Before the

Georgia Public Service Commission

In Re: **Petition for Rule NISI to Examine** **Georgia Power Company's** **Real Time Pricing Structure**	)	**Docket No. 11708-U**

Direct Testimony and Exhibits of

Jeffry Pollock

On behalf of

Georgia Textile Manufacturers Association
and
Georgia Industrial Group

March 2000
Project 7334

BAI
BRUBAKER & ASSOCIATES, INC.

Before the

Georgia Public Service Commission

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Direct Testimony of Jeffry Pollock

Table of Contents

Executive Summary i

I. Introduction 1

II. Why the Petition Was Filed 3

III. The Requested Relief 15
- Adder 16
- Lambda Averaging 22
- Fuel Accounting Practice 26
- Disclosure of Energy Procurement Practices 28

IV. The Commission Has Jurisdiction to Grant the Relief Requested by the Petitioners 31

Appendix A

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In Re:	)	
Petition for Rule NISI to Examine	)	
Georgia Power Company's	)	Docket No. 11708-U
Real Time Pricing Structure	)	
	)	

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List of Acronyms

Customer Baseline Load	CBL
Edison Electric Institute	EEI
Energy Information Administration	EIA
Federal Energy Regulatory Commission	FERC
Florida Power and Light Company	FPL
Fuel Cost Rate	FCR
Georgia Industrial Group	GIG
Georgia Textile Manufacturers Association	GTMA
Georgia Power Company	GPC
Investor-Owned Utilities	IOU
Kilowatt	kW
Kilowatthour	kWh
Megawatt	MW
Megawatthour	MWh
Real Time Pricing	RTP
Real Time Pricing Day-Ahead	RTP-DA
Real Time Pricing Hour-Ahead	RTP-HA
Return on Equity	ROE
Southeastern Electric Reliability Council	SERC
Tennessee Valley Authority	TVA
Non-Utility Generator	NUG
Variable Operation and Maintenance Expense	VOM

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Executive Summary

Real Time Pricing was an innovative cost-based rate that was very beneficial for both Georgia Power Company and its' customers when it was introduced in 1992. It allowed the customers a means to moderate standard industrial tariffs, which are uncompetitive with surrounding states, so that the customer's total blended cost would remain competitive. The rate gave Georgia Power Company a powerful tool to compete for new industry with rates substantially less than the regular standard tariff rates charged to its existing customers.

As Georgia Power Company's capacity reserves decreased during the 90's, the RTP load was served by increasingly expensive native generation and, most significantly, purchase power. This included spot purchases, which are exceedingly expensive and will remain so until the deregulated wholesale markets mature and sufficient merchant capacity is attracted to Georgia to serve available customers. While "hot summers" have been blamed for escalating RTP prices in the past two years, the price increases and volatility are more attributable to Georgia Power Company's apparent unwillingness to protect its captive customers from the extreme high prices

and volatility caused by tight capacity supplies and price-deregulated wholesale markets. Under this scenario, the flaws and inequities of the existing tariff structure have become pronounced with the result that RTP prices have increased at an average of almost 7% a year since 1992. Because of these changing circumstances, RTP is no longer a cost-based rate.

The GTMA/GIG Petition and this testimony identify the specific ways that the tariffs can be modified to restore the cost basis and to more equitably balance the risks until a more permanent cost-based option of purchasing electricity can be allowed to industrial customers. These areas of adjustment are as follows:

- First, remove the risk adder of 0.5¢ per kWh (0.45¢ for RTP-HA). As the RTP tariffs are applied by GPC, the Company has no risk. All risk has been shifted to the customer. The margins from RTP sales are excessive and unreasonable. Removing the adder will restore the margins to a more reasonable level that more clearly reflects the cost to provide the service.

- Second, require GPC to properly administer the RTP tariffs or implement "lambda averaging." The RTP tariffs do not allow purchased power costs to be included in the hourly price, contrary to actual practice. This practice should cease immediately. Alternatively, the price should be based on the average cost of the native and purchased energy resources used to supply RTP (i.e., lambda averaging) so that it reflects the actual cost of the power. GPC prices RTP at the cost of the last and most expensive resource employed. This practice is tantamount to selling a lot full of Ford automobiles at a Mercedes price just because one Mercedes happens to be parked on the same lot.

- Third, modify the fuel accounting to reflect the actual real time cost of the generated or purchased energy used to set the hourly prices. This practice will avoid an artificial underrecovery of fuel under the Georgia Power interpretation. Any underrecovery is separately and additionally recovered from all customers.

- Fourth, require accountability by Georgia Power Company to its customers for its purchasing practices. The design of the RTP rate offers no incentive to GPC to purchase energy for the least dollar cost and the customers presently have no right to seek lower cost suppliers of electricity.

These changes can be made without reopening or violating the terms of the Accounting Order approved in GPC's last rate case, Docket No. 9355-U. The Accounting Order cannot and should not be used as an excuse to deny the Petition, to make only a temporary fix in the rate or

wait until the next rate case before implementing the changes necessary to make RTP fair, just and reasonable.

The next rate case, which cannot give effective relief until January 2002, is an unrealistically long delay to businesses whose performance is judged on a quarterly basis. In today's fast-moving and changing business climate, survival goes to those companies that can minimize their costs, including the cost of electricity. Electricity is a significant operating cost of GTMA and GIG members. Competitive electricity prices are essential to the economic well-being of these customers and the State of Georgia.

The changes to RTP that are described in the testimony are designed to restore the competitiveness that has been lost due to the drastic price increases. Further, they will make RTP a rate that is fair, just and reasonable.

Before the

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In Re: **Petition for Rule NISI to Examine** **Georgia Power Company's** **Real Time Pricing Structure**	**Docket No. 11708-U**

Direct Testimony of Jeffry Pollock

I. Introduction

Q **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A Jeffry Pollock; 1215 Fern Ridge Parkway, Suite 208; St. Louis, Missouri, 63141-2000.

Q **WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?**

A I am an energy advisor and a principal in the firm of Brubaker & Associates, Inc. (BAI).

Q **PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.**

A I have a Bachelor of Science Degree in Electrical Engineering and a Masters in Business Administration from Washington University. Since graduation in 1975, I have been engaged in a variety of consulting assignments including energy and regulatory matters in both the United States and Canada. I have participated in regulatory matters before this Commission since 1977. More details are provided in Appendix A to this testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of the Georgia Textile Manufacturers Association (GTMA) and the Georgia Industrial Group (GIG). Both GTMA and GIG members are customers of Georgia Power Company (GPC). They consume large quantities of electricity primarily for manufacturing. Further, many GTMA and GIG members purchase electricity under the Real Time Pricing (RTP) tariffs.

Q WHAT ISSUES ARE ADDRESSED IN YOUR DIRECT TESTIMONY?

A I shall explain the December 23, 1999 Petition filed by GTMA and GIG. In particular, I shall discuss why the Petition was filed and what relief GTMA and GIG are seeking from the Commission. I shall also provide evidence supporting the requested relief. Finally, I shall discuss how granting the proposed relief will not violate the terms of, or require reopening, the Accounting Order approved in GPC's last rate case, Docket No. 9355-U.

Q ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A Yes. I am sponsoring Exhibits ____ (JP-1) through ____ (JP-9). These Exhibits were either prepared by me or under my supervision and direction.

II. Why the Petition Was Filed

Q WHY DID GTMA AND GIG FILE THE PETITION FOR RULE NISI?

A The GTMA/GIG Petition was filed to address serious problems with GPC's RTP tariffs. These serious problems include:

1. Concerns about the overall competitiveness of GPC's rates in light of recent drastic increases in average RTP prices;

2. The RTP tariffs are not being properly applied because purchased power costs are included in the hourly running cost of incremental generation; and

3. Dramatic changes in circumstances since the inception of RTP have resulted in prices that are no longer fair, just and reasonable and which are providing excessive revenues to GPC. As explained below, certain of the design parameters of the RTP tariffs need to be updated in order to bring the rate more in line with cost and to mitigate the excess revenues being enjoyed by GPC at its customers' expense.

Q WHY IS IT NECESSARY FOR GPC TO OFFER RTP?

A GPC's standard rates are more expensive than the corresponding standard rates of other utilities in the southeastern United States. This is shown in Exhibit ____ (JP-1). As can be seen from this Exhibit, all three comparisons demonstrate that GPC's standard industrial tariff is priced well-above the average rate for similar service offered by investor-owned utilities (IOU) in the Southeast. For example, page 1 shows that, based on industrial rates in effect on July 1, 1998, GPC ranked 15th out of 40 southeastern IOUs. (A ranking of 1 is the most expensive, and a ranking of 40 is the least expensive.) By July 1, 1999 (page 2), GPC ranked 14th most expensive. This means that 25 and 26 other Southeastern IOUs priced their standard industrial service below GPC, respectively in 1998 and 1999.

The rankings shown on pages 1 and 2 were developed from various Edison Electric Institute (EEI) publications for an industrial customer having a 68% monthly load factor, which is consistent with EEI's assumptions.

Q DO GPC'S STANDARD RATES COMPARE MORE FAVORABLY FOR HIGHER LOAD FACTOR CUSTOMERS?

A No. Exhibit ____ (JP-1), page 3, shows the results of a BAI survey of rates in effect on January 1, 2000 for 90% load factor customers. Further, unlike the prior EEI surveys, BAI's Southeastern Survey includes a major competitor to GPC, the Tennessee Valley Authority (TVA).

The BAI survey confirms that GPC's standard industrial tariffs are priced above the average. Specifically, GPC is the 10th most expensive out of 33 utilities in the survey. This means that 23 other utilities, including TVA, charged less for industrial high load factor service than GPC.

Q HOW IS RTP USED IN CONJUNCTION WITH GPC'S STANDARD TARIFFS?

A The standard tariffs apply to a customer's existing load prior to commencing RTP service. This existing load is referred to as a customer baseline load (or CBL). RTP applies to a customer's actual hourly loads when those loads differ from the CBL.

For example, if a customer's hourly load is above the CBL, the customer is charged the hourly real time price. Similarly, if a customer's hourly load is below the CBL, the customer is paid the hourly real time price. If a customer continues to operate at the CBL, then the customer would continue to pay the same total cost as under the standard tariff.

Thus, customers that operate above the CBL during low-cost hours and/or below the CBL in high-cost hours will reduce their average cost of electricity. The net result of

using RTP is that the total blended cost of electricity can be more competitive than the standard firm rates.

Q HOW HAS THE RTP RATE HISTORICALLY HELPED TO MAKE GPC'S RATES MORE COMPETITIVE?

A RTP has historically been used in conjunction with a standard tariff to allow customers to reduce their average cost of electricity.

RTP was designed to be a cost-based rate option designed to reflect GPC's incremental cost of generation and transmission. The standard tariffs, by contrast, are designed to fully recover GPC's embedded cost, which include generation, transmission, distribution and other overhead costs. Because the incremental cost of generation and transmission is below GPC's overall embedded cost of service, RTP service costs less than taking service under GPC's standard tariffs. As explained later, RTP is no longer a cost-based rate and it is no longer providing a competitive advantage for GPC customers.

Q DOES GPC OFFER DIFFERENT TYPES OF REAL TIME PRICING SERVICE?

A Yes. GPC offers two RTP options: Day-Ahead (DA) and Hour-Ahead (HA). The RTP-DA and RTP-HA tariffs are similar in structure. Both require the customer to establish a CBL, and the hourly prices include the running cost of incremental generation, losses and a recovery factor or adder.[1] As discussed later, the adder is a flat charge per kilowatthour (kWh) and it provides a contribution to fixed costs (i.e., profit). Under certain circumstances, the hourly prices will include an outage factor and a charge

[1]Losses are added to the incremental generation cost because this cost is initially quoted at the power plant, and some energy is consumed to deliver electricity from the generator to a customer.

for incremental transmission. However, the running cost of incremental generation, or system lambda, is by far the most significant component of the hourly real time prices.

Q WHAT ARE THE KEY DIFFERENCES BETWEEN RTP-DA AND RTP-HA?

A There are two key differences. First, for RTP-DA customers, GPC determines by 4:00 p.m. the 24 hourly prices applicable on the next day. This is in contrast to HA service where the price for each hour is not determined until one-hour before service commences.

Second, the two RTP options have different adders. The DA adder is 0.5¢ per kWh, while the corresponding HA adder is 0.45¢ per kWh.

Q HOW MUCH LOAD IS PRICED ON RTP VS. THE STANDARD TARIFFS?

A RTP sales account for about 34% of the total energy sold to RTP customers. The remaining 66% is priced under a standard tariff.

Q DO THE LOWER PRICES OFFERED BY RTP COME FREELY WITH NO RISK?

A No. Unlike any other retail customer served by GPC, RTP customers experience immediate price level changes as a result of projected changes in the hourly running cost of generation and purchased power.

For example, if GPC projects a need to purchase power on the wholesale spot market at a cost of $6 per kWh, the same $6 per kWh cost, plus additional markups, will be immediately reflected in the hourly RTP. If GPC does not effectively control these costs, then it jeopardizes the competitiveness of the RTP program. This, in turn, further jeopardizes the competitiveness of the customers that have come to rely upon RTP as a way to keep jobs in Georgia.

There are also circumstances in which a customer cannot respond to higher prices such as to meet current demand for the customer's product. Under these circumstances, reducing electricity purchases would require curtailing production, letting workers go and/or losing sales to a competitor.

Q HAVE RTP CUSTOMERS ALWAYS BEEN EXPOSED TO PRICE RISK?

A Yes. However, recent pricing has demonstrated that the RTP customers are being asked to bear substantially more risk than at any time since the inception of RTP. This is shown in the table below.

Year	Maximum Price	Minimum Price	Ratio of Maximum to Minimum Price	Standard Deviation
RTP-DA				
1996	22.45¢	1.52¢	15	1.1
1997	15.18¢	1.59¢	10	1.0
1998	49.13¢	1.75¢	28	3.5
1999	193.73¢	1.74¢	111	7.5
RTP-HA				
1996	22.40¢	1.49¢	15	1.1
1997	25.61¢	1.55¢	17	1.3
1998	71.01¢	1.68¢	42	3.3
1999	642.66¢	1.49¢	431	12.2

This increased price risk is reflected in both the wider extremes between minimum and maximum prices and the standard deviation. Standard deviation is a measure of the variability of the hourly prices. The larger the standard deviation, the greater the variability. As can be seen from the above table, price variability increased significantly in 1998 and then took a quantum leap in 1999.

Q **IS PRICE VOLATILITY THE MAJOR ISSUE?**

A No. **Price level is more important than volatility to GTMA and GIG members.** Average RTP prices have increased drastically during the summers of 1998 and 1999. Since 1997, average RTP prices have increased by over 1¢ per kWh, a 44% increase. This translates into a 13% overall price increase to an average RTP customer. These drastic increases in RTP prices are in stark contrast to GPC's other rates, which have dropped since 1997. This is primarily due to the base rate reduction implemented in GPC's last rate case.

Q **WHAT HAS BEEN THE LONG-TERM TREND IN THE GPC'S ELECTRICITY PRICES?**

A The long-term trend is shown in Exhibit ____ (JP-2). This Exhibit shows the year-to-year percentage change in average RTP prices with the corresponding prices charged to residential, small business and large business customers. As clearly shown in this chart, RTP-DA prices have *increased* on average by 7.1% per year. During this same period, all other non-RTP prices *decreased* annually by between 0.6% and 1.9%.

Thus, RTP is the only tariff to have experienced price increases over the long-term.

Q **WHAT FACTORS ARE CAUSING THE HIGHER PRICES UNDER THE RTP TARIFFS?**

A The higher average RTPs can be attributed primarily to two factors. First, GPC has improperly included purchased power costs in determining the hourly price. Second, circumstances have changed dramatically since RTP was first implemented as a pilot program in 1993.

Q WHY DO YOU CONTEND THAT GPC HAS IMPROPERLY INCLUDED PURCHASED POWER COSTS IN DETERMINING THE HOURLY PRICES?

A The approved RTP tariffs state that "the hourly prices are based on projections of the hourly running cost of *incremental generation*." (emphasis added) However, generation is not functionally equivalent to purchased power. Generation means electricity produced by a utility from power plants that the utility owns. Purchased power, by contrast, refers to electricity purchased by a utility from resources that are owned by a third party – either a utility, a marketer or a non-utility generator (NUG).

Q IS THERE ALSO A DISTINCTION BETWEEN GENERATION AND PURCHASED POWER IN GENERALLY ACCEPTED ACCOUNTING PRACTICE?

A Yes. The FERC System of Accounts also distinguishes between generation-related expenses and purchased power. Specifically, generation-related expenses are booked to Accounts 500 through 554. Purchased power costs, by contrast, are booked to Account 555.

Q DOES THIS COMMISSION RECOGNIZE THAT GENERATION AND PURCHASED POWER ARE NOT FUNCTIONALLY EQUIVALENT?

A Yes. GPC's FCR tariff distinguishes between the cost of energy generated and the energy cost of purchased power. If generation and purchased power were the same, then there would have been no need for a separate reference to purchased power.

Q WAS THERE ANY INDICATION THAT GPC HAD INTENDED TO INCLUDE PURCHASED POWER IN THE HOURLY REAL TIME PRICES WHEN RTP WAS FIRST IMPLEMENTED?

A No. The testimony sponsored by GPC witnesses in 1992 made no mention that purchased power cost would be included in determining the hourly running cost of incremental generation, or system lambda. Specifically, the term system lambda was used synonymously with *incremental plant operating costs.*[2] This same testimony goes on to state that "the magnitude of this cost [incremental plant operating cost] will vary with the *hourly mix of generation resources that are then in use for meeting Georgia Power Company's territorial load.*"[3]

Q WHY ELSE IS INCLUDING PURCHASED POWER IN DETERMINING THE HOURLY RTPs NOT APPROPRIATE?

A Wholesale power markets have changed dramatically since the inception of RTP in Georgia. The Energy Policy Act of 1992 gave the Federal Energy Regulatory Commission (FERC) authority to require all utilities under its jurisdiction to provide open nondiscriminatory access to the transmission system. The FERC subsequently issued Order No. 888 in April 1996. The effect of Order No. 888 has been a dramatic increase in the use of transmission services by third parties. This, in turn, has reduced the vertical market power of transmission-owning utilities. The FERC has granted authority to allow utilities and other wholesale market participants to buy and sell electricity at market-based prices. This, coupled with the movement to customer choice by 24 states, has resulted in a wholesale market that today is, for all intents and purposes, price deregulated.

[2]Testimony of Jonathan M. Kubler and Michael T. O'Sheasy on behalf of Georgia Power Company, Docket No. 4147-U, May 11, 1992, page 10. (emphasis added)
[3]Id. (emphasis added)

By including spot wholesale purchases in the hourly RTPs, GPC's captive customers are now being exposed to more price risk than ever before. As stated previously, a projected market-based purchased power transaction, as high as $6 per kWh in 1999, will immediately be reflected in the hourly price. No other retail customer will immediately see this $6 per kWh price.[4] If the power is actually purchased, then the cost will be charged to the fuel account and passed through to all customers. This automatic pass-through of actual fuel and purchased energy costs demonstrates that GPC bears absolutely no risk to provide RTP service.

Although RTP is a *regulated* service, the hourly prices are increasingly being influenced by the *deregulated* wholesale market. Fairness demands that if a *regulated* tariff allows the pass-through of *deregulated* prices, then the captive customers should have more options than simply reducing load to offset the higher prices. The most effective option is to allow the customer to choose an alternative supplier. However, until customer choice is authorized in Georgia, the Commission must continue to function as a "surrogate for competition" to ensure that regulated prices are fair, just and reasonable.

Q ARE THERE ANY OTHER REASONS WHY PURCHASED POWER COSTS SHOULD BE REMOVED FROM THE HOURLY PRICES?

A As I shall demonstrate later, the significant increase in the hourly prices has provided a windfall to GPC in terms of excess revenues collected from RTP sales.

Q HOW HAVE CHANGING CIRCUMSTANCES ALSO RESULTED IN DRASTIC INCREASES IN REAL TIME PRICES?

A RTP was implemented at a time when The Southern Company (Southern) system had surplus capacity. Most of the surplus capacity consisted of low-cost base load

[4] $6 per kWh is about 80 times the average cost to serve a residential customer.

resources. Southern's planning reserve margins were in the 15% to 20% range. Wholesale markets were also price-regulated.

Based on these factors, the differential between marginal energy cost and embedded cost was small. Referencing GPC's testimony in Docket No. 4147-U, GPC had projected in 1992 a marginal energy cost (or system lambda) of 1.5¢ per kWh.[5] This is only slightly higher than the FCR in effect in 1992 of 1.3¢.[6]

Today, however, the surplus of low-cost base load resources has been depleted. Southern has lowered its planning reserve margin to 13.5%. Capacity additions have also not kept pace with growing demand. Consequently, Southern has relied increasingly on more expensive generation and purchased power to meet territorial load.

Thus, marginal energy costs are significantly higher than embedded energy costs. For example, in 1999, the average day-ahead RTP price was 3.57¢. The current FCR is 1.37¢. As explained later, this fact demonstrates why the RTP adders should be eliminated.

Q WILL MARGINAL ENERGY COSTS EXCEED EMBEDDED COSTS FOR THE FORESEEABLE FUTURE?

A Yes. Southern will continue to rely on more expensive generation and purchased power in order to maintain reliability. Most future resource additions will be fueled with natural gas. The operating cost of new gas-fired units will be significantly higher than the corresponding cost of operating GPC's coal-fired units, even when the lower heat rate of the new gas facilities is considered.

[5] Id., Footnote 1.
[6] FCR-13 raised embedded fuel costs to over 1.5¢ in late 1993.

The entire Southern Subregion is facing a period of tight reserves for the foreseeable future.[7] This is shown in Exhibit ____ (JP-3), which was developed from information provided to the Energy Information Administration (EIA). Based on this Exhibit, projected reserves in the Southern Subregion will remain below 13.5%, which is Southern's current planning reserve margin.[8] Even more alarming is the fact that without significant new investment in generation, future reserve margins and reliability will continue to deteriorate.

Q WHO BENEFITS FROM THE CHANGING CIRCUMSTANCES THAT YOU HAVE DESCRIBED?

A GPC has benefited greatly from the drastic increase in real time prices. For example, high real time prices in 1999 generated $63 million in excess revenue for GPC.

Q HOW DID YOU DERIVE THE $63 MILLION EXCESS REVENUE?

A The derivation is provided in Exhibit ____ (JP-4). Specifically, $63 million represents the margins derived from RTP sales in excess of the corresponding margins used by GPC to establish its base rates in Docket No. 9355-U. The margin is the difference between the total selling price and the associated Fuel Cost Rate (FCR), which is approximately 1.37¢ per kWh at primary service. In the rate case, GPC assumed that RTP would generate margins of 1.48¢ per kWh. The corresponding margins in 1999 were actually 2.15¢ per kWh. To derive the $63 million excess revenue, I multiplied the differential in the margins (0.68¢) by actual 1999 RTP sales of 9,383,283 megawatthours (MWh).

[7]The Southern Subregion includes: The Southern Company, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, Alabama Electric Cooperative, and South Mississippi Public Service Authority.

[8]As ordered by the Commission, GPC's planning reserve margin is 15%.

Q CAN YOU PUT THE $63 MILLION OF EXCESS REVENUES IN PERSPECTIVE?

A Yes. The $63 million in excess RTP revenues is 60% of the $105 million in excess revenues reported by GPC for the same period. GPC has alleged that the problems in 1999 were again caused by hot weather. However, these excess revenues occurred in a year which was not nearly as hot as the summer of 1998.

Q HOW DID THE WEATHER IN 1999 COMPARE WITH 1998?

A Although 1999 was a hotter-than-normal year, it was no where near as extreme as the record heat during the summer of 1998. Specifically, the cooling degree days in 1999 were significantly below the corresponding cooling degree days in 1998, as shown in the table below.

Cooling Degree Days for Key Georgia Power Cities

			Departure from Normal	
City	1998	1999	1998	1999
Athens	2,119	1,860	410	151
Atlanta	2,023	1,817	356	150
Macon	2,468	2,191	343	66
Savannah	2,526	2,404	296	39

Further, the only month in 1999 that was hotter than the corresponding period in 1998 was August. All of the remaining summer months (May, June, July and September) were cooler in 1999 than in 1998.

III. The Requested Relief

Q WHAT RELIEF ARE GTMA AND GIG SEEKING IN THE PETITION?

A The Petition asks the Commission to modify the RTP tariffs in light of the dramatically changing circumstances and the much greater price risk placed on RTP customers. The suggested modifications would restore the competitiveness to the industrial rates, provide a more equitable balancing of the risks between GPC and its captive RTP customers and would benefit all customers by reducing the FCR.

Q HOW SHOULD THE RTP TARIFFS BE MODIFIED?

A The specific modifications should include:

1. Eliminating the adders entirely or, at a minimum, reducing the adders by at least 50%.
2. Lambda averaging; and
3. Revising the fuel cost accounting.

Q IF THE COMMISSION WERE TO ORDER THE REMOVAL OF PURCHASED POWER FROM THE SYSTEM LAMBDA CALCULATION, WOULD LAMBDA AVERAGING BE NECESSARY?

A No. However, the adders should also be eliminated or reduced to make RTP fair, just and reasonable.

Q WHAT OTHER RELIEF DOES THE PETITION REQUEST?

A The Petition also requests the Commission to establish standards to require GPC to disclose its energy procurement practices.

Adder

Q PLEASE DESCRIBE THE ADDER?

A The adder is a fixed amount that is charged for every RTP kWh purchased or sold. At present, the adder is 0.5¢ under RTP-DA and 0.45¢ under RTP-HA.

Q WHAT IS THE PURPOSE OF THE ADDER?

A The adder was originally designed to serve two purposes. First, it provided a contribution to fixed costs (i.e., profit). Second, it compensated GPC for the risks associated with RTP. This is perhaps why GPC originally described the adder as a "risk recovery factor."[9]

Q WHY IS IT NECESSARY FOR RTP CUSTOMERS TO PROVIDE A CONTRIBUTION TO FIXED COSTS?

A Every rate should provide some contribution of fixed costs or profit, and RTP is no exception. If RTP sales provide some revenue to defray GPC's fixed costs, all other non-RTP customers will benefit. This is because the margins generated from RTP sales will lower the revenue requirement recoverable from, and the rates chargeable to, non-RTP customers.

Q WHAT RISKS WERE INITIALLY ATTRIBUTABLE TO RTP?

A While other utilities were beginning to implement small scale experimental programs, GPC was seeking Commission approval for a full-scale RTP program. At that time, RTP was still a novel pricing mechanism. GPC did not have much experience projecting hourly real time prices on a day-ahead basis. There was a risk that the quoted day-ahead prices would understate actual energy costs.

[9] Id., Footnote 1.

Finally, GPC did not know how customers would respond to RTP. To the extent that customers' response was more than the Company had anticipated, this could produce revenue erosion. The risk recovery factor was designed to offset this erosion and the other risks associated with RTP.

Q IS AN ADDER STILL APPROPRIATE IN TODAY'S CIRCUMSTANCES?

A No. When RTP was first implemented, marginal energy costs and embedded energy costs were similar. Thus, the 0.5¢ adder was necessary to ensure that every kWh sold under RTP would provide some contribution toward fixed cost recovery or profit. Today, however, marginal energy costs are much higher than embedded energy costs. This means that every kWh sold under RTP already provides some profit without the need for an additional 0.5¢ (or 0.45¢) adder.

Q DO OTHER UTILITIES IMPOSE A FIXED ADDER ON ALL RTP KWh SALES?

A Yes. Some southeast utilities, like Duke Power Company and Virginia Electric and Power Company, do charge a flat adder for all RTP kWh sold. Duke Power Company's adder is 0.5¢, the same as GPC's RTP-DA tariff. Virginia Electric and Power Company charges a 0.6¢ adder on RTP sales. However, both utilities have lower standard rates than GPC.[10] Further, Duke Power's average real time prices were lower and less volatile than GPC's during the summers of 1998 and 1999.

[10]Referencing Exhibit ____ (JP-1), Duke Power is ranked 17th/20th (North Carolina/South Carolina) in July 1998; 15th/19th in July 1, 1999; and 14th/27th in July 2000. The corresponding Virginia Power rankings are 19th, 18th and 26th. These compare to GPC rankings of 15th, 14th and 10th (1 = most expensive).

Q IS A FLAT CENTS PER KWh ADDER A UNIVERSAL PRACTICE?

A No. Several southeast utilities charge a variable adder. These utilities include Carolina Power & Light Company, Central Power and Light Company, FPL and Southwestern Electric Power Company. The variable adder is stated as a percentage of the difference between the average cost per kWh under the standard tariff and the corresponding hourly marginal energy cost.

For example, assume that a standard tariff has an average cost of 4¢ per kWh and the utility is allowed to retain 20% of the difference between the standard tariff and marginal energy cost. If the marginal energy cost were 2¢, then the adder would be 0.4¢ per kWh [20% x (4¢ - 2¢)]. On the other hand, if marginal energy costs were above 4¢, then no adder would be charged. The latter circumstance is most likely to occur during extreme hot weather conditions, when generation supplies are tight, and/or the utility is having to purchase spot-market energy to satisfy customer demand.

Q IS THE ADDER NEEDED TO PROVIDE A REASONABLE CONTRIBUTION TO GPC'S FIXED COSTS, OR PROFIT?

A No. RTP sales are generating sufficient margins without the adder to provide a reasonable contribution to GPC's fixed costs, or profit.

Q WHAT MARGINS ARE GENERATED BY RTP SALES?

A RTP sales generate substantial margins, as shown in the table below:

Margins from RTP Sales (Dollar Amounts in Millions)

Year	Total Net Margins	Percent Increase	Cumulative Percent Increase
1996	$ 76.1	168%	168%
1997	$110.3	45%	288%
1998	$176.0	60%	520%
1999	$201.8	15%	611%

Further, as shown in Exhibit ____ (JP-5), these margins have increased drastically since 1994. The margins have ranged from $0.88¢ in 1995 to 2.15¢ in 1999. This represents an average annual increase of 25%.

Q HOW DID YOU CALCULATE THE MARGINS SHOWN IN EXHIBIT ____ (JP-5)?

A The margins were calculated as the difference between total RTP revenues and the FCR recovery associated with RTP sales. This is the same calculation that was used in Exhibit ____ (JP-4).

Q ARE THE MARGINS GENERATED BY RTP SALES REASONABLE?

A No. The margins generated by RTP customers are excessive and unreasonable because the total contributions far exceed GPC's average embedded production plant cost. This is shown in Exhibit ____ (JP-6).

During 1998 and 1999, RTP generated average margins of $189 million per year. This is equivalent to 2.08¢ per kWh. Restating this amount into an annual fixed charge yields a margin of $182 per kW-year (2.08¢ per kWh x 8,760 hours). Assuming fixed

costs of $30 per kW-year and a carrying charge rate of 20%, then the margins derived from RTP sales in 1999 could support production investment of $759 per kW ($152 ÷ 20%). The latter amount is 123% higher than GPC's net production plant, which has a book value of about $340 per kW as of December 31, 1998.[11]

Q IS GPC'S NET PRODUCTION PLANT COST AN APPROPRIATE BENCHMARK FOR DETERMINING THE REASONABLENESS OF THE MARGINS DERIVED FROM RTP SALES?

A Yes. Regulation should afford a utility the opportunity to recover its actual cost of service, plus a reasonable profit, and no more. GPC's net production plant cost is a reasonable benchmark because the margins from RTP are supposed to recover fixed costs associated with GPC's power plants and other generation resources. Recall that GPC's other fixed costs (e.g., transmission, distribution and overheads) are already recovered in the CBL portion of an RTP customer's service.

Q WOULD ELIMINATING THE ADDER RESULT IN MARGINS THAT MORE CLOSELY REFLECT GPC'S PRODUCTION FIXED COSTS?

A No. As can be seen in Exhibit ____ (JP-6), column 2, excluding the adder from the margins would result in an equivalent plant investment of $544 per kW. This is still well above GPC's net production plant investment. Thus, even without the adders, RTP customers are supporting more than a reasonable contribution to GPC's fixed costs.

[11]Because of accelerated depreciation in 1999, GPC's net production plant would be below $340/kW, all other things equal.

Q SHOULD THE ADDER BE RETAINED TO COMPENSATE FOR THE RISKS ASSOCIATED WITH RTP?

A No. GPC has had seven years of experience with RTP. RTP is no longer a novel pricing mechanism. Today, many utilities nationwide, including many in the Southeast, also offer RTP.

Further, GPC's fears about revenue erosion have been unfounded. RTP sales above the CBL are more than 14 times higher than RTP sales below the CBL. This is shown in Exhibit ____ (JP-7).

There is no risk of underrecovery as a result of underforecasting day-ahead energy prices. This is because all eligible fuel and purchased energy costs are recovered to the FCR. Finally, GPCs allowed return on equity already includes a risk premium. No further risk adjustment is necessary.

Q PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING THE ADDER?

A The adder should be eliminated because it is no longer needed to provide a reasonable contribution to fixed costs and because it is no longer necessary to compensate GPC for the risks associated with the RTP program. RTP is now more risky for GPC's captive customers. Eliminating the adder would be the most direct way to compensate these customers for the added risk.

Q WHAT WOULD BE THE IMPACT OF ELIMINATING THE ADDER?

A The adders in the RTP-DA and RTP-HA rates generate about $46.2 million a year in revenue. A 50% reduction would lower GPC's annual revenue by only $23.1 million, or about 0.5%.

Lambda Averaging

Q WHAT IS SYSTEM LAMBDA?

A System lambda is the term used to describe the hourly running cost of incremental generation. It consists primarily of incremental fuel cost and a small amount of incremental variable operation and maintenance expense (VOM).

Q HOW DOES GPC DEFINE SYSTEM LAMBDA IN THE CONTEXT OF THE RTP TARIFFS?

A System lambda is not defined in the RTP tariffs. GPC chooses to define system lambda as the cost of the next kWh generated or purchased to serve territorial load. This definition is illustrated in Exhibit ____ (JP-8).

The illustration is a hypothetical example of a series of resources (either generation or purchased power) that have been dispatched to serve 1,000 megawatts (MW) of RTP load in a given hour. In this hypothetical, the resources are assumed to be equal in size and range in cost from 3¢ to 7¢ per kWh.

Based on this hypothetical example, the system lambda employed by GPC in the RTP tariffs would be 7¢ per kWh. Consequently, all RTP sales in this hour would be priced to reflect the 7¢ system lambda, even though the vast majority of the kWh serving RTP load would cost much less.

Q WHAT IS MEANT BY THE TERM LAMBDA AVERAGING?

A Lambda averaging means calculating the weighted average cost of resources operating on the margin to serve a particular block of load. Using the illustration in Exhibit ____ (JP-8), lambda averaging applied to 1,000 MW of RTP load would result in a charge of only 5¢ per kWh.

Q WHICH APPROACH IS PREFERABLE, GPC'S OR LAMBDA AVERAGING?

A Lambda averaging is clearly the preferable approach. As can be seen in Exhibit ____ (JP-5), using lambda averaging to set the hourly price would reflect the actual hourly incremental cost to serve RTP load. Pricing RTP at the most expensive kWh, as GPC does, is no longer cost-based, and it results in higher costs to customers and excessive margins to GPC.

Q WHY ELSE IS GPC'S DEFINITION OF SYSTEM LAMBDA NO LONGER APPROPRIATE?

A As discussed earlier, circumstances have changed dramatically since the initial implementation of RTP. First and foremost, the size of the RTP program has increased dramatically, from 370 average MW in 1995 to over 1,000 average MW in 1999.

Second, there is a much wider disparity in the cost of marginal resources. For example, the incremental cost of generation can range from 3¢ to 3.5¢ for expensive coal units to up to 7.5¢ for peaking capacity. This is in contrast to purchased power costs, which have ranged in magnitude from 3.5¢ to 50¢ per kWh during the summer of 1998, and from 8.5¢ to $6 per kWh during the summer of 1999.

The widening cost disparity, coupled with the greater reliance on expensive spot market purchases, has caused system lambda to exceed 10¢ per kWh on more than just a few occasions in 1998 and 1999, as shown in the attached table.

Distribution of System Lambdas

Year	Number of Hours When System Lambda Was Below: 2¢	3¢	4¢	5¢	10¢	25¢	50¢	$1.00	At or Above $1
1996	7,920	419	217	139	70	18	---	---	---
1997	7,542	731	239	162	85	---	---	---	---
1998	5,930	1,414	523	264	474	142	13	---	---
1999	5,503	1,699	741	288	310	169	22	14	14
	Generation				Purchased Power				

Prior to 1998, there were only 18 hours when the DA lambda exceeded 10¢. In 1998, 155 hours were priced in excess of 10¢ per kWh. This increased to over 200 hours in 1999, a summer which was not nearly as hot as the summer of 1998.

Q HOW DO INCREASING PROGRAM SIZE AND THE WIDENING COST DISPARITY BETWEEN THE MARGINAL RESOURCES MAKE GPC'S DEFINITION OF SYSTEM LAMBDA UNREASONABLE?

A To illustrate the impact of these factors, I have developed an example comparing GPC's definition of system lambda with lambda averaging under two scenarios. Scenario 1 assumes that only native generation resources (D, E and F) operate on the margin. Scenario 2 assumes a combination of generation and spot wholesale purchases (A, B and C) are on the margin. In both scenarios, I have calculated the system lambda as defined by GPC and lambda averaging. The analysis also assumes RTP load of 300 MW and 1,000 MW, respectively under Scenarios 1 and 2, to demonstrate the impact of program size on the cost relatedness of the system lambda calculation.

III. The Requested Relief

Marginal Resources	Dispatch Cost per kWh	RTP Load (MW) Scenario 1	Scenario 2
A	10.0¢	---	300
B	7.5¢	---	300
C	5.0¢	---	100
D	4.0¢	100	100
E	3.0¢	100	100
F	2.5¢	100	100
Total RTP Load		300	1,000
System Lambda		4.0¢	10.0¢
Lambda Averaging		3.2¢	7.4¢
Margin Above Cost		0.8¢	2.6¢

As can be seen, the amount of overcharges is directly proportional to program size and resource cost disparity; that is, applying GPC's definition of system lambda generates revenues significantly in excess of actual incremental cost as the size of the RTP program increases. This situation worsens as more high-priced spot market purchases become the marginal resource and are used to set the system lambda under GPC's definition.

Q IS GPC'S DEFINITION OF SYSTEM LAMBDA UNIVERSALLY ACCEPTED?

A No. I am aware of at least two utilities in the southeast that define system lambda differently in determining the hourly prices. Florida Power and Light Company (FPL) and the TVA both use a form of lambda averaging in determining the prices under their respective RTP programs. The lambda averaging by FPL and TVA includes all incremental resources, not just purchased power transactions that are projected to occur on the margin. Finally, it is also unclear whether other utilities include wholesale spot purchases in their lambda calculation.

Q WHAT IS THE IMPACT OF LAMBDA AVERAGING?

A At a minimum, lambda averaging of purchased power would reduce GPC revenues by between $7 million and $24 million per year.[12] The specific impact will vary each year depending on the amount and cost of all bottom-of-stack power purchases. GPC refused to quantify the impact of lambda averaging applied to all of the incremental resources (i.e., purchased power and generation) used to serve RTP load. Averaging the entire RTP stack would have a bigger impact than averaging only bottom-of-stack purchases.

Q WHAT ACTION SHOULD THE COMMISSION TAKE ON THE SYSTEM LAMBDA ISSUE?

A For all of the above-stated reasons, the Commission should either:

- Eliminate purchased power expense from the system lambda calculation, consistent with the terms and conditions in the approved RTP tariffs; or
- Replace GPC's definition of system lambda with lambda averaging of at least the last 1,000 MW of resources (generation and purchased power) operating on the margin, similar in concept as FPL and TVA. The 1,000 MW approximates the average RTP load served by GPC.

Lambda averaging, as described above, will ensure that the revenues collected from RTP sales more closely reflect actual incremental generation cost.

Fuel Accounting Practice

Q WHAT IS THE PROBLEM WITH THE FUEL ACCOUNTING PRACTICE ASSOCIATED WITH RTP?

A GPC does not charge the appropriate amount of fuel cost recovery from RTP sales. As a consequence, all customers are paying higher fuel costs. This problem is illustrated in

[12]GPC's response to Staff Data Request 2-1.

Exhibit ____ (JP-9). The illustration in this Exhibit is based on the same hypothetical example used to explain lambda averaging.

In this hypothetical example, I have assumed that system lambda, as defined by GPC, would be 7.0¢. The actual incremental fuel and VOM (or purchased power) expense is assumed to be 5.0¢. This represents the weighted average cost of all of the resources operating on the margin to serve 1,000 MW of RTP load. This 5.0¢ actual cost would go into the FCR account as an eligible expense.

The problem arises because of the 5.0¢ expense added to the FCR account, GPC assumes that only average fuel costs are recoverable from RTP customers. In this case, the average fuel cost, or FCR, is assumed to be 1.4¢. Therefore, 3.6¢ (the difference between actual cost of 5.0¢ and recovery of 1.4¢) becomes an uncollected fuel expense.

Q WHAT HAPPENS TO THE 3.6¢ OF REVENUE THAT WAS COLLECTED IN THE HOURLY PRICE?

A GPC deems this to be a recovery of nonfuel-related costs. Thus, the 3.6¢ provides an additional margin to GPC. Based on the hypothetical illustration in Exhibit ____ (JP-9), the 7¢ system lambda, coupled with GPC's erroneous fuel accounting practice, will yield a total margin of 5.6¢ (7.0¢ - 1.4¢) before the adder.

Q HOW DOES THIS ACCOUNTING PRACTICE AFFECT FCR?

A The FCR is designed to enable the Company to recover all of its eligible fuel and purchased power costs. Thus, any under-collection of these costs, regardless of the source of the under-collection, will cause the FCR to be higher than would otherwise be the case.

Q IS GPC'S TREATMENT OF RTP FUEL COSTS REASONABLE?

A No. If a pricing mechanism adjusts GPC's revenues to reflect actual system operating conditions, then it is just as reasonable for a cost recovery mechanism to reflect similar real time adjustments. Using the hypothetical illustration, if GPC incurs a 5¢ fuel cost and that cost is reflected in the hourly RTP, then the corresponding fuel cost recovery should also be 5¢. In other words, the Company should deem the fuel recovery at 5¢, rather than 1.4¢.

Q HOW WOULD THIS CHANGE IN THE FUEL ACCOUNTING PRACTICE AFFECT GPC?

A GPC's earnings would be reduced because a portion of the RTP base revenues would be used to offset eligible fuel and purchased power costs. This would lower the FCR. A lower FCR would benefit all customers.

Disclosure of Energy Procurement Practices

Q WHY DOES THE PETITION SEEK TO ESTABLISH STANDARDS FOR GPC TO DISCLOSE ITS ENERGY PROCUREMENT PRACTICES?

A This is a very important element of the Petition because GPC has no real incentive to minimize purchased energy costs. All purchased energy costs are recoverable in the FCR. If GPC were, instead, to acquire options or to prearrange purchases in advance, the cost of such options and any capacity-related costs would not be recoverable through the FCR.

For example, if GPC projects that purchased power will cost $6 per kWh, all of this cost, plus the various markups, will be immediately reflected in the projected RTP prices. Had this purchase been prearranged at a cost of only 10¢, and assuming that this resource was projected to be on the margin, then the 10¢ cost would be reflected in

the RTP. However, the capacity charges and option payments associated with this prearranged purchase would be charged against current earnings. Thus, there is no incentive for GPC to prearrange purchases.

Q WHY IS IT REASONABLE TO REQUIRE GPC TO DISCLOSE ITS ENERGY PROCUREMENT PRACTICES?

A Although RTP is a *regulated* service, RTP customers are now exposed to *competitive* market price risks. As long as these customers cannot choose an alternative provider, they are entitled to know whether GPC's purchasing practices are reasonable and appropriate and that their interests are being adequately protected. Disclosure would also give customers a better opportunity to access the risks and benefits of RTP. This would also provide regulators with a more effective tool to ensure that the utility's power procurement practices are reasonable and, further, that these practices result in the lowest reasonable energy cost for all consumers.

Q WHAT TYPES OF ENERGY PROCUREMENT PRACTICES SHOULD BE INCLUDED IN A DISCLOSURE REQUIREMENT?

A At a minimum, the Commission and the customers need a better understanding of the various wholesale markets in which the utility is presently operating. This would include both physical as well as financial markets. Specific wholesale markets (e.g., DA, HA, options, swaps, etc.) and the different types of commercial transactions (e.g., 16-hour strips, 8-hour strips, block sales at 100% load factor) should be identified.

The Company should also reveal the evolution of specific transactions among the various buyers and sellers. It would be especially insightful to know how many times a particular transaction is purchased and sold, by whom and the extent to which the price is adjusted before the final physical delivery occurs.

Finally, the Company should reveal the decision-making processes surrounding the decision to participate in some markets but not others or to engage in certain types of transactions. To the extent that the Company's decisions are influenced by cost recovery considerations, then this motivation should be clearly revealed.

Q WOULD DISCLOSING ENERGY PROCUREMENT PRACTICES REQUIRE GPC TO REVEAL CONFIDENTIAL TRADE SECRET INFORMATION?

A No. There are adequate mechanisms already in place to ensure that confidential trade secret information is not publicly disclosed. In fact, many of the data responses in this case and in other Commission proceedings are protected.

IV. The Commission Has Jurisdiction to Grant the Relief Requested by the Petitioners

Q WOULD GRANTING THE RELIEF REQUESTED IN THE PETITION REQUIRE THE COMMISSION TO REOPEN THE ACCOUNTING ORDER ADOPTED IN DOCKET NO. 9355-U?

A No. The requested relief will only affect two tariffs, RTP-DA and RTP-HA. Neither tariff was changed by the Accounting Order.[13]

Second, the Petitioners are not asking the Commission to relitigate issues raised in GPC's last rate case. In fact, the serious problems with RTP had only just begun to surface in the spring of 1998, after the last rate case had been filed. None of the evidence or arguments presented in this testimony was ever presented in the testimony or the hearings in that case. RTP rate design was not specifically addressed.

Finally, the Petitioners are not asking the Commission to change the terms of the Accounting Order. The Accounting Order provides GPC with a reasonable opportunity to earn a return on equity (ROE) of between 10% and 12.5%. Nothing in this Petition would affect GPC's ability to earn within this range based on past experience under the two Accounting Orders.

Q IF THE COMMISSION WERE TO GRANT THE RELIEF REQUESTED IN THIS PETITION, WILL IT AFFECT GPC'S EARNINGS?

A Yes, it could. However, earnings are a function of both revenues and expenses. As the Commission is well aware, revenues and expenses are not static. They will necessarily change from the assumptions used to determine revenues and expenses or to assess the appropriateness of a Accounting Order in GPC's last rate case.

[13]No other existing tariff was modified by the Accounting Order.

Revenues may increase or decrease depending on sales levels, economic conditions, weather and other factors. Expenses may similarly increase or decrease based on the same factors and also on how well the Company manages its operations. A reduction in revenues to make the RTP tariffs fair, just and reasonable will not threaten GPC's ability to earn within the 10% to 12.5% range established in the Accounting Order.

Q HAVE GPC'S EARNINGS ALWAYS REMAINED WITHIN THIS RANGE?

A No. Since 1996, GPC's earned ROE has been 12.5% or higher.[14] In just the first year of the current Accounting Order, the Company reported earnings above a 12.5% ROE. The amount of excess revenues was reported to be $105 million. As stated previously, the excess margins collected from RTP customers account for about $63 million of this excess revenue.

Q DOES THE ACCOUNTING ORDER PROVIDE ANY GUARANTEE THAT GPC'S EARNINGS WOULD FALL INTO THIS RANGE?

A No. The Accounting Order most certainly does not *guarantee* that GPC will earn at least at 12.5% ROE. It does provide a reasonable *opportunity* for GPC to earn a 10% to 12.5% ROE. There are also specific mechanisms in place to keep GPC's earnings within this range. For example, if GPC earns more than 12.5% ROE in the year 2000, then two-thirds of all of the excess revenues will be returned to customers.[15] Likewise, if GPC's earnings drop below a 10% ROE, then GPC can petition the Commission to increase rates.

[14]Ignoring accelerated depreciation, GPC's earnings have consistently exceeded a 12.5% ROE.
[15]In the years 2000 and 2001, the Company gets to keep the first $50 million of excess revenue above a 12.5% ROE. Two-thirds of excess revenues above $50 million will be returned to customers.

Q WOULD CHANGING THE RTP TARIFFS AT THIS TIME BE CONSISTENT WITH THE ACCOUNTING ORDER?

A Yes. The Accounting Order specifically states that the Commission retains its jurisdiction to ensure that the Company's rates are fair, just and reasonable. The Order also specifically provides for consideration of lambda averaging. As I have demonstrated above, RTP is no longer fair, just and reasonable. RTP prices have escalated dramatically and the Company has profited handsomely as a result. The requested relief must be granted in full to restore fairness, justness and reasonableness to the RTP rates.

Finally, to the extent that any future over-earnings are to be refunded to customers, the Commission retains jurisdiction to allocate the over-earnings to all customers, including RTP. RTP customers should receive a proportional share of any excess revenues refunded by GPC.

Q DOES THAT CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Appendix A

Qualifications of Jeffry Pollock

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Jeffry Pollock. My business mailing address is PO Box 412000, 1215 Fern Ridge Parkway, Suite 208, St. Louis, Missouri 63141-2000.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A I am a consultant in the field of public utility regulation and a principal in the firm of Brubaker & Associates, Inc., energy, economic and regulatory consultants.

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A I am a graduate of Washington University. I hold the degrees of Bachelor of Science in Electrical Engineering and Master of Business Administration. At various times prior to graduation, I worked for the McDonnell Douglas Corporation in the Corporate Planning Department; Sachs Electric Company; and L. K. Comstock & Company. While at McDonnell Douglas, I analyzed the direct operating cost of commercial aircraft.

Upon graduation, in June, 1975, I joined the firm of Drazen-Brubaker & Associates, Inc. Drazen Brubaker & Associates, Inc. (DBA) was incorporated in 1972 assuming the utility rate and economic consulting activities of Drazen Associates, Inc., active since 1937. Brubaker & Associates, Inc. (BAI) was formed in April, 1995. In the last five years, BAI and its predecessor firm has participated in more than 700 regulatory proceeding in forty states and Canada.

During my tenure at both DBA and BAI, I have prepared numerous financial and economic studies of investor-owned, cooperative and municipal utilities, including revenue requirements, cost of service studies, rate design, site evaluations and service contracts. Recent engagements have included advising clients on electric restructuring issues, developing responses to utility requests for proposals (RFPs), and managing RFPs for clients. I am also responsible for developing and presenting seminars on electricity issues.

I have worked on various projects in over twenty states and in two Canadian provinces, and have testified before the regulatory commissions of Alabama, Arizona, Colorado, Delaware, Florida, Georgia, Illinois, Iowa, Louisiana, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, Ohio, Pennsylvania, Texas, Virginia and Washington. I have also appeared before the City of Austin Electric Utility Commission, the Board of Public Utilities of Kansas City, Kansas, the Bonneville Power Administration, Travis County (Texas) District Court, and the U.S. Federal District Court.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

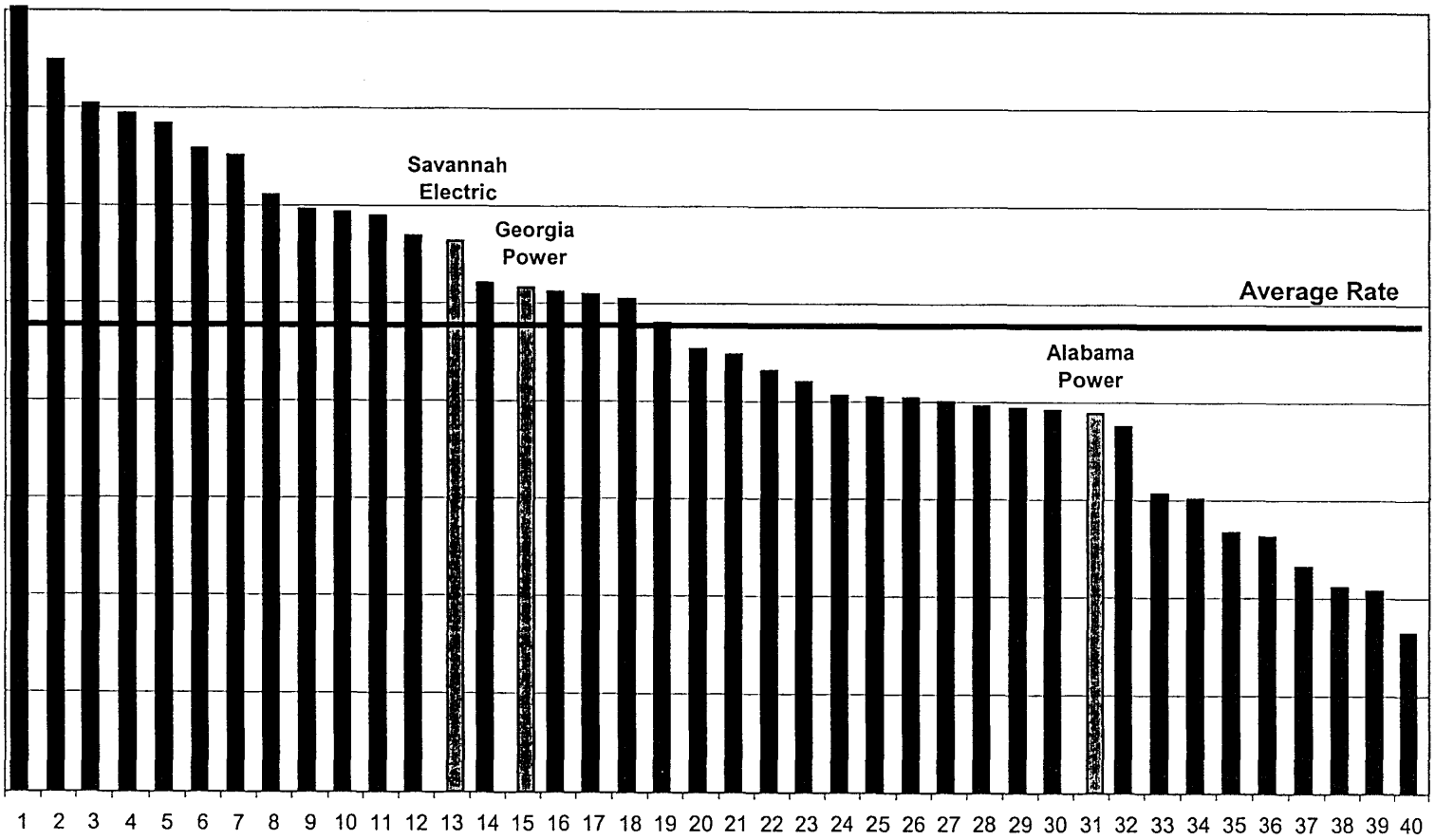
In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation.

In addition to our main office in St. Louis, the firm also has branch offices in Kerrville, Texas; Plano, Texas; Denver, Colorado; Chicago, Illinois; and Washington, DC.

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Exhibit___(JP-1)
Page 1 of 3

EEI Survey of Standard Industrial Rates
Southeastern Investor-Owned Utilities
Effective July 1, 1998



Exhibit___(JP-1)
Page 1 of 3

Exhibit___(JP-1)
Page 2 of 3

EEI Survey of Standard Industrial Rates
Investor-Owned Utilities
Effective July 1, 1999

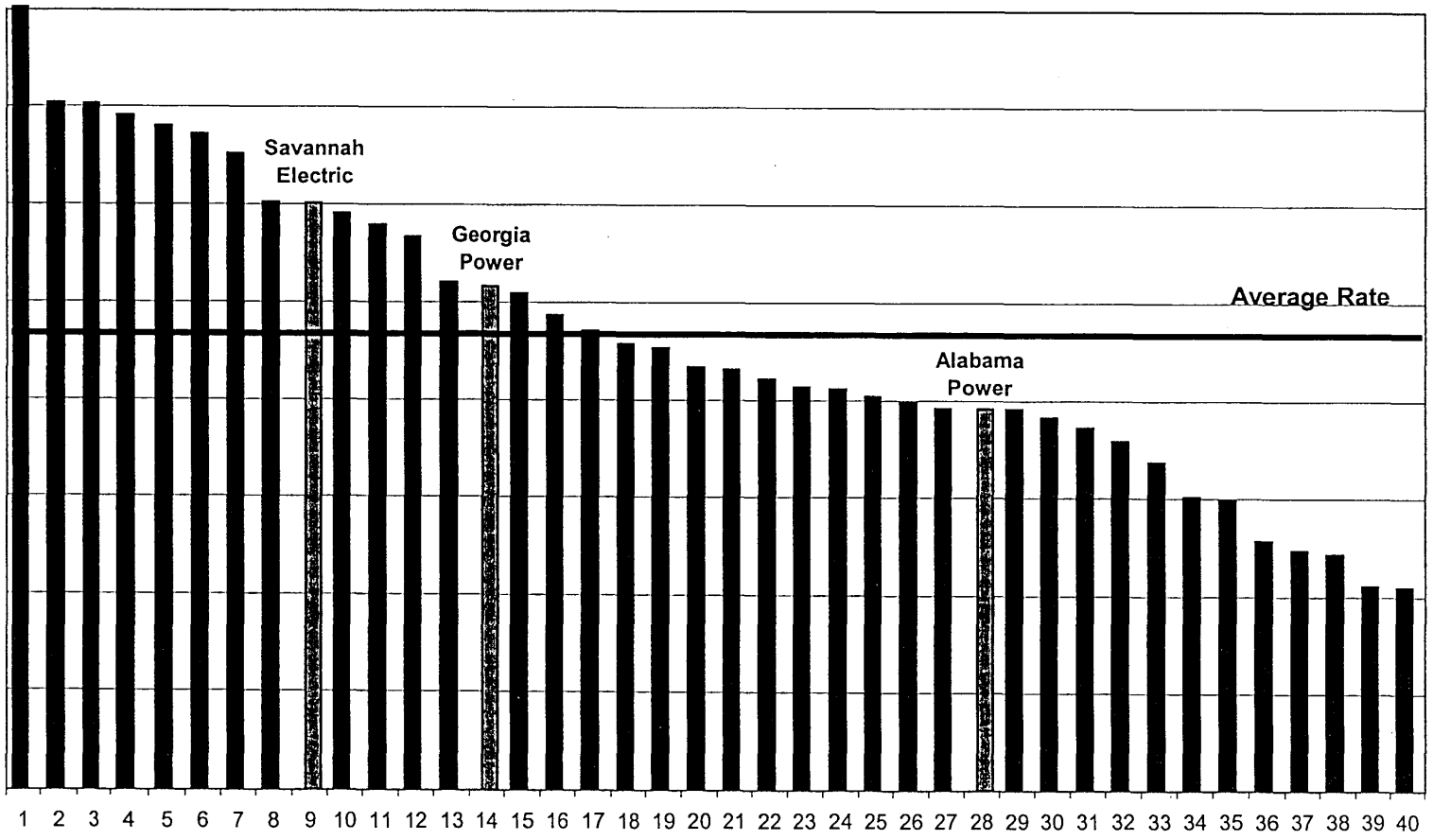


Exhibit ___ (JP-1)
Page 2 of 3

BAI Survey of High Load Factor Industrial Rates
Southeastern Investor-Owned Utilities and TVA
Effective January 1, 2000

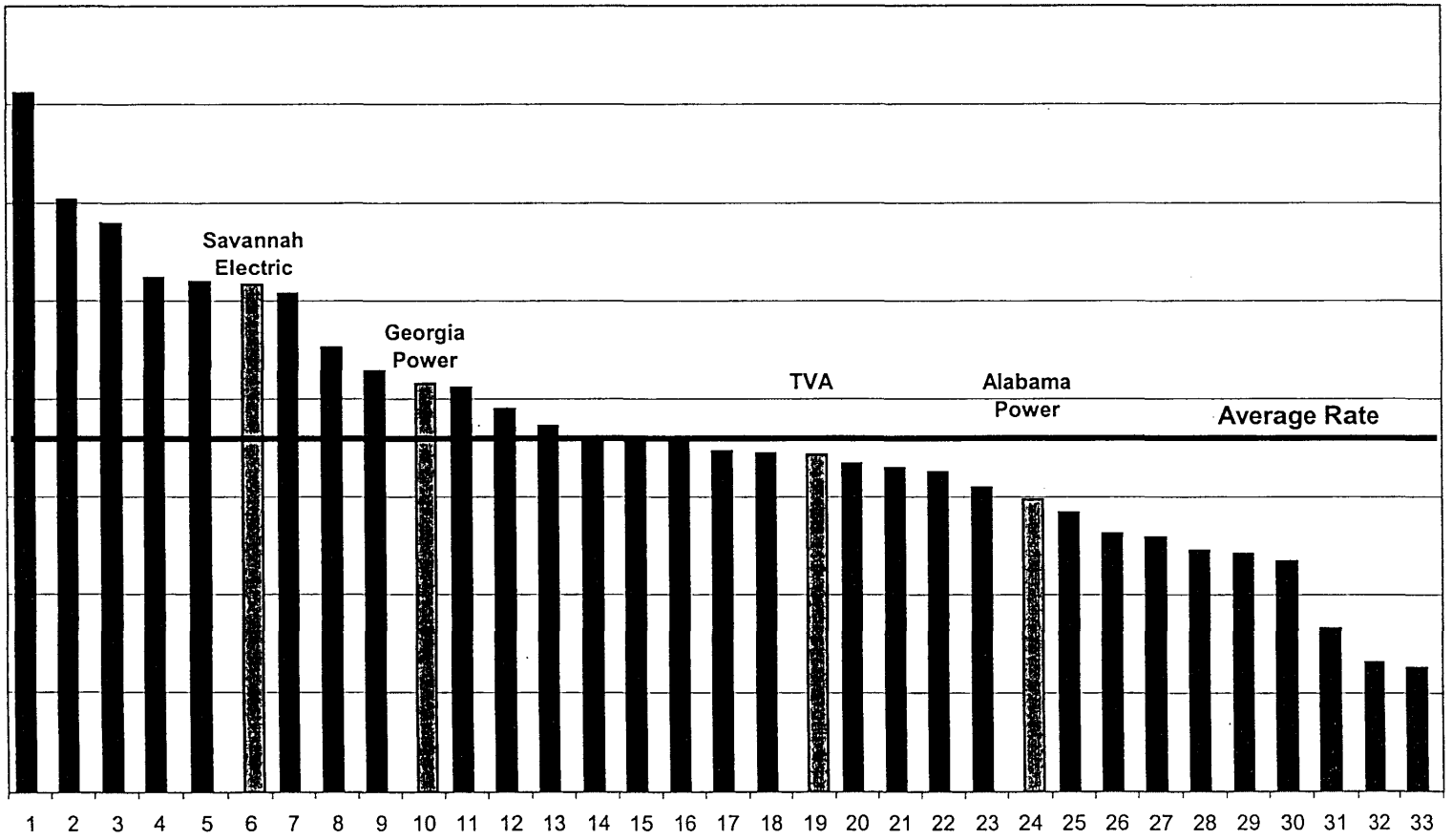


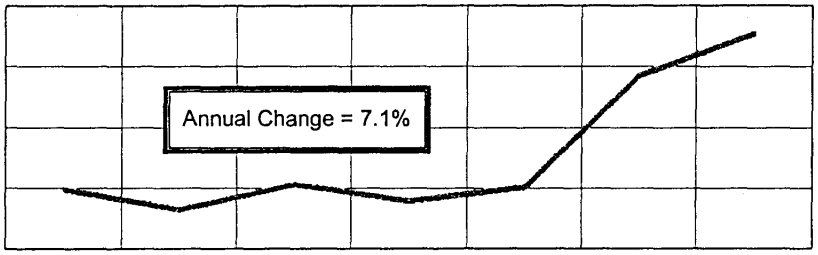
Exhibit ___ (JP-1)
Page 3 of 3

Exhibit ___ (JP-2)

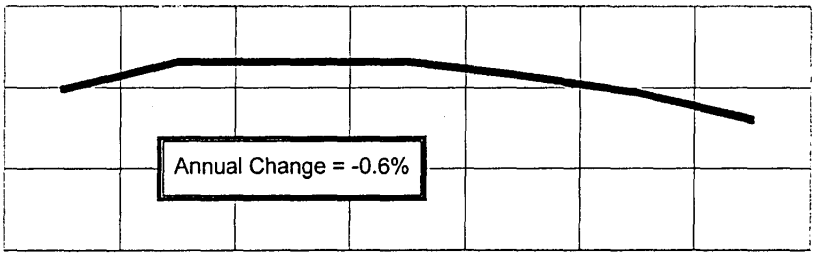
GEORGIA POWER COMPANY

Annual Percentage Change in Average Prices

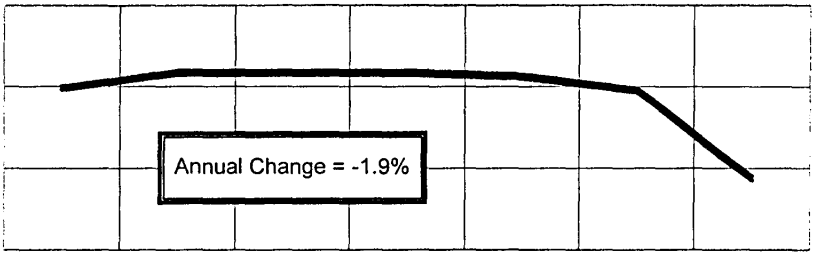
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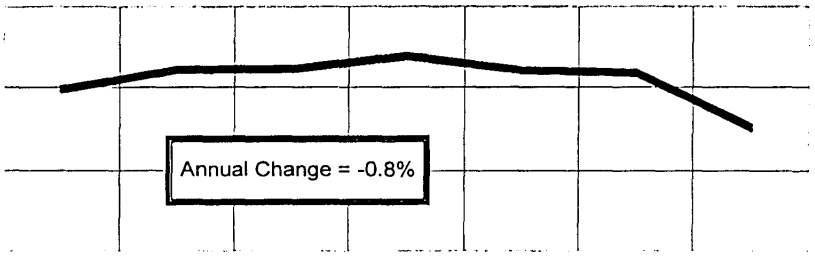
Large Business



Small Business

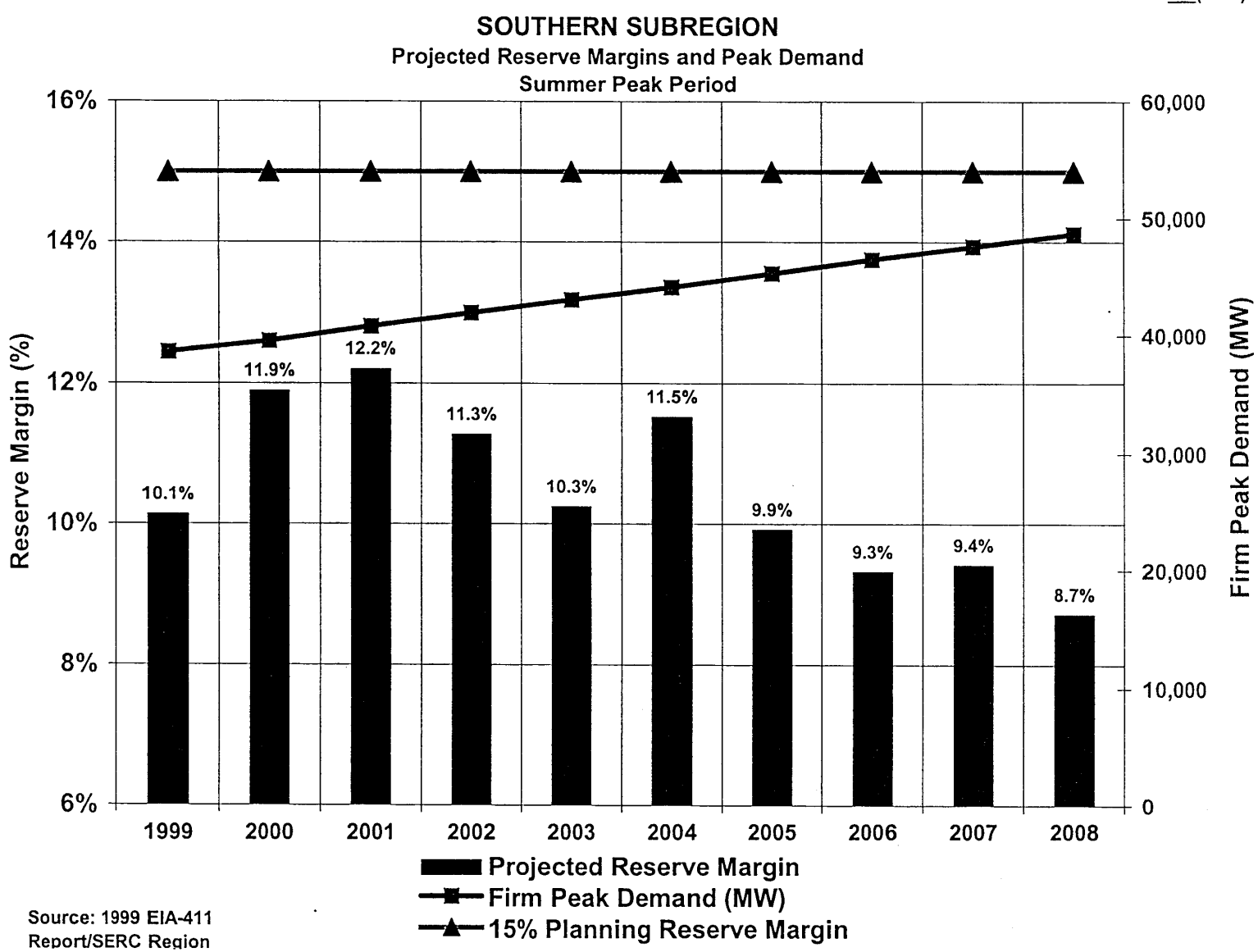


Residential



1993 1994 1995 1996 1997 1998 1999

Exhibit___(JP-3)



Source: 1999 EIA-411 Report/SERC Region

Exhibit ____ (JP-3)

Exhibit ___(JP-4)

GEORGIA POWER COMPANY

Derivation of Excess Revenues Generated Under RTP
During the Year 1999

Line	Description	Revenues (1)	Sales (MWh) (2)	Revenue (Cts Per kWh) (3)
	Rate Case Assumptions:			
1	RTP Incremental Revenues	$200,671,000		
2	Less: Fuel Recovery	$91,675,000		
3	Margins	$108,996,000	7,388,704	1.48
	Actual 1999			
4	RTP Incremental Revenues	$330,570,210		
5	Less: Fuel Recovery	$128,737,997		
6	Margins	$201,832,213	9,383,236	2.15
7	**Excess over Rate Case**			0.68
8	**1999 Excess Margins**	**$63,413,464**		

Exhibit ___(JP-5)

Margins From Real Time Pricing Sales

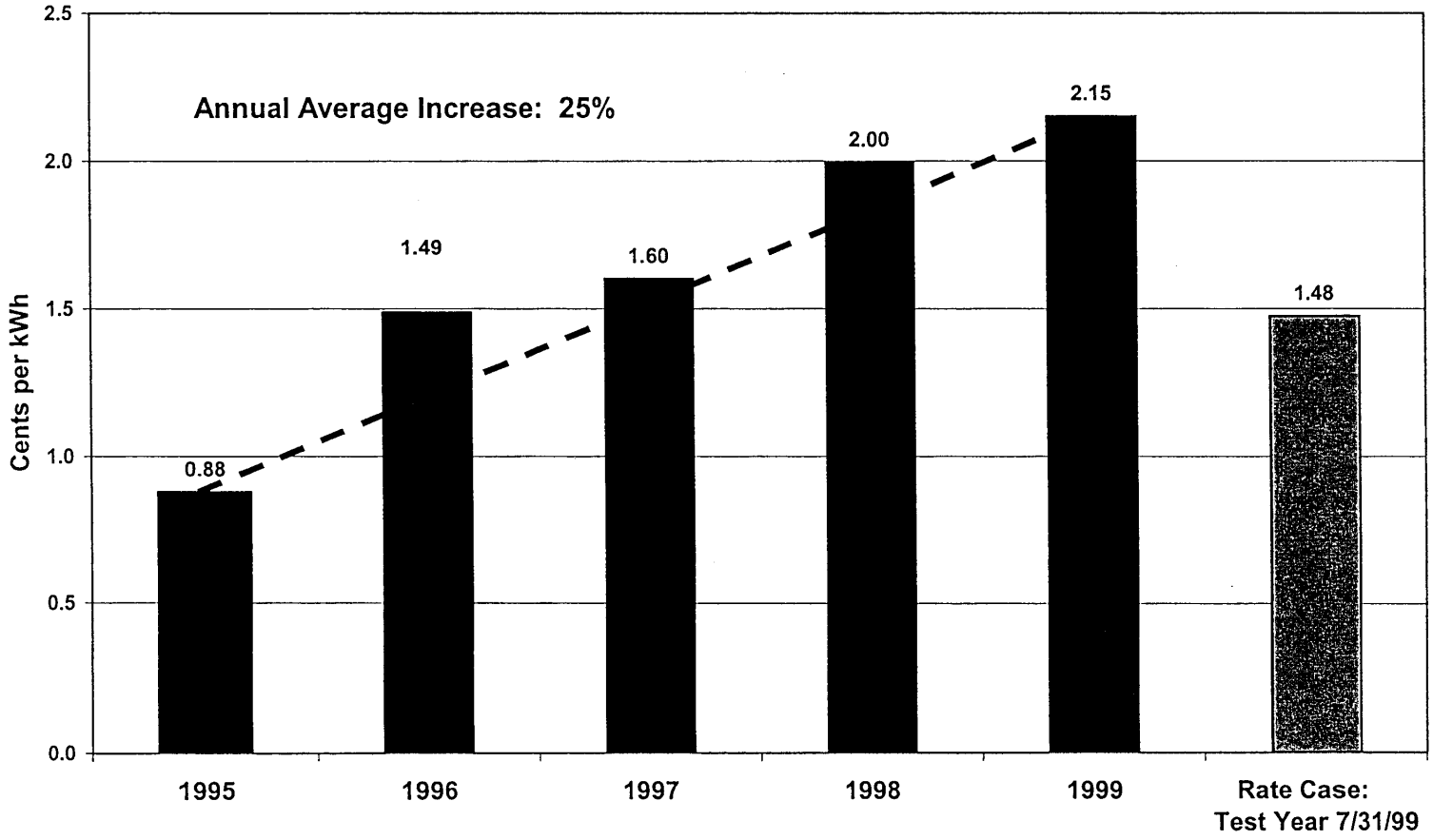


Exhibit ____ (JP-5)

Exhibit___(JP-6)

GEORGIA POWER COMPANY

Assessment of RTP Margins
During the Years 1998 and 1999

Line	Description	As Billed (1)	Excluding Recovery Factor (2)
1	Average 1998 and 1999 Margins	$188,925,387	$ 144,270,136
2	Average 1998 and 1999 RTP Sales (MWh)	9,100,922	9,100,922
3	Margins in Cents per kWh (Line 1 / Line 2)	2.08	1.59
4	Hours in the year	8,760	8,760
5	Margins per kW (Line 3 X Line 4)	$ 182	$ 139
6	Less: Fixed O&M per kW at $30	$ 152	$ 109
7	Annual Fixed Charge Rate	20%	20%
8	Equivalent Investment per kW (Line 5 / Line 6)	$ 759	$ 544
9	GPC Net Production Investment per kW	$ 340	$ 340
10	**Excess Margins per kW**	**$ 419**	**$ 204**

Exhibit___(JP-7)

GEORGIA POWER COMPANY

RTP Sales Above and Below
The Customer Baseline Load (CBL)

Year	RTP-DA Sales (MWh)		Ratio of Sales Above to Sales	RTP-HA Sales (MWh)		Ratio of Sales Above to Sales
	Above CBL	Below CBL	Below CBL	Above CBL	Below CBL	Below CBL
	(1)	(2)	(3)	(4)	(5)	(6)
1994	1,378,165	88,620	15.6	334,152	17,389	19.2
1995	2,795,292	194,803	14.3	651,105	21,261	30.6
1996	4,351,317	199,872	21.8	983,219	17,724	55.5
1997	5,576,262	250,181	22.3	1,597,873	36,787	43.4
1998	7,203,953	257,093	28.0	1,882,952	11,204	168.1
1999	8,453,862	596,313	14.2	1,666,101	140,415	11.9

Exhibit ___(JP-8)

Comparison of System Lambda Definitions
Hypothetical Example

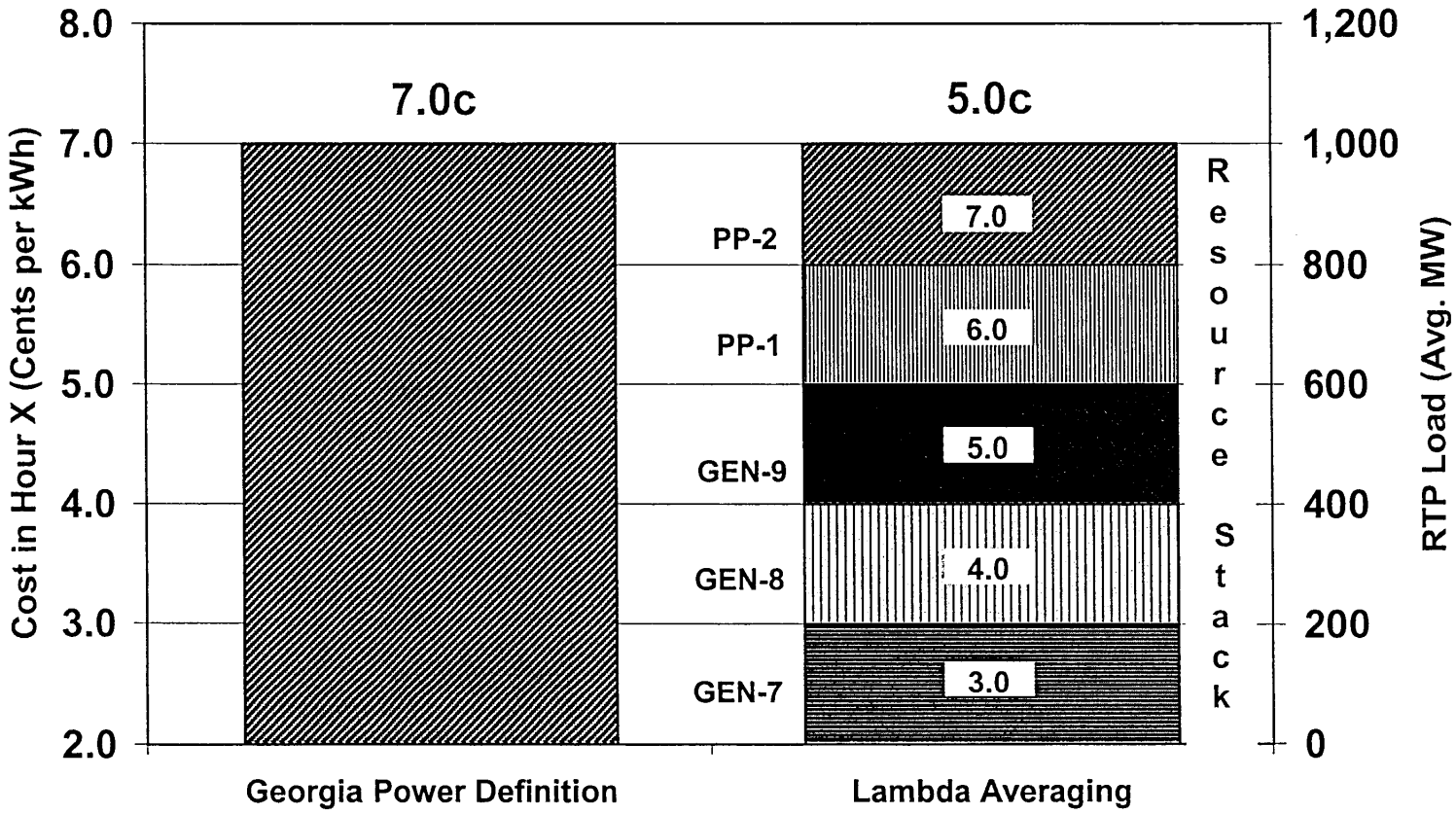


Exhibit ___ (JP-8)

RTP Fuel Accounting Illustration
Hypothetical Example

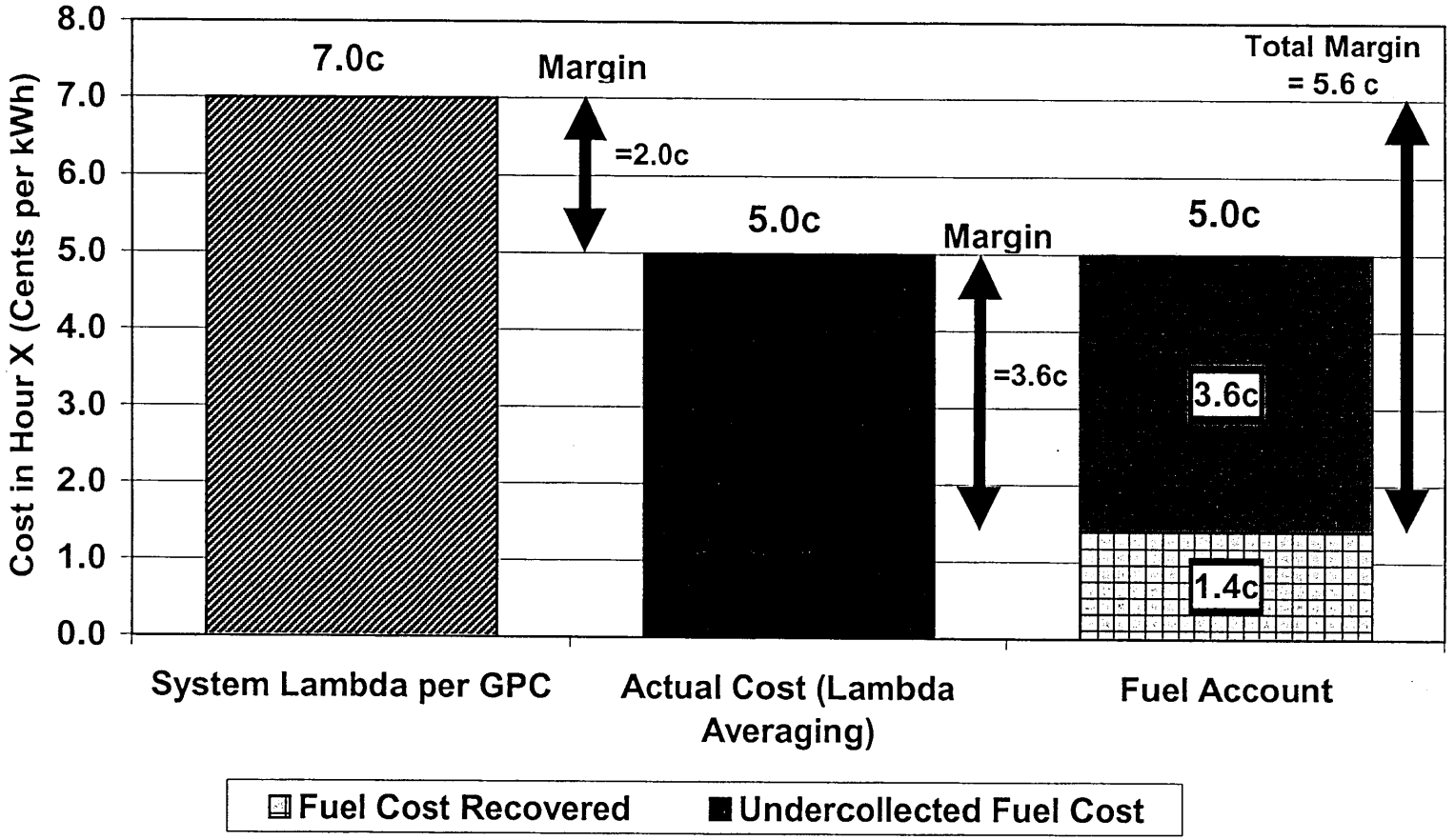


Exhibit ___(JP-9)

CERTIFICATE OF SERVICE

This is to certify that I have this day served a copy of the foregoing Direct Testimony and Exhibits of Jeffry Pollock on behalf of Georgia Textile Manufacturers Association and Georgia Industrial Group in GPSC Docket No. 11708-U by depositing same in the United States Mail with proper postage affixed and addressed as follows:

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Troutman Sanders
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This 6th day of March, 2000.

Peyton S. Hawes, Jr.