Southeastern Infrastructure Assessment

Prepared by:
The Southeastern Association of Regulatory Commissioners

May 8, 2002

Table of Contents

I. Executive Summary

Across the nation, State regulatory agencies are deliberating issues regarding the formation of Regional Transmission Organizations (RTOs). As a foundation for any discussion, one must first understand the underlying system before any changes are made in order to preserve the existing level of reliability. As the President of the Southeastern Association of Regulatory Commissioners (SEARUC), Chairman Jacobs of the Florida Public Service Commission initiated an assessment of the electric infrastructure in the Southeastern region on October 9, 2001. The current President of SEARUC, Commissioner Baez from the Florida Public Service Commission, has orchestrated the continuation of the Southeastern Infrastructure Assessment (Assessment) which required the cooperation and coordination of several state public service commission's staff, utility representatives, and regional reliability councils. Sections I and II of the Assessment provides an inventory of existing facilities and a projection of additional generation and transmission facilities on a comparable basis. Sections III and IV of the Assessment provide a summary of individual state's planning and siting processes and current state public service commission activities regarding the development of Regional Transmission Organizations (RTOs). In this manner, the Assessment provides a useful foundation for any discussion regarding the future development of an RTO.

The data relied upon for the Assessment was gathered through responses to survey questions to individual state commissions and utilities, web sites, and other publicly available forms of information. Much of the data requested, such as transmission line loading relief (TLR) occurrences or transmission transfer capabilities, is only accumulated on a control area (or system) basis. Therefore, it became apparent that the least common denominator for data presentation would be at the Southeastern Electric Reliability Council (SERC) and Florida Reliability Coordinating Council (FRCC) level. Because of the cooperation of the SERC, FRCC, and state commission staff, the data was made available in a timely fashion. Generation and transmission data for Kentucky was not requested since Kentucky is a member of the East Central Area Reliability Coordination Agreement (ECAR).

In summary, the Assessment indicates that the southeastern states have adequate infrastructure in place to accommodate modest changes in the wholesale market. The bulk of the existing generation fleet is comprised of low cost coal and nuclear units. Planned additions are predominately natural gas-fired combined cycle and combustion turbine units, much like the rest of the country. Summer generation reserve margins for 2001 range from 8% in the SERC/Entergy subregion to 21% in the FRCC region. The SERC/Entergy reserve margin does not include announced merchant capacity. Tie line capabilities appear adequate in most regions as evidenced by the low number of TLR events. However, a rapid influx of non-utility generation may require significant upgrades to the transmission system, particularly in the Entergy and Southern subregions of the SERC. A key issue facing regulators is whether retail customers should pay for these transmission enhancements. The integration of these new units will require close coordination among the utilities and associated reliability councils. Most states have a process in place to monitor and react to utility plans for generation and transmission additions. In addition, it appears that adequate generation and transmission facilities are currently being planned in order to maintain reliable service to end-use customers.

II. Assessment of Generation Infrastructure

EXISTING CAPACITY MIX

The Southeast Region – comprising the SERC and FRCC regions – currently has a combined summer capacity of over 212,000 MW. The vast majority of this capacity is located in the SERC region. As shown in Table 1, the largest component of the Southeast Region's capacity is coal-fired. For the SERC Region, coal and nuclear generation provide the bulk of the capacity. For the FRCC Region, over half of the existing capacity is comprised of fossil steam and coal.

TABLE 1. SOUTHEAST REGION
EXISTING SUMMER CAPACITY BY FUEL TYPE

UNIT TYPE	SERC Region		FRCC Region		SOUTHEAST Region (SERC + FRCC)	
	MW	% OF TOTAL	MW	% OF TOTAL	MW	% OF TOTAL
Nuclear	31,328	18.3%	3,898	9.5%	35,226	16.6%
Hydroelectric	12,529	7.3%	11	0.0%	12,540	5.9%
Pumped Storage	6,219	3.6%	0	0.0%	6,219	2.9%
Coal	70,662	41.3%	10,265	25.0%	80,927	38.1%
Fossil Steam	17,531	10.2%	12,055	29.4%	29,586	13.9%
Combustion Turbine	18,516	10.8%	6,080	14.8%	24,596	11.6%
Combined Cycle	4,876	2.8%	4,067	9.9%	8,943	4.2%
Other	4,105	2.4%	2,851	6.9%	6,956	3.3%
Net Firm Capacity Interchange	5,399	3.2%	1,845	4.5%	7,244	3.4%
TOTAL	**171,165**	**100.0%**	**41,072**	**100.0%**	**212,237**	**100.0%**

SOURCES: SERC Response to 1/31/2002 FPSC Data Request; SERC 2001 EIA 411
FRCC 2001 *Regional Load and Resource Plan*

Table 2, on the next page, breaks down the SERC Region's existing capacity by fuel type for each of the four SERC subregions. This table illustrates that the SERC/VACAR subregion is the largest of the SERC subregions, with an existing capacity of over 62,000 MW.

TABLE 2. SERC SUBREGIONS
EXISTING SUMMER CAPACITY BY FUEL TYPE

UNIT TYPE	SERC/Entergy		SERC/Southern		SERC/TVA		SERC/VACAR		SERC Region TOTAL	
	MW	% OF TOTAL	MW	% OF TOTAL	MW	% OF TOTAL	MW	% OF TOTAL	MW	% OF TOTAL
Nuclear	4,643	16.8%	5,724	11.9%	6,668	20.2%	14,293	22.9%	31,328	18.3%
Hydroelectric	70	0.3%	3,938	8.2%	4,875	14.8%	3,646	5.8%	12,529	7.3%
Pumped Storage	0	0.0%	1,146	2.4%	1,578	4.8%	3,495	5.6%	6,219	3.6%
Coal	6,188	22.3%	24,844	51.7%	15,367	46.7%	24,263	38.9%	70,662	41.3%
Fossil Steam	14,388	51.9%	1,304	2.7%	0	0.0%	1,839	2.9%	17,531	10.2%
Combustion Turbine	858	3.1%	5,950	12.4%	3,203	9.7%	8,505	13.6%	18,516	10.8%
Combined Cycle	895	3.2%	3,041	6.3%	0	0.0%	940	1.5%	4,876	2.8%
Other	0	0.0%	2	0.0%	1	0.0%	4,102	6.6%	4,105	2.4%
Net Firm Capacity Interchange	670	2.4%	2,119	4.4%	1,246	3.8%	1,364	2.2%	5,399	3.2%
TOTAL	**27,712**	**100.0%**	**48,068**	**100.0%**	**32,938**	**100.0%**	**62,447**	**100.0%**	**171,165**	**100.0%**

SOURCE: SERC Response to 1/31/2002 FPSC Data Request

PLANNED CAPACITY ADDITIONS

As shown in Table 3, below, electric utilities in the Southeast Region forecast an addition of over 53,000 MW of new capacity by the year 2010. The majority of these additions (over 39,000 MW) are forecast for the SERC Region. Most of this new capacity is expected to come from combined cycle and combustion turbine units.

Nearly all of the 14,000 MW of the FRCC Region's planned capacity additions are expected to come from combined cycle and combustion turbine units. An estimated 8,000 MW of additional merchant generation has been announced as of August, 2001. Nearly all announced merchant capacity in the FRCC is forecasted to be completed between 2002 and 2005. This capacity is not included in Table 3 because it has not yet been committed to serve retail load in the FRCC region.

According to the North American Electric Reliability Council's *2001 Summer Assessment*, a substantial amount of merchant capacity has been announced for the SERC Region. For example, approximately 16,000 MW of merchant generation either exists or is planned in the State of Mississippi. This generation is not included in Table 3.

TABLE 3. SOUTHEAST REGION
PLANNED ADDITIONS / (REDUCTIONS) TO SUMMER CAPACITY BY FUEL TYPE

UNIT TYPE	SERC Region		FRCC Region		SOUTHEAST Region (SERC + FRCC)	
	MW	% OF TOTAL	MW	% OF TOTAL	MW	% OF TOTAL
Nuclear	(238)	-0.6%	0	0.0%	(238)	-0.4%
Hydroelectric	516	1.3%	0	0.0%	516	1.0%
Pumped Storage	186	0.5%	0	0.0%	186	0.3%
Coal	(1,391)	-3.5%	(314)	-2.2%	(1,705)	-3.2%
Fossil Steam	(265)	-0.7%	(413)	-2.9%	(678)	-1.3%
Combustion Turbine	12,109	30.6%	2,633	18.7%	14,742	27.5%
Combined Cycle	17,929	45.3%	13,482	95.8%	31,411	58.5%
Other	8,779	22.2%	(851)	-6.0%	7,928	14.8%
Net Firm Capacity Interchange	1,991	5.0%	(469)	-3.3%	1,522	2.8%
TOTAL	**39,616**	**100.0%**	**14,068**	**100.0%**	**53,684**	**100.0%**

SOURCES: SERC Response to 1/31/2002 FPSC Data Request
FRCC 2001 *Regional Load and Resource Plan*

Table 4, on the next page, breaks down the SERC Region's net planned capacity additions by fuel type for each of the four SERC subregions. Among the four SERC subregions, SERC/Southern is forecasted to add the most capacity (over 17,500 MW) by 2010.

TABLE 4. SERC SUBREGIONS
PLANNED ADDITIONS / (REDUCTIONS) TO SUMMER CAPACITY BY FUEL TYPE

UNIT TYPE	SERC/Entergy		SERC/Southern		SERC/TVA		SERC/VACAR		SERC Region TOTAL	
	MW	% OF TOTAL	MW	% OF TOTAL	MW	% OF TOTAL	MW	% OF TOTAL	MW	% OF TOTAL
Nuclear	195	7.3%	0	0.0%	0	0.0%	(433)	-3.0%	(238)	-0.6%
Hydroelectric	0	0.0%	0	0.0%	196	3.8%	320	2.2%	516	1.3%
Pumped Storage	0	0.0%	0	0.0%	138	2.7%	48	0.3%	186	0.5%
Coal	6	0.2%	(1,021)	-5.8%	164	3.2%	(540)	-3.8%	(1,391)	-3.5%
Fossil Steam	0	0.0%	(265)	-1.5%	0	0.0%	0	0.0%	(265)	-0.7%
Combustion Turbine	1,117	41.6%	5,966	34.1%	616	11.9%	4,410	31.0%	12,109	30.6%
Combined Cycle	105	3.9%	11,346	64.8%	0	0.0%	6,478	45.5%	17,929	45.3%
Other	0	0.0%	325	1.9%	6,050	117.1%	2,404	16.9%	8,779	22.2%
Net Firm Capacity Interchange	1,264	47.0%	1,162	6.6%	(1,997)	-38.6%	1,562	11.0%	1,991	5.0%
TOTAL	**2,687**	**100.0%**	**17,513**	**100.0%**	**5,167**	**100.0%**	**14,249**	**100.0%**	**39,616**	**100.0%**

SOURCE: SERC Response to 1/31/2002 FPSC Data Request

DEMAND AND NON-FIRM LOAD

For 2001, the Southeast Region has a combined summer net firm peak demand of approximately 187,000 MW. This net value has been reduced by over 11,000 MW of non-firm load in the form of load management and interruptible service. The bulk of non-firm load reductions (over 8,400 MW) are from the SERC region. By 2010, firm summer peak demand is expected to increase by over 42,000 MW in the region. The SERC region is expected to contribute to approximately 33,000 MW of this increase. By 2010, the level of non-firm load in the Southeast Region is expected to drop by over 600 MW from 2001 levels.

Table 5 shows the impact of non-firm load on the combined summer peak demand forecast for the Southeast Region.

TABLE 5. SOUTHEAST REGION
IMPACT OF NON-FIRM LOAD ON SUMMER PEAK DEMAND
CURRENT AND FUTURE

	SERC Region		FRCC Region		SOUTHEAST Region (SERC + FRCC)	
	MW	% OF TOTAL	MW	% OF TOTAL	MW	% OF TOTAL
Firm Peak Demand - 2001	151,527	94.7%	35,666	92.7%	187,193	94.3%
Non-Firm Load - 2001	8,403	5.3%	2,812	7.3%	11,215	5.7%
TOTAL PEAK DEMAND - 2001	**159,930**	**100.0%**	**38,478**	**100.0%**	**198,408**	**100.0%**
Firm Peak Demand - 2010	184,440	95.9%	44,988	94.3%	229,428	95.6%
Non-Firm Load - 2010	7,868	4.1%	2,727	5.7%	10,595	4.4%
TOTAL PEAK DEMAND - 2010	**192,308**	**100.0%**	**47,715**	**100.0%**	**240,023**	**100.0%**

SOURCES: SERC Response to 1/31/2002 FPSC Data Request
FRCC 2001 *Regional Load and Resource Plan*

Table 6, on the next page, breaks down the impact of non-firm load on summer peak demand for each of the four SERC subregions. Among the four SERC subregions, SERC/Southern is forecasted to have the largest growth in firm summer peak demand (nearly 12,500 MW) by 2010, while SERC/TVA is the only SERC subregion forecasting an increase (estimated 136 MW) in the amount of non-firm load.

TABLE 6. SERC SUBREGIONS
IMPACT OF NON-FIRM LOAD ON SUMMER PEAK DEMAND
CURRENT AND FUTURE

	SERC/Entergy		SERC/Southern		SERC/TVA		SERC/VACAR		SERC Region TOTAL	
	MW	% OF TOTAL	MW	% OF TOTAL					MW	% OF TOTAL
Firm Peak Demand - 2001	25,733	95.0%	42,616	95.3%	27,578	92.1%	55,600	95.6%	151,527	94.7%
Non-Firm Load - 2001	1,351	5.0%	2,121	4.7%	2,356	7.9%	2,575	4.4%	8,403	5.3%
TOTAL PEAK DEMAND - 2001	**27,084**	**100.0%**	**44,737**	**100.0%**	**29,934**	**100.0%**	**58,175**	**100.0%**	**159,930**	**100.0%**
Firm Peak Demand - 2010	29,971	97.2%	55,263	96.4%	32,361	92.9%	66,845	96.5%	184,440	95.9%
Non-Firm Load - 2010	872	2.8%	2,086	3.6%	2,492	7.2%	2,418	3.5%	7,868	4.1%
TOTAL PEAK DEMAND - 2010	**30,843**	**100.0%**	**57,349**	**100.0%**	**34,853**	**100.0%**	**69,263**	**100.0%**	**192,308**	**100.0%**

SOURCE: SERC Response to 1/31/2002 FPSC Data Request

RESERVE MARGIN

Based on the data previously discussed, Figures 1 and 2, on the next two pages, illustrate forecasted reserve margins for the FRCC region, the SERC region, and the four SERC subregions. The utilities comprising the SERC subregions are summer-peaking, due to the availability of natural gas for winter heating uses. As a whole, the FRCC region is a winter-peaking region due to a comparatively lesser availability of natural gas for winter heating uses. Because of this diversity, transactions between the regions tend to be seasonal.

The FRCC Region plans to exceed its region-wide minimum reserve margin criterion of 15%, during summer and winter seasons, each year through 2010. Approximately 8,000 MW of announced merchant plant capacity (as of August, 2001) is not included in Figures 1 and 2 because this capacity has not been committed to serve retail load in the FRCC Region.

For the SERC Region, forecasted reserves are expected to consistently be near 15% summer (30% winter) through 2010. Specifically, the SERC / Entergy subregion forecasts summer reserves of less than 10% throughout the planning horizon. However, easy access to ample natural gas supplies in the SERC / Entergy subregion has made it very attractive to new merchant power plant activity. According to the North American Electric Reliability Council's *2001 Summer Assessment*, merchant projects exceeding the current demand of the SERC/Entergy subregion have been announced for construction over the next ten years. Projections as of May, 2002, indicate reserve margins in the 15% to 20% range for the SERC/Entergy subregion. This generation is not included in Figures 1 and 2 because it is based on data as of January, 2001.

Figure 1. FORECASTED SUMMER RESERVE MARGIN

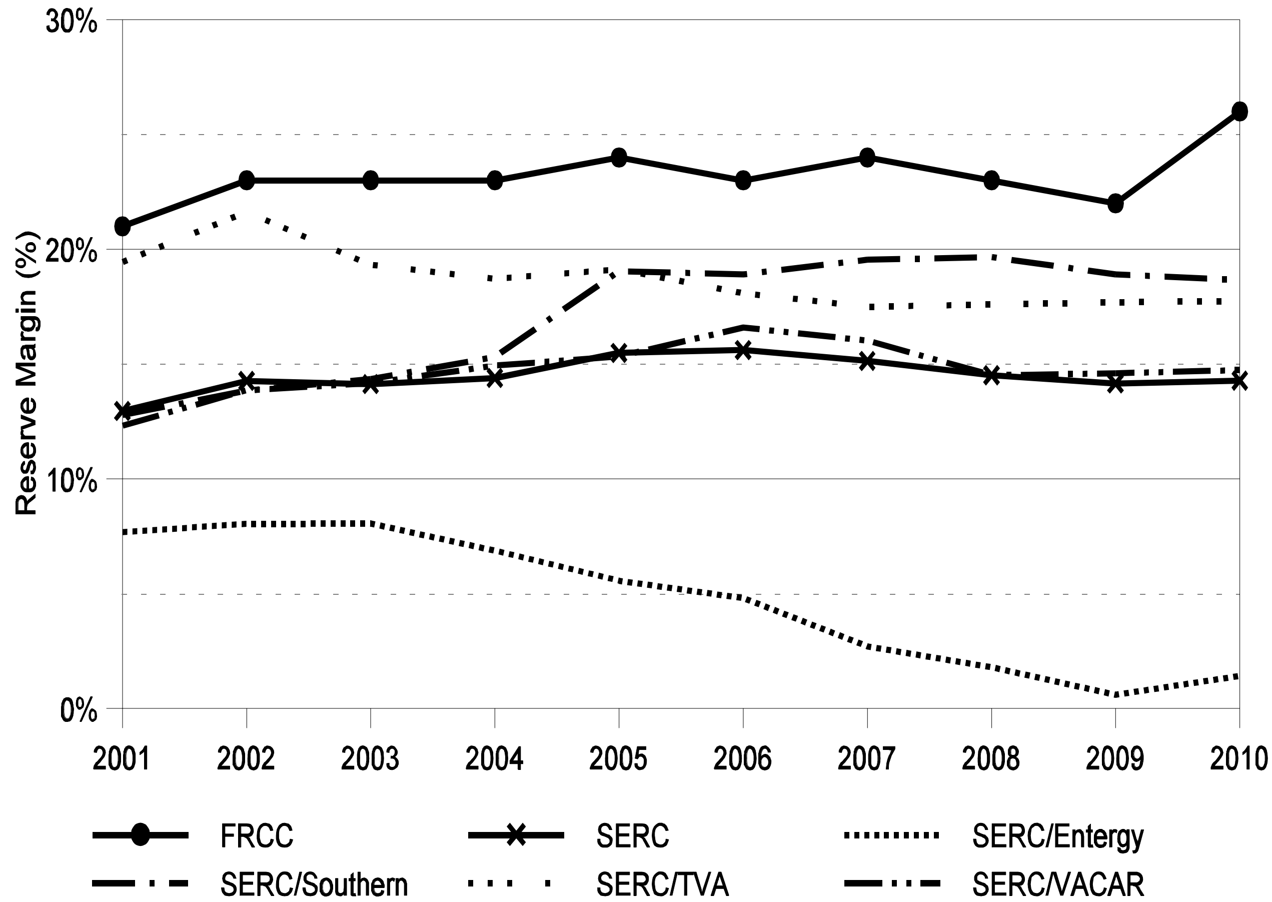
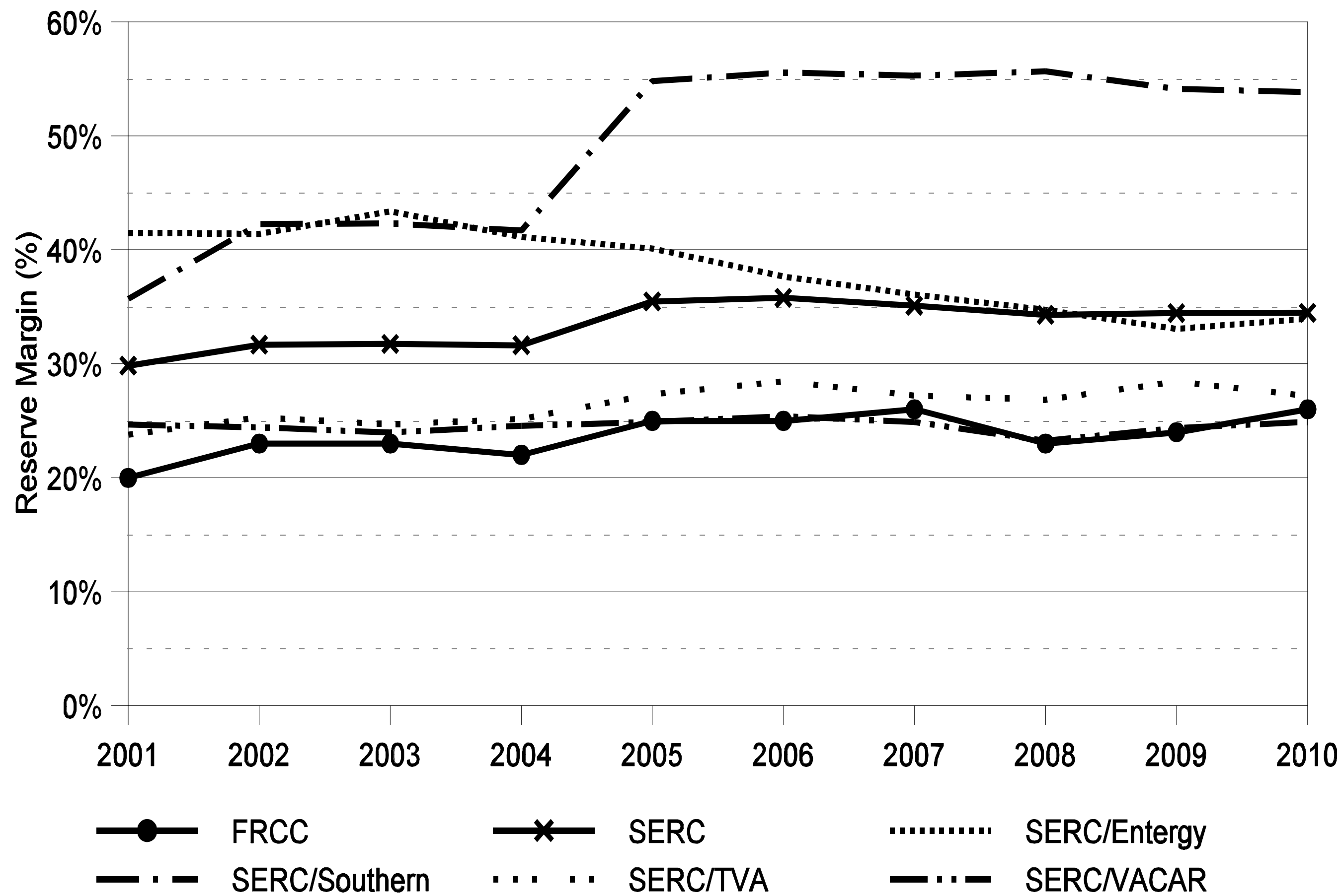


Figure 2. FORECASTED WINTER RESERVE MARGIN



III. Assessment of Transmission Infrastructure[1]

The reliability of the interconnected transmission systems are highly dependent upon the location of new generating resources. Generating facilities must be located and dispatched in a manner to minimize the use of constrained transmission corridors. The close coordination of generation and transmission planning of the past that resulted in the highly reliable electric systems of North America must now be accomplished through different means and coordinated among many different market participants. Market signals and regulatory decisions will dictate the location and timing of generating capacity additions, and also will influence the planning of transmission additions.

Portions of the transmission systems are reaching their limits as customer demand increases and the systems are subjected to new loading patterns resulting from increased power transfers. Although some transmission constraints are recurring and well known, others are not. Many electricity transfers are influenced by weather diversity across the continent that frees up resources in one area to serve demand in another. Because weather patterns are unpredictable in the long term, transmission constraints and congestion have the potential to shift from season to season and year to year. In cases where generation redispatch options have been exhausted or are ineffective, among the options to remove the constraints are increasing the capability of the transmission system or building new generation close to the demand centers, removing the need for the power transfer.

[1]Reliability Assessment 2001-2010, NERC, October 16, 2001

The transmission resources in the Southeast region are substantial as shown in Table 7. 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 5,318 miles of 230 kV transmission lines, and 1,351 miles of 500 kV transmission lines. The utilities in the SERC and FRCC regions plan to add approximately seven percent or 2,715 miles of transmission lines by 2009.

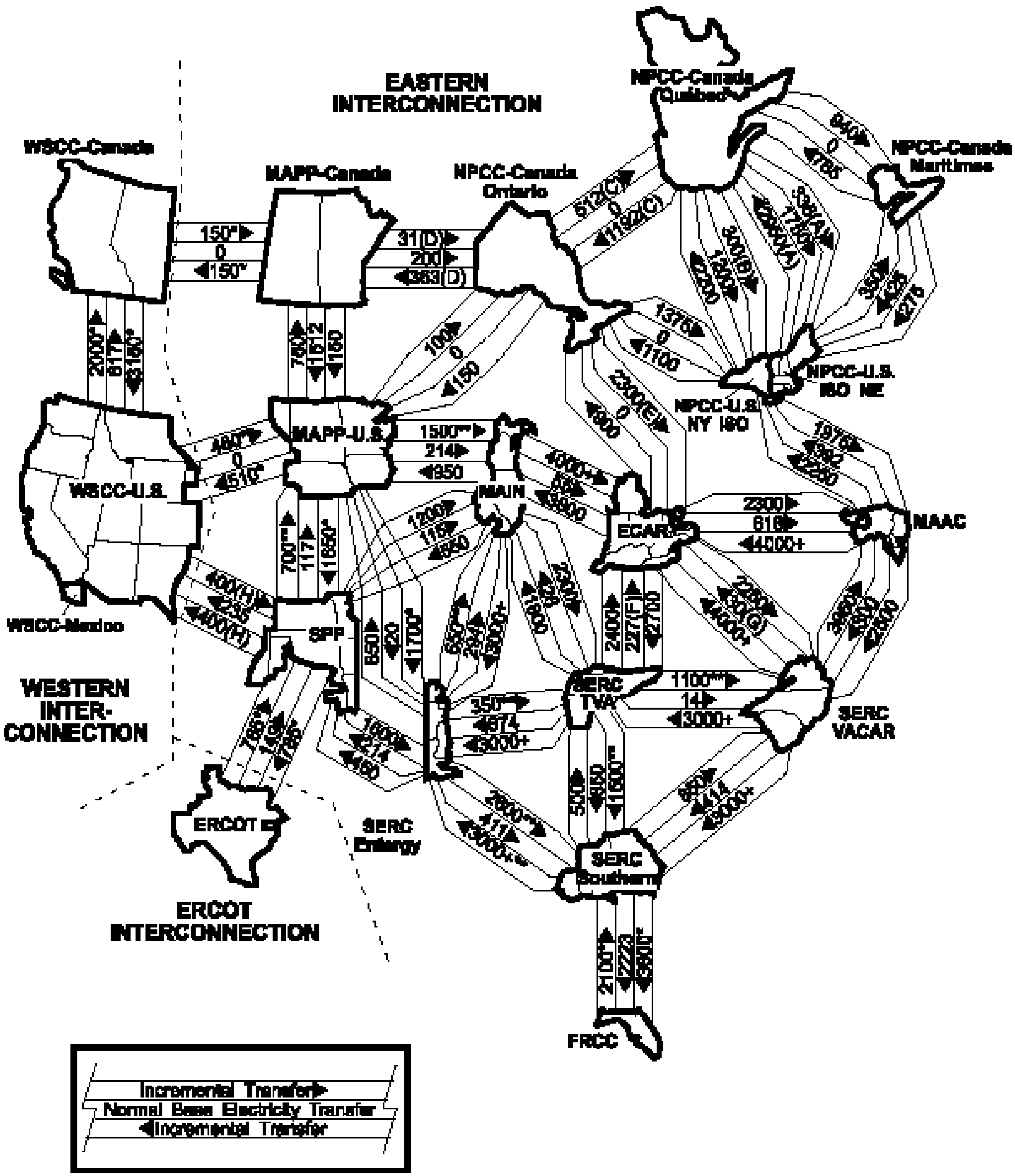
Table 7: EXISTING AND PLANNED TRANSMISSION CAPACITY (Miles)

Subregion	Existing				Planned (2000- 2009)			
	230 kV	**345 kV**	**500 kV**	**Total**	**230 kV**	**345 kV**	**500 kV**	**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	5,318	-	1,351	6,669	582	-	36	618
Total Southeast	25,876	753	10,581	37,210	2,411	-	304	2,715

Source: NERC ES&D 2000 database, Form EIA-411.

Figure 3, taken from the North American Electric Reliability Council's *2001 Summer Assessment*, shows the non-simultaneous transfer capabilities representing the ability of the transmission network to transfer electricity from one area to another for a single native load and generation pattern. Different patterns of demand and generation cause variations in transfer capabilities on a day-to-day (or hour-to-hour) basis. Therefore, the numbers given in this diagram should be considered as representative, rather than definitive. This figure shows that no inter-regional constraints exist, however constraints may exist within subregions.

Figure 3
Normal Base Electricity Transfers and First Contingency Incremental Transfer Capabilities (Nonsimultaneous), MW



The transmission system is being subjected to flows in magnitudes and directions that were not contemplated when it was designed or for which there is minimal operating experience. New flow patterns result in an increasing number of facilities being identified as limits to transfers, and transmission loading relief (TLR) procedures have been required in areas not previously subject to overloads to maintain the transmission facilities within operating limits. TLR procedures are to be called by security coordinators as a last resort to curtail transactions that cause transmission facility overloads or violations of operational security limits. Several steps or classifications of NERC TLR exist, ranging from Level 0 to 6. Curtailments of transactions do not occur until Level 3 (non-firm) and Level 5 (firm).

Table 8 shows the number and level of TLR events for 1998-2000 for the SERC and FRCC regions. Note that a breakdown of the TLR levels for events in the FRCC region are not available. An original purpose of TLRs was to address extreme constrained situations. The data shows an increase in TLRs declared in the SERC region over the 1998-2000 period. This raises the issue of whether curtailment of transmission transactions has become an impediment to the competitive operation of the market. The increase in incidence of TLRs may suggest that some non-firm transmission capacity is being oversold. Remedies include augmenting transmission capabilities.

Table 8: Number of Transmission Loading Relief (TLR) Events

	1998	1999	2000
SERC			
Level 1	4	43	25
Level 2	0	1	0
Level 2A	1	39	0
Level 2B	1	4	41
Level 2C	0	3	30
Level 3	1	4	30
Level 3A	0	0	4
Level 4	0	2	11
Level 5	0	0	1
FRCC	18	2	0

Source: SERC, FRCC responses to 1/31/2002 FPSC data requests.

Transmission Assessment FRCC

An FRCC transmission study for 2001–2010 showed that operational procedures such as generation redispatch, sectionalizing, planned load shedding, reactive device control and transformer tap adjustments successfully mitigate all the reportable demand and voltage violations appearing in the first five years. In the long term, violations of reliability criteria can be resolved by planned transmission projects where there is adequate time to monitor trends and construct required network upgrades. None of the problems are considered significant to the reliability of the system. Interregional transmission studies are performed to evaluate the transfer capability between the Southern subregion of SERC and FRCC. Joint studies of the Florida/Southern transmission interface demonstrate there is adequate capability for additional FRCC power imports over and above the 1,845 MW currently being imported on a firm basis. As regional transmission organizations are formed, FRCC will update processes and procedures to ensure complete transmission system assessments are performed.

Transmission Assessment SERC

SERC is directly interconnected with the transmission systems in ECAR, FRCC, MAAC, MAIN, and SPP. Transmission expansion plans in SERC are coordinated by joint modeling and study efforts among member systems and with these interconnected Regions. Results of Regional and interregional studies demonstrate that the SERC transmission systems meet NERC and SERC reliability criteria and should have adequate capability to supply forecast demand and energy requirements under normal and contingency conditions. Interregional transfer studies indicate that the ability to transfer power between SERC and other regions, above contractually committed uses, has become marginal on some interfaces. This could be a reliability concern because it impacts the geographic diversity of external resources that can be called upon during emergency import scenarios that may result from large unit outages.

Heavy north-to-south electricity transfers into the SERC Region in 1999 and 2000 have caused significant voltage depression and concerns that voltage stability limits may be exceeded. Recent studies have determined the maximum simultaneous power transfers that can be supported while ensuring system reliability. Results of these studies will be used by system operators and security coordinators to monitor system conditions and to ensure that maximum transfer limits are not exceeded. In addition, SERC and NERC are working together to update transfer limits as conditions change. In 2001, the flows were reversed with transfers flowing south to north.

Entergy Subregion

The Entergy subregion of SERC is served by several natural gas pipelines and transmission facilities making it a fertile ground for the location of merchant generation. A significant amount of the proposed merchant generation is being constructed, thereby increasing the prospect of higher transmission flows. The Entergy transmission system is continuously improved to meet system demands. The influx of generation could be of great benefit in increasing system capacity margin, although there is no way to know what the destination markets will be for incremental capacity. The merchant generation, which is greatly in excess of native load needs, increases transmission flows in areas where it has not previously been contemplated. In some examples, existing transmission constraints are actually worsened. In addition, to the extent that a significant percentage of this new generation is destined to be exported to off-system markets, significant transmission upgrades will be needed.

Southern Subregion

A large number of new generators have applied for interconnection in the Southern Subregion. In some areas, depending on the number of new interconnecting facilities, interconnection studies have shown major stability problems that result in large portions of the system pulling out of synchronism. The solution to these stability problems could include the addition of major transmission system improvements.

TVA Subregion

Transmission assessment studies indicate that a heavy dependence on “market purchases” from resources physically located outside the subregion will bear a degree of risk based on transmission constraints. Recent operating experience and planning studies have increased awareness of the impacts on the TVA bulk transmission system that result from large-scale imports into SERC. On the other hand, the impact of increasing merchant plant capacity interconnecting in SERC, tilting the supply/demand balance, will provide significant challenges to modeling and analysis of transmission system performance.

VACAR Subregion

The VACAR Subregion is directly connected with transmission systems in ECAR and MAAC, as well as with the TVA and Southern Subregions of SERC. Transmission assessment studies and recent operating experience indicate that the limitations on these interfaces tend to occur on facilities outside of VACAR. The development of new merchant generation within VACAR, as well as the uncertainties associated with future interregional transfer requirements, will make it more difficult to conduct transmission reliability assessments in the future.

IV. Roles of State Commissions and Agencies with Regard to Planning and Siting of Generation and Transmission

The siting and planning responsibilities for State Commissions vary widely. For example, Florida law requires a Determination of Need for plants with a steam cycle capacity greater than 75 MW but North Carolina requires a certificate of public convenience and necessity for plants greater than 300 MW. The Louisiana PSC has no formal integrated resource planning (IRP) process or filing requirements while the Georgia PSC can approve, deny, or modify a utility's IRP. A summary of each state's planning and siting responsibilities is provided below.

Alabama

The Alabama Public Service Commission (APSC) has legislative jurisdiction over the construction of plant, property, and/or facilities for the production, transmission and/or delivery of gas, electricity, water, or steam by a public utility, except for the normal and ordinary extensions of existing systems. The public utility is required to make a written application to the Commission for a Certificate of Public Convenience and Necessity and, after a public hearing, the Commission may or may not, at its discretion, issue the Certificate to the public utility.

The APSC does not have formal requirements or authority regarding the siting or planning of generation and transmission facilities. In addition, the APSC does not have any formal Integrated Resource Plan filing requirements for electric and gas utilities. However, the IRP process has been recognized and accepted by the Commission as a prudent means of identifying necessary and appropriate additions of electric generating capacity. On an informal basis, this information is presented to the Commission staff for informational purposes only. The Commission has also adopted Request for Proposal (RFP) Guidelines to be followed by the public utility seeking to build new electric generating capacity.

Arkansas

The Arkansas Public Service Commission requires public utilities to obtain a Certificate of Public Convenience and Necessity for the construction or operation of any new equipment or facilities for supplying a public service. Public utilities are also required to obtain a Certificate of Environmental Compatibility and Public Need for the construction of a major utility facility. Exempt wholesale generators are not considered public utilities and are not required to obtain such certificates from the Commission, but still must obtain air and water permits from the Department of Environmental Quality.

Florida

Florida has both power plant and transmission line siting legislation. For power plants with a steam capability of greater than 75 MW, an applicant must obtain a Determination of Need from the Florida Public Service Commission (FPSC). The same is true for transmission lines that are 230 kV or greater, cross a county line, and are greater than 15 miles in length. Both the transmission and power plant siting laws require approval from the Florida Department of Environmental Protection and ultimately, the Governor and Cabinet issue the final certification. In this manner, the laws of Florida seek courses of action that will fully balance the increasing demands for electrical power plant/transmission line location and operation with the broad interests of the public.

Florida also has existing legislation that requires certain utilities to file Ten-Year Site Plans that include both generation and transmission planned additions. While not a formal integrated resource plan, the FPSC reviews this information annually and reports to the DEP for use in future siting proceedings. In addition, local water management districts comment on the proposed plans.

Georgia

The Georgia Public Service Commission (GPSC) has authority under the Integrated Resource Planning (IRP) Act to approve an Integrated Resource Plan for the IOUs in the state (Georgia Power and Savannah Electric & Power Companies) and to certify certain capacity additions used to serve retail load. The GPSC does not have jurisdiction over siting of transmission facilities -- just approval amount of costs associated with the portion of transmission facilities that are allocated to serve retail load which are recovered through base rates.

The GPSC has no specific requirements for siting and construction of transmission lines. Utilities are encouraged to work with the Georgia Department of Transportation to ensure that lines conform to road and highway specifications. Other state agencies such as the Georgia Department of Natural Resources may also have certain jurisdiction if construction involves a river or wetland crossing.

Kentucky

All electric transmission lines greater or less than 400 kV require a Certificate of Public Convenience and Necessity from the Kentucky Public Service Commission. Utilities that operate under the jurisdiction of the Commission must obtain Commission approval before they begin to construct any generating facilities or major transmission facilities, particularly those needed to tie generation into the existing transmission grid. The approval process consists of two separate and distinct analyses arising under different statutory provisions.

One analysis, arising under KRS 278.020(1), requires the Commission to grant a certificate of public convenience and necessity before the proposed facilities are constructed. This analysis examines the extent to which a utility's existing facilities are or will soon be inadequate to provide reasonable service to current or future customers. If an inadequacy exists, the proposed facilities are then examined to ensure that they will not result in any wasteful duplication. In addition, if the proposed facilities include a new transmission line that will operate at 400 kilovolts ("kV") or higher, KRS 278.027 requires consideration of the route of that line. Specifically, the Commission cannot grant a certificate of public convenience and necessity for a 400 kV or higher transmission line unless it finds that the proposed route "will reasonably minimize adverse impact on the scenic and environmental assets of the general area concerned, consistent with engineering and other technical and economic factors."

The other analysis, arising under KRS 278.025, requires the Commission to determine whether the utility should be granted a certificate of environmental compatibility to construct facilities to be used for the generation of electricity. This analysis examines the environmental impacts of the proposed facilities and requires any adverse impacts to be balanced against the community needs, industrial development, customer requirements, and the economics of the facilities.

Louisiana

The State of Louisiana does not have any legislative requirements concerning the certification of electric generation and transmission facilities or integrated resource planning. Approvals for the construction of such facilities are subject to local zoning and the normal state and federal environmental permits. For example, the Louisiana Department of Environmental Quality issues air permits for new generation facilities based on federal standards.

In September 1983, the Louisiana Public Service Commission (LPSC) adopted a General Order requiring the certification of new capacity resources. A Louisiana utility must obtain a certificate of public convenience and necessity (CPCN) from the Commission prior to commencing construction or entering in to a purchase power contract. (This does not apply to economy energy or emergency power purchases.) Under the General Order, the Commission shall rule on a CPCN application within 120 days, and the utility must provide justification for the proposed resource acquisition along with the supporting cost data.

The Commission recently completed rulemaking docket which may supplements and modifies the 1983 General Order (Docket No. R-26172). The approved Rule requires the use of a market-based mechanism (such as a formal RFP process) whenever a Louisiana electric utility seeks to construct or acquire new generation resources, above certain size thresholds. This Rule requires the RFP solicitation process and project review to be conducted subject to Staff oversight and consultation.

The LPSC does not have formal integrated resource planning process or detailed filing requirements. Bulk power supply planning issues are reviewed at various times in rate cases, certification cases (pursuant to the 1983 General Order), fuel clause reviews and other special proceedings.

At the present time, the LPSC does not have formal requirements regarding transmission planning or certification. However, the Commission recently initiated a transmission certification rulemaking proceeding, and depending on the outcome of that proceeding may adopt a certification requirement for new transmission investments (Docket No. R-26018). Energy Louisiana, Inc., in cooperation with Staff, recently completed a major cost/benefit study of transmission expansion investments. (Docket No. U-23356, Subdocket A)

Mississippi

The Mississippi Public Service Commission issues a Certificate of Public Convenience and Necessity authorizing the construction of electric facilities, which Mississippi courts had previously determined as a prerequisite to the utility's right of eminent domain. Other state or federal agencies may require separate permits for transmission lines. For example, if a natural feature such as a river is crossed, the utility must contact the appropriate state or federal agency.

Under Mississippi law, the PSC has siting authority for any generation unit or transmission addition regardless of ownership. The siting must be in the public interest. Permitting requirements of other federal, state and local entities must be met as well. Once the certificate of public convenience and necessity is granted the PSC has no other authority for wholesale units. Obviously, there is full authority for retail units and the planning thereof. Merchant plant certificates have been granted expeditiously. Several months more or less has been required to complete the filing and hearing process. The PSC also has the authority to approve or deny the transfer of assets as might be required in the establishment of Transcos or RTOs or in the case of mergers or sales.

North Carolina

Under North Carolina law, any public utility or other person proposing to construct an electric generating facility must first obtain from the North Carolina Utilities Commission a certificate that the public convenience and necessity requires, or will require, such construction. Notice of an application is provided to the public, and a hearing is commenced within three months of the date of the application. A decision must be issued within 90 days after the conclusion of the hearing. By Commission rule, certain information must be filed 120 or more days before the filing of an application for facilities with a capacity of at least 300 megawatts and which are proposed to be constructed by a public utility.

This certification requirement does not apply to persons who construct an electric generating facility primarily for their own use; however, any such proposed construction must nevertheless be reported to the Commission. In addition, any person proposing to construct an electric generating facility must apply to the North Carolina Department of Environment and Natural Resources (DENR) for the appropriate air and water permits and must comply with local zoning ordinances.

In addition, no one may begin construction of a new electric transmission line in North Carolina without first obtaining from the Utilities Commission a certificate of environmental capatibility and public convenience and necessity. A transmission line is defined as an electric line designed with a capacity of at least 161 kilovolts. Notice of an application is provided to the public, and a hearing is scheduled (subject to cancellation if no significant protest are received) within four months of the date of the application. A decision must generally be issued within 60 days after the conclusion of the hearing.

Copies of an application to construct either an electric generating facility or a transmission line are distributed through the North Carolina State Clearinghouse to the permitting divisions of DENR as well as other state agencies (such as the Historic Preservation Office, the Department of Agriculture, and the Department of Transportation) and the relevant county clearinghouse. The information returned to the Utilities Commission through the Clearinghouse includes comments from these non-permitting agencies and further information from the permitting agencies on whether all permits have been identified by the applicant.

The Utilities Commission reviews the public utilities' plans for construction of generation and transmission annually through the integrated resource planning (IRP) process. Investor-owned utilities and the state-wide electric cooperative are required to file annual reports on September 1 of each year including forecasts of load and generation resources to meet the load, transmission planning, and certain other information. Comments on the utilities' IRP plans are received from interested parties and a hearing is held to receive testimony from public witnesses.

South Carolina

The Public Service Commission of South Carolina is responsible for issuing a Certificate of Environmental Compatibility and Public Convenience and Necessity for electric transmission lines greater or less than 125 kV. An application to the South Carolina Public Service Commission should include a description of the facility and its location; summary of any environmental impact studies; a statement explaining the need for the facility; and such other information that the applicant considers relevant or that the Commission may require.

Within 60 to 90 days of receipt of the application by the Commission, a public hearing must commence. Before granting a Certificate, the Commission must determine the basis of the need for the facility and determine the nature of the probable environmental impact. The Commission must also determine whether the environmental impact is warranted, considering current technology and alternatives; whether the facility will serve the interests of system economy and reliability; and whether convenience and necessity require the construction of the facility. The applicant must also provide reasonable assurance that the facility will conform to applicable state and local laws and regulations.

Tennessee

The Tennessee Valley Authority (TVA) serves as the clearinghouse for electric transmission line siting. Siting follows guidelines based on the National Environmental Protection Act and any other pertinent national environ-mental laws. TVA solicits appropriate input from state agencies when considering a new line.

Virginia

The Virginia State Corporation Commission issues Certificates of Public Convenience and Necessity for lines greater or less than 150 kV, or for lines which are greater or less than 150 kV and which extend beyond a utility's service territory. In this latter case, the Commission requires a hearing only if an inter-utility or public dispute over the facility occurs.

In exercising its authority the Commission may permit the construction and operation of electrical generating facilities, which shall not be included in the rate base of any regulated utility, upon a finding that such generating facility and associated facilities including transmission lines and equipment (i) will have no material adverse effect upon the rates paid by customers of any regulated public utility in the Commonwealth; (ii) will have no material adverse effect upon reliability of electric service provided by any such regulated public utility; and (iii) are not otherwise contrary to the public interest. In review of its petition for a certificate to construct and operate a generating facility described in this subsection, the Commission shall give consideration to the effect of the facility and associated facilities, including transmission lines and equipment, on the environment and establish such conditions as may be desirable or necessary to minimize adverse environmental impact.

V. Southeast RTO/Wholesale Market Development

RTO Development

A key question for Southeastern states is how the wholesale market can be encouraged and strengthened within and across state borders without causing a detrimental effect on retail customers. There are fears that prices for retail electricity customers could rise, in part due to the huge investment in transmission infrastructure that would be necessary to implement the market changes that FERC envisions. Though SEARUC membership states are in line with the rest of the nation in wanting a robust wholesale electricity market to develop, their pace has been more cautious.

The FERC continued its strong push for RTO development across the nation by ordering the parties in the Northeast, Midwest and Southeast to participate in separate mediation efforts last fall. These mediation efforts grew out of the RTO application filed by Entergy Services, Inc. in October 2000. The Entergy Operation Companies include: Entergy Arkansas, Inc., Entergy Gulf States, Inc., Entergy Louisiana, Inc., Entergy Mississippi, Inc., and Entergy New Orleans, Inc. Their application for approval of an RTO included a request for approval of the transfer of transmission assets to the RTO. The FERC rejected the proposed SPP/Entergy Partnership RTO on July 12, 2001.

FERC then ordered Entergy to participate in mediation to form a single RTO in the Southeast. FERC also required GridSouth (Duke, CP&L, et al) , SETrans (Southern et al), SPP (at least initially) to participate and encouraged GridFlorida and TVA to participate. The mediation discussions began in Washington D.C. on July 17, 2001 and involved more than 200 participants.

Two models emerged from the mediation process, the Collaborative Governance Model and the Independent System Administrator (ISA) Model. The Collaborative Model was developed by GridSouth, GridFlorida, and Entergy. It is a Transco model, with an Independent Market Administrator (IMA). The Administrative Law Judge (ALJ) attached both proposals to the report, with a strong recommendation in support of the Collaborative Model. The ALJ noted that the Collaborative Model was better developed and more clearly in compliance with Order 2000 and recommended the FERC consider adoption of the Collaborative Model to the fullest extent possible. The ALJ also urged the FERC to establish a collaborative process with state regulators.

With Entergy's recent inclusion as participating transmission owners in the SeTrans RTO, three RTOs within the SEARUC region remain potentially viable: GridSouth, SeTrans, and GridFlorida. Each of these transmission organizations and the respective states involved are discussed below.

GridSouth (Docket No. RT01-74-000) - On May 14, 2001, in Docket No. RT01-74-002, Carolina Power & Light Company (CP&L), Duke Energy Corporation (Duke) and South Carolina Electric & Gas Company (SCE&G) submitted a filing to comply with the FERC's March 14, 2001 order, which granted provisional RTO status to GridSouth Transco, LLC (GridSouth) and the FERC accepted it on July 12, 2001.

SETrans - (Entergy Services, Inc., et al. Docket No. RT01-75-000 and Southern Company Services, Inc. Docket No. RT01-77-000) The SeTrans RTO development process is being proposed by the following companies: Dalton Utilities, Entergy Services, Inc., Georgia Transmission Corporation, JEA, MEAG Power, South Carolina Public Service Authority, South Mississippi Electric Power Association, Southern Company and City of Tallahassee, Florida. Owners of transmission systems in Alabama, Florida, Georgia, Mississippi and South Carolina signed a memorandum of understanding to form a Regional Transmission Organization (RTO) for the Southeast. The SeTrans RTO was expanded in November 2001 to include the Entergy Companies as participating transmission owners.

Once it becomes operational, SeTrans would be one of the nation's largest RTOs, serving an area with more than 73,000 Megawatts of generation, and operating some 53,000 miles of transmission with an investment in assets in excess of $9 billion.

SeTrans established a Stakeholder Advisory Committee (SAC) in January 2002. The structure chosen by the participating transmission owners will involve the hiring of a proven independent operator for the transmission system. The agreements between the operator and transmission owners will provide incentives to the operator to maintain or enhance reliability, minimize the cost of the operation of the system and enhance the efficient use of the system. A detailed description of the proposed governance structure of SeTrans, the proposed role of stakeholders in the selection of the independent third party operator, and the ongoing role of the Stakeholder Advisory Committee, are all described in the FERC filing.

GridFlorida (RT01-67-000) - In response to FERC's Order 2000, Florida Power Corporation (FPC), Florida Power & Light Company (FPL), and Tampa Electric Company (TECO) (collectively, the GridFlorida Companies) developed a Peninsular Florida RTO proposal referred to as GridFlorida. After supplemental filings were made, the FERC issued an order provisionally approving the GridFlorida proposal on March 28, 2001.

GridFlorida will be an electric utility subject to the FPSC's jurisdiction through a number of existing statutory processes. This includes Section 366, Florida Statutes which provides the FPSC jurisdiction over the planning, development, and maintenance of a coordinated electric power grid throughout Florida. The FPSC annually reviews utility Ten-Year Site Plans which include projections of load and resources, including transmission facilities, needed to maintain and enhance reliability. Presumably, these same rules would apply to any RTO developed in Florida.

State by State Retail Competition and Wholesale Market Development (Note: Still requires additional information from States on FERC activities.)

Alabama

Alabama is not a deregulated state and there are no plans to deregulate at this time. On October 4, 2000, the Alabama Public Service Commission issued an Order (Docket No. 26427) which stated that the Commission cannot mandate or otherwise allow retail competition or electric industry restructuring without state enabling legislation. The Order further stated that restructuring of the electric industry in Alabama is not in the public interest at this time.

The Alabama Public Service Commission has filed requests to intervene in the following FERC RTO dockets:

Southern Company Services, Inc. (RTO1-77-000)

Arkansas

In April of 1999, the Electric Consumer Choice Act (Act 1556) became law. The Act would have introduced retail competition in the electric industry by January 1, 2002, but no later than June 30, 2003. However, the Act was amended to change the implementation date to no sooner than October 1, 2003, and no later than October 1, 2005. Other amendments to the Act clarified that the Commission may delay implementation of retail open access upon findings that most customers would not have a reasonable opportunity to realize net benefits, specifically including relative price benefits for residential and small business customers, and that demonstrably effective wholesale market structures are not in place. The amendments were largely in response to a recommendation by the Arkansas Public Service Commission (APSC). The APSC said in its recommendation that the wholesale electricity markets in the state had not developed as quickly as anticipated, and the systems needed to make retail competition work were not being created quickly enough to meet the initial deadline. In a December 2001 Report to the General Assembly, the Commission recommended further delay of repeal of the Act.

The APSC has intervene in the following FERC RTO dockets:

Alliance Companies (RT01-88-010), Southwest Power Pool (RT01-34), Entergy (RT01-75), Southeast (RT01-100), Midwest ISO (RT01-87), State-federal panels (RT02-2), Market design and Structure (RM01-12)

Florida

No legislation has been passed at the state level that opens the industry to full retail competition. In May of 2000, Governor Jeb Bush created the Florida Energy 2020 Study Commission to propose an energy plan and strategy for Florida. In December of 2001, the Study Commission issued its final report.

Upon petition by each of the individual GridFlorida Companies, this Commission conducted an expedited proceeding to review the prudence of the formation of an participation in GridFlorida. An evidentiary hearing on these petitions was conducted October 3-5, 2001. In an Order issued December 20, 2001, the FPSC found that, in light of FERC's Order No. 2000 and its subsequent statements strongly encouraging participation in RTOs, the GridFlorida Companies were prudent in proactively forming GridFlorida. However, the FPSC also found that certain aspects of GridFlorida were not in the best interest of Florida's retail ratepayers at this time, most particularly the transfer of ownership of transmission assets that would take place under GridFlorida. The FPSC ordered the GridFlorida companies to refile a proposal within 90 days that conforms with the Commission's findings and which uses an independent system operator (ISO) structure wherein each utility maintains ownership of its transmission facilities.

The FPSC has filed requests to intervene in the following FERC RTO dockets:

GridSouth, LLC., et al. (RT01-74-000), Entergy Services, Inc. et al. (RT01-75-000)

Georgia

No legislation has been passed at the state level that opens the industry to full retail competition. The GPSC will continue to examine the impact of competition in accordance with guiding principles set forth in its staff report on electric competition. If true benefits are demonstrated, the GPSC will recommend legislation to the General Assembly within the next few years.

The GPSC has not officially intervened in any FERC RTO dockets.

Kentucky

There is currently no electric restructuring in the State. Kentucky could potentially be split among at least three different RTOs - the Midwest ISO, the Alliance RTO, and possibly another public power RTO led by TVA. The Kentucky Public Service Commission (KPSC) is studying utilities depending entirely upon bulk wholesale electricity contracts compared to owning their own generation facilities. There is concern about the proliferation of merchant generation plants in the state and its potential strain on Kentucky's transmission system since the additional capacity is exported to other states. This may cause problems such as possible failures due to transmission system overloads, curtailment of native load, siting issues relating to transmission line construction, and cost increases for transmission.

The KPSC has not officially intervened in any FERC RTO dockets.

Louisiana

In November 2001, after conducting a lengthy investigation, the LPSC ruled that retail competition for electric service is not in the public interest at this time. However, the Commission directed Staff to conduct collaboratives on certain retail access implementations issues and to monitor developments relating to retail competition in other states.

On September 27, 2001, the Louisiana Public Service Commission (LPSC) issued an Order to Show Cause on Cleco Power LLP, Entergy Gulf States, Inc., Entergy Louisiana, Southwestern Electric Power Company, and Louisiana Generating LLC (collectively referred to as Transmission Owning Entities). After holding hearings, the LPSC found that the transfer of ownership or control of transmission assets to a for-profit transmission entity presumptively is not in the public interest; directed the Louisiana utilities not to join any RTO without performing certain analyses; and, directed the Staff to proceed to analyze congestion management methods and develop, as necessary, ratepayer protection mechanisms to deal with potential adverse consequences of the "financial rights" model for congestion management.

The LPSC has filed requests to intervene in the following FERC RTO dockets:

Cleco Utility Group, Inc. (RTO1-25-000), Southwest Power Pool, Inc. (RTO1-34-000),Central Power and Light Company, et al. (RTO1-43-000), Entergy Services, Inc. (RTO1-75-000), Southern Company Services, Inc. (RTO1-77-000), Regional Transmission Organization (Southeastern United States) (RTO1-100-000)

Mississippi

In May of 2000 the Mississippi Public Service Commission found that retail competition in the provision of electric generation may not be in the public interest at this time. The Order stated that the Commission and the Staff will continue to monitor retail and wholesale restructuring activities at both the state and federal level, and reserves the right to order additional formal hearings should new evidence demonstrate that retail competition would be in the public interest and all consumers would see a reduction in the total costs of their electric service.

The Mississippi Public Service Commission has filed requests to intervene in the following FERC RTO dockets:

SeTrans RTO (Docket Nos. RT01-100-000,RT01-77-000 and RT01-75-000), Regional Transmission Organizations (RT01-100-000), Southern Company Services, Inc., et al. (RT01-77-000), Entergy Services, Inc., et al. (RT01-75-000), Southwest Power Pool (RT01-34-000)

North Carolina

In April 1997, the North Carolina General Assembly established the Study Commission on the Future of Electric Service in North Carolina. The members of the Study Commission include legislators and representatives from the various electric suppliers, residential, industrial and commercial consumers, the environmental community, and a power marketer. On April 3, 2000, the Study Commission recommended that the General Assembly implement fully competitive retail electric service as of January 1, 2006, with retail choice available to up to 50% of each power supplier's load as of January 1, 2005. Although the Study Commission further stated that it intended to provide specific legislative language to the General Assembly to accomplish the recommendations and to address other issues, no such legislation has been proposed.

At its January 2001 meeting, the Study Commission requested additional reports from its consultant on (1) "issues relating to the wholesale market, what makes for a robust and competitive market with the ability to deliver the power that is bought and sold," and (2) "consumer issues, what needs protection in a new competitive environment and how should those people be protected." In addition, the Study Commission requested that the Utilities Commission reconsider and attempt to streamline its rules for certification of merchant plants in North Carolina. In response to this request, the Utilities Commission, after receiving comments from a number of parties representing many diverse interests, issued an Order in May 2001 adopting a new rule regarding certification of new merchant plants. At the Study Commission's February 2002 meeting, the co-chairs stated that the dates included in the April 2000 recommendations should be reconsidered.

The North Caroline Utilities Commission has filed requests to intervene in the following FERC RTO dockets:

Grid Transco, L.L.C. (RTO1-74-000), Regional Transmission Organizations (RTO1-100-000), Electricity Market Design and Structure (RMO1-12-000)

South Carolina

In February 1998, the South Carolina Public Service Commission submitted a report, *A Proposed Electric Restructuring Implementation Process,* to the state legislature. The fundamental question of whether electric restructuring is in the public interest has not been addressed by the Commission. The only issue which has been addressed is the proposed process which would be used to implement electric restructuring should legislation become law.

The South Carolina Public Service Commission has not officially intervened in any FERC RTO dockets.

Tennessee

The generation and transmission of electricity in Tennessee is almost exclusively provided by the TVA but the Tennessee Regulatory Authority does not regulate any of the electricity activities of the TVA. Therefore, the TRA is concerned about being able to keep TVA's low cost generation within Tennessee.

Tennessee has not officially intervened in any FERC RTO dockets.

Virginia

The Virginia Electric Utility Restructuring Act, adopted by the 1999 General Assembly, requires Virginia electric utilities to join or establish a regional transmission entity (RTE) by January 1, 2001. On July 19, 2000, the Virginia State Corporation Commission (VSCC) issued an Order giving Virginia's five electric companies until October 16, 2000 to submit applications to the State Corporation Commission (SCC) for transferring ownership or control of their transmission facilities to an independent operator. The phase-in of electric deregulation for retail customers began January 1, 2002.

The Virginia State Corporation Commission has filed requests to intervene in the following FERC RTO dockets:

Alliance Companies, et al and National Grid USA (EL02-65-000), Electricity Market Design and Structure (RMO1-12-000), PJM Interconnection, L.L.C. and Allegheny Power (RTO1-98-000), Midwest Independent Transmission System Operator, Inc. (ERO2-485-000), Northeast RTO (RTO1-99-000 through 001), PJM (RTO1-2-001), Southeast RTO (RTO1-67-000 through RTO1-002, RTO1-74-003 through RTO1-74-005, RTO1-75-000, RTO1-75-001, RT01-77-002, RTO1-100-000), Alliance Companies (RTO1-88-000 through 012, ER99-3144-000 through 014, EC99-80-000 through 014), Illinois Power Company et al. (ERO1-123-000, ER01-780-000, ERO1-966-000, EC96-80-000, ER99-3144-000), AEP (ERO1-2995-000), Virginia Electric and Power Company (ERO1-2993-000), Midwest Independent Transmission System Operator, Inc. (ERO1-3000-000, RTO1-101-000, ECO1-146-000, EROO-3295-000 through 002, ECO1-137-000, ELO1-116-000, RTO1-87-000 through 002, ERO1-3142-000 through 004, ERO2-108, ERO2-106-000), National Grid USA (EL01-80-000)