and to address and eliminate seams issues with neighboring control areas. This is true even though TVA has its Transmission Service Guidelines which are modeled after the Commission's pro forma open access transmission tariff.

Because of the Commission's limited jurisdiction over TVA, the Commission does not have full access to the information it normally has to determine the extent of transmission access and other market problems on the TVA system. But from the information available to the Commission, as also discussed elsewhere in this report, it appears that TLR, CBM, ATC, and other common transmission problems exist to the same degree or more on TVA as they do at utilities whose transmission is regulated by this Commission. TVA is alleged to have: unfairly rejected requests to perform interconnection studies; required an excessive time, required excessive deposits, and charged excessive fees to complete interconnection studies when it agreed to do them; assessed excessive charges for interconnection facilities; required an excessive time to

[34] TVA News, August 28, 2000.

process requests for transmission service; given a preference to an affiliate's transmission request over a prior non-affiliate's transmission request for the same service; incorrectly rejected a transmission request for failing to specify an NERC control area; provided transmission capacity for an affiliate when posted ATC was zero; rejected requests for transmission when ATC was available; allowed TVA Marketing but not other participants to designate TVA as a sink for transmission service and park power on TVA's system; and unjustifiably increased its tagging deadline.

Recent proposals by TVA to enhance the development of bulk power markets and the quality of its open access transmission service do not appear to have great potential. Small volumes have moved under TVA's “5 percent” program thus far and a number of restrictions and questionable practices limit the potential effectiveness of that program. For example, market participants are not provided information on how TVA calculates its “point of indifference” price, participants must purchase power on a 5-day basis, and are limited to specific receipt and delivery points. Some problems concerning this program, such as certain penalties, have been worked out, and discussion continues about others. But even if the program was fully used, the 5-percent limitation on the amount of outside power that can be purchased would remain a severe and arbitrary restriction on the free flow of power and the development of a more efficient and reliable Eastern grid.

F. Florida Law

Florida law restricts construction of merchant plants. Regardless of the purpose of the state statutes construed by the state court, granting licenses only to an applicant who has demonstrated that a utility serving retail customers has a specific need for all of the power to be generated at the proposed plant severely limits the market mechanisms by which power may be delivered to loads. In so limiting the generation and delivery of power, it creates inefficiency by replacing market allocation with administrative determinations. The Florida decision creates a significant barrier to entry and imposes costs on IPPs that have made plans to site new generation in Florida that cannot now be brought to fruition.

G. Standards of Conduct

The Commission's standards of conduct, codified at 18 C.F.R. § 37.4 (2000), require separation of a utility's transmission function and wholesale merchant function employees. An FRCC Agent Operational Audit Report, issued September 8, 2000, contained findings of an apparent violation of the Commission's standards of conduct.

The report stated that in some instances, confidential reliability information about Florida Power & Light's (FPL's) transmission system was posted on EMS displays that were available to` FPL's wholesale merchant affiliate. One such display, for example revealed the interchange information for other entities. The report concluded that FPL does not have an established procedure for review of EMS displays to ensure that confidential information does not get displayed in error. Instead, the report states that "[i]t seems to be up to individual Managers [sic] discretion.'[35] Violations of the standards of conduct undermine competition in the wholesale energy market and the industry's confidence in the integrity of transmission system operations. Staff is unable to determine at this time whether violations of the standards of conduct are widespread.

6. Conclusion

In conclusion, a number of inefficiencies exist in the Southeast which are similar to those that exist in the Midwest. These inefficiencies are exacerbated by the relatively high amount of IOU-owned generation. Given the inefficiencies discussed above, the Commission may wish to consider the options set forth at the conclusion of the Midwest report.

[35] FRCC Agent Operational Audit Report, September 8, 2000, at 8. The report may be found on FRCC's website at www.frcc.com.

Appendix

SERC Regular Members

Investor-Owned Utilities
Alabama Power Co.
Entergy Arkansas, Inc.
Carolina Power & Light Co.
Duke Power Co.
Florida Power & Light Co.
Georgia Power Co.
Gulf Power Co.
Entergy Gulf States, Inc.
Entergy Louisiana, Inc.
Entergy Mississippi, Inc.
Entergy New Orleans, Inc.
Mississippi Power Co.
Nantahala Power & Light Co.
Savannah Electric & Power Co.
South Carolina Electric & Gas Co.
Tapoco, Inc.
Virginia Power
Yadkin, Inc.

Cooperatives
Alabama Electric Cooperative, Inc.
Associated Electric Cooperative, Inc.
Cajun Electric Power Cooperative
North Carolina Electric Membership Corp.
Oglethorpe Power Corp.
Old Dominion Electric Cooperative
Sam Rayburn G&T Electric Cooperative, Inc.
South Mississippi Electric Power Association

Municipals
Fayetteville Public Works Commission
JEA
Municipal Electric Authority of Georgia
N.C. Eastern Municipal Power Agency
N.C. Power Agency #1

Federal/State Systems
Crisp County Power Commission
South Carolina Public Service Authority
Southeastern Power Administration
Tennessee Valley Authority

Independent Power Producers
Air Liquide America Corp.
Cogentrix Energy, Inc.
LG&E Power Development, Inc.
Enron S.E. Corp.

SERC Associate Members

Investor Owned
Florida Power Corp.
Tampa Electric Co.

Marketers
AES Power Inc.
Aquila Energy Power Corp.
Avista Energy, Inc.
Calpine Power Services Co.
Cargill-Alliant, LLC
Cinergy Corp.
Citizens Power Sales
CLECO Corp.
Conoco Power Marketing, Inc.
Constellation Power Source, Inc.
Coral Power
Delmarva Power & Light Co.
Duke Energy Trading & Marketing
Dynegy Power Marketing Corp.
Enron Power Marketing
Enserch Energy Services, Inc.
Entergy Power Marketing Corp.

Equilon Energy Services
Koch Power Services
PECO Energy Co.
PG&E Energy TradinQ - Power, L
PP&L, Inc.
ProLiance Energy, LLC
Public Service Energy, LLC
Reliant Energy Services
SCANA Energy Marketing, Inc.
SONAT Power Marketing
Southern Energy Marketing, LP
Tenaska Power Services Co.
Williams Energy Services Co.

<u>Municipals</u>
City of Tallahassee
Rivera Utilities

FRCC Members

Aquila Power
Citizens Power Sales
City of Homestead
City of Lakeland
City of Lake Worth Utilities
City of Tallahassee
City of Vero Beach
Constellation Power Source
Duke Energy Power Services
El Paso Merchant Energy
ENRON Power Marketing, Inc.
Entergy Power Marketing Corp.
Florida Municipal Power Agency
Florida Power Corp.
Florida Power & Light Co.
Fort Pierce Utilities Authority
Gainesville Regional Utilities
Gulf Power Co.
Indiantown Cogeneration, LP
JEA
Kissimmee Utility Authority
Morgan Stanley Capita'- Group, Inc.
Ocala Electric Utility
Orlando Utilities Commission
PECO Energy Co. - Power Team
Reedy Creek Improvement District
Reliant Energy Services
Seminole Electric Cooperative, Inc.
Southeastern Power Administration
Tampa Electric Co.
The Energy Authority
Utility Board of the City of Key West
Utilities Commission of New Smyrna Beach

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