Georgia Public Service Commission Staff Report on Electric Industry Restructuring
Docket Number 7313-U January 23, 1996

1. EXECUTIVE SUMMARY

Nationally, the electric power supply industry is slowly undergoing a transition from the current regulated monopoly structure to a competitive market environment in large part as a reaction to extraordinarily high electric rates in some parts of the country. However, Georgia's electric customers enjoy retail rates at or below the national average, so there is not the same urgency to restructure as in some other states. Therefore, clear evidence of benefits to the citizens of the state should be shown prior to any electric industry restructuring in Georgia.

Georgia's electric industry has several characteristics that currently benefit its customers: economies of centralized dispatch are already being realized with the Southern Company Control Area; retail competition is in place for new loads of at least 900kW under the Georgia Territorial Act of 1973; and open access for wholesale power exists with the Integrated Transmission System. Even though there was no immediate need to restructure the electric industry in this state, the Commission initiated this docket to evaluate the advantages and disadvantages of expanding competition in Georgia's electric industry. Several factors prompted the Commission to study electric industry restructuring: the national momentum toward retail electric competition; the 1995 and 1997 state statutes opening Georgia's telecommunications and natural gas industries to competition; and, the theoretical benefits of choice, such as lower prices, enhanced services, increased economic efficiency and innovation.

To this end the Commission sponsored workshops, solicited written comments, developed this report and will continue to study whether Georgia would benefit from greater retail competition and, if so, how the industry should be restructured and when. The following action plan includes a number of dockets to continue the Commission's evaluation of electric industry restructuring. To date the discussion of restructuring has been essentially academic in nature because the impact of proposed scenarios has not been quantified. Through these proposed proceedings the Commission should identify and quantify, as accurately as possible, the impacts of changes to the electric industry in terms of costs, rates and reliability of service. Specific, comprehensive and factual information will be more useful to the decision-makers than general observations and opinions. In order to develop such data and information the proposed plan of action of the Georgia Public Service Commission is to:[1]

1. Adopt a set of guiding principles to form the foundation upon which any future legislative or Commission action can be based.[2]

2. Establish a vision docket to further consider any and all issues relating to restructuring and to expand the Commission's knowledge base on these issues. The most important question to be addressed is whether a more competitive environment will benefit Georgia and, if so, how and when. Consumer protection, taxes and other issues not addressed in a separate proceeding should be evaluated in this docket.

3. Evaluate the status of investor-owned utilities' regulatory assets and liabilities and asset recovery practices in Docket No. 8345-U. This investigatory docket is expected to conclude prior to the Georgia Power Company rate case to be filed in July 1998.

4. Address traditional cost of service issues, as well as the functional unbundling of various electric services, in Docket No. 8346-U. This cost of service docket is also expected to conclude prior to the 1998 Georgia Power Company rate case.

5. Establish an investigatory docket to evaluate planning, reliability and system structure. This study should begin in 1998 and address the advantages and disadvantages of an Independent System Operator and Power Exchange as well as reliability planning and system security.

6. Initiate a docket on positive and negative stranded costs in late 1998. Issues in this proceeding will include the determination of potentially strandable costs, the quantification of stranded costs, whether stranded costs can be or have been mitigated, and the recovery of these costs.

[1] See timeline in Appendix A , Flowchart of Proposed Dockets, on page 82 of this report.
[2] A recommended list of principles begins on page 72 of this report.

This report is based on written comments and workshop presentations from all sectors of the electric industry and is a first step in compiling relevant information to assist decision-makers who must address this complex topic. Chapter Three describes the purpose and history of Docket No. 7313-U. Chapters Four and Five describe the current structure of the industry and the primary issues relating to restructuring, respectively. The Staff's proposed guidelines are in Chapter Six and the recommended action plan is in Chapter Seven. Supporting documentation can be found in the Appendices in Chapter Eight. Information obtained in this docket and through the proposed proceedings will prepare the Commission to advise the Georgia General Assembly in the formulation of new laws and to implement effectively any legislation that may be adopted.

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3. INTRODUCTION

3. A. PURPOSE AND SCOPE OF THE PROCEEDINGS

Beginning in April 1997 the Georgia Public Service Commission held a series of four informal workshops to examine issues related to restructuring the electric industry in Georgia. The purpose of these workshops was to bring about a heightened awareness of the issues involved in restructuring the electric industry and to examine the advantages and disadvantages of making such a change. The workshops also served to begin examination of the appropriate regulatory and legislative steps necessary for restructuring to successfully unfold. Workshop participants were able to discuss their opinions and concerns and to hear the positions of other industry segments. Although many differences of opinion exist, all participants increased their understanding of both the issues and the rationale behind opposing views. The workshops and written comments enabled the Commission to identify topics and issues needing closer examination before the Georgia General Assembly addresses electric industry restructuring.

Topics for these workshops included current and proposed industry structure, market power, reliability, stranded costs, public policy, tax implications and other issues related to electric industry restructuring. The workshops were open to the public and input was requested from all interested parties through presentations, white papers, public comments and participation in focus groups.

This report is based extensively on the white papers submitted and positions of parties gathered during the workshops and focus groups. An attempt has been made to identify the major issues involved in restructuring the electric industry in Georgia, some of the potential solutions, and the pros and cons of each. Areas for further study or investigation have also been identified. A plan has been outlined for the Commission to address these issues and to prepare for restructuring should the federal or the state lawmakers choose to expand retail competition for electric generation. This report should not be considered as the final Commission position on electric restructuring and related issues but represents the Commission’s initial examination of the issues and potential solutions.

3. B. CASE HISTORY, DOCKET NO. 7313-U

In January 1997 the Georgia Public Service Commission decided to hold a series of informal workshops to address issues related to the possible restructuring of the electric industry in Georgia in Docket No. 7313-U. An open planning meeting was held to discuss the format and structure of the workshops and to compile a list of the most appropriate topics for discussion. There was also discussion of the need to form smaller focus groups to explore certain complex issues in greater detail. Participation in the focus groups was considered voluntary and open to anyone interested.

In February 1997 the Staff outlined the structure, format and topic for the first workshop. A notice was sent to a list of potential participants. Eleven questions were posed with a request that interested parties submit comments or white papers to the Commission. The suggested topics were “The Current Structure of the Electric Industry in Georgia” and “What Structure Should the Electric Industry Take in the Future?” Similarly, topics for subsequent workshops were mailed to participants several weeks prior to each workshop to allow sufficient time to address the questions.

During March 1997 the Staff mailed a notice to all parties on the topic for the second workshop, “Operational Issues including Reliability and Independent System Operator” along with fourteen additional questions. The second workshop was scheduled for May 9,1997.

On April 4, 1997 the Commission held the first electric restructuring workshop. Attendance for the workshop was astounding.[3] More than 200 people were present. Presenters at the workshop included representatives from each sector of the electric industry, including: investor-owned utilities, municipals, cooperatives, independent power producers and power marketers. Also present were consumer advocates, environmentalists, various governmental agencies, including members of the State Legislature, and representatives from the residential, commercial and industrial customer classes. Public policy and regulatory perspectives were also represented. Presenters focused their discussion on the current structure of the industry in Georgia and what modifications may be necessary to establish a more efficient framework for the future. At the first

[3] A complete list of attendees, focus group participants, and parties submitting white papers or comments is included in Appendix B, Workshop Attendees, on page 83 of this report. A list of presenters is found in Appendix C, Presenters at the Workshops, on page 91 of this report.

workshop, interested parties were encouraged to volunteer to participate in the focus groups. Five topics were selected for the focus groups to study: (1) Principles to Abide by in a Competitive Market; (2) Systems Operations and Reliability; (3) Statutory Changes; (4) Tax Implications in a Restructured Electric Industry; and, (5) Stranded Costs and Stranded Benefits. Focus groups began meeting within a few weeks.

In May 1997 notice was given for the third workshop. Nineteen questions were posed regarding “Regulatory Issues including Stranded Costs, Market Power, and Public Policy” to elicit comments or white papers from interested parties.

On May 9, 1997 the Commission Staff held the second workshop. Presentations were made by representatives from: the current market participants (investor-owned, municipals, cooperatives, independent power producers, and marketers); the public policy perspective (environmental and conservation); various classes of customers; and the regulatory arena. Each presenter discussed reliability and adequacy of the current system, the potential use of an independent system operator, and other related issues.

In June 1997 the Staff mailed the notice for the Commissions’ fourth and final workshop in this series. This letter contained five questions with respect to the future actions required to restructure the electric industry in Georgia. Comments on these questions were solicited from all interested parties. Topics for this workshop included “Focus Group Findings, Discussion of Conclusions, and Development of Plan for Future Action.”

On June 6, 1997 the third workshop was conducted. Presentations for this workshop were provided by the Regulatory Assistance Project.[4] Areas of discussion included stranded costs, market structure and market power, universal service, consumer protection, and stranded benefits. In keeping with the workshop structure all interested parties were invited to ask questions and make comments.

On July 18,1997 the fourth and final workshop was held. At this workshop representatives from each of the five focus groups were given an opportunity to discuss in detail the group’s findings and conclusions. The topics included: (1) Principles to Abide by in a Competitive Market; (2) Systems Operations and Reliability; (3) Statutory Changes; (4) Tax Implications in a Restructured Electric

[4] Regulatory Assistance Project is a non-profit organization which provides educational services to state regulatory agencies.

Industry; and, (5) Stranded Costs and Stranded Benefits. At the conclusion of the presentations, the Commission Staff presented a proposed plan for future action and a time line for further analysis of certain restructuring issues.

After the workshops were completed the Staff continued to compile data and information from the written comments, white papers, focus group reports, presentations and transcripts. This information was invaluable to the Staff in determining the issues and concerns that require more in-depth analysis and in preparing this report.

3. C. CONCLUSIONS AND RECOMMENDATIONS

The current transition of the electric power supply industry from a regulated monopoly structure to a competitive market environment was initiated by the enactment of the Public Utility Regulatory Policies Act of 1978 (PURPA), the Energy Policy Act of 1992 (EPAct) and the Federal Energy Regulatory Commission's (FERC) Order No. 888. To develop a fully competitive electric market in Georgia one or both of the following steps must be taken: (1) enactment of comprehensive federal legislation that establishes national standards for the transition to competition; and, (2) appropriate legislative and regulatory actions at the state level to ensure that the benefits of full and fair competition are realized by all electric power customers.

The regulatory system has worked well in Georgia. Georgia currently enjoys electric rates generally at or below the national average. Future prices of electricity can be expected to remain flat or drop even under continued retail rate regulation. Due to the relatively low cost of electricity in this state there is no urgent need to restructure the electric industry in Georgia as opposed to other areas of the country.

The Federal Regulatory Energy Commission (FERC) has promoted competition at the wholesale level while the Georgia General Assembly and this Commission have encouraged limited retail competition through the Georgia Territorial Act and bidding requirements for new generation. Long-term reliability and assurance of adding best-cost generation to the system have been advanced through the Integrated Resource Planning Act.

The existence of a fully Integrated Transmission System (ITS) in Georgia has allowed the co-owners of this system to compete for customer choice loads provided for under the Georgia Territorial Act exemptions. The ITS has made it economically feasible for limited competition to exist in Georgia for the past 20 years. The creation of the ITS has avoided duplication of transmission facilities that otherwise would have occurred among the Georgia utilities transmitting power to serve their respective customers.

The importance of the electric industry to Georgia's economy and quality of life cannot be overstated. The State of Georgia and this Commission must carefully evaluate any new paradigm before replacing the existing system, which is working well and has provided this state with universally available electric energy at reasonable prices. In any process to restructure the electric industry in Georgia, the General Assembly and this Commission must avoid creating a structure where a supplier is allowed to become an unregulated monopoly, where only some customers derive the benefits of competition, or where the short-term and long-term reliability of the electric supply system is compromised.

The Commission recognizes that the electric industry in Georgia and the nation is in a state of transition. Georgia should strive to have an electric industry that enables the state to attract new residents and businesses, provides low cost electricity to all customers, encourages increased levels of energy service options for retail customers, and maintains a reliable and adequate supply of electricity. Restructuring the electric industry to increase retail competition through customer choice may allow these goals to be achieved, but there are many related issues that must be resolved in order for restructuring in Georgia to be successful. These include, among others:

1. How should potential stranded costs be calculated and who should be responsible for paying these costs, if any exist?
2. How can market power be mitigated and is the formation of an Independent System Operator necessary?
3. How can continued system reliability, both on a short-term and long-term basis, be ensured in a competitive market?
4. What options exist to minimize any adverse tax implications due to restructuring?
5. Should the State continue certain public policies relating to universal service, energy conservation and other societal benefits currently funded through electric utility rates and, if so, how should the cost of these programs be allocated?

The following are conclusions and recommendations reached by the Commission Staff as a result of information received in this docket. These conclusions do not constitute a final decision on the part of the Commission or its Staff but are initial thoughts on how to address the relevant issues prior to any move toward restructuring the electric industry:

1. Any transition from the current electric structure to a more competitive one should adhere to certain basic principles. These principles should establish the foundation upon which any future legislative or Commission action is based. The Staff recommends the adoption of the list of principles beginning on page 72 as a guide for future Commission dockets concerning restructuring of the electric industry and in the formation of any state legislation.

2. The Georgia Territorial Act of 1973 has allowed competition for new loads of at least 900kW demand and territorial assignments for distribution lines. This Act, in some form, should be retained. The workshop consensus model for restructuring the electric industry is designed for transmission service to be priced by the FERC, distribution service to be priced by the Commission and generation service to be priced competitively. Changes to the Territorial Act that are required for restructuring will primarily impact generation services and not territorial assignments. A detailed discussion of the Territorial Act begins on page 24.

3. Generation, transmission and distribution assets must be planned and operated reliably in a restructured electric industry and the cost of maintaining historical levels of reliability should be equitably borne by all users of the electrical system. Georgia should proceed cautiously with any plan to restructure the electric industry to ensure conformance with industry-wide reliability criteria and standards. The issue of reliability is discussed on page 44.

5. Georgia's present system for taxing electric utilities may place inequitable burdens on some participants in a competitive electricity market and adversely impact the tax revenues of local governments. Tax reform should be an integral part of any restructuring proposal to ensure equitable tax treatment. Legislators and others involved in establishing the taxing policies must be made aware of the tax implications of restructuring and give careful consideration to the potential adverse impacts. A discussion of taxes is on page 61.

6. In a competitive market, all participants must share equitably in the costs of maintaining universal service. This could be accomplished through non-bypassable surcharges, exit fees or wheeling charges. There must be an entity with a continuing obligation to serve customers not participating in competitive markets or a mechanism to randomly assign customers to a competitive provider with all competitors shouldering this obligation to serve. Universal service and other public policy issues are discussed starting on page 65.

7. The establishment of an Independent System Operator and a Power Exchange may help alleviate market power concerns. Either these entities should be established, or comparable controls should be put in place, prior to expanding retail competition. Market structure and market power are discussed on pages 31 and 37, respectively.

8. A market structure must be established that ensures that competition among electric suppliers and buyers is fair, non-discriminatory and consistent. Similarly-situated competitors should be subject to the same legal and regulatory requirements to ensure equitable treatment for competitors and consumers. Market structure is discussed starting on page 31.

9. Stranded costs are generally defined as prudently-incurred costs that would have been recovered through rates set under traditional regulation but may not be recoverable through market-based rates. Georgia should consider the recovery of only legitimate, unmitigatable stranded costs. Recovery of stranded costs should be predicated upon prudence reviews and past regulatory actions. The exact formula for calculating potentially stranded costs, the method of recovery, the amount to be recovered and the length of the recovery period should be studied by this Commission in a separate docketed proceeding. Determination and recovery of stranded costs is covered starting on page 51.

4. CURRENT STRUCTURE OF THE ELECTRIC INDUSTRY

4. A. GEORGIA'S ELECTRIC INDUSTRY

Three types of electric utilities provide retail electric service in Georgia. These include investor-owned utilities, customer-owned utilities (cooperatives) and government-owned utilities (municipals). There are two investor-owned utilities, Georgia Power Company (GPC) and Savannah Electric and Power Company (Savannah Electric). Both of these are operating subsidiaries of Southern Company. Southern Company Services, another Southern Company subsidiary, operates the Power Control Center in Birmingham, Alabama, which coordinates the integrated operations of the Southern electric system, including generation and transmission facilities in Georgia. There are 42 Electric Membership Cooperatives, 39 of which distribute power received from Oglethorpe Power Corporation (OPC) while the remaining three distribute power received from the Tennessee Valley Authority (TVA). There are 47 cities and one county (Crisp County) that are members of the Municipal Electric Authority of Georgia (MEAG). There are other municipals, not members of MEAG, that also provide service to customers at the retail level. These include the City of Dalton, the City of Hampton, the City of Acworth and the City of Chickamauga.[5] Georgia has an Integrated Transmission System, jointly-owned by Georgia Power Company, Oglethorpe Power Corporation, MEAG, and the City of Dalton. Each of these organizations is discussed below.

Georgia Power Company

Georgia Power Company (GPC), the largest electric utility in Georgia, is an operating subsidiary of Southern Company. GPC has a total of 14,367 megawatts of generating capacity. Its generation mix is comprised of approximately 74.3% coal, 22.4% nuclear, 2.7% hydro and 0.6% combustion turbines. GPC wholly owns numerous generating facilities and co-owns other generating facilities with OPC, MEAG, the City of Dalton, and Savannah Electric.[6] GPC has wholesale contracts

[5] Memorandum of Municipal Electric Authority of Georgia, Docket No. 7313-U, March 20, 1997 and Written Comments of Georgia Power Company, Docket No. 7313-U, March 20, 1997.

[6] A list of generating facilities owned by GPC and a list of jointly-owned facilities are included in Appendix D, List of Generating Facilities, on page 98 of this report.

for capacity and energy with cogenerators and other providers both within and outside the State of Georgia.[7]

As of December 1996 Georgia Power Company served 1.7 million customers and provided electric service in all but six of the state's 159 counties. The overall average price paid by all customer classes in 1996 was 6.15 cents per kilowatt-hour.[8] GPC's December 31, 1996 FERC Form No. 1 indicated operating revenue of $4,415,615,956 and total assets of $13,508,046,332.

Savannah Electric and Power Company

Savannah Electric, part of the Southern Company since 1988, is an investor-owned utility regulated by the Commission. Savannah Electric serves customers in five counties located in Southeast Georgia. These include Chatham, Effingham, Bryan, Bulloch, and Screven County. As of December 1996 Savannah Electric served 120,448 customers at an overall average rate of 6.40 cents per kWh.[9]

Savannah Electric has a total generating capacity of 840 megawatts. Their generating mix consists of 74% coal and 26% combustion turbines.[10] They also contract for capacity with the City of Savannah and purchase energy from a number of cogenerators. Savannah Electric's December 31, 1996 FERC Form No. 1 indicated operating revenue of $ 225,919,194 and total assets of $ 564,257,221.

Southern Electric System

Southern Company is a utility holding company with five electric utility operating subsidiaries that provide electric service in four southeastern states: Georgia Power Company and Savannah Electric and Power Company in Georgia; Alabama Power Company; Gulf Power Company in Florida; and, Mississippi Power Company. The geographic area served by these utilities constitutes the Southern Control Area. Southern Company Services, Inc., an affiliated company, operates the Southern electric system from Southern Company's William R. Brownlee Power Control Center (PCC) in Birmingham, Alabama.

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[7] Georgia Power Company, 1997 Facts and Figures.
[8] Georgia Power Company, 1996 Annual Report.
[9] Savannah Electric and Power Company, 1996 Annual Report.
[10] A list of Generating Facilities owned by Savannah Electric is included as Appendix D List of Generating Facilities, on page 98 of this report.

The PCC was established to provide integrated and coordinated operation of the generation and transmission systems of Southern's operating companies. Using the guidelines established by the Operating Committee in the Intercompany Interchange Contract (IIC), the PCC is responsible for coordinating the operation of the bulk power supply resources. Its objectives are to supply the territorial power requirements of the respective service areas of the operating companies at the lowest practical cost consistent with a high degree of reliability of the bulk power supply, and fulfill the interconnected contractual agreements with non-associated utilities.

The scope of the Power Coordination Center's responsibilities consists of the following:

(1) Unit Commitment—Determine the appropriate set of generating units and other power supply resources required to economically meet projected integrated system demand on a daily basis.

(2) Economic Dispatch—Determine the desired loading of the generating units and power supply sources connected to the integrated system.

(3) Common Interchange—Implement the interchange of power with the non-associated companies that are interconnected with the Southern electric system.

(4) Bulk Power Transmission Security—Evaluate the security (reliability) of the bulk power transmission system (500 kV, 230 kV and all interconnections) and concur on actions required to ensure its integrity under first contingency conditions.

(5) Maintenance Outage Coordination—Coordinate the unit maintenance outage requirements of the operating companies, including any auxiliary equipment which could curtail unit capacity, in such a way as to minimize cost to the system.

(6) Record Keeping – Maintain specified operating data and records.

All major utility systems in the eastern half of the United States and Canada (except in Texas) are interconnected and operated synchronously as part of the Eastern Interconnection—an interconnected grid of roughly 700,000 MW capacity. Within the Southern electric system generation is economically dispatched to meet resources without regard for operating company boundaries. Power flows are scheduled and controlled between the Southern electric system and non-associated companies. The Southern Company complies with FERC requirements and operational guidelines established by the North American Electric Reliability Council (NERC).

Interchange between independent utilities is regulated by the FERC, which regulates pricing and contract administration pursuant to the Federal Power Act. All Southern Company contracts must be filed with FERC. Standard practices and operating procedures are set forth by NERC, a voluntary organization of utilities that sets standard and practices for the industry. NERC's Operational Guidelines are observed by all utilities.

The Southern electric system acts as a tight pool with the PCC at Southern Company Services, Inc. acting to provide integrated and coordinated operation of the system. A power pool is a group of interconnected utilities that act together in a closely coordinated manner to enhance reliability and economics. Loose pools may coordinate only a few operational functions—typically interchange, spinning reserves and system security—among independent utilities. Tight pools, such as the Southern electric system, share common unit commitment, economic dispatch and interchange functions to maximize reliability while minimizing production costs.

By operating as a pool the Southern electric system derives significant economic and operational efficiencies: (1) Reserve sharing: An independent utility would have to carry reserves equal to its largest unit. A pool also carries reserves equal to its largest single unit, but each pool member carries only a portion of such reserves; (2) Construction staging: Individual utilities must add generation in increments too small to take advantage of the economies of scale. A pool may add generation in larger increments to be shared among several utilities and take advantage of the economies offered by size; (3) Buying power: A pool generally has more clout in purchasing off-system capacity and energy than individual companies; and, (4) Reliability is generally enhanced by pool operations.[11]

Oglethorpe Power Corporation and the Electric Membership Cooperatives

Oglethorpe Power Corporation (OPC), the nation's largest electric cooperative, supplies power to 39 of the state's 42 Electric Membership

[11] "Power Pooling in the Southern Electric System," Raymond L. Vice, Bulk Power Operations, Southern Company Services, Inc.

Cooperatives (EMCs). OPC was created in 1974 by the General Assembly. The EMCs were formed during the 1930s and 1940s to supply electricity to rural customers. Each EMC is customer-owned and self-regulating with rates set by their decision-making entity, the EMC Board of Directors. The Commission's limited regulatory jurisdiction over the EMCs includes resolution of territorial disputes and approval authority over financing applications. Although the Commission does not approve rates for the EMCs, the EMCs are required to file their rates with the Commission.

Earlier this year OPC reorganized into three separate companies: Oglethorpe Power Corporation, Georgia Transmission Corporation and Georgia System Operations Corporation. Oglethorpe Power Corporation continues to provide power to the member EMCs. The Georgia Transmission Corporation manages OPC's transmission lines and substations. Georgia System Operations Corporation operates the generating facilities, control room and dispatch of electricity. This reorganization differs from the usual vertically-integrated utility in that it functionally unbundles the major electric services. The three companies are collectively owned by the EMCs. However, each of the three companies has its own separate decision-making board.

Oglethorpe Power supplies energy to the EMCs from 3,338 MW of owned or leased generating capacity. The generating mix includes 37.7% coal, 36.9% nuclear and 2.4% hydro. The remaining energy needs, approximately 23%, are met with purchased power from other utilities. In total, the 39 EMC's serve 2.6 million customers.

Municipal Electric Authority of Georgia (MEAG) And The Municipals

MEAG is a public generation and transmission corporation, created in 1975 by the Georgia General Assembly. MEAG has assets of $4.7 billion and owns a total of 1,558 MW of generating capacity from facilities co-owned with Georgia Power Company, OPC and the City of Dalton. MEAG supplies electricity to its 48 member municipal electric utilities for distribution to their approximately 635,000 customers. Retail rates for each municipal are set by their respective governing body, e.g., the city council or mayor. The Commission has limited jurisdiction over municipals. However, they are required to file their rates with the Commission.

Tennessee Valley Authority (TVA)

Parts of extreme northern Georgia are supplied electricity by TVA. TVA is a federally-owned electric power system supplying power through five separate distribution systems in Georgia: Blue Ridge Mountain EMC; North Georgia EMC; Tri-State EMC; the City of Chickamauga; and, the Electric Power Board of Chattanooga. Approximately 117,000 customers in ten North Georgia counties are served by these distribution systems which have long-term, all-requirements wholesale power contracts with TVA. TVA also serves as the regulator of these distribution systems and has authority over rates and other matters for these distributors.

Congress established the TVA electric service territory through the Tennessee Valley Authority Act, as amended in 1959. In defining the service area, Congress included a prohibition on the sale of TVA generated power by either TVA or a TVA distributor outside the TVA boundary. The Georgia Territorial Act of 1973 allows other utilities in Georgia to compete for new loads above 900kW demand in the TVA distributors' service territory while TVA distributors are federally restricted from competing for similar customers in other suppliers' service areas.[12]

Other Suppliers

The cities of Acworth, Chickamauga, Dalton and Hampton are not members of MEAG Power. These municipalities purchase electricity on the wholesale market from MEAG, TVA, Georgia Power and others. Other suppliers exist in Georgia who currently sell, or will soon sell, energy and capacity in the wholesale electric market. These include Independent Power Producers (IPPs), such as Hartwell Energy and U.S. Generating, and numerous Qualifying Facilities (QFs), such as cogenerators and small power producers. These facilities are capable of producing in excess of 1000MW of capacity and may provide in-state competition in a future competitive retail market.[13]

[12] Comments submitted by the Tennessee Valley Public Power Association, Docket No. 7313-U, March 1997.

[13] Approximate Capacity Ratings: Hartwell Energy has 300MW; U.S. Generating has 475MW; and Mid Georgia Cogen. has 300MW.

Integrated Transmission System

Currently, Georgia Power Company, Oglethorpe Power Corporation, MEAG and the City of Dalton jointly own the majority of Georgia's transmission system. Savannah Electric is connected to the Integrated Transmission System through an interface but does not have any financial investment in the system. In January 1975 Georgia Power Company entered into separate contracts with each of the other utilities, selling them ownership interests and equal access to the transmission facilities.

Several factors led to the creation of the Integrated Transmission System (ITS). During the early 70's OPC, MEAG and the City of Dalton purchased generating capacity from Georgia Power Company. These companies also purchased ownership interest in the transmission system. This made it possible to receive energy from the generating plants in which they had purchased an ownership interest. The creation of the ITS avoided the duplication of transmission facilities that otherwise would have occurred among the Georgia utilities transmitting power to serve their respective customers. With a jointly-owned integrated facility, Georgia utilities have access to over 16,000 miles of transmission line.

The ITS is a $3.4 billion investment that is used primarily to serve Georgia load. It is interconnected with neighboring utilities through transmission tie lines. These ties allow utilities to transfer power from one system to another. The ties also allow Georgia utilities to purchase power from neighboring utilities when it is less expensive than operating their own units. It also allows the utilities to sell and transmit any excess power they may have available.

At the local level, the ITS is operated by Georgia Power Company through two Transmission Control Centers (TCC). The TCCs are the system operations agents for all of the owners of the ITS. One TCC is located in the northern region of the state, while the other is located in the southern region. The Transmission Control Center monitors bus voltage, transmission line loading and network status throughout the ITS. The TCC also reviews maintenance outage requests from the ITS owners to see if the transmission system can withstand any single contingency during scheduled maintenance activities. The ITS is located within the Southern Company Control Area and Southern Company Services is responsible for operating the control area in compliance with NERC and SERC guidelines.[14]

[14] NERC is the North American Electric Reliability Council and SERC is the Southeastern Electric Reliability Council.

A Joint Committee, comprised of two members from each of the owners of the ITS, was established in August 1976. The Joint Committee, along with three subcommittees, make up the decision-making body for the ITS and are responsible for changes, additions and improvements to the transmission facilities. This body ensures that the system can handle current and future loads of the co-owners and that tie lines with neighboring utilities are adequate. The Joint Committee also ensures adherence by all parties to the ITS Agreements.

The existence of a fully integrated transmission system in Georgia allows the owners of this system to compete for customer choice loads provided by the Georgia Territorial Act. The ITS has made it economically feasible for limited competition to exist in Georgia for the past 20 years.

Although the transmission system is defined as jointly-owned, each transmission facility has a single owner. Each utility is responsible for maintaining its own facilities and develops separate maintenance standards for its respective facilities. These standards make no distinction between the facilities that serve the owner and the facilities that serve the other ITS participants. The cost of maintenance is the responsibility of the owner of the facility.

As of December 1996 the ownership investment percentages in the Integrated Transmission System were Georgia Power Company 66.48%, Oglethorpe Power Corp. 23.43%, MEAG 8.68%, and the City of Dalton 1.41%. The utility's percentage investment in the system is equal to its peak load ratio. If the utility's investment is not equal to its load ratio, it can consider the purchase or sale of transmission facilities from or to another co-owner.

In the event that a utility has more invested in the system than is required, then the under-invested utility is required to pay the over-invested utility the amount of the over-investment multiplied by the higher of the two utilities' carrying charge. However, paying this amount does not confer any ownership interest in the facilities.

The ITS arrangement, which has existed for more than 20 years, is unique to Georgia. The ITS allows Georgia utilities access to power delivery systems for buying and selling available wholesale electric energy both within and outside of Georgia. This helps reduce energy prices in Georgia while minimizing the impact on the physical environment. The ITS enabled joint transmission services to be offered in Georgia years ahead of the recent federal initiative, creating transmission open access at the wholesale utility business level on a regional and national basis.

It remains to be seen what impact a federal retail access mandate may have on the ITS. If competition is not federally mandated, but increased competition is brought about through amendments to the Georgia Territorial Act, it may be advantageous to keep the ITS, or some variation of the ITS, in place.

4. B. REGULATORY ENTITIES AND STATUTES AFFECTING THE ELECTRIC INDUSTRY

The Georgia Public Service Commission

Duties and powers of the Georgia Public Service Commission (Commission) extend to electric light and power companies, or persons owning, leasing or operating public electric light and power plants furnishing service to the public.[15] The Commission has exclusive power to determine just and reasonable rates and charges to be made by any person, firm or corporation subject to its jurisdiction. Georgia Power Company and Savannah Electric are the two investor-owned electric companies under full Commission rate-making jurisdiction. The Commission has limited authority with respect to cooperatives or municipals, who must file their rate with the Commission. The Commission approves the issuance of certain EMC bonds and notes and enforces rules and regulations to provide electric service to an EMC's members. Where EMCs receive financial support from the federal Rural Utilities Service (RUS) agency, RUS guidelines and Commission approvals exist to help assure that all financial requirements are met. The Commission also has certain authority granted under the Georgia Territorial Electric Service Act.[16]

Currently, the Commission's authority over investor-owned utilities includes regulation of bundled rates for generation, transmission, distribution and other costs necessary to serve the retail customer. If retail generation is opened to competition, it is expected that the Commission would no longer set the rates for the commodity portion of electric service; however, the Commission would continue to set rates for distribution and other customer services currently bundled with the commodity charge. In addition, other regulatory responsibilities, such as ensuring the quality of service and fair treatment of customers, would remain.

[15] O.C.G.A. § 46.
[16] See Georgia Territorial Electric Service Act on page 24 of this report.

The Integrated Resource Planning Act

The Commission has responsibility pursuant to the Integrated Resource Planning Act to review and approve supply-side and demand-side resource options filed by the utility companies. The purpose of this certification process is to ensure that energy requirements are met and customers receive safe and reliable electric service. The Integrated Resource Planning Act (IRP Act) was established by the state legislature in 1991.[17] The IRP Act resulted from the Commission's ex post facto reviews of generating plants, such as the Commission's review of Georgia Power Company's construction of Plant Vogtle. Prior to enactment of the IRP Act, the Commission did not review a utility's management decisions pertaining to the need, planning and construction of expensive electric generating facilities until the company applied for financing approval or filed for recovery of these costs in rate case proceedings after the plants were partially built or completed. If planning or construction management decisions were found to be imprudent or if the facility was deemed unnecessary, the Commission could disallow recovery of certain costs.

The IRP Act gave the Commission the authority to review, modify, reject or approve a plan for meeting future energy demands prior to any commitment regarding construction of the facility, contracting for purchase power or the expenditure of large sums of capital. This certification process helps to ensure the energy is needed, gives the utility more certainty in recovery of expenditures and ensures that the source of power with the best value is selected after considering both cost and reliability.

The IRP Act provides for utilities to file a plan at least every three years. The plan must include a 20-year projection of energy requirements and consider the economics of all options available to meet these requirements including supply-side resources, demand-side resources, purchased power and cogeneration. Long-term plans for the type of facility needed, the size, and the required commercial operation date are determined and approved by the Commission. Before construction of a facility has begun or a purchased power agreement is finalized, the Commission must first certify the need for the facility, contract or conservation program, and determine that it is the appropriate type facility based on economic analysis. Once certified, the utility is guaranteed recovery of the actual prudently incurred costs. The IRP Act also provides the Commission a means to ensure that a reliable supply of low cost energy will be available for the long term.

[17] O.C.G.A. § 46-3A et seq.

In the past, long range planning and the orderly addition of power facilities to supply a defined service territory have given consumers in Georgia a highly reliable and efficient electric generation, transmission and distribution network. This system has responded well to accidents, natural disasters and rapid growth in customer power demands. The following questions illustrate some of the planning issues which must be resolved or considered prior to legislative alterations to the current regulatory scheme.

> In the short term, if price becomes the driving force of competition, will the incentive remain to plan, maintain, and develop a reliable power system?[18]
>
> Some parties believe that the planning function will not be compromised by competition. It can only be enhanced. The traditional command-and-control type of planning that is the basis of the monopoly IRP approach aggregates system planning and market planning.[19]
>
> Competitive bidding has been used as a proxy for and transition vehicle to full competition. However, in many situations, the competitive bidding process has worked to delay entry into the electric marketplace. If any party is able to control market entrance through design of a bidding process, new market entrants will continue to find the door shut to the market. A fully competitive market will demand quick supplier response and will not tolerate the suppression of market function.[20]
>
> Will generators or suppliers be required to provide reserves to the distribution company? How will both spinning and planning reserves be provided and paid for? What will be the penalties for non-delivery?[21]

[18] Comments submitted by the Tennessee Valley Public Power Association, Docket No. 7313-U, March 1997.
[19] "Retail Competition in the U. S. Electricity Industry," A Special Report by the Electricity Consumers Resource Council, June 1994.
[20] Comments submitted by U. S. Generating Company, April 1997.
[21] GPSC Electric Workshop "Presentation of Conclusions, and Development of Plan of Future Action" Statutory Changes Focus Group Report, July 1997.

> What future role will the Commission retain in assuring reliability and cost-effective energy supplies for Georgia? Should the legislature amend the IRP Act in advance of overall restructuring of the industry, depending on the pace and direction of that overall change?[22]
>
> Will IRP or DSM programs have any role in the competitive retail electric environment?[23]
>
> How will requiring adequate power reserves protect the integrity of the system?[24]

This Commission should retain regulatory oversight concerning reliability to ensure that the supply of generation is adequate and system security is not compromised. The manner and extent of this oversight would vary depending upon the market structure and actions of the market participants. Possible Commission roles could be coordinating a long-term planning forum or setting reliability and planning requirements for newly certificated suppliers and for existing suppliers in the generation market in Georgia.

The Georgia Territorial Electric Service Act

Customer choice for new large commercial and industrial customers with a load of 900kW or more has been in place in Georgia for more than 20 years, long before the national debate on electric industry restructuring began. The Georgia Territorial Electric Service Act of 1973 (Territorial Act or Act) established territories for serving residential and small commercial customers as well as initiating the customer choice provisions for large customers.[25] These legislative and regulatory provisions in Georgia have provided the foundation for an effective electric utility structure.

The Territorial Act was enacted March 29, 1973 to assure the most efficient, economical and orderly rendering of retail electric service within the state, avoid duplication of electric lines, foster the extension and location of electric suppliers' lines in a manner most compatible with the state's preservation and enhancement

[22] Ibid.
[23] Comments submitted by the Tennessee Valley Public Power Association, Docket No. 7313-U, March 1997.
[24] Ibid.
[25] O.C.G.A. § 46-3-1 through O.C.G.A. § 46-3-15

of the physical environment, and to protect and conserve lines lawfully constructed by electric suppliers.

Electric suppliers under the jurisdiction of the Territorial Act are Georgia Power Company, Georgia's Electric Membership Cooperatives (42 EMCs), Municipal Electric Authority of Georgia (MEAG), Savannah Electric and Power Company, North Carolina's Haywood EMC and Tennessee's Electric Power Board of Chattanooga.

Under the Territorial Act, every geographic area within the state was either assigned to an electric supplier or declared unassigned as to any electric supplier by the Commission. Customers with connected loads of less than 900kW (about the size of a modern grocery store) must take electricity from the franchised supplier. However, if any customer with a load of 900kW or more locates within the corridors of an electric supplier's lines, that customer may have a choice of suppliers. Once a customer chooses a supplier, the Territorial Act provides that the chosen electric supplier has the exclusive right to serve that customer for the life of the premises.[26]

Georgia Power Company estimates that since enactment of the Territorial Act, approximately 2,800 large and small customers throughout the state have been able to choose their electric supplier when locating new facilities in Georgia. Georgia electric suppliers compete for about 500 MW of load each year.

The Territorial Act was the result of a compromise negotiated by all of the electric suppliers doing business in the State of Georgia during the early 1970s. A 900kW level was agreed upon as the load threshold for customer choice. This load level was chosen because a 900kW load was considered sufficient to justify the economics of the investment necessary to serve the load and foster competition for that load.

Some advantages of the current structure have been to produce extremely reliable electric service and provide that service at prices that are reasonable when compared to many other states and the nation as a whole. While some parties believe that the Territorial Act has worked well to foster competition, others believe the Territorial Act should be repealed and the market should be allowed to develop as it will.

[26] O.C.G.A. § 46-3-1, Allocation of Territorial Rights to Electric Suppliers.

Still others believe that competition could be increased by modifying the Territorial Act. This could be accomplished by reducing the 900kW threshold exemption and by allowing existing customers to renegotiate contracts after a specified period of time. While increasing competition this would limit the competitive choices to those suppliers currently providing retail electric service within the State of Georgia. If retail access is mandated by the federal government, this scenario may or may not be acceptable since it could prohibit out-of-state suppliers from providing retail generation service in Georgia. This scenario could also cause duplication of distribution facilities at levels that may or may not be cost-effective, which the Territorial Act had intended to mitigate. For these reasons competition at levels below the 900kW threshold exemption should be restricted to generation services and not for the extension of distribution facilities. Changes to the Territorial Act that impact generation services may be appropriate, whereas changes that affect territorial assignments or exemptions for transmission and distribution services may not.

The participants at the workshops and in the focus groups reached a general consensus for restructuring the electric industry. The consensus was that, if generation was opened to competition, territorial assignments for distribution lines should be kept and distribution service should remain as a state regulated service. Transmission services would be regulated by the FERC. For this consensus model to work access to the distribution system must be granted to all suppliers. Any access charge should be the same for all customers connected to that distributor.

Under the Georgia Territorial Act, all utilities are now permitted to compete for new load over the 900kW threshold, even if the load is not located in their service territory. This has allowed competing utilities to “cherry-pick” large industrial customers in the TVA distributors’ service territory, while TVA distributors are federally restricted from competing for similar customers in other suppliers’ service areas. These conflicting laws have created an inequitable situation with an artificial boundary to fair, bilateral competition.

Consideration should be given to how the TVA regulatory role will relate to that of the State of Georgia, and particularly: (a) how the State of Georgia should address the impact of the Energy Policy Act of 1992 upon the transmission obligations of TVA; (b) how the State of Georgia would contemplate dealing with any changes in federal law that would affect TVA and the distributors of TVA power as to any territorial restrictions upon the sale or resale of electric power within the TVA region; and (c) how the State of Georgia would equitably provide for fairness to the ratepayers of the TVA distributors in Georgia, given the all-requirements long-term contracts with TVA and the applicable federal law.[27]

Federal Energy Regulatory Commission (FERC)

The Federal Energy Regulatory Commission was created by the Department of Energy Organization Act on October 1, 1977 to replace the Federal Power Commission. The FERC's legal authority comes from the Federal Power Act of 1935, the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978, the Public Utility Regulatory Policies Act of 1978, and the Energy Policy Act of 1992.

FERC oversees wholesale electric rates and service standards, as well as the transmission of electricity in interstate commerce. The FERC ensures that wholesale and transmission rates charged by utilities are just and reasonable and not unduly discriminatory or preferential. It also reviews utility pooling and coordination agreements.

In addition, the FERC oversees the issuance of certain stock and debt securities, assumption of obligations and liabilities, and mergers. The FERC reviews the holding of officer and director positions between top officials in utilities and major firms supplying electrical equipment to the power companies and underwriting securities.

Finally, FERC reviews rates set by the federal power marketing administrations, such as the Tennessee Valley Authority, makes determinations as to exempt wholesale generator status under the EPAct, and certifies qualifying small power production and cogeneration facilities.

Rural Utilities Service (RUS)

The Rural Electrification Act of 1936 established the Rural Electrification Administration (REA) in the U. S. Department of Agriculture to provide affordable electric service to rural communities. Early investor-owned utility companies, located in large and moderately-sized cities, could not profitably provide service to less populated rural areas. REA offered low cost loans to encourage groups in rural areas to start customer-owned utilities to provide electric service for their members.

[27] Comments submitted by the Tennessee Valley Public Power Association, Docket No. 7313-U, March 1997.

The Rural Electrification Loan Restructuring Act of 1993 amended the 1936 Act. The Rural Utilities Service (RUS) replaced the REA and makes loans and loan guarantees to non-profit rural electric cooperatives. These loans finance the construction, operation and improvement of electric facilities. The loan program offers the incentive of low cost financing to ensure continued reliable service to rural areas in Georgia and throughout the country.

4. C. The Regulatory Compact

Any effort to restructure the electric industry in Georgia will be complicated by the mix of regulatory schemes that have developed over the years. Three different regulatory paradigms are in place—one for each of three main categories of suppliers—investor-owned utilities (IOUs), electric membership cooperatives (EMCs), and municipal suppliers. The investor-owned electric utilities in Georgia are rate base/rate of return regulated by the Commission for all sales to the end user, i.e., retail sales. Municipal's and EMC's prices are not rate regulated by the Commission; however, the Commission administers the Territorial Electric Service Act that applies to all distribution companies. All suppliers are regulated by the FERC for sales for resale, i.e., wholesale transactions. Each of the three types of supplier operates under a different "regulatory compact":

1. The vertically-integrated Southern Company through its Georgia subsidiaries, Georgia Power and Savannah Electric, has a regulatory compact with the Commission and the FERC. In exchange for a commitment to serve their area (Obligation to Serve and Universal Service) with electric energy at reasonable rates, the operating companies are given a reasonable opportunity to recover all prudently-incurred costs including a comparable return on capital invested in plant used in the reliable production and delivery of electric energy. Prices are set through rate base/rate of return regulation to achieve the level of revenue required to cover the utility's operating and capital costs;

2. The municipals have a regulatory compact with their own citizen customers. MEAG is a generation and transmission company serving the member municipal systems. Since the municipals are government-owned, ultimate regulation is by the citizens through the political process. The Commission has no rate regulation over the municipal systems; and

3. The EMCs have a regulatory compact with the RUS (formerly the REA) to provide universal service in exchange for low cost loans. Since the customers are the owners, there is no rate regulation of the cooperatives. Any profits above the required margins are returned to the customer/owners as capital credits after a period of time. Oglethorpe Power Corporation is the generation and transmission cooperative serving the distribution cooperatives.

The most recent paradigm shift has been to replace a regulated monopoly with a competitive generation market, based on the theory that a competitive market is the most efficient in allocating resources for the production of goods and services. A number of industries have been restructured and made more competitive, including the electric industry. The FERC is committed to a competitive wholesale market for electricity. Some states have restructured to allow competitive retail markets. People expect lower prices or better service, or both, from a competitive supplier or they take their business elsewhere. As with other industries, these expectations may or may not be met. Of particular concern is the universal availability of electric power. Virtually every person has electric power in Georgia. Competitive markets, however, tend to serve only the more profitable markets or charge higher prices to serve high-cost areas. In the electric industry, the unprofitable customers are those with low usage and those in remote locations. The regulatory compacts have resulted in universal service, reasonable prices and a safe, reliable and adequate supply of electricity in Georgia. A restructured electric industry must build upon the strengths of the current system.

4. D. STATUS OF ELECTRIC INDUSTRY RESTRUCTURING IN OTHER STATES

The electric industry is rapidly changing. During the next five years the electric power industry will experience many changes and uncertainties. Some states are taking an aggressive approach to competition and moving quickly to make changes in their electric markets by approving comprehensive restructuring plans. Others are taking a slower approach and are establishing timetables to phase-in competition over a period of several years. Many states are still in the early stages of discussing and studying the impacts of restructuring.

There is significant variation in the reasons why states are restructuring their electric industry. Many states would like to reap the perceived benefits of competition. Some states with electric rates far in excess of the national average have restructured, including California, New Hampshire, Pennsylvania and Rhode

Island. Rate reductions are mandated under some of the restructuring plans adopted to date. Other states wish to improve economic conditions by attracting industry and jobs. Still others believe that competition is inevitable and do not want to be forced into a federally-mandated, “one-size-fits-all,” model. They would prefer to restructure their electric industry to accommodate their state’s unique circumstances. For example, the State of Washington, where the rates are below the national average, is seriously considering restructuring and Oklahoma and Montana with low electric rates have already passed restructuring legislation.

Ten states have passed various forms of legislation that allow some retail wheeling.[28] The most recent states to adopt legislation include Nevada, Maine, Oklahoma, Montana, Massachusetts and Illinois. Eleven states have implemented retail pilot programs, for example, Illinois, New Hampshire and Massachusetts. Twenty-one states have adopted principles or guidelines. Some states have allowed the recovery of stranded costs and have established an independent system operator, including California.[29]

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[28] A listing of the status of restructuring in the 50 states and the District of Columbia as of November 1997 is included in Appendix E, Status of Restructuring in the United States, on page 102 of this report. NRRI, Electric Industry Restructuring Box Score; GDS Associates, Inc., Report on State Restructuring; Brubaker & Associates, Inc., “Industry Restructuring Newsletter.”

[29] National Regulatory Research Institute's (NRRI) Electric Industry Restructuring Box Score, GDS Associates, Inc.’s Report on State Restructuring, Brubaker & Associates, Inc.'s, Industry Restructuring Newsletter, Workshop Transcript.

5. ISSUES IN STRUCTURING A COMPETITIVE MARKET

During the workshops and focus groups several key issues were raised relating to structuring an effectively competitive market. These issues have been grouped under the following topics and each is discussed in this chapter:

- Market Structure
- Market Power
- Reliability of the Electric System
- Determination and Recovery of Stranded Costs
- Tax Implications of Electric Industry Restructuring
- Public Policy

5. A. MARKET STRUCTURE

Currently, there are different market structures being developed for retail competition. In the United Kingdom, all generators compete to sell into a pool company, known as UK PoolCo. Customers may buy directly from the pool at the hourly spot price, or they can sign so-called contracts for differences that provide for a fixed or stable price. The UK PoolCo model ensures that all customers receive at least some of the benefits of competition. In California, the pool structure will be similar to the UK model by allowing customers to sign contracts for the physical supply of electricity. An independent system operator (ISO) will run the system based on schedules provided by individual customers signing bilateral contracts for the physical supply of electricity. In New Hampshire, the retail competition pilot program relies solely on bilateral contracts without a pool. However, suppliers are allowed to aggregate customers and serve them at retail.

While various suppliers in Georgia have been following recent developments in market structure, no firm positions have been adopted concerning the type of structure that would be most beneficial for Georgia and its consumers. From a consumer standpoint, plans that only allow for wholesale competition, such as the PoolCo plan, may lower wholesale rates but lack provisions for retail customer choice. Some customers believe they should be allowed to aggregate loads for purposes of purchasing electricity and transmission services. Independent third parties (i.e., aggregators, marketers, and brokers) believe they should be allowed to act on behalf of customers, suppliers and investors through market hubs, commodity exchanges and secondary markets typical of other competitive markets. For example, one marketer supports the development of a fully competitive electric industry that consists of: (1) a competitive generation sector whose participants operate in an arena with competitively neutral financing, environmental conditions and standards; (2) unbundled, open and non-discriminatory access to transmission and distribution services; and, (3) a customer supply sector working to link customers to the competitive market.[30] Before the electric industry in Georgia is restructured various market structures, including the status quo, must be analyzed with care to ensure that the structure with the greatest benefits and the fewest unintended consequences is identified. Advantages must outweigh disadvantages. One of the primary market structure issues that must be addressed in Georgia is whether or not an Independent System Operator should be established.

Independent System Operator (ISO)

As long as future loads cannot be predicted with absolute certainty and as long as contingencies exist, the laws of physics require some form of real-time system operator. Under traditional cost-of-service regulation, the typical vertically-integrated utility operated its own control area.[31] Initially, the system operator's responsibility was reliability preservation by ensuring that generation and load were matched at all times. Subsequently, duties were expanded to include economic dispatch of generation and off-system sales and purchases.

The advent of retail direct access and a fully competitive generation market has focused attention on the system operator and the need for independent operational control of the interconnected grid. An Independent System Operator (ISO) can be defined as an entity that is independent of any individual market participant or any single class of participants (e.g., transmission owners, generators or end-users) and whose primary purpose is to ensure fair and non-discriminatory access to transmission services and ancillary services. The consensus of many market participants is that a competitive generation market requires an impartial "traffic cop" to operate the grid on a real-time basis and enforce grid reliability.

[30] Mr. Gregory Kelly, U.S. Generating Company.

[31] A control area is an electrical system, bounded by interconnection metering and telemetry. It continuously regulates, via automatic generation control (AGC), generation within its boundaries, and schedules interchange back and forth across the inter-ties to match its system load while contributing to frequency regulation of the interconnection. Some utilities, including those in the Southern electric system, operate a control area jointly in a "tight" power pooling arrangement.

ISO Principles

In Order No. 888 issued on April 24, 1996, FERC developed eleven principles to give guidance to the electric industry on the formation of an ISO.[32] FERC encourages the formation of ISOs and believes that "properly constituted" ISOs are a means by which public utilities can comply with FERC's non-discriminatory transmission tariff requirements. The System Operations and Reliability Focus Group assessed the current situation in Georgia and the Southern Control Area against the eleven principles developed by FERC. The results of that discussion indicate substantial obstacles and issues that must be resolved involving multiple transmission owners, state regulatory bodies and federal regulators prior to formation of an ISO involving Georgia or the Southern Control Area.[33]

Overall conclusions from focus group discussions regarding the extent to which the current structure in Georgia conforms to FERC's principles were:

- Current organizational structures, including the functional separation of transmission and marketing functions by the Southern Companies, are intended to satisfy most of the principles. However, full satisfaction of Principles 1 and 2 would increase the perceived level of independent operation and strengthen market confidence in the provision of non-discriminatory transmission service.[34]

- Principle 1, relating to non-discriminatory governance, and Principle 2, relating to financial interest of employees, are not fully met in the current environment. Complete independence beyond functional separation is desired by many market participants and required by FERC to conform to these principles.[35]

- Principle 3, requiring a single, grid-wide tariff, is not met due to the existence of multiple transmission owners and the resulting potential for pancaked rates within the ISO controlled area.

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[32] See Appendix F, FERC ISO Principles, on page 104 of this report.
[33] See Appendix G, Analysis of FERC ISO Principles, on page 108 of this report.
[34] Appendix H, Recent Changes in FERC Regulation, on page 112 of this report gives a description of FERC's regulations to ensure non-discriminatory access.
[35] Appendix I, Summary of ISO Governance Structures, on page 116 of this report provides a summary of the governance structures and Appendix J, Summary of ISO Functions, on page 118 of this report provides a list of the functions of various existing and proposed ISOs.

- Principles 4 through 11, primarily relating to the roles and responsibilities of the ISO, are substantially met within current organizational structures. Implementation of an ISO would increase the perception of independence of these functions.

Potential Benefits of ISO Formation

During discussions of the focus group, potential benefits and obstacles to the formation of an ISO were identified. Benefits include full independence of transmission operation to help extinguish market power concerns, comprehensive regional planning and operations, maintenance coordination between multiple owners and potential facilitation of a power exchange.

Facilitation of a power exchange function is one of the primary benefits of an ISO. A power exchange is a centralized pool that solicits bids for a predetermined and structured power market, establishes a market clearing price, and sells at that price. The structured power market could be hour-ahead and day-ahead energy markets or markets for ancillary services. In some power exchange proposals, the market clearing price is called the "spot" price and is set by an auction process. Several types of auctions are available, each having different effects on the bidding behavior of potential bidders and the outcome of the auction. Some power exchange proposals are viewed as being symptomatic of mistrust in markets based solely on bilateral trades. In extreme cases, such a pool can displace the market. Some participants view a "PoolCo" as an example of an extreme case. Potential benefits of a power exchange in a restructured electric industry include overcoming market power issues, promoting development of new merchant generation and providing geographic aid to identify transmission congestion points through the location of "spot" prices.[36]

Potential Obstacles To ISO Formation

The obstacles identified were: 1) involvement of entities in other states; 2) implications of retail access on Georgia rates if based on a system-wide tariff; 3) release of control of transmission facilities by owners; 4) additional costs associated

[36] "Independent System Operations," Profiles on Electricity Issues, Electricity Consumers Resource Council, No. 18, page 17, March 1997.

with the formation of an ISO;[37] and, 5) existence of Integrated Transmission System Agreements (ITSA).

Several of these obstacles to the formation of an ISO revolve around the existence of the Southern Companies' tariff and the ITSA. The Southern tariff as a system-wide tariff is in compliance with FERC Open Access orders for wholesale transmission service at a single system-wide rate. It covers the transmission systems of Georgia Power, Savannah Electric, Alabama Power, Gulf Power and Mississippi Power. The ITSA are transmission tariffs regulated by FERC and consist of the three two-party agreements that Georgia Power Company has with Oglethorpe Power, MEAG Power and the City of Dalton. Both MEAG Power and Georgia Transmission Corporation have begun implementation activities to voluntarily comply with the FERC Open Access orders. Third party transmission wheeling is already provided by Georgia Transmission Corporation (formed from Oglethorpe) and is expected to be provided by MEAG.

The provision stated in FERC's ISO Principle 3 is that an ISO should provide open access at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff. In contrast, since each Georgia entity may have its own transmission rate or price resulting from the ITSA, this condition would not be met and a resolution to this issue might be required prior to approval of an ISO formation. Similarly, since the ITSA provides each participant a pro-rata right to use transmission interfaces, this provision might not conform to the single, non-pancaked rate principle.

Another potential problem with the formation of an ISO is the geographic area now served by the Southern Company and its operating subsidiaries. The consensus of the System Operations and Reliability Focus Group is that the area covered by the system-wide tariff is the minimum acceptable area for formation of an ISO encompassing Georgia. This consensus was based on the application of FERC's ISO Principle 3, as well as other factors. For example, FERC has maintained that a single system-wide tariff for the Southern Companies is required due to the integrated transmission system development and operation of Southern in a centralized dispatch. Another underlying factor is that wide-area access to the power markets in the Southeast, currently provided by the Southern tariff, may be inhibited if a smaller tariff area were formed.[38] Formation of a regional ISO would be complicated by having to coordinate entities in each of the four states served by

[37] Appendix K, ISO Funding, on page 120 of this report summarizes estimates that have been made for the formation of certain ISOs.

[38] For further explanation of this consensus, please refer to page 4 of the focus group report entitled "System Operations In A Restructured Electric Industry."

the Southern Company. Having an ISO with boundaries congruent with Georgia's borders might be simpler to coordinate, but does not appear to be feasible. In addition, the economic benefits of a larger control area, such as shared reserves, would be lost if the control area was limited to the State of Georgia.

Conclusions

A properly structured, implemented and operated ISO would greatly enhance the effectiveness of a competitive generation market. However, as concluded by the focus group, formation of an ISO is not a necessary condition for initial implementation of retail access. This results from the federal requirement that jurisdictional utilities provide fair and non-discriminatory access pursuant to FERC Open Access orders. As for non-jurisdictional entities (i.e., cooperatives and municipals), concerns can be mitigated through the reciprocity rules, voluntary adherence to the rules, or other structural means. While the State of Georgia may encourage or mandate that transmission owners in Georgia pursue ISO formation, such efforts would necessarily involve other transmission owners, state authorities and the FERC.

Overall, the formation of an ISO in a fully competitive environment would strengthen the confidence of market participants that transmission service will be provided in a fair and non-discriminatory manner. Although obstacles exist that oppose the formation of an ISO, careful forethought and analysis by all entities involved could result in a properly structured ISO in a light of a fully competitive electric industry. An ISO, or comparable controls, should be established to ensure that:

- The safety and reliability of the interconnected grid is adequately maintained and improved;
- All market participants have equal and nondiscriminatory access to transmission services at just and reasonable rates approved by the FERC; and
- The timely addition of new or enhanced transmission facilities are planned and built.[39]

A consensus was formed by focus group participants that the power exchange function is secondary in importance to the ISO, but is probably important

[39] "*Independent System Operators,"* Profiles on Electricity Issues, Electricity Consumers Resource Council, No. 18, page 2, March 1997.

in overcoming market power issues in a competitive marketplace. Further research of a power exchange function is needed prior to implementing full retail competition.

The Commission should study the possible formation of a regional ISO that will encompass Georgia. Comments should be solicited from a wide range of sources including the FERC, transmission owners, market participants, state authorities in the Southeast region and other interested parties. Research on the establishment of a regional ISO should take into account such topics as governance, operational control, long-term planning, transmission congestion management and other ISO responsibilities, as well as the economic and legal obstacles to establishing an ISO.

5. B. MARKET POWER

The structure of the electric industry until now has been largely a natural monopoly with regulatory oversight to ensure reliable and affordable electric power to the residential, commercial and industrial sectors of the economy. The monopoly structure was created to avoid duplication of services and increase efficiencies in serving customers. Regulatory oversight has substituted for competition to ensure monopoly utilities did not abuse their monopoly power. One issue that arises with the move to open electric generation to competition is undue market power.

In a recent decision the California Public Utilities Commission (CPUC) referred to three types of market power.[40] The first is the utility's "established customer relationships, customer contact, and customer information [that] would yield advantages in marketing activities and customer retention programs." The second results from combining "preexisting market dominance" with "common ownership ties" in distribution and generation, for example, resulting in the possibility of transactions that would give a competitive advantage to the utility's power retailing affiliate. The third is the lack of meaningful choices for customers.[41]

Market power is described as the ability to control price or total output, or exclude competitors from a relevant market. In a competitive market setting a firm that is able to artificially raise prices and increase profits to its advantage is said to have market power. Market power in generation could be due to: (1) one seller

[40] Decision 97-05-040 dated May 6, 1997.
[41] Comments on Regulatory Issues Including Stranded Costs, Market Power, and Public Policy, Cellnet Data Systems, Inc.

having a disproportionate amount of generation in the relevant market; (2) transmission constraints that limit import capability in a certain area; or (3) running certain generating units to maintain reliability (or for other reasons) regardless of whether they are the least expensive during that period of time. It is interesting to note that the latter two potential sources of generation market power are independent of ownership—that is, market power problems exist regardless of who owns the generation.[42]

Because electricity must be supplied on an instantaneous basis, owners of existing multiple units have the ability to dictate the hourly or daily market price. This is because these units will be dispatched into the market as demand and pricing dictates. If transmission constraints restrict new power from coming into the state, the dominant supplier can control the price by determining which units to run and which units to withhold from the market.

Another generation-related market power issue involves metering. Frank Wolak of Stanford University and Robert Patrick of Rutgers University, both economics professors, studied market power in the U.K. and found that the lack of hourly metering enabled generators to manipulate market prices for energy and capacity, resulting in excess profits.[43] They found that the lack of hourly (half-hourly in the U.K.) metering has resulted in serious market inefficiencies in the U.K., including forcing consumers to pay high market prices—sometimes exceeding $1.50 per kWh—during peak periods.[44] Without hourly metering, customers were unable to reduce their usage when prices rose during peak periods.

Market power problems related to the transmission system could exist if transmission owners were able to stifle competition by withholding comparable transmission access to competitive generators or by providing affiliated generation with information or advantages not available to competitors. However, with respect to investor-owned utilities, such market power issues have been resolved with the issuance of Orders 888 and 889 by FERC. Order 888 requires FERC jurisdictional (investor-owned) utilities to provide access to their transmission systems to all eligible requesters under prices, terms and conditions comparable to transmission services the utility provides to itself. Order 889 sets up standards of conduct and

[42] Written Comments, Georgia Power Company, "Regulatory Issues Including Stranded Cost, Market Power, and Public Policy."
[43] The Impact of Market Rules and Market Structure on the Price Determination Process in the England and Wales Electricity Market, Frank Wolak and Robert H. Patrick, June 1996.
[44] Comments on Regulatory Issues Including Stranded Costs, Market Power, and Public Policy by Cellnet Data, Systems, Inc.

"fire walls" to ensure that a utility cannot use private information about transmission to gain an advantage in competitive markets. Market power problems could exist with respect to transmission owned by utilities which are not jurisdictional to FERC and which have not agreed to voluntarily comply with FERC open access rules.[45]

An ISO would provide a means for mitigating or eliminating market power issues with respect to transmission. It is important that any ISO developed in the restructuring process be nondiscriminatory and truly independent, with no financial or political interests in the generation aspect of the business. This will help to further lessen the chances for undue market influence of a generator also controlling the transmission of its electric power. Furthermore, in order to foster innovation and efficient operations, the ISO should develop market-based pricing approaches. It should be noted that in the management of transmission service, some generation-related ancillary services, such as load following, voltage regulation and frequency control, will be impacted and need to be controlled or coordinated to some degree by the generation function. As such, a truly independent body such as an ISO can help to alleviate concern over potential market power abuses in the transmission segment. And current state antitrust laws are available to address any issues dealing with abuse of market power.[46]

Measurement of Market Power

Market dominance is defined as the degree of monopoly market power exhibited by a firm in a competitive market. Concentration measures the degree of market domination using market share data. Hence, by looking at the concentration in a market, we can assess whether the firms in the relevant market have market power.[47] Concentration is affected by two factors: (1) the number of firms in the market, and (2) their relative size.[48] Considering the extremes of market structure, a monopoly would have the highest level of concentration (100% of the market is supplied by one firm), while a perfectly competitive market would have the lowest level of concentration (100% of the market is supplied by a large number of firms). Generally, concentration is a function of the number of firms and the degree of inequality in their market share. For a given number of firms, concentration

[45] Written Comments, Georgia Power Company, "Regulatory Issues Including Stranded Costs, Market Power, and Public Policy."
[46] Comments of CNG Energy Service Corporation.
[47] Comments on Regulatory Issues Including Stranded Costs, Market Power, and Public Policy by Cellnet Data Systems, Inc.
[48] This section is based on Burgess, Giles H. (1989). Industrial Organization, Prentice Hall.

increases with inequality. If all firms in a market have the same market share, concentration decreases as the number of firms increases.

Concentration is the single most important attribute of market structure. More research has been based upon concentration and its apparent effects than on any other factor in the field of industrial organization. To correctly calculate market power, a specific geographic area and a relevant product market must be defined, then an appropriate methodology selected to measure market power. There are two most commonly used measures of market concentration:

Concentration Ratio: The concentration ratio (CR) is a measure of concentration which reflects both the number of firms and the inequality in their market shares. CR is an unweighted sum of the market shares of the N largest firms in the market. (N could be any number: 2, 4, 8, 16, 20 . . .) CR is expressed in terms of percentage so that the values range from a maximum of 100 (number of firms ≤ n) to a minimum of 0 (high number of firms, all of similar size).

Herfindahl-Hirschman Index: The Herfindahl-Hirschman Index (HHI) is a measure of concentration that also reflects the number of firms and the inequality of their market shares. The HHI is a weighted sum of the market shares of all firms in the market.

Mitigation of Market Power

The measurement of market power and how to mitigate it must be evaluated on a case-by-case basis. Any mitigation efforts should be specifically directed to the aspect(s) of the supplier's business that gives the supplier undue market power. To determine if a particular supplier has market power, a relevant geographic market and relevant product market must first be defined. The relevant geographic market is really the area in which customers could feasibly find alternatives to a particular supplier. For example, the relevant geographic market for customers of Georgia Power would include all utilities within economic transmission distance of its service territory. The relevant product market refers to potential alternatives to any supplier's product that would place a limit on the ability of that supplier to raise prices. For example, if third parties can build new generation in the service area of Georgia Power to serve retail customers, then Georgia Power's ability to raise prices in retail markets beyond the marginal costs of new generation would be limited. The construction of new generation in this case is a viable competing product that limits any ability to exercise market power. Barriers to entry are a primary factor affecting the relevant product market.

It must be noted that the existence or absence of market power is a temporal and constantly changing phenomenon. For example, a market power problem that results from transmission constraints may be a problem only on the two or three highest use days of the year. Even market power problems resulting from generation dominance may change from day to day, week to week, and month to month. During some periods of time the ability to import power may be unrestricted. We need to take care that we don't fashion solutions for market power concerns that ignore this temporal dimension of the problem. For example, we should worry about mitigation of market power only in those time periods when it is a concern, and allow the market to operate freely at all other times.

By the same token, the relevant product may be different for different situations and different customers. For example, the relevant market for interruptible customers is different than the relevant market for firm customers. There are probably many fewer market power concerns with respect to interruptible markets than with firm markets. Other markets that should be differentiated include on-peak vs. off-peak energy, short-term vs. long-term capacity, capacity vs. energy, and uncommitted capacity vs. installed capacity. Each of these is a distinct relevant market that should be examined separately. Market power mitigation should apply only to those products where a market power concern exists. The method of mitigation is likely to be different for different products.

After examining the relevant geographic and product markets, if undue market power is found to exist, there are multiple alternative approaches to mitigation. These alternatives include, for example, continued regulation of the facilities creating market power, behavioral solutions such as "fire walls" and codes of conduct, structural solutions such as reorganization of the business, limitations on price changes during a transition, choice of market structure, or voluntary divestiture of facilities. The particular mitigation measure best suited to a market power problem is, again, case specific.

Complete elimination of market power is probably unreachable. In fact, the possession of market power will continue to be a fact in the electric industry, as noted above, simply because of transmission constraints and the necessity to run units in certain areas to maintain reliability. The possession of market power is not the problem—the problem is the exercise of market power to raise prices beyond what they would otherwise be in a competitive market. Market power, its existence, extent, and mitigation, have to be determined based on the specific facts and circumstances of the market.

Finally, market power concerns relate not only to investor-owned utilities, but also to public power and cooperative utilities. Many of the mitigation measures discussed above could not be forced on such entities under current law, and most federal legislation introduced to date would give neither FERC nor the state commissions any regulatory authority to address market power problems. This is a situation that would need to be corrected through state and possibly federal legislation.[49]

The ability of generators to artificially inflate peak period energy prices can be eliminated with widespread availability of hourly meters. Such meters can cost as little as $1 to $2 per meter per month, all inclusive.[50] Widespread availability can be achieved via the Commission providing Georgia's utilities with an incentive to provide such meters—this is the lowest-cost approach—or, as the CPUC decided in its Decision 97-05-039, via opening of metering services to competition. Hourly meters give customers the choice of whether they want to pay high peak period prices or to shift usage to other periods; without metering, customers must pay the high peak prices based on their assumed usage during the peak period. With hourly metering, peak prices will fall, because many customers can be expected to reduce usage in response to higher peak prices. According to the Electric Power Research Institute (EPRI) and the Edison Electric Institute (EEI), small commercial and residential customers reduced peak energy use by 20 percent when given the choice between high on-peak and low off-peak electricity prices.[51]

Another important mitigation of market power is aggregation of small customer loads. With aggregation, these customers can achieve the same buying power and negotiating leverage as large corporate electricity users. However, low-cost and effective aggregation requires automated technology. Hourly metering and transparent price signals can also deal effectively with transmission market power issues.[52]

[49] Written Comments, Georgia Power Company, "Regulatory Issues Including Stranded Costs, Market Power, and Public Policy."

[50] According to the California Direct Access Working Group Report, August 30, 1996.

[51] Impact of Demand-Side Management on Future Customer Electricity Demand: An Update, EPRI and EEI, 1990.

[52] Comments of CELLNET.

Comments on Market Power

Market power can be classified as either vertical or horizontal. In the case of the electric utility industry, vertical market power has been exercised by vertically-integrated utilities through their control of generation, transmission and distribution networks. Some participants suggest that existing vertically-integrated utilities be required to divest their generation and transmission assets in order to alleviate market power. For example:

> Past monopoly status must not confer competitive advantages to utilities or their subsidiaries. Fair and open competition will be impossible if one entity maintains monopoly ownership over all aspects of the utility system. Requiring a distribution of assets among independent companies will enhance competition and help to protect consumers from the potential abuses of monopoly control. In order to protect against such abuses, utilities must be required to separate their generation, transmission, and distribution assets into distinct and unaffiliated corporate entities. Divestiture incentives will assist in protecting consumers against concentrated market power, but divestiture alone will not be sufficient consumer protection.[53]

Others suggest that, “A remedy for potential market power abuses would be to modify the Territorial Electric Service Act to enable all customers, regardless of size, to choose their generation supplier and to eliminate the ‘grandfather’ clause, which restricts existing retail customers from switching suppliers.”[54]

Conclusions

In the process of restructuring the electric industry in Georgia, the General Assembly and the Commission must ensure that a structure is not created where a supplier possesses sufficient market power to essentially become an unregulated monopoly. The focus group on "Principles to Abide by in a Competitive Market" came up with the following guidelines that should be adhered to while deregulating the electric industry in Georgia:

[53] Comments of Campaign for A Prosperous Georgia.
[54] Comments of Georgia Industrial Group.

> There must be a market structure established to provide fair competition. . . . Competition among electric suppliers and buyers must be fair, non-discriminatory, and consistent, competitors should be subject to legal and regulatory treatment which will ensure a level playing field for competitors and consumers.

In order to do this, both establishing an Independent System Operator and requiring divestiture of generation assets should be studied as possible methods for reducing market power. Other, less extreme, methods of mitigating market power should also be evaluated. If the retail generation market is opened to competition, we must ensure that effective competition can develop.

5. C. Reliability of the Electric System

The reliability of an electric system can be viewed as two interrelated elements: adequacy and security. Adequacy refers to the amount of capacity resources needed to meet peak demand and security refers to the ability of the system to withstand contingencies (or sudden changes) on a daily and hourly basis, such as the loss of a generating unit or transmission line. Without adequate generation, security concerns are greater. This dual nature of reliability is the responsibility of each independent system; however, all interconnected systems are coordinated through the regional reliability councils of The North American Electric Reliability Council (NERC).

Historically, electric systems have been planned, designed and operated for the delivery of electric energy from fixed resources to geographically fixed loads, usually native load. This fundamental concept involves constraints on resources in terms of adequacy and security. That is, the physics of an electric system limits the way the system can be operated.[55] Hence, there must be control over the planning and operation of generation, transmission and distribution resources to properly allocate capacity and to maintain reliability standards.

While the Commission has a primary responsibility for oversight of electric service operations within the State of Georgia, reliability is currently the subject of analysis and initiatives that have regional and national implications. NERC is

[55] For more information on the physics of an electric system and definitions of terms see Appendix L, Physics Of An Electric System, on page 122 of this report.

establishing mandatory reliability policies, standards, principles and guidelines for its regional councils and market participants. The achievement of reliability performance criteria will be influenced by the geographical boundaries and electric system characteristics of the control area, such as the Southern Control Area. Georgia should proceed cautiously with any plan to restructure the electric industry to ensure conformance with the reliability criteria and standards being developed in other industry-wide initiatives.

If retail open access is implemented in Georgia, current responsibilities for reliability conformance may need to be modified to conform to responsibilities that are generally expected upon the initiation of statewide retail open access. It is important to recognize that an entity charged with planning for a standard level of adequacy of generation supply may not necessarily be the entity with responsibility for maintaining daily security. Ideally, separate groups would be responsible for establishing operating standards, implementing the required actions and monitoring compliance. Moreover, there are distinct and separate reliability concerns pertaining to generation, transmission and distribution planning and operations that must be factored into any restructuring plan.

Electric System Reliability in Georgia

In Georgia, electric energy is delivered to consumers over the Integrated Transmission System (ITS) whose ownership is shared jointly by Georgia Power Company, Georgia Transmission Corporation, Municipal Electric Authority of Georgia and the City of Dalton. Savannah Electric and Power Company is not an owner, but interconnects to the ITS. Other privately-owned transmission exists in the state. These participants coordinate the planning and operation of the ITS according to NERC/SERC reliability standards. Currently, the Southern Company Power Coordination Center, in conjunction with the Georgia Power Transmission Control Centers, provides security coordination for operation of the ITS within the larger Southern Control Area. The Power Coordination Center is responsible for balancing load and generation within the Southern Control Area to ensure that sufficient capacity is committed on a daily basis to meet anticipated load, plus reserves. The Power Coordination Center also performs the economic dispatch of generation units within the Southern Control Area to minimize costs of balancing load and generation. The Transmission Control Center monitors bus voltages, transmission line loading and network status within Georgia.

Focus Group Considerations and Concerns

To help form the basis of a more complete dialogue on System Operations and Reliability, the Commission set up a focus group on this topic. The focus group identified two separate reliability considerations: adequacy and security. *Adequacy* considerations involve capacity reserve planning and load forecasting and are oriented toward the long-term establishment and maintenance of reliability levels. *Security* considerations are more complex and involve operational planning, usually short-term, plus the requirements for actions or services to maintain system reliability at acceptable levels on a daily and hourly basis. Due to distinct reliability considerations pertaining to generation, transmission and distribution planning and operations, the focus group made separate observations as follows:

Generation

The focus group members reached consensus regarding many aspects of reliability responsibilities and involvement relating to generation. These responsibilities were categorized into four separate functions:

- Establishment of Standards
- Implementation of Reliability Standards and Procedures
- Responsibility for Compliance Monitoring and Measurement
- Regulation of Utility Processes

The focus group contrasted current conditions with those which would be necessary, according to group members, for equivalent reliability maintenance under retail open access. Differences of opinion would exist depending on whether or not a formal ISO was established that would overlay or supplant some control area operator or security coordinator functions. It is important to note two observations made by focus group members:

1. Whereas the current five major suppliers in Georgia[56] function both cooperatively and separately in setting and implementing reliability procedures, other new suppliers and retail customers will also have to be involved under retail open access. This is because those other

[56] Georgia Power Company, City of Dalton, MEAG Power, Oglethorpe Power Corporation, and Savannah Electric and Power Company control and operate all major generation facilities; however, MEAG Power and Oglethorpe Power Corporation have numerous municipal and cooperative utility members, respectively, which supply load at the retail level.

suppliers and customers will add non-native resources or contract for services involving non-native resources to supply part of the current native total customer base, and any failure of those new resources to operate reliably will impact overall reliability for all customers. Conversely, state-resident customers of new suppliers should be assured (or have the opportunity to elect) utility service which is comparable in reliability to that provided to any other resident customer.

2. The Commission's current IRP process serves to help set and ensure uniform, statewide generation reliability levels. With the advent of retail open access, however, the Commission must consider how (or if) to exercise jurisdiction over services to retail customers of new suppliers as well as services to those customers retained by current suppliers (i.e., universal service customers). Since the services will be for retail customers, it is the opinion of the focus group that some form of jurisdiction at the state level is necessary. This suggests both an expanded role for the Commission in assuring compliance and added roles in regulation.

The group members recognized that these observations imply that municipals and cooperatives (particularly, the member systems under MEAG and OPC) would be subject to the same regulatory jurisdiction regarding retail services as all other providers of services to state-resident retail customers.[57] This was generally considered a necessary element to assure equal treatment to all customers regarding service reliability. However, it was noted that the Rural Utility Service (RUS) reviews reliability practices of cooperatives, via resource plans, in terms of adequacy, and some accommodation of those processes should be included.

There is also a potential for adverse reliability impacts on in-state retail customers due to in-state suppliers providing service to out-of-state retail customers. This points to a need for coordination of reliability between state jurisdictions in the event that in-state resources are utilized or needed for backup supply.

[57] The focus group did not assess whether there might be any different or special regulatory requirements which might pertain to cooperative utilities in the North Georgia area which are currently supplied by the Tennessee Valley Authority.

Transmission

The introduction of retail open access will add complexities to the transmission network that should be addressed at the state level. It is the presumption of the focus group that retail customers who contract for service from suppliers using transmission facilities from another resource will be required to also contract for (or otherwise self-supply) the same ancillary transmission services as is now required for wholesale customers. It would also be necessary to define additional ancillary services for retail supply. In FERC Order 888-A, ancillary services are categorized as:

- Scheduling, System Control and Dispatch Service
- Reactive and Voltage Control from Generating Sources Service
- Regulation and Frequency Response Service
- Energy Imbalance Service
- Spinning and Supplemental Operating Reserve Service

There will be vital interest from various parties in assuring that appropriate and sufficient ancillary services are provided so that existing (retained) wholesale and retail customers do not bear the cost of providing reliability services by default.

Although ancillary services are to be administered under arrangements for transmission services to wholesale customers, they essentially apply to the operation and reliability of generating facilities. The mechanism for application of mandatory or elective ancillary transmission services to retail customers is yet to be determined.

Distribution

Utility companies perform distribution reliability functions within their defined service territories based on the traditional “obligation to serve” retail customers. The focus group noted that the boundary between distribution facilities and metering facilities provided a natural separation for possible “wires” and metering services that might not necessarily be contracted for with the same service supplier. However, reliability spans all service categories. One possible method of ensuring reliable service might be to assign appropriate and fair cost responsibilities to those services that enhance or promote such service, and to fairly penalize those actions that detract from it.

Retail open access will require changes to, or redefinition of, current approaches and practices relating to reliability, quality of service and obligation to provide service. The focus group believes that a necessary requirement will be the functional unbundling of distribution services. This would provide a mechanism for the definition of optional and mandatory services similar to what has been done in relation to transmission services. Retail open access also gives attention to such concepts as “the supplier of last resort,” “universal service customer” and “default supplier.” Different scenarios involving these concepts are described in the white paper submitted by the focus group.

With the possible advent of retail open access in Georgia, Commission jurisdiction over suppliers must be clearly defined. A certification, licensing or qualification process should be considered that evaluates the managerial, technical and financial capability of suppliers, similar to that in the telecommunications and natural gas industries. It is also necessary for the service levels and actions in all service territories to be consistent. While retail open access should promote competition, native customers should be protected from any adverse impacts of new suppliers operating within their local areas.

Initiatives and Issues Impacting Reliability

Independent utilities originally interconnected via tie lines to neighboring utilities to maximize reliability of electricity supply to their customers. One of the advantages of an interconnected system is reserve sharing. If a contingency occurred in one company, power could be supplied temporarily by the other companies. Hence, an interconnected system of reliable suppliers enhances overall reliability and decreases the reserve levels needed by independent utilities. This assumes that each supplier in an interconnected system provides a proportionate amount of reserves to meet load.

Once interconnected, utilities began to buy and sell wholesale power to reduce their cost of generation. Scheduled power sales emerged whereby the selling company increases its generation by the amount of the sale at the same time that the buying company decreases generation. However, power flow is controlled by physics, not contracts. Loop flow would occur where some or all of the scheduled interchange between two companies flows through the transmission system of a third company not directly involved in the scheduled sale. Changing generation patterns only provides limited control over actual power flow. Currently, it is not a legal requirement for contracts to include the actual path. At times availability and reliability of the transmission system has been diminished and third parties have been adversely affected by scheduled sales of others. Wholesale power exchanges have caused an increase in the use of the transmission system by multiple parties. The development of competitive retail service has the possibility of further stressing transmission capacity as the number of participants using the system increases. In response, NERC and its member regions are instituting operation procedures to mitigate any detrimental reliability effects of increased competition.

Some initiatives in progress are transaction tagging, security monitoring process, new policies for interconnected operations, and mandatory compliance with NERC policies. Currently, there is an effort to tag the purchase and sales of electricity to allow tracking of such transactions. Tagging of transactions between regions when they may be split up after being sold initially, is a major undertaking. Without tagging, it will be difficult to control the system and there will be participants using the system in regions that have not paid for its use. Another concern, as retail open access unfolds, is the exchange of information between security monitors, such as an ISO, to ensure that security is maintained over a wide area. With large amounts of power being shipped over wide areas, an organized security process and a good tagging system are necessary to avoid reliability risks. Other initiatives include NERC/SERC's development and enforcement of policies and standards for interconnected operations that are necessary for grid reliability. The extent of mandatory compliance with NERC policies and standards has yet to be determined. The Department of Energy (DOE) has a reliability task force that is proposing different ways of enforcing NERC policies.

In addition to the aforementioned initiatives, there are many issues that need to be resolved prior to retail open access. These issues include future projects regarding actual path scheduling, pricing of generation imbalance, and mandatory on-line security analysis. In terms of actual path scheduling, there can be some argument that as long as you have rules and procedures about non-firm sales and some method of tracking system security, you may not need to pay by the actual path. On the other hand, one can argue that if your use of the system impacts the owners' right to use their system, you should compensate the owners for that use. This issue ties into the process of transaction tagging. Another issue is the pricing of generation imbalance. With the possibility of an intensely competitive environment, discussions have emerged on the need to price generation imbalance. That is, there should be a price associated with the failure to meet obligations. Furthermore, this leads to the issue of mandatory on-line security analysis to track imbalances. Based on their discussions, the focus group believes these issues should be addressed during further consideration of retail open access.

Conclusions

With retail competition on the horizon in Georgia, the major issues set forth herein must be resolved to ensure that the true costs of providing our historical level of reliability will continue to be equitably borne by all users of the electrical system. These reliability issues pertain to all aspects of planning for and operation of the generation, transmission and distribution systems. In terms of planning and operating difficulties, the bulk transmission system was designed based on known transactions and certified generators for geographically fixed load. Under retail access, generation resources will be provided by the competitive marketplace. This requires knowing the location of resources to adequately meet peak demand and maintain reliability control. Moreover, there are many economic issues overlapping the technical difficulties that must also be resolved prior to retail competition. Institutions and market structures are not yet in place to sustain reliability in a retail competitive environment. For this reason, more in-depth discussions with market participants are needed to develop solutions and proposals addressing all issues.

5. D. DETERMINATION AND RECOVERY OF STRANDED COSTS

One of the most controversial issues associated with restructuring the electric industry is the determination and recovery of stranded costs. Regulated electric rates are designed specifically to cover a utility's cost of doing business, i.e., to recover its operating costs and invested capital and to provide an opportunity to earn a reasonable return on its capital. On the other hand, market-based prices are indifferent to the costs incurred by any individual market participant. Therefore, as electric markets are opened to competition the level of revenue earned by a utility may no longer closely match the level required to cover its costs. Some may earn more than their cost of doing business, others less. The difference between costs expected to be recovered under rate regulation and those recoverable in a competitive market is termed "stranded costs." If market prices are lower than regulated rates, as many expect, utilities could be faced with investments that are unrecoverable in the competitive market.

The issue of stranded costs has several facets. One is to clearly define what is meant by "stranded costs." The utility's cost obligations must be identified and quantified. Although a company may have "strandable" costs, future market conditions will dictate whether these costs are unrecoverable. Therefore, expected future market revenues must be quantified, as well. Other considerations are: Whether stranded costs should be recovered? If so, should 100% of the stranded costs be recovered or only a portion? Who should pay for the stranded costs and what mechanism should be used for recovery? Has the utility company made a bona-fide effort to mitigate its stranded costs? and, Were the original investments and expenditures prudent?

Definition of Stranded Costs

To address the issue of stranded costs the Commission set up a focus group which included representatives from IOUs, EMCs, MEAG, Industrial end-users, CUC and CPG. Each party's views and definitions of stranded costs, the reasons for the existence of stranded costs and the appropriate recovery mechanisms differed.

No consensus was reached on a precise definition of stranded costs. A definition should be developed within the context of a Commission proceeding on this subject. Other states have already addressed this issue. For example, the Public Utility Commission of Texas acknowledges that "the concept of stranded investment has become confusing because of the number of definitions and interpretations." They also recognize that no costs are actually stranded until such time as customers begin to switch suppliers. As such, they define two concepts, "stranded investments" and "potentially strandable investments." The definitions made by Texas are as follows:

> Stranded investment is defined as the historic financial obligations of utilities incurred in the regulated market that become unrecoverable in a competitive market. In the past, utility investments, i.e. "Financial Obligations," have been made in the regulated market, the market in which utilities "historically" operated. In that market, utilities anticipated that investment would be recovered in rates charged to customers. These obligations may become "unrecoverable in a competitive market" because prices in a competitive market are uncertain, and as such, may be below regulated prices. If a utility cannot charge as much in a competitive market as it would have charged in a regulated market, a portion of the asset becomes

"unrecoverable" or "stranded." Thus the change from a regulated to a competitive market can create stranded investment.

The term "potentially strandable investment" is used because no investment is necessarily unrecoverable. The portion of potentially strandable investment that will ultimately become stranded is unknown. Costs may become stranded because the customer leaves a regulated utility for a market-based source of supply. However, the level of strandable costs is not dependent solely upon the customer's behavior. Rather, the quantity of potentially strandable investment is also affected by market conditions. Even if the customer continues to buy from their local utility, the difference between the previous regulated price and the new market price will drive the amount of stranded investment.[58]

Determination of Stranded Costs

Stranded costs can be determined in a variety of ways. One approach is to measure the stranded costs associated with each generating asset or purchase contract. Under this method the market value of the asset is compared to the fixed and operating costs of the asset. The determination of market value requires numerous assumptions and sophisticated modeling and therefore results may vary widely.

The market value is usually defined as the potential revenue a particular asset or investment can earn in a competitive market place. This value is calculated in terms of the price of electricity in the marketplace multiplied by the energy sold from that asset. Most models of stranded cost calculate this value over the life of the asset. If the revenues collected do not cover the historical costs associated with that asset, the difference is "stranded." The critical assumptions required in calculating the market value are those concerning the competitive market price. First, since a competitive market is not currently in existence, there are no real prices to evaluate. Instead, there are models that will, under simplified assumptions, calculate the market price for whole regions. However, these models are simplifications of a very complex system. As such, the assumptions used and the simplifications made could drastically alter the results. These uncertainties and simplifications have resulted in estimates that are of such large variance that they appear to be unusable for making decisions about how to allocate stranded costs.

[58] Report to the 75th Legislature: The Potential for Stranded Investment in the Electric Utility Industry in Texas (Second Staff Draft, Review Version) Public Utility Commission of Texas, October 27, 1996.

Future or forecasted market price is defined as the price that can be expected to be charged for the output of the generating unit in a deregulated market. The future market price may be forecasted over an hourly, weekly, annual or other defined period of time. The final actual market prices will differ from forecasted prices. As with other competitive markets, sellers will sell their plants' output at the highest price that they can receive. The seller is not expected to sell below the operating cost of the unit. Thus, a counterbalance of supply and demand is created at the marginal cost of the unit. That is, suppliers will continue to make electricity available to the market as long as they can earn more than their cost of production. The prevailing market price will determine if the unit is run or not run to meet the price and demand expectations of the market. The market clearing price is the price of the available generation that can be supplied against the expected demand created for that generation. Excess generation and low use will create low market prices while a shortage of generation and high use will create higher market prices.

The determination of a forecasted market clearing price is based on the forecasted cost of generation available against the forecasted demand to be supplied by the available generation. Any forecast will differ from actual results over a period of time. While many factors influence the determination of forecasted market pricing, three key factors form the core of any market price forecast. These key factors are fossil fuel costs, expected forecasted use and the reliability of the generation output to meet the demand requested.

Forecasted fossil fuel costs for coal, gas and oil will provide the competitive basis for existing generating units (including nuclear power), the economic viability of new units and the use of alternative fuels. Forecasted energy use will determine the extent to which current generation is used, the demand for new generating additions, the upgrading of existing units and the development of alternative power sources. In the future, the expansion of generation facilities will be dependent upon the market place. Estimates of the cost to install new generation as well as estimates of the operating cost of those units can be made without designating who will own the facilities. The choice of new generator type and the timing of construction will greatly impact the estimate of potentially strandable investments. A delay of a year or two, or a change from one generation type to another, will alter the market price and therefore change the stranded cost estimate. Because of the necessity to match on an instantaneous basis the supply or demand of electricity, an adequate supply of generation plus sufficient backup reserves will be required for reliability. The cost of this backup will be driven by the adequacy of reserves in the generating region, transmission constraints and the degree of any continuing obligation to provide service to all customers. These factors will form the basis of the forecasted market price.

Once determined market value is compared to the fixed and operating costs of the assets. These costs must be determined for each period of time over the life of the asset. In a purely regulated environment, these costs would be adjudicated in a regulatory setting in which all parties are allowed to present their points of view. The costs associated with an asset should include acquisition or fixed costs as well as the costs associated with the operation of the facility. In financial terms, this is the total of both the undepreciated assets remaining on the balance sheet as well the operating expenses. These costs must be established for each year until the asset has completed its used and useful life. The values assumed for costs will cause wide variations in the results of the strandable cost calculation. In those states that have attempted to calculate stranded costs, such as Texas, the assumptions for fuel cost have greatly affected the resulting strandable investment.

Given an estimate of both the market value and the cost profile of the assets, several methods may be utilized to determine stranded cost. One method of determining stranded costs is a net present value analysis. The revenues required to be collected over the remaining life of the generating asset to pay for the operating cost of the unit including debt cost are compared to the market revenues that may be charged for the output of the same unit over the remaining life. By comparing the projected costs, including debt cost, that must be recovered for each of the utility's generating units to the projected market operating revenue that may be charged for each unit, it is possible to forecast which units are able to run and recover their full costs, and which ones are not. Thus, the net present value of costs of the generating asset which are in excess of the net present value of the forecasted market revenue become the stranded cost. This may be expressed as: NPV of the forecasted operating cost of the unit minus the NPV forecasted market price for the generating unit's output.

The key to this approach, obviously, is making accurate forecasts of both future generation costs and the future market price of power. Errors in such forecasts could drastically affect the stranded cost estimates, either up or down. Another concern with this model is that some assets will not only cover their costs but earn revenues in excess of the operating and capital costs. These "negative" stranded costs should be netted against the "positive" stranded costs to form a more accurate estimate for the company as a whole.

To reduce the forecasting error of future market value and future operating costs inherent in this analysis other approaches could be used to determine stranded costs. One way to reduce, but not totally eliminate, forecast error would be to estimate market price by developing a range of prices based on a range of reasonable assumptions for all key variables affecting market price, and then negotiate or adopt a number within that range. Such a simulation would require modeling the region under different competitive assumptions. Another alternative would be to look at wholesale markets for some indication of what market prices may look like in competitive retail markets. Another approach is to use actual market prices once the competitive market is in place. A mechanism based on actually realized market prices could eliminate over-recovery of stranded costs and obviate the need to forecast market prices. A variation of this approach would be to make an initial forecast which would be trued-up over a period of time as the competitive market develops. This would be time-consuming and require extensive review and analysis each year. Another approach is the divestiture model. Market price would be based on the actual sales price of above market value assets or on an appraisal of what the assets would be worth if sold.

Given the uncertainty of estimating future market prices, regulatory agencies currently addressing stranded costs are developing alternatives to up-front estimates of stranded costs based on market price forecasts. For example, FERC, in its Order 888 provides an alternative to market price forecasts based on the actual contract price negotiated by departing customers. In California, while the issue is not fully settled, it appears that actual prices achieved by the power exchange will be used to calculate stranded costs, thus providing the opportunity to true-up forecasts over a period of time based on real market price data. In Pennsylvania, utilities have proposed market price estimates based on modeling forecasts and assumptions about all of the above variables. In Rhode Island, the legislature set a fixed amount per kWh for stranded cost recovery, based on a negotiated settlement.

Recovery of Stranded Costs

If costs will be stranded in a competitive market the level, method and timing of stranded cost recovery must be determined. One step in this examination of stranded costs is identifying who is responsible for the cost being stranded.

Some claim that stranded costs arise directly as a result of faulty investment decisions, e.g., plant technology or source of purchased power, by the utility management. They believe that the formation of a regulated monopoly was never meant to be an entitlement program. It was intended to provide the utility a return on capital, for the exchange of a fair price structure. It was never the intent of the regulatory compact to guarantee that all investments will be fully amortized in all future situations. According to others, the only reason we have stranded costs is that we can replace the existing system with one that lowers prices. The attempt to emulate competitive prices by regulating the monopoly has failed. Hence, they argue the stranded cost burden should be borne by shareholders.

Others, primarily the utilities, offer the "regulatory compact" argument. Briefly stated this argument purports that: As a result of the obligation to provide electric service invoked by regulators in exchange for monopoly status, electric utilities have installed generating facilities and committed to contracts with other suppliers to ensure safe and reliable service. In exchange for accepting the obligation to serve, the utilities were guaranteed recovery of these investments plus, in the case of investor-owned utilities, an opportunity to earn a fair rate of return. As the industry contemplates moving from a regulated market to a competitive market there exists a potential for the utilities to be unable to collect these historically incurred costs. Therefore, the utilities should not be penalized when the rules of the game change and stranded costs should not be borne by the shareholders.

Some suggest that the burden of stranded costs should be shared. Any sharing of stranded costs must be based on principle and consideration must be given to the adverse impacts on any group selected to bear a portion of these costs. The potential exists for rate shock to residential and small commercial customers in a restructured electric industry, even though competition should, theoretically, benefit all customers. Smaller customers, who may have less sophistication and less bargaining leverage than larger users, will likely have the most difficult transition to make. To burden these customers with a greater share of stranded costs than they deserve may make it impossible for them to receive affordable and reliable electric service in a restructured environment. The stranded cost issue needs to be resolved in a way that does not eliminate, or significantly delay, any benefits that residential and small commercial ratepayers may gain from competition. At the same time, rate shock must be avoided. This means that it could be acceptable for consumers to bear some stranded costs if doing so will help avoid rate shock.

If utilities do not recover their stranded costs, the shareholders will bear the burden. The demographics of investors and the effect that absorption of stranded costs will have on the utility's ability to attract sufficient capital to provide safe, reliable and affordable power must be considered. However, utilities should not recover imprudent investments or stranded costs that can be or could have been mitigated prior to the market being opened to competition.

It should be noted that two Congressional proposals for restructuring the electric industry include recovery of stranded costs:

> The state regulatory authority may require, as a condition for the purchase by any person or municipality of retail electric energy services, the payment of a charge to recover costs incurred by an electric utility that become unrecoverable due to the availability of retail electric service choice. (U. S. Representative Dan Schaefer)
>
> Electric Utility companies that prudently incurred costs pursuant to a regulatory structure that required them to provide electricity to consumers should not be penalized during the transition to competition. A retail electric energy provider shall be entitled to full recovery of its stranded costs, over a reasonable period of time, through a non-bypassable Stranded Cost Recovery Charge imposed on its distribution and retail transmission customers. No class of customers will be assessed a stranded cost recovery charge in excess of the class's proportional responsibility. (U.S. Senator Dale Bumpers)

One recovery method being discussed extensively is securitization of stranded costs. Using this method the utilities are able to recover their stranded costs immediately. An estimate must be made of the level of stranded costs. Then revenue bonds or other securities are issued for this amount. The utility receives the proceeds of the security issue as recovery of the stranded costs and the cash flow from a transition charge or other non-bypassable charge is used to fund the debt service over the life of the bonds. These are the key steps to securitization:[59]

(1) Legislation creates a "non-bypassable" customer charge with a transferable guaranteed right to collect for the utility;

(2) State utility commission determines and authorizes the amount to securitize;

[59] Discussion of securitization is based on "'Stranded Costs' and Benefits and Risks to Customers from Securitization," a presentation by Dr. Kenneth Rose, National Regulatory Research Institute.

(3) Utility sells the right to collect the customer charge through a trust in the capital market; and,

(4) Utility receives the proceeds.

Securitization can save on capital carrying costs by replacing the utility's higher cost debt and equity with the lower cost bond rate based on the legislatively guaranteed revenue stream. In order for securitization to achieve this savings, investors have to be given assurances that the payment stream is secure; that is, more secure than ordinary utility debt. Securitization would replace the annual revenue the utility would have received with a lump-sum, up-front payment of cash. The money could be used to: (1) buy back stock and retire debt in equal proportion or replace higher cost equity; (2) restructure power purchase contracts from non-utility generators and others; or, (3) invest in new power projects.

The cost-of-capital savings come from lowering the risk to investors by increasing customer risk. Several problems are inherent in securitization:

- Securitization is an irrevocable ratepayer commitment to pay the security in full;

- The forecast error, that is the risk of guessing wrong, when estimating the amount of stranded costs is placed on customers. Stranded cost estimates are highly sensitive to relatively small changes in assumptions. Many of these assumptions are highly speculative guesses about how things will turn out in a competitive market; and,

- Finally, securitization results in regulatory and market bypass. Customer protections from the regulation and monitoring of costs are removed. Supervision of these costs is placed beyond the oversight of the market and regulation.

At least one state has opted to use securitization, that is, California. Five others have laws that allow securitization. Another state has concluded that: "Exit fees and securitization are recovery mechanisms that should not be adopted because of their anti-competitive characteristics."[60] Before seriously considering securitization for Georgia it must be determined whether securitization is an appropriate policy tool to apply to the "stranded cost" problem and whether securitization is harmful to the development of a competitive generation market.

Conclusions

In sum, even though a utility may have potentially stranded costs, these costs may still be recoverable in a competitive market place. The determination of stranded costs must be done on a total company basis, not just for selected assets. Unless it is based on actual market prices, the estimate of stranded costs is subject to considerable forecast error. Stranded cost recovery guidelines should be adopted to ensure that the allocation of sharing of stranded costs is equitable and that the time period for recovery is appropriate. No group should achieve a windfall at the expense of another. The focus group on "Principles to Abide by in a Competitive Market" developed the following guidelines:

> The State of Georgia should consider the recovery of legitimate, unmitigatable stranded costs . . . Recovery of stranded costs should consider prudence reviews and past regulatory actions . . . The length of time for any transition period to increased competition should consider what is necessary to recover stranded costs. . . The State of Georgia, rather than the Federal Government, should set the rules to determine the recovery from stranded costs and investments. . . There should be no cross-subsidy and over-recovery of stranded costs.

The Commission should thoroughly investigate these issues associated with stranded costs in a docketed proceeding.

[60] Mississippi Public Utilities Staff, "Proposed Transition Plan for Retail Competition in the Electric Industry," 11/1/97, page 35.

5. E. TAX IMPLICATIONS OF ELECTRIC INDUSTRY RESTRUCTURING

Any significant restructuring of the electric industry in Georgia should be accompanied by appropriate changes to state and local tax laws. The Tax Implications Focus Group concluded in its report that Georgia's present system of taxing electric utilities would be counterproductive to an open, competitive electricity market. Tax inequities would occur if some electric suppliers receive more favorable tax treatment than others, allowing them to market their power at tax-advantaged prices. State and local government revenues could decline because of lower-priced electricity, an increase in market share by less heavily taxed providers and a decline in the values of utility-owned property located within the state.

Electric utilities are major contributors of tax revenue to local, state and federal governments. With about twenty cents of every dollar paid for electricity going toward the payment of taxes, a reliable stream of revenue is provided to governmental entities. Electric utilities pay more in state and local taxes, as a percent of revenues, than any other type of business. Utilities also collect certain taxes imposed on utility customers and remit these funds to the appropriate agencies. In 1996 Georgia Power Company's accrued taxes totaled $612 million, or 13.8 percent of operating revenues.[61] Georgia EMCs pay over $155 million annually in local, state and federal taxes.[62]

The current system of utility taxation was designed for a highly regulated natural monopoly. Taxes are included among those costs that are recovered through regulated electric rates. Among the taxes paid by Georgia utilities' retail customers in their electric bills are sales and use tax on generating fuels, municipal franchise fees and property taxes. New suppliers producing electricity outside Georgia for sale in this state would not be subject to these taxes. In a competitive environment, more highly taxed, in-state providers may not be able to pass the difference in taxes on to their customers.

In most states, generating fuel is treated like other raw materials and not subject to sales tax. In Georgia, generating fuel is subject to sales and use tax, adding to the sales tax paid by consumers on electricity generated within the state. Suppliers producing electricity outside Georgia could have a pricing advantage over a utility generating inside Georgia. Suppliers outside of Georgia would have an unfair pricing advantage over suppliers within the state and would then gain market

[61] Georgia Power Facts & Figures.
[62] 1997 GEMC Directory, p.3.

share. At the same time, electricity being generated out-of-state that replaces power from in-state generating units will cause sales tax revenues to decline.

Franchise fees are paid by most utilities, except the municipal electric systems, to cities and towns throughout Georgia. These fees are paid to compensate for the right to provide services in an area and for use of public roads and rights-of-way. The amount paid is based on a percentage (usually 4%) of gross receipts within the municipal jurisdiction. Municipally-owned systems pay similar fees by way of general fund transfers. Although franchise fee revenues benefit the jurisdiction where the franchise agreement exists, these costs are recovered through rates collected from all customers of the investor-owned utilities.

Increased competition could impact franchise tax revenues in two ways. Suppliers generating electricity out-of-state, with no local distribution system, would have only distribution charges paid by its customers subject to franchise fees. In-state suppliers, however, would have both distribution and energy charges paid by its customers subject to these fees. Franchise fee revenue could also be impacted by a decline in electricity prices resulting from increased competition.

The valuation of electric utility assets is also important. Property taxes are a significant source of revenue to local jurisdictions where generating facilities are located. Assessment percentages are applied to the fair market value of the utility property, as determined annually by the State Revenue Commissioner. If the economic values of generating plants decrease due to competition, property tax revenue would decline as well.

While property tax revenues could be adversely affected by deregulation of electric generation, this may actually be an area in which electric utilities may be able to enhance their profits. Daniel H. Israel, an attorney specializing in state and local taxes in Arizona, states in a May 15, 1997, Public Utilities Fortnightly article that “utilities can secure considerable savings by taking a knowledgeable and creative approach to state and local taxes.” Reducing utility income attributable to real property, recognizing economic and functional obsolescence, and developing a method to discount the role of capital investment and real property are examples offered by Israel for mitigating exposure to property taxes. Any resulting savings to the utility can, of course, be passed on to utility customers. Local jurisdictions, however, may have to raise millage rates for all property owners to compensate for lost revenues.

Some of the income tax issues concerning Georgia utilities include tax-exempt financing, income tax liability determination and deferred income taxes. Adverse tax consequences are also expected relative to federal income tax rules involving tax normalization requirements, nuclear decommissioning costs and many others. However, most discussions in the focus group, related to state and local tax implications. The focus group felt that since Georgia's income tax laws conform to federal law, for the most part, resolution of income tax issues would be at the federal level.

The Tax Implications Focus Group also expressed concerns for potentially adverse impacts on economic development. The closing or downsizing of inefficient plants may not only affect the property tax base but could also impact local jobs, the local economy and income taxes. Competition may also cause utilities to reduce spending on economic development as the benefits of such efforts are reduced.

A Deloitte and Touche analysis states that "New Jersey's Board of Public Utilities and Treasury Task Force listed as a principal reason for New Jersey's tax policy being under consideration is that New Jersey's 'energy taxes are among the highest in the nation, hindering economic development and growth.'" Proposals to reduce New York State's utility gross receipts tax came about because businesses in that state expressed similar concerns.

An opposing viewpoint is that the problem of obtaining tax equity and revenue neutrality may not be as difficult to remedy as some may think. Joanne Melcher of the Home Depot and The Alliance for Competition in Electricity asserts, in an attachment to the focus group report, "that the business of Georgia utilities will increase as deregulation unfolds in the United States . . . Open markets will generate greater tax dollars to the state in the form of income tax, occupational tax and sales tax." Ms. Melcher and others believe economic development will increase with competition. She states, "The ability of a manufacturing customer to work with a supplier or cogenerate in a state that has low cost energy will actually create more jobs and tax dollars for the state."

However, Pennsylvania was identified in the March 17, 1997 State Tax Notes as "the only state to have faced up to the state tax implications of electric utility deregulation. Pennsylvania did not totally subscribe to supply-side arguments that economic growth fostered by cheaper power would sustain the previous level of utility tax collections, at least in the near term." Worried about losing any part of utility tax revenue, Pennsylvania legislators left all five taxes imposed on its utilities in place.

The Tax Implications Focus Group stated that any alternatives offered as potential solutions to tax problems associated with restructuring the electric industry should meet the following criteria: Allocative efficiency, which means that tax revenues are raised without unduly affecting the patterns of production and consumption that would occur in the absence of taxation; and horizontal equity, meaning that equivalent businesses should be treated the same. Suggestions offered for consideration were a tax on electricity transmitted into Georgia from out-of-state generators, an energy sales and use tax on energy suppliers and an energy consumption tax on the consumer.

Some states have already taken steps to address the problems of decreased revenues and unequal tax treatment. In Arizona a house bill was introduced in January 1997 to establish a joint legislative study committee on electric generation taxation. In January 1997 a house bill was introduced in Delaware that would provide for a tax of 4.25 percent on the gross receipts of any distributor of public utilities. If a customer purchases power from an out-of-state entity, the customer pays the tax. Legislation was introduced in Iowa to replace electric utility property taxes on distribution property with a commodity tax on sales to end-users; the tax would be paid by the distribution utility. Mississippi has introduced a model electric industry restructuring bill that makes all competitors subject to the same tax treatments and directs the State Tax Commission to recommend any necessary tax changes. New Jersey's tax plan would eliminate the state's 13 percent gross receipts tax; all retail electricity sales would instead be subject to the state's 6 percent sales tax (currently electricity is exempt from sales tax).

Utility industry taxation should be one of the major areas of legislative change. The Commission should ensure that tax reform is an integral part of any restructuring proposal. Legislators and others establishing tax policies must be made aware of the tax implications of restructuring and the need to give careful consideration to the potential impacts on state and local revenues. They should also be aware of the need for equitable tax treatment to the various electric power suppliers in order to guarantee the lowest possible cost to their customers.

Electric utilities should be involved in efforts to educate legislators and others in order to ensure tax equity for both utilities and non-utility competitors. Marketers and other non-utility sellers of energy should be involved to make certain their tax paying obligations are clearly stated. Legislative activities involving taxation issues in other states should continue to be monitored. Mayor Gerald Thompson of Fitzgerald, Georgia spoke at the fourth workshop on behalf of MEAG and the

Electric Cities of Georgia suggesting "that this issue needs to be the subject of a comprehensive, professional study to provide the potential exposures and recommend the best treatment of these issues in any deregulation model."

5. F. PUBLIC POLICY

Historically, policy makers have used electric utilities and electric rates as vehicles for implementing public and social policy initiatives. Most of these initiatives relate to utility service, such as ensuring universal service, encouraging energy efficiency and increasing the use of renewable fuels, but not all. The cost of these programs is embedded within our regulated utility rates. It is possible that some competitors will not continue to support these public policy goals if the electric industry is restructured. Others will fully support some policies and use this support for niche marketing, e.g., selling green power.[63] Thus, the benefits of our public and social policies cannot be guaranteed in a competitive market. Unless we make provisions to continue these efforts, we risk their elimination. Universal service, obligation to serve, energy efficiency, renewable resources, research and development, and consumer protection are all public policy issues that should be addressed during the process of restructuring the electric industry.

Universal Service

Universal service is perhaps the most critical of these public policy issues. At the third workshop, entitled "Regulatory Issues Including Stranded Costs, Market Power and Public Policy," universal service was discussed extensively. The focus groups also addressed this topic. Universal service can be defined as the assurance that all residents of Georgia will have access to affordable electric service. However, the goal is not to fund subsidized service through rates if there is clear evidence that a competitive market place would result in affordable electric rates without governmental intervention. Comments of some of the workshop participants regarding universal service were:

> The Commission should develop appropriate mechanisms to fully reimburse utilities that continue to provide universal service. For the longer term, the Commission should explore approaches for allowing providers to compete for the role of

[63] Green power is electricity produced in a manner that reduces any harm to the environment, such as using wind power or renewable fuels.

'default supplier.' Social programs, such as low-income assistance, should be continued in a competitive market. The idea of coordinating social programs related to electric service with other state-provided assistance programs should be investigated.[64]

A universal access fund should be created to ensure that low-income customers receive electric service in a restructured industry. This fund needs to be structured in such a way that does not make it impossible for firm customers to benefit from competition.[65]

Universal service and consumer protection programs (e.g. restricted ability to terminate service during winter months) will not be offered at adequate levels, if at all, in a competitive market. Public policy should dictate that all consumers, whether in metropolitan or rural areas, have equitable access to electricity. The obligation to serve, however, should be structured such that the suppliers' ability to compete for profitable loads is not affected.[66]

In a competitive market, all participants must share equitably in the costs of maintaining universal service through some type of non-bypassable surcharge on utility bills, exit fees or wheeling charges. There must be an entity with a continuing obligation to serve customers not participating in competitive markets; however, once a customer leaves to purchase from another supplier, the local utility should have no obligation to supply power to that customer other than what is agreed upon by contract. To the extent the local utility is later required to take back such customers, it should only be at the incremental cost to serve those customers.[67]

Sometimes utility prices reflect costs of certain mandated social programs that do not directly relate to the costs of producing

[64] Comments of CNG Energy Services Corporation.
[65] Comments of Consumers' Utility Counsel.
[66] Comments of Georgia Electric Membership Corporations and Oglethorpe Power.
[67] Comments of Georgia Power Company.

> electricity. These cost could be removed from the price of electricity.[68]
>
> The "obligation to serve" should be eliminated. Deregulation demands the end of the utility company having to bear the cost of social burdens [sic]. Instead, state and local officials should be allowed to design targeted means and tested methods of delivering assistance to impoverished individuals, independent of the utilities, such as a voucher system. This should become a state obligation, not the utility's.[69]
>
> The necessity for universal service is one that must be mandated and accepted by either the regulatory body or some state agency. The oversight of cost must ensure adequate pricing to recover costs and provide equivalent market access on a competitively neutral basis. In a deregulated environment, with no assurance of financial recovery for the obligation to serve, the requirement to ensure service to low-income customers is passed on from the generator to either the government or the local "wire" supplier.[70]
>
> Universal service is beneficial to society as a whole, but is uneconomic from a business stand-point.[71]

<u>Other Public Policy and Consumer Issues</u>

An independent consultant contracted by the Regulatory Assistance Project, Barbara Alexander, cited various issues to be addressed relating to universal service: redlining; default service provider; metering and right of access; customer grace period after choosing a competitive provider; disconnection policies; and price disparities.

Redlining is the process by which geographical areas are excluded from receiving services. With the arrival of retail competition, redlining is a valid concern. Left completely vulnerable to the power of the market certain groups of customers

[68] Comments of Georgia Textile Manufacturer's Association.
[69] Comments of Jim Laird, Manager Of Energy Programs, Home Depot.
[70] Comments of Municipal Electric Authority of Georgia (MEAG).
[71] Comments of Savannah Electric And Power Company.

may be considered unprofitable to serve and therefore not be given access to service. The Federal Equal Credit Opportunity Act prohibits discrimination in the granting of credit; all electric marketers must adhere to this law. Reasons which cannot be used for denying credit include race, sex, religion, zip code or income. Redlining may violate the provisions of this Act.

Another topic related to universal service is default service. The default service provider is the supplier who serves customers if choice is unavailable or those customers whose service is cancelled by a competitive provider. Currently, most states have designated the distribution company as the default service provider and the supplier of universal service.

The onset of retail competition is fueling concern about metering and the right of access to customers' premises. The distribution company now owns, installs and reads meters and is the only entity with the right to access meters on customer premises. Changes will be needed if other companies require similar access. Others may require access if metering services are opened to competition. Under retail competition market prices may vary according to the time-of-day or day-of-week. Providing more sophisticated meters and handling the communication of data to and from these meters are two services that could be opened to competition. A uniform procedure for right of access must be developed.

Disconnection policies need to be reevaluated. When a customer changes supplier, there should be continuity of service. If a customer fails to choose a competitive provider, service should not be disconnected. A process is needed to handle customers who do not choose a supplier within a reasonable grace period after the retail market is opened to competition. A random assignment to a provider based on market share and assignment to the default provider are two possible approaches. The former is being used in the natural gas industry in Georgia under the 1997 Gas Deregulation Act. Safeguards should be adopted to keep customers from switching back and forth at will between the default supplier and competitive suppliers. Some states have stated that once you leave the regulated supplier you cannot come back again unless your contract has been cancelled. There may also be a fee attached to changing suppliers.

Other concerns are handling collections for nonpayment of various electric services and disconnecting customers for nonpayment. Every state so far has addressed these issues the same way. Customers can only be disconnected by the distribution company for nonpayment of regulated charges, for example, distribution and transmission service. There should be no disconnection for nonpayment of unregulated competitive charges from suppliers. Competitive electric suppliers may use the same debt collection procedures available to any other competitive market in the state.

Cost disparity may need to be addressed for rural customers who pay more for electric service. Electricity will probably not be more expensive in rural areas, but the distribution of power could be. A significant disparity in prices may adversely impact universal service.

Conclusions

The satisfactory resolution of public policy and consumer protection issues is a prerequisite to opening the retail electricity market to competition. Universal service has been achieved under regulation, and quality of service standards and consumer protection rules have been enforced. These policies, standards and rules must be revisited in light of the changed circumstances of a competitive market in order to protect both the supplier and the public interest.

6. GUIDING PRINCIPLES

The Commission should adopt guiding principles before the electric market is restructured in Georgia. The threshold criteria for opening the retail electric market to full competition would be established. Guiding principles will assist the Commission in maintaining a leadership role and ensuring that the economic benefits of competition are being realized by all classes of customers. These principles will also provide law-makers with the evaluative criteria to ensure fair competition that meets Georgia's specific needs. Steps must be taken in advance of allowing full retail competition to prevent consumers in Georgia from being adversely affected, and to ensure that consumers are provided the best possible electric service at the lowest possible cost without threatening the reliability and safety of electric service.

6. A. FINDINGS OF THE PRINCIPLES FOCUS GROUP

The primary purpose of the focus group on "Principles to Abide by in a Competitive Market" was to provide the Commission with a set of guidelines that could be used to guide restructuring of the electric industry in Georgia. The Group had detailed discussions regarding the issues that must be resolved before moving into a competitive market.

The following is a list of some of the issues discussed:

1. How much competition is wanted or needed in Georgia?
2. How do we keep electric customers in Georgia from being adversely affected by restructuring?
3. When should retail competition begin?
4. What are the potential benefits and risks of restructuring?
5. How can we ensure continued reliability and safety of the electric system?
6. How can we ensure customer choice?
7. What customer and supplier protections are required and what benefits would these protections afford?
8. Should municipals and cooperatives have the right to opt in or out of competition?
9. How will restructuring impact customers?

10. How long should the transition period to competition be and on what date certain should full competition be in place?
11. How can we ensure equitable treatment of all market participants?
12. Should one entity be selected as the default service provider?
13. What competitive barriers need to be removed?
14. Which services should be opened to competition and which should remain regulated?
15. Should an Independent Service Operator (ISO) be established?
16. How should stranded costs be determined and should they be recovered? If stranded cost should be recovered, who should pay and through what mechanism?
17. What is the impact of restructuring on state and local revenue?

The focus group participants represented a diverse interest of buyers and sellers of electricity in Georgia. The participants determined that these difficult issues and others must be resolved before the electric market is restructured in Georgia. The perception of how much time is available to decide these issues varied depending upon the participant’s view of when restructuring should take place. Some participants expressed the desire to see the State of Georgia move quickly toward retail competition because of the possible benefits of competition, e.g., lower prices and customer choice. Since Georgia currently has electric rates that are generally at or below the national average, and the Territorial Electric Service Act and the competitive bidding process currently allows some level of retail competition in Georgia, others suggested a slower, more cautious approach of workshops, studies and monitoring other states’ activities. Still others preferred taking no action, but instead just take a “wait and see” approach. Despite a difference of opinion on the timing of restructuring, participants agreed that the adoption of guiding principles is desirable.

For the purpose of discussion, the participants were asked to provide a list of principles. Those complying with the request included: Georgia Power, Municipal Electric Authority of Georgia, Georgia Electric Membership Corporation, Georgia Retail association, KLT Associates, Campaign for a Prosperous Georgia, and Center for Energy and Economic Development.

There was general agreement on basic principles among the focus group participants; however, there was not complete consensus on some key issues. It should be noted that some parties entered the process late and only some of their viewpoints were reflected in the focus group's Final Report to the Commission. A few of the areas where a consensus could not be met included:

- **Transition to Competition or Date Certain.** Having set dates to transition into competition was desired by some of the participants, while others participants strongly disagreed;

- **Elimination of Federal Barriers.** Some participants think PUHCA should be eliminated only after federal consumer protections comparable to or stronger than PUHCA are adopted; and,

- **Independent Service Operator (ISO).** Many, but not all of the focus group participants considered the establishment of an ISO to be necessary.

6. B. Recommended Guiding Principles

Having considered the findings of the focus group on "Principles to Abide by in a Competitive Market" the Staff recommends that the Commission adopt the following eleven principles:

1. **Competition.** If benefits to customers can be assured and if the reliability of the electric system can be maintained or improved, retail prices for electric generation should be set in a competitive market rather than through regulation. A reasonable transition period should transpire before realizing full competition to avoid disruptions and to establish the necessary institutions and controls required to foster and sustain effective competition.

2. **Regulation.** Regulation should be used in those circumstances where competition cannot provide results that best serve the public interest. Therefore, government intervention will continue to be warranted to protect the public interest in areas other than price-setting for competitive services. Transmission and distribution prices should continue to be regulated and pricing methodologies should enhance reliability, compensate owners fairly, allow for the widest possible markets and relieve transmission congestion. Distribution should remain a regulated service to ensure access to all customers and to ensure that distribution providers recover all prudent costs and have an

opportunity to earn a reasonable return on investment. Where rate regulation remains, performance-based ratemaking should be considered.

3. **Customer Choice.** If retail competition is expanded, all classes of customers should simultaneously be allowed to have the maximum practicable degree of choice among electric service options and qualified suppliers of electricity. All classes of customers must be treated fairly, equitably and in a non-discriminatory manner. All customers should have the opportunity to share in the benefits of competition, choose among suppliers and not be harmed from competition. Customer choice should include access to unbundled and ancillary energy services. All customers should have access to information regarding their own electric usage. That information should be released to suppliers of electricity and services only with the informed consent of the customer. Consumers should have access to the necessary information about prices, services and suppliers in order to make informed buying decisions. The State of Georgia must have all authority necessary to prevent and prosecute fraud, and unfair and deceptive acts and practices in the provision of electricity and related ancillary services.

4. **Corporate and Industry Structure.** If utility generation, transmission and distribution assets and operations are not separated into distinct and structurally separate corporate entities, a strict code of conduct, stringent cost allocation rules and other appropriate controls should be adopted. If utility generation, transmission and distribution assets and operations are separated into distinct and structurally separate corporate entities, a strict code of conduct for affiliates should be adopted.[72] Only generation services should be considered for full retail competition, while the provision of transmission and distribution should remain regulated. The triple objectives of open access, comparability of service for all users and nondiscriminatory pricing should be accomplished, while recognizing that federal and state jurisdictional uncertainties over wholesale and retail services should be resolved. Companies that own transmission and distribution facilities, as well as generation facilities, should not be allowed to use any monopoly position in transmission and distribution services as a barrier

[72] No position is taken in this report as to which, if either, is the preferred mode.

to competition in generation. An Independent Service Operator and Power Exchange may be necessary to mitigate market power. The market structure must provide for fair and effective competition.

5. **Open Access.** Where distribution access is deemed appropriate, all distribution system owners and operators should be required to provide nondiscriminatory open access in competitive markets. Distribution policy and pricing must not discriminate against particular generation fuels and facilities. The Territorial Act, in some form, should continue to determine the provider of distribution facilities and prevent the unnecessary duplication of transmission and distribution systems. Distributors should have the obligation to provide distribution service in a nondiscriminatory manner to all customers in their service territory.

6. **Supplier Registration or Certification**. All suppliers should be certificated by the Commission only after a showing of managerial, financial and technical capability. All certificated providers should be subject to the same standards of conduct, e.g., quality of service and customer service requirements. All electric suppliers must abide by the same laws and regulations, be judged by the same criteria and have access to all customers at the same time in accordance with the rules established by the Commission.

7. **Reliability and Safety.** Reliable, safe and adequate electric service is essential and must be maintained at current or improved levels. The state and federal regulatory bodies should have the necessary authority to ensure that electric service is consistent with accepted industry-wide planning and operating standards and that long-term and short-term reliability is assured.

8. **Stranded Cost Recovery.** Only legitimate, unmitigatable stranded costs should be recovered. Prudence reviews and past regulatory actions should be considered in determining whether stranded costs should be recovered. The length of the transition period to increased competition should consider the time necessary to recover stranded costs. The state, rather than the federal government, should set the rules to determine the recovery of stranded costs and investments. There should be no cross-subsidies or over-recovery of stranded costs.

9. **Universal Service.** Universal Service must be maintained so that electric service is available to all customers. Distribution companies must continue to connect all customers to their networks. No reasonable request for service should be denied. Competitive providers should be required to provide service to all customers who wish to buy their services. There must be reasonable payment policies and access to competing suppliers and affordable service.

10. **Environmental and Social Policy.** To the extent that the state mandates programs designed to accomplish public policy objectives, such as low-income assistance, environmental programs and requirements for using renewable fuels, a system of financing should be used whereby all providers and users of electricity contribute equitably.

11. **State and Local Taxes.** The State of Georgia should minimize the negative tax implications and adverse revenue impacts of restructuring the electric industry on state and local governments. All competitors should receive equitable tax treatment; taxes that favor certain competitors or disadvantage others should be eliminated.

7. COMMISSION ACTION PLAN

The issues addressed in this report should form the basis for the Commission to continue an objective review of any potential consequences and results of electric industry restructuring on Georgia's economy and infrastructure. The results of this review should be provided to the General Assembly for assistance in the formulation of new laws, should Georgia decide to expand retail competition in the electric industry.

7. A. ADOPTION OF GUIDING PRINCIPLES

Any transition from the current electric structure to a more competitive one should adhere to certain basic principles. These principles should establish the foundation upon which any future Legislative or Commission action is based. Development of a restructured electric industry based on the proper principles will help ensure that all users of electricity in Georgia benefit from this change. The Staff recommends the adoption of the principles listed on page 72 as a guide for this Commission to follow in formulating positions in future dockets concerning restructuring of the electric industry.

7. B. VISION DOCKET ON ELECTRIC INDUSTRY RESTRUCTURING

The Commission Staff has proposed establishing a vision docket to further consider any and all issues related to restructuring and to expand the Commission's knowledge base on these issues. This docket will provide a vehicle for gathering information, receiving public comments and adopting policy statements on this subject.

The most important question to be answered before restructuring occurs is whether restructuring the electric industry to expand retail competition will benefit the consumers of Georgia through lower rates and increased economic efficiencies, and produce benefits to the state as a whole. In addressing this question, a major function of this docket will be to monitor and analyze experiences in other states moving more rapidly to a restructured market. The lessons learned by other states can be used by the Legislature and the Commission in determining the direction Georgia should take. Other issues to be addressed in this docket may include development of consumer protection measures to be included in legislation, development of product disclosure requirements for electric suppliers, development of rules to govern monopoly transmission systems and review of other public policy and tax issues that should be considered by the General Assembly.

Relating to this vision docket are several dockets designed to evaluate specific issues. The substance of each of these dockets is discussed below. The Commission Staff has laid out the time line for these dockets.[73] For planning purposes the time line for these dockets assumes that the earliest possible date for the legislature to establish a Legislative Task Force on electric restructuring would be 1999 with possible legislation being considered for passage in the year 2000. Action could be taken by the General Assembly either before or after these assumed dates.

This Commission will work to assist the legislators in any way possible to help determine if restructuring is beneficial for Georgia and, if so, develop legislation that produces a restructured electric industry that will benefit all customers while maintaining a reliable and safe electric system.

7. C. Asset Recovery Docket

An investigatory docket, Docket No. 8345-U, has been opened by the Commission to examine asset recovery of investor-owned utilities. One of the most important questions this Commission and the State must answer is how to handle potentially stranded costs. A first step in quantifying potentially stranded costs is to identify and examine all of the current regulatory assets and liabilities. Regulatory assets and liabilities are assets and liabilities created by the regulatory environment that would not otherwise exist in a competitive market. Mitigation of regulatory assets will move regulated utilities' financial position closer to that of competitive non-regulated utilities and will also work to reduce potentially stranded costs. Any effort to mitigate regulatory assets now will also help to lower rates in the long-term even if restructuring and retail competition does not come to fruition.

The Commission Staff has been designated as discover agent and this docket has been declared complex litigation to allow for more than fifty interrogatories. Some of the topics covered in this docket will be:

[73] See flow chart provided in Appendix A , Flowchart of Proposed Dockets, on page 82 of this report.

1. Definition of regulatory assets and liabilities.
2. Identification of the types of regulatory assets and liabilities.
3. Determination of the current levels of regulatory assets and liabilities.
4. Allocation of regulatory assets and liabilities between various services—generation, transmission, distribution.
5. Current recovery practices and amortization schedules for regulatory assets and liabilities.
6. Current recovery practices, depreciation rates and amortization schedules for generation, transmission and distribution plant.
7. Dismantlement and decommissioning cost recovery.

No action regarding capital recovery or disposition of regulatory assets and liabilities will be taken in this docket. Any change in depreciation rates or amortization schedules will be litigated in future rate proceedings. The Commission will not determine how to calculate stranded costs in this proceeding. However, information collected through this investigatory docket may be used by the Commission in deciding future earnings or stranded costs issues.

7. D. Positive and Negative Stranded Cost Docket

The difference between costs expected to be recovered under rate regulation and those recoverable in a competitive market is termed stranded costs. If market prices are lower than regulated rates, as many expect, utilities could be faced with investments that are unrecoverable in the competitive market. On the other hand, depending upon the volatility of market prices a utility may earn more than their embedded costs for some assets, e.g., low cost generating units. The converse of stranded costs is termed "negative" stranded costs. To assess the true financial position of the utility, positive stranded costs should be netted against negative stranded costs over the life of the assets. Therefore, this docket will review both positive and negative stranded costs.

How potential stranded costs should be calculated, how they can be mitigated, who pays for the stranded costs and how and when they are collected are all questions that must be answered before the electric industry is restructured. This docket will address these and related issues.

Information gathered in this docket may be used to encourage further mitigation of strandable costs, such as regulatory assets. Minimizing these costs will reduce rates in the long term even if restructuring does not occur. Also, a reasonable estimate of potential stranded costs will be useful in determining whether stranded cost recovery will pose a barrier to retail access. Findings from the Asset Recovery docket will be used in this docket as the basis for calculating stranded costs. Where relevant the findings and conclusions in this docket on stranded costs will be used in the vision docket on restructuring.

7. E. COST-OF-SERVICE DOCKET

The Commission has opened Docket No. 8346-U on cost-of-service to address traditional as well as unbundled cost-of-service issues prior to the Georgia Power Company rate case to be filed in July 1998. The pricing of unbundled generation services for Georgia Power Company and Savannah Electric will be evaluated to help ascertain methodologies for unbundling. However, at this time functional unbundling of generation will not be used for rate-making purposes.

Functional unbundling is needed to identify any cross-subsidies that may exist between rate classes. Results from this docket will be considered in the Georgia Power Company rate case and may be used in designing rates that are more closely comparable to rates in a competitive market. The first step in this docket will be to solicit comments from interested parties through a Notice-of-Inquiry.

7. F. PLANNING, RELIABILITY AND SYSTEM STRUCTURE DOCKET

Planning, reliability and system structure will be studied in an investigatory docket. Maintenance of short-term and long-term reliability and the development of a competitive market structure will be the primary focus of this proceeding. Some of the issues to be addressed will include:[74]

1. Planning
   a) To what extent should generation adequacy be left to market forces?
   b) Should a minimum standard be set through a state-wide planning process?

[74] Based in part on the System Operations and Reliability Focus Group Report.

c) Should municipal and cooperative utilities, and other suppliers be included in reliability planning?

d) What level of long-term reliability should be maintained in a restructured electric Industry?

2. Reliability

a) To what extent should NERC/SERC be relied upon for development of standards, enforcement, and other aspects of operations necessary for grid reliability?

b) Should compliance with NERC/SERC standards be mandated?

c) Should the State of Georgia establish an organization for setting standards and regulating compliance with reliability criteria?

d) How should reliability services be provided and priced?

e) Should distribution ancillary services be defined and mandated?

f) How can (or should) the Commission participate in daily security operations?

3. System Structure

a) Should the State of Georgia encourage the establishment of an Independent System Operator (ISO) to coordinate reliability?

b) How should an ISO be structured?

c) What controls should be used in lieu of an ISO?

d) How will Georgia's current Integrated Transmission System be affected by restructuring?

e) Should the Commission certify market participants for financial, managerial and technical capability?

f) How should the traditional "obligation to serve" be modified or re-interpreted?

i) Regarding a supplier of last resort?

ii) Regarding a default supplier?

iii) Regarding an obligation to provide emergency supply?

Comments from interested parties will be solicited through a Notice-of-Inquiry. Findings and conclusions from this docket will be used in the overall vision docket on restructuring.

8. APPENDICES

APPENDIX A. FLOWCHART OF PROPOSED DOCKETS

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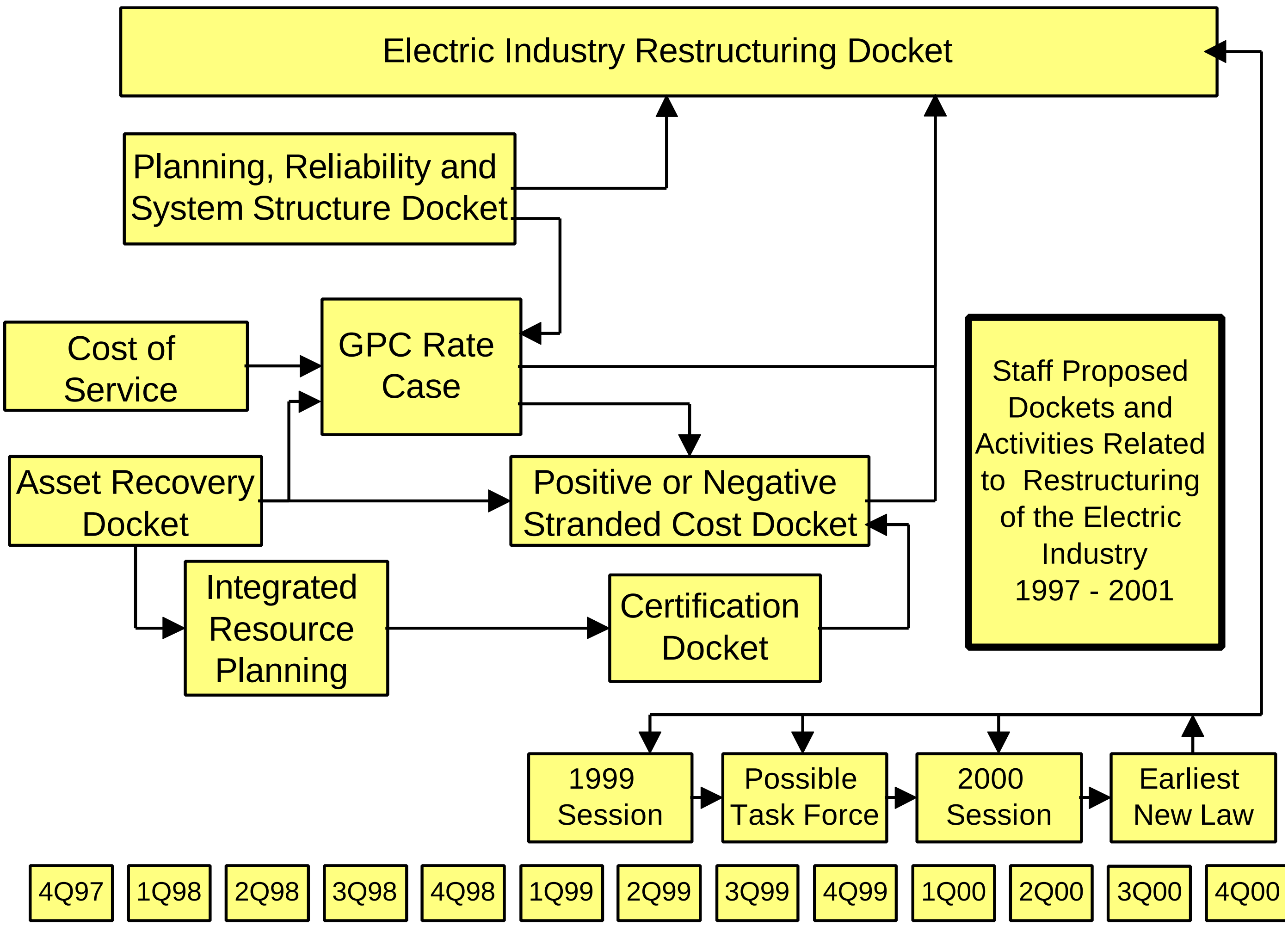

APPENDIX B. WORKSHOP ATTENDEES

NAME	COMPANY/AFFILIATION
Adams, Cliff	Alston & Bird
Allgood, Kathy	Oconee EMC
Allison, Jim	MEAG Power
Ambrose, Kim	Savannah Electric
Amon, Phil	U.S. GAO
Anderson, John	ELCON
Arsah, Nick	Southern Engineering
Autry, Charles	Autry, Holden & Horton
Autry, Jay	Autry Petroleum Co.
Autry, Joey	Autry Petroleum Co.
Baker , Hugh D. Jr.	Capstone Energy
Barrs, Craig	Georgia Power Company
Baulkmon, Jeane	ANR
Beck, Kenneth	Jackson EMC
Belser, Deryl	GPC
Berry, Tom	MEAG Power
Black, Larry	KLT Associates, Inc.
Bowen, Roy	Georgia Textile Manufactures Assoc.
Boyd, David M.	EDS
Bradley, Mike	HM & C
Brian, David	GDS Associates, Inc.
Brown, Merv	Georgia Power Company
Brown, Phil	Rayle EMC
Brownlee, Larry	Oglethorpe Power Corp.
Bullard, D.	OPC/Little Ocmulgee EMC
Bullock, Gary	Carroll EMC
Bullock, George	Center for Energy & Economic Dev.
Bunce, Gary	WEMC
Bundros, Tom	Dalton Utilities
Burns, Robert E.	National Regulatory Research Inst.
Cade, Joe	Flint EMC
Caldwell, James	CEERT
Calsetta, Alfred B.	MEAG Power

Camus, Glenn E.	CNG Energy Services Corp.
Carver, Brad	Georgia Municipal Association
Casey, Rolland A.	Alabama PSC
Cathy, Richard	ACCG
Cave, Tom	Atlanta Gas Light Co.
Chapman, Robert A.	Washington EMC
Clarkson, Jim	El Paso Energy
Clower, Tim	Greystone Power
Coleman, Zach	Atlanta Business Chronicle
Coley, Barbara	EDS
Conner, Matt	Savannah Electric
Conroy, Shawn	CUC
Cope, Don	Dalton Utilities
Cornwell, Kelly	City of Calhoun
Cox, Joe B.	Gold Kist, Inc.
Crane, Frank	MEAG Power
Crawford, Jim	Jackson EMC
Crawford, R.C.	TUPPA
Dalton, Carol Ann	Campaign for a Prosperous Georgia
Danielson, Albert	University of Georgia
Davis, Louis K.	Union of Conc. Science
DeBolt, Bruce	City of East Point
DeForrest, Parrett	Dalton Utilities
DeLong, Russell	Walton EMC
Diamond, Ty	Flint EMC
Dixon, Deb	Oglethorpe Power Company
Dodd, Jere	Robinson Humphrey Co.
Dotson, Rumanous	Altamaha EMC
Dowdy, Craig L.	Long, Aldridge, & Norman
Drechsel, Susan	Office of Legislative Counsel
Dymecki, Kimberly	w/Peyton Hawes
Edelston, Bruce	Georgia Power Company
Edwards, Steven E.	US GEN
Egan, Mike	Senate
Ellis, John	IPS
Elsberry, Bob	Cobb EMC
Evans, George	GDS Associates
Evans, Larry	Savannah Electric
Ferris-Smith, Stacey L.	Attorney General’s Office
Fletcher, Bryan	Georgia Power Company

Floer, Jamie D.	Chartwell
France, Cynthia	Southern Company
Frankenhauser, Nancy	Savannah Electric
Fricks, George	Cartersville Electric System
Fridlin, Bert	NFIB
Fuchs, Dean R.	Newton M. Galloway & Associates
Gaines, Jack	Southern Engineering Co.
Garbaez, Chris	Mississippi Public Utility Staff
Gazondo, Paul	Nationsbank
Gerstner, Edward	USA Center for Public Work
Gibbs, Daniel R.	Electric Power Board
Gibson, Alan D.	US Department of Energy
Gignilliat, Arthur	Savannah Electric
Gignilliat, Matt	Savannah Electric
Gilling, Zaneta	Department of Community Affairs
Givan, Bernard	Alabama PSC
Gleason, Jeff	Southern Environmental Law Center
Goldberg, Edward	Macy’s
Goodroe, Mike	Sawnee EMC
Graetz, Stuart	Southern Engineering
Graniere, Bob	NRRI
Greene, Kevin	Troutman Sanders
Greer, Miles	Savannah Electric
Groome, Jim	Georgia Industrial Group
Habiger, Theresa	TVA
Halabi, Bill	Georgia Tech
Ham, Tony	Okefenoke REMC
Hamilton, Janice M.	Alabama PSC
Hanes, Gene	Alabama PSC
Hardigree, Clyde	Oglethorpe Power
Hardy, Steve	Holland & Knight
Harrelson, Larry	Dalton Utilities
Harris, Robin	Frito Lay Co.
Harunuzzaman, M.	NRRI
Hawes, Peyton	GTMA
Hawk, Nelson	Oglethorpe Power
Hayet, Phil	Hayet Consulting
Heffernan, Tony	Bill Shipps, GA
Hegazy, Youssef	EDS
Hinson, Ron	Georgia Power Company

Hirst, Eric	Oak Ridge National Lab.
Hodgin, Faye	Senate Research Office
Hoellwarth, Craig	Heery International, Inc.
Hoffman, Ronald	The Kroger Co.
Holland, Don W.	Okefenokee EMC
Holliday, Lea	Savannah Electric
Hood, Charles	Georgia Pacific Corporation
Hopkins, Robert M.	City of Cairo
Hostie, Rod	Oglethorpe Power
Hubbard, James	Georgia EMC
Hubbard, Jim	Georgia Power Co.
Huckaby, Clay	Georgia Industry Association
Hunt, Chuck	Cobb County Government
Hurt, Jim	CUC
Ingram, Daryl	Cartersville Electric System
Ingram, John	Hicks, Maloof & Campbell
James, Lynwood	Greystone Power
Jarrell, Fred	Flint EMC
Johnson, Grooms	Hart EMC
Johnson, Jill	Sonat Marketing Co.
Johnson, John	Citizens Lehman Power
Johnson, Joseph	Global Track
Johnson, Ken	EDS
Johnston, Bob	MEAG
Jones, Doug	NRRI, Ohio State University
Jones, Greg	Oglethorpe Power
Jones, Ray C.	Jackson EMC
Jones, Stuart	College Park Power
Keehan, Jenny	IMRA
Keith, Greg	Jackson EMC
Kelly, Gregory	US GEN
Kelly, Henry	Georgia Power Company
Kilgore, Tom	Oglethorpe Power Corp.
Kilpatrick, Rita	Campaign for a Prosperous Georgia
Kim, Peter H.	Coopers & Lybrand
Kincel, Kenneth L.	US Army/Decision Analysis Corp of VA
Kingery, Hudson	Flint EMC
Kirkpatrick, David	Ernst & Young
Kittel, R.	Army
Kornetzke, Scott	Johnson Controls, Inc.

Kuhel, Gerry	Cutler-Hammer
Kuzava, Kathy	GFIA
Lamm, Jim	Utilicom
Langstaff, Bob	Water/Gas/Light Albany
Lanier, Lynn	GDS Associates, Inc.
Lauderdale, Melissa	Enron
Ledford, Bobby	D&B Enterprises
Lee, Norman	Oglethorpe Power
Lee, Ronnie	WEMC
Lockwood, Anne	Department of Community Affairs
Loria, Tom	UAI
Lyon, William	Federated Department Stores
Magruder, Kathleen E.	Enron
Mallory, Alice J.	Coweta-Fayette EMC
Marsh, Bob	Mississippi Public Utility Staff
Marshall, Ron	Walton EMC
Mayhew, Jim	MEAG Power
McConnell, Julianna	Georgia EMC
McCormick, D.A.	U.S. Dept. of Defense
McKenney, Hank	DSM
McMahon, G.	Camp, Presser & McKee
McMillan, Ted M.	Sumter EMC
McWilliams, Steve	Georgia Retail Association
Meecham, Bill	Georgia Electric Cities
Melcher, Joanne	Home Depot/ACE
Miller, Gary	Greystone Power
Minor, Steve	Georgia EMC
Morgan, Jay	J.L. Morgan Co.
Morris, Allison	CUC
Moss, David	Penske Truck Leasing
Mote, Lamar	Habersham EMC
Mulligan, Mike	Not Given
Murphy, Therrell	Sterling Energy
Myers, Jay	Glass, McCullough, Sherrill & Harrold
Newman, William K.	Georgia Power Company
Norman, Robbie	Flint EMC
O’Leary, Helen	Law Department
O’Neil, Chuck	Sierra Club
Orr, James	Sutherland, Asbill & Brennan
Pallets, Leonard	Associated Press

Paris, Patrick	Publix Super Markets
Patterson, Sonny	Equity Office
Payne, Robert	Amicalola EMC
Peacock, Todd	Habersham EMC
Pearson, Doug	Grady Health System
Pettit, Boyd	Attorney
Pettit, Vickie	Cobb EMC
Phelps, Andy	Oglethorpe Power Company
Podwoski, Chris	Not Given
Pollock, Jeff	BAI/GIG
Price, Mike	Georgia Transmission Corp.
Price, Randy	Snapping Shoals EMC
Pritchett, Edward	Mitchell EMC
Pugh, Randall	Jackson EMC
Purvis, Bruce	Progress Energy
Quinn, Matthew	Atlanta Journal Constitution
Quintrell, Randy	Georgia Industrial Group
Read, Lisa	Holland & Knight
Reed, Bill	Not Given
Rich, Dave	Grass Roots Power
Richeson, Mike	Colonial Pipeline Company
Riggs, Nancy	Savannah Electric
Robare, Renee	Gaslantic
Robertson, Wayne	Heery Energy Cons.
Robinson, Roy	AGL Resources, Inc.
Rowe, Alvin J.	Citizen
Rozier, Garey	Southern Company
Saacks, Jerry	Georgia System Operations Corp.
Salak, Beth	Florida PSC
Satterfield, Joe	Blue Ridge Mountain EMC
Sax, John	Not Given
Schanding, Don	GMA
Schultz, Bob	Alexander & Alexander
Searfoss, Robert	Georgia Hospital Association
Seaton, Bob	Dalton Utilities
Sell, John	GPC
Setzer, Bob	Robinson-Humphrey
Sharpton, Bill	Greystone Power
Shaw, Carl	UAI
Shellabarger, Charles	GDS Associates, Inc.

Sheppard, Mike	Savannah Electric
Simmons, Jack W.	Soleil Energy
Simon, Julie	Electric Power Supply Association
Sitherwood, Suzanne	AGL
Slappey, Joe	Department of Revenue
Smalling, Charles	Congresswoman Cynthia McKinney 4th
Smith, Brian	BCS Assoc.
Smith, Ed	Georgia Pacific
Smith, Jim	Jackson EMC
Smith, Marty	Oconee EMC
Standifer, Florida	GSA
Stanley, Haydon	Georgia Apartment Association
Stanley, Tammy	CUC
Stewart, Don	Jackson EMC
Stone, Danny	Snapping Shoals EMC
Stowe, Roy	Jackson EMC
Struchtemeyer, Leon	Schlumberger
Sutterow, Sam	Glass, McCullough, Sherrill & Harrold
Sylvan, Donna	Southern Company
Tankersley, Chuck	Cobb EMC
Tanner, Tony	Gwinnett Co. School System
Thomas, Jeanie	Governors Development Council
Thompson, Gerald H.	MEAG Power
Thornton, Bill	Georgia Municipal Association
Thornton, Danny	Okefenoke REMC
Tisinger, Richard G., Sr.	Georgia EMC
Trapp, Bob	Florida PSC
Treadwell, Chad	The Kroger Co.
Tucker, Craig	Huron Tech Corp
Turner, Don	US Army Forces Command
Underwood, Debra	MEAG Power
Ussery, Billy	Sawnee EMC
Vaquer, Mike	Union Camp
Vawter, Martha	General Acct. Office
Veal, Felix W.	Not Given
Verner, Bill	Georgia EMC
Wade, Allison	Holland & Knight
Waldrep, Marvin L.	Georgia Pacific Corporation
Walsh, Dan	CUC
Walton, James M.	U.S. Army

Wansley, Jeff	Home Depot
Warshall, Ron	Walton EMC
Weatherly, Phil	Georgia EMC
Weaver, George	Central Georgia EMC
Weisman, Jeannie	Hansen Assc.
West, Carl W.	Weyerhaeuser Co.
Westergard, Lynn	Resource Service Ministries
White, Richard	Savannah Electric
Widener, Bruce	Conditioned Air Asso. Ga.
Wilkerson, Susan	Troutman Sanders
Williams, Tim	Greystone Power
Williamson, Rosemary	Southern Company Services
Williford, Lawrence	Robinson Humphrey
Willis, Kirby	Savannah Electric
Willis, Roger	Jackson EMC
Winkles, Mildred	Coweta-Fayette EMC
Woods, Cliff	Weyerhaeuser
Wrightson, Glen S.	Southern Engineering
Yoder, Jim	State University of West Georgia
Yost, Donna	Sawnee EMC

APPENDIX C. PRESENTERS AT THE WORKSHOPS

First Workshop

April 4, 1997: "The Current Structure of the Electric Industry in Georgia and What Structure Should the Electric Industry Take in the Future?"

Facilitator

Doug Jones
National Regulatory Research Institute

Presenter	Topic
Kenneth Rose, Ph.D. Senior Institute Economist National Regulatory Research Institute	Restructuring Issues Around the Country
Bruce Edelston Director, External Affairs Georgia Power Company	Investor-Owned Utility perspective on the current utility structure in Georgia
Randall Pugh President/CEO Jackson EMC	Cooperatives' perspective on the current utility structure in Georgia
Tom Berry City Manager Thomasville GA	Municipals' perspective on the current utility structure in Georgia
Jim Clarkson Director Southeastern Power Mktg El Paso Energy Marketing Co	Power Marketers' perspective on the current structure and what role they could play in a restructured industry
Gregory B. Kelly Director, Marketing & Project Dev. U.S. Generating Company	Independent Power Producers' role in the current structure and the role they could play in a restructured industry

Edward A. Smeloff Senior Member, Board of Directors Sacramento Municipal Utility District	Public Policy and Conservation Issues to consider in a restructured Industry
Robert Graniere, Ph.D. Senior Institute Economist National Regulatory Research Institute	Regulatory Issues to consider in a restructured electric industry
Jim Hurt Director Consumers' Utility Counsel	Residential and Small Commercial customers' perspective in a new electric industry
Roger Colton Principal Fisher, Sheehan & Colton	Low-income and small customers' perspective in a restructured industry
John A. Anderson, Ph.D. Executive Director Electricity Consumers Resource Council	Industrial customers' perspective in a restructured industry and the advantages of competition
William Lyon Operating Vice President-Energy Federated Department Stores	Retail customers' perspective in a restructured industry and the advantages of competition

Second Workshop

May 9, 1997: System Operation Issues including Reliability and Independent System Operator

Facilitator

Kenneth Rose
National Regulatory Research Institute

Presenter	Topic
William K. Newman Senior VP, Trans. Planning and Oper. Southern Company Services	Southern Company Day-to-Day System Operations and Reliability
Eric Hirst Corporate Fellow Oak Ridge National Laboratory	Bulk Power Systems: Reliability and Competitive Markets
Garey C. Rozier Director, Bulk Power Supply Southern Company Services	Investor-owned utility perspective on long-term system operations and reliability planning
Jerry J. Saacks Chief Operating Officer Georgia System Operations Corp.	Cooperatives' perspective on current reliability and long-term system operations and planning
Bob Johnston VP-Engineering, Planning and Oper. Municipal Electric Authority of GA	Municipals' perspective on current Reliability and long-term system operations and planning
Julie Simon Director of Policy Electric Power Supply Association	Independent Power Producer and Marketer perspective on how competition will affect planning and reliability
Robert E. Burns Senior Research Specialist National Regulatory Research Institute	Independent System Operators

James H. Caldwell Jr. Technical Director CEERT	Environmental and Conservation issues
Mohammad Harunuzzaman Senior Research Specialist National Regulatory Research Institute	Regulatory Issues as to the reliability and planning of system operations
Jeffry Pollock Principal Brubaker & Associates, Inc	Industrial customers' perspective on competition and the use of an Independent System Operator
William Lyon Operating Vice President-Energy Federated Department Stores	Retail customer perspective on competition and the use of an independent system operator

Third Workshop

June 6, 1997: Regulatory Issues including Stranded Costs, Market Power, and Public Policy

Facilitator

Cheryl Harrington
Regulatory Assistance Project

Presenter	Topic
Paul Centolella Senior Economist Science Applications Intl. Corp.	Market Structure, Horizontal and Vertical Market Power Issues
Cheryl Harrington Director Regulatory Assistance Project	Stranded Cost Measurements, Mitigation and Recovery Issues
Barbara Alexander Consumer Affairs Consultant	Ensuring Universal Service, Basic Consumer Protections, and Stranded Benefits

Fourth Workshop

July 18, 1997: Focus Group Reports and Staff Concluding Remarks

Facilitator

Dan Cearfoss
Georgia Public Service Commission

Presenters

Focus Group 1: Principles to Abide By In a Competitive Environment

George Bullock	Center for Energy and Economic Development
Kevin Greene	Troutman Sanders
Carl Shaw	Utilities Analyses Inc.
Joanne Melcher	Home Depot

Focus Group 2: System Operations In a Competitive Environment

Greg Kelly	U.S. Generating Inc.
Garey Rozier	Southern Company
Alfred Calsetta	MEAG Power

Focus Group 3: Statutory Changes

Peyton Hawes	Georgia Textile Manufacturers Association
Kevin Greene	Troutman Sanders

Focus Group 4: Tax Implications in a Restructured Electric Industry

Richard Downs	Georgia Power Company
Andy Phelps	Oglethorpe Power Company
Bill Culpepper	MEAG Power
Joanne Melcher	Home Depot

Focus Group 5: Stranded Costs/Stranded Benefits

Michael Goodroe	Sawnee EMC
Ed Smith	Georgia Pacific
Ron Hinson	Georgia Power Company
Jim Laird	Home Depot
Jim Mayhew	MEAG Power
Jim Hurt	Consumers Utility Counsel
George Bullock	Center for Energy and Economic Development
Carol Ann Dalton	Campaign for a Prosperous Georgia

Commission Staff Presentation—Future Action by the Commission

Deborah Flannagan	Executive Director
Bev Knowles	Director of Utilities Division

APPENDIX D. LIST OF GENERATING FACILITIES

Georgia Power Company[75]

NAME	FUEL SOURCE	CAPACITY (MW)[76]
Arkwright	Coal, Gas	160
Arkwright	Oil, Gas (Combustion Turbine)	30.6
Atkinson	Oil, Gas	180
Atkinson	Oil, Gas (Combustion Turbine)	78.72
Barnett Shoals	Hydro (Leased unit)	2.8
Bartletts Ferry	Hydro	173
Bowen	Coal	3,160
Bowen	Oil (Combustion Turbine)	39.4
Branch	Coal	1539.70
Burton	Hydro	6.12
Estatoah	Hydro	.24
Flint River	Hydro	5.4
Goat Rock	Hydro	26
Hammond	Coal	800
Hatch	Nuclear	840.25
Langdale	Hydro	1.04
Lloyd Shoals	Hydro	14.4
McDonough	Coal	490
McDonough	Oil, Gas (Combustion Turbine)	78.8

[75] Source: Facts and Figures, Georgia Power. Capacity as of December 31, 1996.
[76] Nameplate capacity rating of the plant.

NAME	FUEL SOURCE	CAPACITY (MW)[76]
McIntosh	Oil, Gas (Combustion Turbine)	480
McManus	Oil	115
McManus	Oil (Combustion Turbine)	481.7
Mitchell	Coal	170
Mitchell	Oil (Combustion Turbine)	118.2
Morgan Falls	Hydro	16.8
Nacoochee	Hydro	4.8
North Highlands	Hydro	29.6
Oliver Dam	Hydro	60
Riverview	Hydro	.48
Robins	Oil, Gas	160
Rocky Mountain	Hydro	215.3
Scherer	Coal	750.9
Sinclair Dam	Hydro	45
Tallulah Falls	Hydro	72
Terrora	Hydro	16
Tugalo	Hydro	45
Vogtle	Nuclear	1,060.24
Wallace Dam	Hydro	321.3
Wansley	Coal	925.55
Wansley	Oil (Combustion Turbine)	26.3
Wilson	Oil	354.1
Yates	Coal	1,250
Yonah	Hydro	22.5

Savannah Electric and Power Company
Generating Facilities
As of December 31, 1996 [77]

NAME	FUEL SOURCE	CAPACITY (MW)[78]
McIntosh	Coal	177.6
Kraft	Coal	333.9
Riverside	Coal	108
McIntosh	Oil, Gas (Combustion Turbine)	156
Kraft.	(Combustion Turbine)	18.6
Boulevard	(Combustion Turbine)	46.8

[77] Source: Savannah Electric and Power Company.
[78] Nameplate capacity rating of the plant.

Jointly-Owned Generating Facilities
Ownership Percentages
As of December 31, 1996

Plant	Units	OPC[79]	MEAG[80]	Dalton[81]	GPC[82]
Hatch	1 & 2	30	17.7	2.2	50.1
Rocky Mountain	1, 2 & 3	74.6	---	---	25.4
Scherer	1 & 2	60	30.2	1.4	8.4
Scherer	3	---	---	---	75
Vogtle	1 & 2	30	22.7	1.6	45.7
Wansley	1 & 2	30	15.1	1.4	53.5
Wansley (Combustion Turbine)	5A	30	15.1	1.4	53.5

NOTE: Combustion Turbines at Plant McIntosh are jointly owned by Savannah Electric and Georgia Power. Savannah Electric owns units 5 and 6 (159.28 MW) and Georgia Power owns units 1, 2, 3, 4, 7, and 8 (480 MW).

79 Oglethorpe Power Corporation
80 Municipal Electric Authority of Georgia
81 City of Dalton, Georgia
82 Georgia Power Company

APPENDIX E. STATUS OF RESTRUCTURING IN THE UNITED STATES

State	Bill Introduced	Bill Passed	Bill Failed/ Vetoed	Legislative Study	Court Litigation	Staff Report	Guide-lines Adopted	PSC/PUC Hearings
Alabama	X				X			
Alaska	X							X
Arizona	X		X	X	X	X		
Arkansas				X				
California	X	X						
Colorado	X		X			X		
Connecticut	X		X	X			X	
D.C.								
Delaware	X			X		X		X
Florida	X		X	X				
Georgia	X		X					
Hawaii	X							
Idaho				X			X	X
Illinois	X	X		X		X		
Indiana	X			X		X		
Iowa						X	X	X
Kansas	X			X				
Kentucky	X							
Louisiana	X			X		X	X	
Maine	X	X		X		X	X	X
Maryland				X		X	X	
Massachusetts	X	X		X	X			X
Michigan					X	X		X
Minnesota	X		X	X		X	X	
Mississippi	X			X		X		X
Missouri			X	X				

Appendix E. Status of Restructuring in the United States (Continued)

State	Bill Introduced	Bill Passed	Bill Failed/ Vetoed	Legislative Study	Court Litigation	Staff Report	Guide-lines Adopted	PSC/PUC Hearings
Montana	X	X		X			X	
Nebraska				X				
Nevada	X	X		X			X	
N. Hampshire	X	X			X		X	X
New Jersey						X		
New Mexico	X			X				
New York	X			X	X		X	X
N. Carolina				X				
N. Dakota	X			X				
Ohio	X			X			X	
Oklahoma	X	X		X			X	X
Oregon	X		X	X				
Pennsylvania	X	X				X	X	X
Rhode Island	X	X				X	X	
S. Carolina	X					X		
S. Dakota								
Tennessee								
Texas	X		X	X		X	X	
Utah	X			X		X	X	
Vermont	X			X			X	X
Virginia	X			X		X		
Washington							X	
West Virginia								
Wisconsin				X		X	X	X
Wyoming						X	X	
Totals	35	10	9	31	6	21	21	14

APPENDIX F. FERC ISO PRINCIPLES

In Order 888 issued on April 24, 1996, the Commission recognizes that some utilities are exploring the concept of an Independent System Operator and that the tight power pools are considering restructuring proposals that involve an ISO. While FERC does not require utilities to form ISOs, it encourages the formation of properly-structured ISOs. To this end, Order 888 gives the industry some guidance on the principles that the Commission will use in assessing ISO proposals that may be submitted to it in the future. The order states that because an ISO will be a public utility subject to its jurisdiction, the ISO's operating standards and procedures must be approved by the FERC. The principles for ISOs are:

1. The ISO's governance should be structured in a fair and non-discriminatory manner.

The primary purpose of an ISO is to ensure fair and nondiscriminatory access to transmission services and ancillary services for all users of the system. As such, an ISO should be independent of any individual market participant or any one class of participants (e.g., transmission owners or end-users). A governance structure that includes fair representation of all types of users of the system would help ensure that the ISO formulates policies, operates the system, and resolves disputes in a fair and non-discriminatory manner. The ISO's rules of governance, however, should prevent control, and appearance of control, of decision-making by any class of participants.

2. An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.

To be truly independent, an ISO cannot be owned by any market participant. We recognize that transmission owners need to be able to hold the ISO accountable in its fiduciary role, but should not be able to dictate day-to-day operational matters. Employees of the ISO should also be financially independent of market participants. We recognize, however, that a short transition period (we believe 6 months would be adequate) will be needed for employees of a newly formed ISO to sever all ties with former transmission owners and to make appropriate arrangements for pension plans, health programs and so on. In addition, an ISO should not undertake any contractual arrangement with generation or transmission owners or transmission users that is not at arm's length. In order to ensure independence, a strict conflict of interest standard should be adopted and enforced.

3. An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner.

An ISO should be responsible for ensuring that all users have non-discriminatory access to the transmission system and all services under ISO control. The portion of the transmission grid operated by a single ISO should be as large as possible, consistent with the agreement of market participants, and the ISO should schedule all transmission on the portion of the grid it controls. An ISO should have clear tariffs for services that neither favor nor disfavor any user or class of users.

4. An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role in this responsibility should be well-defined and comply with applicable standards set by NERC and the regional reliability council.

Reliability and security of the transmission system are critical functions for a system operator. As part of this responsibility an ISO should oversee all maintenance of the transmission facilities under its control, including any day-to-day maintenance contracted to be performed by others. An ISO may also have a role with respect to reliability planning. In any case, the ISO should be responsible for ensuring that services (for all users, including new users) can be provided reliably, and for developing and implementing policies related to curtailment to ensure the on-going reliability and security of the system.

5. An ISO should have control over the operation of interconnected transmission facilities within its region.

An ISO is an operator of a designated set of transmission facilities.

6. An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.

A key function of an ISO will be to accommodate transactions made in a free and competitive market while remaining at arm's length from those transactions. The ISO may need to exercise some level of operational control over generation facilities in order to regulate and balance the power system, especially when transmission constraints limit trading over interfaces in some circumstances. It is important that the ISO's operational control be exercised in accordance with the trading rules established by the governing body. The trading rules should promote efficiency in the marketplace. In addition, we would expect that an ISO would provide, or cause to be provided, the ancillary services described in this Rule.

7. **The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open market.**

Management and administration of the ISO should be carried out in an efficient manner. In addition to personnel and administrative functions, an ISO could perform certain operational functions, such as: determination of appropriate system expansions, transmission maintenance, administering transmission contracts, operation of a settlements system, and operation of an energy auction. The ISO should use competitive procurement, to the extent possible, for all services provided by the ISO that are needed to operate the system. All procedures and protocols should be publicly available.

8. **An ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption. An ISO or an RTG of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions.**

Appropriate price signals are essential to achieve efficient investment in generation and transmission and consumption of energy. The pricing policies pursued by the ISO should reflect a number of attributes, including affording non-discriminatory access to services, ensuring cost recovery for transmission owners and those providing ancillary services, ensuring reliability and stability of the system and providing efficient price signals of the costs of using the transmission grid. In particular, the Commission would consider transmission pricing proposals for addressing network congestion that are consistent with our Transmission Pricing Policy Statement. In addition, an ISO should conduct such studies and coordinate with market participants including RTGs, as may be necessary to identify transmission constraints on its system, loop flow impacts between its system and neighboring systems, and other factors that might affect system operation or expansion.

9. An ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the Commission's requirements.

A free-flow of information between the ISO and market participants is required for an ISO to perform its functions and for market participants to efficiently participate in the market. At a minimum, information on system operation, conditions, available capacity and constraints, and all contracts or other service arrangements of the ISO should be made publicly available. This information should be made available on an OASIS operated by the ISO.

10. An ISO should develop mechanisms to coordinate with neighboring control areas.

An ISO will be required to coordinate power scheduling with other entities operating transmission systems. Such coordination is necessary to ensure provision of transmission services that cross system boundaries and to ensure reliability and stability of the systems. The mechanisms by which ISOs and other transmission operators coordinate can be left to those parties to determine.

11. An ISO should establish an ADR process to resolve disputes in the first instance.

An ISO should provide for a voluntary dispute resolution process that allows parties to resolve technical, financial, and other issues without resort to filing complaints at the Commission. We would encourage the ISO to establish rules and procedures to implement alternative dispute resolution processes.

APPENDIX G. ANALYSIS OF FERC ISO PRINCIPLES

In Order 888, the Commission gives the industry guidance on the principles that it will use in assessing ISO proposals that may be submitted to it in the future. The following discussion shows how these principles are (or are not) being met within the existing structure of the industry.

1. **The ISO's governance should be structured in a fair and non-discriminatory manner.**

   The current operation of the transmission system in the Southern Control Area does not meet the requirement that an ISO should be independent of any individual market participant. However, the FERC requirements in Order 888 for jurisdictional utilities to functionally unbundle, file open access transmission tariffs, operate an OASIS, and adhere to strict standards of conduct provide a mechanism to ensure non-discriminatory transmission access. The implementation of the SERC Security Coordinator with the responsibility for "policing" the use of the transmission system through implementation of a NERC approved curtailment process will provide additional assurance of non-discriminatory transmission access.

2. **An ISO and its employees should have no financial interest in the economic performance of any power market participant. An ISO should adopt and enforce strict conflict of interest standards.**

   The current ownership and operation of the transmission system in the Southern Control Area does not meet this requirement at this time. However, as addressed above, Order 888 attempts to provide a workable means of assuring that non-discriminatory open access transmission occurs.

3. **An ISO should provide open access to the transmission system and all services under its control at non-pancaked rates pursuant to a single, unbundled, grid-wide tariff that applies to all eligible users in a non-discriminatory manner.**

   This requirement is not met due to the number of transmission providers in the Southern Control Area and the pancaking of transmission rates to cross multiple tariff areas. The size of the Southern tariff area makes the issue of pancaking of transmission rates less important than for areas where there are multiple control areas in a region the size of one control area in the Southeast. For example, Southern provides transmission service across its entire system, which covers portions of the states of Alabama, Florida, Georgia, and

Mississippi at a single, system-wide rate. However, in some instances, a transmission customer may be required to pay two transmission rates to cross the Georgia ITS if neither ITS participant has sufficient interface capability to provide the requested service.

4. **An ISO should have the primary responsibility in ensuring short-term reliability of grid operations. Its role in this responsibility should be well-defined and comply with applicable standards set by NERC and the regional reliability council.**

   Responsibility for the short-term reliability and security of the transmission system is ensured by the control area operators. The implementation of the SERC Security Coordinator will add another entity to support the reliability functions of the control areas.

5. **An ISO should have control over the operation of interconnected transmission facilities within its region.**

   Responsibility for control over the operation of the interconnected transmission facilities within the region rests with the control area operators. The implementation of the SERC Security Coordinator will add another entity to support the reliability functions of the control areas.

6. **An ISO should identify constraints on the system and be able to take operational actions to relieve those constraints within the trading rules established by the governing body. These rules should promote efficient trading.**

   The responsibility to identify constraints and take operational actions to relieve those constraints rests with the control area operators. Order 888 provides transmission owners with rules to follow when curtailing use of the transmission system. The implementation of the SERC Security Coordinator with the responsibility for "policing" the use of the transmission system through implementation of a NERC approved curtailment process will provide additional assurance of non-discriminatory transmission access.

7. **The ISO should have appropriate incentives for efficient management and administration and should procure the services needed for such management and administration in an open market.**

Transmission owners already have appropriate incentives for efficient management of their existing transmission facilities. Increased transmission utilization will help keep rates low for existing retail and wholesale customers. However, concerns exist among some market participants that existing transmission providers do not have sufficient incentives to expand the system or maximize operations for competitors.

8. An ISO's transmission and ancillary services pricing policies should promote the efficient use of and investment in generation, transmission, and consumption. An ISO or an RTG of which the ISO is a member should conduct such studies as may be necessary to identify operational problems or appropriate expansions.

Transmission and ancillary services are provided by transmission owners at rates approved by the FERC. The FERC has a policy statement on transmission pricing which provides guidance on rate methodologies that it finds acceptable. Transmission planning is conducted by the transmission owners and individual transmission expansion plans are submitted to SERC which develops a list for the region. This information is available to the public. Additionally through OASIS posting and FERC Form 715 filing requirements of jurisdictional transmission owners, substantial transmission information is available to the public.

9. An ISO should make transmission system information publicly available on a timely basis via an electronic information network consistent with the Commission's requirements.

All jurisdictional transmission owners are required to operate an OASIS. Some non-jurisdiction transmission owners in the region have voluntarily developed an OASIS.

10. An ISO should develop mechanisms to coordinate with neighboring control areas.

Mechanisms to coordinate operations with neighboring control areas are already in place. Neighboring control areas have interconnection and interchange agreements that address how reliability will be maintained and coordinated in emergencies. Additionally, communication links provide control area operators with real-time system information, such as transmission line loadings, for neighboring control areas. The implementation of the SERC

Security Coordinator will provide another mechanism for coordination among the control areas.

11. An ISO should establish an ADR process to resolve disputes in the first instance.

NERC has an alternative dispute resolution process in place that is available to all market participants. Additionally, the transmission tariff developed by the FERC has procedures for ADR before bringing a complaint before the commission.

Appendix H. Recent Changes in FERC Regulations

On April 24, 1996, the Federal Energy Regulatory Commission (FERC) issued Order 888 requiring all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to have on file open access nondiscriminatory transmission tariffs that contain minimum terms and conditions of nondiscriminatory service. The order also permits public utilities and transmitting utilities to seek recovery of legitimate, prudent and verifiable stranded costs associated with providing open access and transmission services under section 211 of the Federal Power Act (FPA). The Commission's goal is to remove impediments to competition in the wholesale bulk power marketplace and to bring more efficient, lower cost power to the Nation's electricity consumers.

In Order 888, the Commission concludes that functional unbundling of wholesale services is necessary to implement nondiscriminatory open access transmission and that corporate unbundling should not now be required. Functional unbundling means three things: (1) a public utility must take transmission services (including ancillary services) for all of its new wholesale sales and purchases of energy under the same tariff of general applicability as do others; (2) a public utility must state separate rates for wholesale generation, transmission, and ancillary services; (3) a public utility must rely on the same electronic information network that its transmission customers rely on to obtain information about its transmission system when buying or selling power. In Order 889, the Commission establishes standards of conduct to ensure that a public utility's employees engaged in transmission system operations function independently of the public utility's employees engaged in wholesale purchases and sales of electric energy in interstate commerce. The order states that it is not the purposes of these rules to compromise reliability. In emergency circumstances affecting system reliability, system operators may take whatever steps are necessary to keep the system in operation.

Key provisions of the standards of conduct include: (1) any employee of the transmission provider, or any employee of an affiliate, engaged in wholesale merchant functions is prohibited from conducting transmission system operations or reliability functions and having access to the system control center or similar facilities for transmission operations or reliability functions that differs in any way from the access available to other open access transmission customers; (2) any employee of the transmission provider, or any of its affiliates, engaged in wholesale merchant functions shall have access to only that information available to the transmission provider's open access customers on the Open Access Same-Time Information System (OASIS) and must not have preferential access to any information about the transmission provider's transmission system that is not available to all users on the OASIS; (3) a transmission provider may not share any market information, acquired from nonaffiliated transmission customers or potential nonaffiliated transmission customers with its own employees (or those of an affiliate) engaged in merchant functions, except to the limited extent information is required to be posted on the OASIS in response to a request for transmission service or ancillary services; and (4) employees of the transmission provider engaged in transmission system operations must apply all tariff provisions relating to the sale or purchase of open access transmission service in a fair and impartial manner that treats all customers (including the public utility and any affiliate) in a nondiscriminatory manner.

Order 889 requires jurisdictional utilities that own or control transmission systems to set up an OASIS. Five major types of information must be posted on the OASIS, including: (1) available transfer capability, (2) transmission service offerings and prices of the transmission owner and resellers, (3) ancillary service product offerings and prices of the transmission owner and third parties, (4) specific transmission service requests and responses, and (5) informal communications about the transmission system. The Commission states that with these requirements in place, we are opening up the "black box" of utility transmission information.

The Commission concludes that functional unbundling, coupled with the ability of any entity to file a complaint with the Commission detailing any alleged misbehavior, is a reasonable and workable means of assuring that non-discriminatory open access transmission occurs. As a further precaution against discriminatory behavior, the Commission will continue to monitor electricity markets to ensure that functional unbundling adequately protects transmission customers. At the same time, the Commission will analyze all alternative proposals, including formation of Independent System Operators (ISOs), and, if it becomes apparent that functional unbundling is inadequate or unworkable in assuring non-discriminatory open access transmission, the Commission will reevaluate its positions and decide whether other mechanisms, such as ISOs, should be required. While the Commission is not now requiring any form of corporate unbundling, it encourages utilities to explore whether corporate unbundling or other restructuring mechanisms may be appropriate in particular circumstances. In Order 888, the Commission recognizes that some utilities are exploring the concept of an ISO and that the tight power pools are considering restructuring proposals that involve an ISO. While the Commission does not require utilities to form ISOs, it encourages the formation of properly-structured ISOs. To this end, Order 888 gives the industry some guidance on the principles that the Commission will use in assessing ISO proposals that may be submitted to it in the future. The order states that because an ISO will be a public utility subject to its jurisdiction, the ISO's operating standards and procedures must be approved by the Commission.

For about the last decade, the Commission has been requiring merging utilities to offer concessions in their operations to assist new electricity suppliers and spur competition in wholesale electric markets. In the late 1980s and early 1990s, for example, a common merger concession was the filing of an open access transmission tariff by the entity created from the merger. Such concessions, imposed by the Commission as conditions for approval of mergers, became a major factor in bringing about changes in electric utility structure and operations. As a result, merger policy became, and remains, a major tool for the Commission to bring about and to shape industry change. In December 1996, FERC issued a Policy Statement on Merger Policy. The purpose of the Policy Statement is to ensure that mergers are consistent with the public interest and to provide greater certainty and expedition in the commission’s analysis of merger applications. The Policy Statement shows FERC’s: (i) intention to give close scrutiny to market concentration of generation, (ii) interest in considering utilities’ voluntary structural changes as mitigation, and (iii) promise of quicker approval of problem-free mergers. The revised criteria consider the effect of a proposed merger on three factors: competition, rates, and regulation. The principal focus is toward competitive issues, i.e., the evaluation of market power. The key element in the process to determine the effect of the merger on competition is an analytical screen derived from the Department of Justice Merger Guidelines. FERC’s claimed options for “conditioning” problem mergers include: divestiture of generation assets, relinquishment of control of the transmission grid to an independent system operator, restrictions on trades over constrained transmission paths, concrete commitments to improve transmission facilities to relieve constraints, and pricing transmission on a region-wide basis rather than an individual company basis.

The Commission can be expected to continue to use its conditioning authority and look for other ways to promote industry change. The Commission’s has stated a preference for ISOs as the mechanism to ensure non-discriminatory access to the transmission system. The Commission’s recent order denying the Primergy merger shows that turning over control of the transmission system to an ISO will not be sufficient by itself, in many cases, to mitigate market power concerns regarding the concentration of generation. However, it is doubtful that the Primergy order will have a significant impact on the current ISO discussions underway in many regions of the country.

APPENDIX I. SUMMARY OF ISO GOVERNANCE STRUCTURES

ERCOT ISO	PJM ISO	Ca
• Board of Directors membership from 6 market groups: IOU, municipal, cooperative, transmission dependent, IPP, power marketers • 3 representatives per group • 2/3 majority of votes to pass (13 of 18) • 2 Board Committees: Executive Committee, Nominating Committee • PUC and Office of Public Utility Commission will each have one ex-officio nonvoting member on the Board • Board will hire ISO Director and an Executive Director, appoint a Director of Technical Advisory Committee, approve reliability and operating guidelines, approve budgets, etc.	• Board of Directors will consist of the President and CEO and 6 Directors serving three-year terms • Of the 7 Directors on the Board of PJM Services Company, only 2 may be affiliated with members of the existing PJM pool and may serve on the Board for only the first five years • Other directors may not be affiliated with any entity engaged in the generation, transmission, distribution, purchase or sale of electric energy in the Mid-Atlantic region • 3 Board Committees: Nominating Committee, Compensation Committee, Audit Committee	• Board of Directo market groups a transmission ow (4), sellers (3), e (3) • No one class ma • No two classes r • An entity can be • Board members will rotate every • 12 votes require • 7 votes required

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NEPOOL ISO	NYPP ISO
• Board of Directors composed of ten members with no affiliation with any NEPOOL member • NEPOOL voting will be conducted in the Management Committee • Every NEPOOL member will be entitled to a seat on the Management Committee and a vote • Voting bases on a six-factor formula which allocates voting shares on the basis of peak and energy load responsibility, generation ownership, transactions, and transmission ownership • 66% majority needed to pass an action • 20% needed to block an action • 4 Committees below the Management Committee: Regional Market Operations, Regional Transmission Operations, Market Reliability Planning, and Regional Transmission Planning	• Board of Directors comprised of 4 classes of market groups: buyers (8), sellers (8), consumer and environmental (4), and transmission providers (8) • A vote of 17 of 28 members will be needed to pass any measure • Board members will serve 4 year terms, with terms initially set at varying lengths in order to ensure staggered terms • 3 standing ISO committees; Operating, Business Issues, Dispute Resolution

APPENDIX J. SUMMARY OF ISO FUNCTIONS

ERCOT ISO	PJM ISO	Cali
• NERC Regional Reliability Council became the ISO • No load and generation balance - Policeman • Line load relief • Direct dispatch for transmission congestion • Administer OASIS • Administer transmission tariff and loss compensation • Provide a forum for coordinated regional transmission planning • Develop operating and reliability guides	• Operate the PJM control area • Manage and administer the competitive energy market • Direct and coordinate the operation of the designated transmission facilities • Administer the transmission tariff, including determination of available transfer capability • Performing system impact studies • Schedule transmission service • Curtailing transmission service • Coordinate regional transmission planning • Support the administration and implementation of an agreement to establish necessary reserve levels and sharing of such reserves	• System reliability, • Controls dispatch transmission • Compile and valic • Administer transn • Perform congesti • Obtain unbundlec market • Settlements for gı ancillary services • Real time control

APPENDIX J--PAGE 2 OF 2

NEPOOL ISO	NYPP ISO
• Control area operator • Controls bulk transmission system operation • Dispatches all generation subject to participant self scheduling • Administers market settlement rules and regional transmission tariff	• Control area operator • Direct the operation and maintain the reliability of the bulk power system • Provide transmission service and ancillary services to eligible customers under the tariff • Coordinate maintenance scheduling of the bulk power transmission system • Coordinate planned outages and schedules for generating units under contract to provide installed capacity to the bulk power system • Facilitate the financial settlement of ISO and Power Exchange transactions • Require customers entering into service agreements under the tariff to maintain appropriate levels of installed and operating capacity.

APPENDIX K. ISO FUNDING

ISO implementation costs will vary widely depending on whether an existing control center is used or a new facility is required. If a new facility is required, significant capital costs will be incurred. The experience in California shows that significant implementation costs will be incurred to form an ISO in regions where no existing institution performs many of the functions of an ISO. However, if an existing institution performs many of the functions of an ISO, which is the case in some of the tight power pools in the Northeast, then implementation costs may not be significant. Little information is available concerning the true implementation costs for many of the ISOs currently proposed or under discussion. Estimates of implementation costs for certain ISOs or similar functions are listed below.

ERCOT

Implementation estimated to cost roughly $1,100,000. Implementing a single ERCOT ISO in a stand-alone manner would add roughly $200,000 to the estimate. ERCOT is currently looking at building two stand-alone ISO Security Centers at a total cost of roughly $2,500,000. We have not seen the annual costs associated with the ERCOT ISO implementation at this time. The annual budget is estimated to be $3 to $5 million for a single ERCOT ISO using an existing member company control center.

Southwest Power Pool

The Southwestern Power Pool (SPP) is implementing a standalone Security Coordination Center which is roughly equivalent to an ISO. They estimate that it will cost them roughly $1,750,000 to implement and have an ongoing cost of roughly $1,500,000 per year. They include in their estimate a staffing of 14 people, including a 5 person rotation for floor coverage, staff and administrative support.

California ISO

The start-up cost of the California ISO is projected to be about $250 million for both hardware and software.

NYPP ISO

New York Power Pool estimates an annual budget of $20 million.

Primergy ISO

The merger applicants agreed to an initial capitalization of $2 million. Intervenors argued that the amount should be increased to at least $10 million.

APPENDIX L. PHYSICS OF AN ELECTRIC SYSTEM

Increased demand for transmission services are expected due to actions taken by State Commissions and FERC's Open Access orders to promote competition in the electric industry. The development of a more competitive environment in Georgia, and throughout the Southeast, carries the possibility of stressing transmission capacity as more participants use the transmission network to deliver or receive purchased power. When transmission capacity becomes stressed, an electric utility must offer to enlarge its transmission capacity, as necessary, to provide transmission services pursuant to the Energy Policy Act (EPAct) of 1992. However, approval to build new transmission facilities is becoming more difficult to obtain because of concerns over the environment, the potential health effects of electric and magnetic fields (EMF), and the decline of property values along transmission routes. As a result, possible alternatives to building new lines, for example upgrading the transmission system, must be examined to maximize the capability of existing transmission facilities. Transmission upgrades can be a feasible option because the associated cost and lead times are typically less than for new construction. To examine viable alternatives, it is important to understand the physics of an electric system, particularly, the thermal, voltage, and operating constraints on a system's capability to transmit power from one area to another. "Additional power can be transmitted reliably if there is sufficient available transfer capability on all lines in the system over which the power would flow to accommodate the increase and certain contingencies or failures that could occur on the system." [83] A discussion of these constraints is presented in this section along with a brief description of the control system used for the Southern Control Area.

Thermal and Electrical Current Constraints

Of the three constraints that limit the transfer capability of the transmission system, thermal limitations are the most common. Heat is produced along transmission lines and equipment due to the resistance of the flow of electrons through it. Temperatures occurring in the line equipment depend on the rate of flow of electrons (i.e., current), and on ambient weather conditions that affect the dissipation of the heat into the air. However, thermal ratings for transmission lines are normally expressed in terms of current flows rather than actual temperatures.

[83] *"Upgrading Transmission Capacity for Wholesale Electric Power Trade,"* Arthur H. Fuldner, Electric Information Administration (Washington, D.C.) pp. 1- 2.

Overheating of transmission lines can lead to two problems: (1) loss of line strength which can reduce its expected life, and (2) expansion and permanent sagging of line spans between supporting towers which can cause ground clearance violation associated with safety requirements. These are eventual results if overheating occurs extensively. Emergency ratings of transmission lines refer to higher levels of current flow that can be supported for limited time periods. A "normal" thermal rating is the current flow level the line can support indefinitely. Thermal constraints also limit underground cables and power transformers. Operation of these facilities at excessive temperatures can cause damage to their insulation resulting in shorter service lives.

Voltage Constraints

Voltage (pressure-like quantity) is a measure of the electromotive force necessary to maintain a flow of electricity on a transmission line. Fluctuations of voltage can result from changes in demand and failures on the grid. Maximum voltage levels are set by the design of the transmission line. If the maximum level is exceeded, short circuits, noise, and radio interference can occur. Also, substation equipment and customer facilities can be damaged. Power requirements of the customers also constrain minimum voltage. Voltage levels below minimum limits cause inadequate operation of customer's equipment and possible damage to motors.

A decrease in voltage on a transmission line, known as a voltage drop, occurs from the sending end to the receiving end. This occurrence is almost directly proportional to reactive power flows and line reactance in an alternating-current (AC) line. Reactive power is a characteristic of AC power resulting from a time difference between voltage and current variations that depend on the power dispatch and the power requirements of the system. Reactance is a characteristic of the design and length of the line. The installation of capacitors and inductive reactors on lines help to control the amount of voltage drop. In essence, voltage and current levels determine the power that can be delivered to customers.[84]

[84] *"Upgrading Transmission Capacity for Wholesale Electric Power Trade,"* Arthur H. Fuldner, Electric Information Administration (Washington, D.C.) p. 2.

System Operating Constraints

Operating constraints stem from security and reliability concerns related to maintaining power flows. Power flow patterns redistribute when demand and generation patterns change, or when the system grid is altered due to a circuit being switched on or put out of service. When power is transmitted from one utility, or control area[85], to another, the resulting power flows along all paths joining the two areas, regardless of ownership of the lines. The amount of power transmitted on each path of the system depends on the impedance of the various paths. Impedance is the opposition to the power flow on an AC circuit. Moreover, impedance depends on the length of the line and design details for the line. A path of low impedance attracts a greater part of the total transfer than a path of high impedance.

In a wholesale power transaction, a pro forma "contract path" of transmission lines or systems is designated through which the power is expected to flow. However, the actual power flows do not necessarily follow the contract path but may flow through parallel paths in other transmission systems depending on the loading conditions at that time. These are known as "parallel path flows." "Loop flows" are a result of interconnected transmission systems whereby power flows can inadvertently travel into the other systems' networks and return. This reiterates the point that power flow is controlled by physics, not contracts. Currently, it is not a requirement of law that contracts reflect the actual path. Parallel path flows and loop flows can limit the transfer capability of other systems that are not a part of the scheduled contract path.[86]

Preventive operation for system security also represents constraints on system operation. The bulk power system is designed and operated to avoid service interruptions, referred to as "contingencies," due to component outages such as loss of a generation unit, loss of a transmission line, or a failure of a single component of the system. The adoption of NERC guidelines has increased security of interconnected systems throughout its jurisdiction by requiring systems to operate in such a manner that they can withstand the single largest contingency possible and, when practical, withstand multiple contingencies. The preventive operating

[85] A control area is an electrical system, bounded by interconnection metering and telemetry. It continuously regulates, via automatic generation control (AGC), generation within its boundaries and scheduled interchange back and forth across the inter-ties, to match its system load while contributing to frequency regulation of the interconnection. Some utilities operate a control area jointly in a "tight" power pooling arrangement.

[86] *"Upgrading Transmission Capacity for Wholesale Electric Power Trade,"* Arthur H. Fuldner, Electric Information Administration (Washington, D.C.) pp. 3-4.

guidelines provided by the NERC include running sufficient generation capability to provide operating reserves in excess of demand and limiting power transfers on the transmission system. This allows the system to operate so that each element remains below normal thermal constraints under normal conditions and under emergency limits during contingencies. Proper levels of reserve capacity accommodate contingencies.

One of the advantages of an interconnected system is reserve sharing. Utility management must have access to additional power facilities (reserves) that can be put into service either immediately (spinning reserves) or after a short period of preparation (supplemental reserves). This reserve capacity is needed in case of contingencies or customer demand in excess of plant capability. Reserves may be obtained from spare generating units or through interconnection. If a contingency occurs in one company, power can be supplied temporarily by the other companies. Thus, an interconnected system of reliable suppliers enhances overall reliability and decreases the reserve levels needed by independent utilities. This assumes that each supplier in an interconnected system provides proportionate reserve margins to accommodate "the vagaries of demand and for unexpected breakdowns of generators." The proper level of generating reserves (i.e., reserve margin) depends on system characteristics, such as types of generators, load growth, and demand conditions. Moreover, reserves can be offset by interruptible arrangements. Some utilities make large sales to interruptible customers whose service the utility can turn off at will.[87] Normally, the desired reserve margin is set by a loss of load probability (LOLP) analysis designed to assure that blackouts and brownouts will be limited.[88]

System operating constraints also involve system stability. Problems associated with system stability are typically grouped into two types: (1) maintaining synchronization among system generators and (2) preventing voltage collapse. In the United States, interconnected systems are considered synchronous when all generators rotate in unison at a speed that produces a consistent frequency of 60 hertz (cycles per second). Disturbances (i.e., faults) and their removal cause oscillations in the speed at which the generator rotates and in the frequency of the power flows in the system. Unless natural conditions or control systems damp out the oscillations, the system is unstable. This occurrence is known as transient instability and can lead to collapse of the system. Along these

[87] *"America's Electric Utilities: Past, Present and Future,"* 6th Edition, Leonard S. Hyman, Public Utilities Report, Inc., Arlington, Virginia, page 29, March 1997.

[88] Blackouts are power outages occurring over extended areas of service territory; whereas, brownouts are spot outages or voltage reductions within a service area resulting from intermittent or curtailed power supply.

lines are other types of instability, such as steady-state and dynamic.[89] These conditions can lead to large voltage and frequency fluctuations. To avoid unstable conditions, power transfers between areas are limited to levels determined by contingency studies.

Finally, voltage collapse can occur from a chain of events that stem from voltage instability. This occurs if transmission lines are not adequately designed to handle large amounts of reactive power, resulting in severe voltage drops at the receiving end. This causes the consuming entities to draw increasing currents that create additional reactive power flows and voltage losses in the system. If the process continues, voltages can collapse further and may require users to be disconnected in order to prevent serious damage.[90]

Southern Control Area

Constraints on the transfer capability of a power pool require utilities to control their interconnected operations by monitoring tie line flows and accounting for capacity and energy interchanges (i.e., net sum of tie line flows) between non-associated utilities via real time metering and telemetry. This is accomplished on the Southern electric system through the use of Automatic Generation Control (AGC) and the concept of Area Control Error (ACE). AGC is a control system that matches the level of generation on the Southern electric system to the real time load obligations of the system while maintaining system frequency near 60 Hz. As the amount of electricity used by the customers increases and decreases throughout the day, the output of the power plants is automatically raised or lowered via AGC to match the load. AGC adjusts the level of generation every few minutes. ACE is the difference between the amount of power scheduled to flow into or out of the system and actual system interchange experienced plus a number based on deviation from 60 Hz, which represents contribution to frequency regulation on the Eastern Interconnection. AGC always acts to drive ACE toward zero, which implies

[89] Steady-state instability can occur if too much power is transferred over a transmission line or part of a system to the point that the synchronizing forces are no longer effective. Dynamic instability (also known as small-signal instability) occurs when normal variations in generation or consumption are too small to be considered disturbances, but initiate oscillations at low frequencies.

[90] *"Upgrading Transmission Capacity for Wholesale Electric Power Trade,"* Arthur H. Fuldner, Electric Information Administration (Washington, D.C.) pp. 4-5.

system balance and frequency stability in accordance with NERC/SERC guidelines for reliable system operation.[91]

Conclusion

For the bulk power system to operate reliably, it must be designed and operated based on the following principles:

A. The total generation at any moment must be kept equal to total electricity consumption and losses on the system including transmission and distribution.

B. The electricity is allowed to flow through the transmission system in accordance with physical laws and cannot be directed to flow through specific lines.

C. The system must be designed with sufficient reserve capacity in generation and transmission to allow for uninterrupted service when contingencies occur.[92]

The three constraints, thermal, voltage and operating, described above limit a system's ability to transfer power along a transmission system. Upgrade options are available but must be carefully considered with other alternatives to control the transfer of bulk power. Changing the generation pattern provides limited control over actual power flow. Other methods of control may include upgrade remedies, such as rebuilding lines, refining methods to determine thermal ratings of equipment for different conditions, installing phase shifters and building high voltage direct current (HVDC) lines. Use of HVDC lines may not be economically feasible. Some technologies have been developed to help mitigate preventive operating constraints. For example, the concept of a Flexible AC Transmission System (FACTS) uses new power-electronic switches and other devices to provide faster and more refined control of equipment to change the way power flows redistribute

[91] *"Power Pooling on the Southern Electric System,"* Bulk Power Operations of Southern Company Services, Inc., pages 23 – 31.
[92] *"Upgrading Transmission Capacity for Wholesale Electric Power Trade,"* Arthur H. Fuldner, Electric Information Administration (Washington, D.C.) p. 2.

under normal conditions or during contingencies. This can allow for increased transfer capability in transmission and distribution systems. Other technologies are being developed to move toward "corrective," rather than "preventive" methods of operation.[93] As increased competition continues in the electric power industry, the transfer capability of the transmission system will be a major concern for future operators.

[93] *"Upgrading Transmission Capacity for Wholesale Electric Power Trade,"* Arthur H. Fuldner, Electric Information Administration (Washington, D.C.) p. 11.

9. ACKNOWLEDGMENTS

The Electric Industry Restructuring Workshops, organized and conducted by the Georgia Public Service Commission during 1997, have been considered a great success due primarily to the overwhelming interest and participation of the numerous parties involved. The Commission and its Staff would like to thank those parties who submitted white papers and comments, participated in focus groups, gave workshop presentations and attended the workshops. The Commission is grateful for the many long hours taken out of busy schedules to participate and provide input to this process. The information received from all parties has been invaluable to the Commission and its Staff during the compilation of this report. A complete list of presenters, focus group participants, parties submitting white papers or comments and workshop attendees is included in Appendix B on page 83.

The project team consisted of the following staff members who organized and conducted the workshops, reviewed the comments and white papers, researched relevant issues and wrote this report:

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Sherée Williams
Veronica Thomas

A special thanks to the National Regulatory Research Institute and the Regulatory Assistance Project who assisted with the workshops and to Nancy Gibson, Special Assistant Attorney General, who assisted with writing the report.