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**

Rebuttal 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

In Re:	)	
Petition for Rule NISI to Examine	)	
Georgia Power Company's	)	**Docket No. 11708-U**
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Rebuttal Testimony of Jeffry Pollock

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Q PLEASE STATE YOUR NAME.

A Jeffry Pollock.

Q ARE YOU THE SAME JEFFRY POLLOCK WHO PREFILED DIRECT TESTIMONY ON BEHALF OF THE GTMA AND GIG IN THIS DOCKET?

A Yes.

Q WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A I shall address various assertions raised in the testimony of Ron Hinson, Jonathan M. Kubler and Michael T. O'Sheasy on behalf of Georgia Power Company (GPC). Although these witnesses make numerous assertions about the real time pricing tariffs and my analysis, in the interests of brevity, I shall limit my rebuttal testimony to four main points:

(1) RTP is no longer a cost-based rate even under GPC's new capital substitution (CAPSUB) theory;

(2) The changes proposed by GTMA and GIG to the RTP pricing structure would not adversely affect non-RTP customers because, as discussed in my Direct Testimony, non-RTP customers will benefit from a lower Fuel Cost Rate (FCR). Further, contrary to GPC's contention, non-RTP base rates would not increase if the GTMA and GIG proposals are adopted;

(3) GPC has provided no persuasive evidence to justify retaining the adders. In contrast with the system lambda, which is a marginal cost, the adders represent a pure profit to GPC and are not a marginal cost. Because the adders apply to every kWh sold under RTP, eliminating the adders would not reduce price response below historical levels; and

(4) GPC is trying to mislead this Commission into believing that its average rates are more competitive than most of the electric utilities in the Southeastern United States. GPC's so-called price comparisons are meaningless because they fail to account for differences in load factor, delivery voltage, size, quality of service (e.g., firm vs. nonfirm), price risk and load shapes of the various GIG and GTMA members, as well as the various customers served by each of the utilities shown in this Exhibit. It is also wrong to compare a select subset of GPC customers, which have different characteristics than the vast majority of GPC's other industrial customers, with the average characteristics of all industrial customers served by other Southeastern utilities.

The fact that I have not addressed all of GPC's numerous assertions should not be interpreted as an agreement with or endorsement of GPC's positions.

Q WERE ANY OF THESE ISSUES ADDRESSED IN GPC'S LAST RATE CASE?

A No.

Q ARE YOU SPONSORING ANY REBUTTAL EXHIBITS?

A Yes. Exhibits ____ (JP-10) through ____ (JP-13) are attached to my rebuttal testimony.

1. RTP Cost Basis

Q GPC WITNESSES STATE ON PAGE 7 THAT THE INTENT OF RTP IS AND ALWAYS HAS BEEN TO REVEAL THE MARGINAL COST OF MAKING MARGINAL CHANGES IN LOAD. DO YOU CONCUR WITH THIS STATEMENT?

A Yes, I do. It is important to note that RTP was designed to recover GPC's marginal cost of producing and delivering electricity. These marginal costs include:

- Incremental generation costs (i.e., fuel and variable operation and maintenance expense);
- Incremental transmission costs;
- Incremental generation capacity costs related to maintaining reliability; and
- Line losses.

RTP was not designed to recover embedded transmission costs, distribution costs and other overhead costs. This is because changes in electricity consumption do not directly result in corresponding changes in these embedded costs.

Q IF RTP DOES NOT RECOVER EMBEDDED TRANSMISSION, DISTRIBUTION AND OVERHEAD COSTS, WHERE ARE THESE COSTS RECOVERED?

A These costs are recovered in the customer baseline (CBL) portion of an RTP customer's service. The CBL represents a customer's historical load that GPC was serving prior to the inception of RTP service. The CBL portion of this service is priced under one of the Company's standard embedded cost rates. Therefore, all of the Company's embedded costs that are related to a customer's CBL are recovered in the CBL portion of RTP customers' electricity costs.

Q IS THIS SEPARATION OF COST RECOVERY BETWEEN THE CBL AND RTP COMPONENTS GENERALLY ACCEPTED IN THE INDUSTRY?

A Yes. This practice is described in a study conducted for the Electric Power Research Institute (EPRI). Specifically, the EPRI study states that:

> "The revenues from a customer can be thought of as covering two kinds of costs: marginal costs and overhead costs. Marginal costs are those that are clearly assignable to the customer's usage. They represent the additional costs that the utility has to incur in order to serve the customer – or the cost that the utility would save if the customer reduced usage to zero. *For our purposes in this guidebook, overhead costs are all those costs that are not marginal costs.* Under RTP service, the customer pays for marginal costs in the hourly energy charges. The methods of payment for overhead costs depend upon whether the RTP structure is one- or two-part. Under a one-part structure, overhead is collected in the adder or multiplier that is applied at marginal cost to arrive at the hourly price. *In the two-part structure, overhead is collected through the access fee.*"[1]

Q DOES GPC HAVE A ONE-PART OR TWO-PART RTP STRUCTURE?

A GPC's RTP tariffs have a two-part structure. This means that overhead is collected in the CBL portion of the bill.

Q BASED ON THIS EXPLANATION, IS IT VALID TO COMPARE MARGINAL COST AND EMBEDDED COST AS SHOWN IN EXHIBIT ____ (HKO-12)?

A No. This comparison is invalid because RTP was not designed to recover the same types of costs as GPC's standard embedded cost tariffs. Further, comparisons of this type fail to recognize the substantial price risks borne by RTP customers. This risk differential can be seen in Exhibit ____ (HKO-2). The Exhibit clearly shows that two-part RTP service poses virtually no cost risk on the seller, meaning that all of the risk is borne by the buyer, or customer. This is in contrast to other standard pricing options in which the seller appropriately bears most of the cost risk.

[1]Christensen Associates, "Real Time Pricing Quick Start Guide," prepared for EPRI, Final Report, dated August 1995, Page xxi. (emphasis added). In GPC's case, the access fee is the same as the CBL or Standard Bill.

Q WHAT IS THE IMPLICATION OF THE GREATER RISK BORNE BY RTP CUSTOMERS?

A The greater the risk borne by the customer, the lower the price that the customer should be required to pay for electricity. RTP service requires the customers to bear all of the price risk. Therefore, RTP should be the least costly service provided by GPC on a per kWh basis, all other things being equal.

Q GPC WITNESSES STATE THAT RTP IS BASED UPON THE THEORY OF CAPITAL SUBSTITUTION AND THE PEAKER METHODOLOGY. IS THERE ANY REFERENCE TO EITHER THEORY IN THE TESTIMONY FILED BY GPC IN 1992 IN SUPPORT OF REAL TIME PRICING?

A No. Paraphrasing GPC's 1992 testimony, RTP was designed to recover the cost of generating the next kWh, which is primarily fuel, plus an adder to provide a contribution to fixed cost (i.e., profit).[2]

Q HAVE THE GPC WITNESSES PROVEN THAT THE RTP TARIFFS ARE COST-BASED USING EITHER THE CAPITAL SUBSTITUTION OR THE PEAKER THEORIES?

A No. GPC has not presented any cost study, applying either theory, demonstrating that RTP is cost-based.

Q WOULD APPLYING THE CAPITAL SUBSTITUTION THEORY DEMONSTRATE THAT THE RTP TARIFFS ARE STILL COST-BASED?

A No. Exhibit ____ (JP-6) to my Direct Testimony demonstrates that, even if we now use capital substitution theory, the RTP tariffs are no longer cost-based. Capital substitution

[2]Georgia Power Testimony in Docket No. 4147-U, pages 10 and 12.

theory requires that the recovery of the capital costs plus operating costs should equal the utility's embedded generation cost. Exhibit ____ (JP-6) showed that, during the years 1998 and 1999, the total recoveries under RTP exceeded GPC's embedded generation cost, including a reasonable profit. Therefore, RTP is not cost-based even under this theory.

Q GPC WITNESSES CRITICIZED EXHIBIT ____ (JP-6) BECAUSE THE MARGIN IS NOT PURELY PRODUCTION PLANT MARGIN. DOES THIS CHANGE YOUR CONCLUSIONS ABOUT RTP NO LONGER BEING A COST-BASED RATE?

A No. The average selling price used to quantify the margins in Exhibit ____ (JP-6) for the years 1998 and 1999 included incremental transmission costs. However, removing those costs does not change my conclusion that RTP is recovering more than GPC's embedded generation cost. This can be seen in Exhibit ____ (JP-10), which quantifies the excess margins excluding incremental transmission costs.

Q GPC WITNESSES ALSO STATE THAT THE INTENT OF RTP IS AND ALWAYS HAS BEEN TO REVEAL THE MARGINAL COST OF MAKING MARGINAL CHANGES IN LOAD. IS IT NECESSARY FOR GPC TO COLLECT MORE THAN ITS EMBEDDED COST OF GENERATION THROUGH THE RTP RATE IN ORDER TO SEND THE PROPER PRICE SIGNALS?

A No. The Commission sets GPC's rates on the basis of average or embedded cost. It is appropriate for rates to be designed to provide the necessary price signals to reveal the cost consequences of marginal changes in load. However, regulation only affords the utility a reasonable opportunity to recover its actual or embedded cost of service, and an opportunity to earn a reasonable profit.

Q DOES THIS SAME PRINCIPLE ALSO APPLY TO RATES CHARGED FOR INDIVIDUAL SERVICES PROVIDED BY A UTILITY?

A Yes. The rates applicable to each customer and customer class should also reflect the actual cost of providing service. This time-tested standard should apply to RTP as well. However, with the dramatic escalation of real time prices during the past several years – primarily due to GPC's increasing purchases of energy in price-deregulated wholesale markets – RTP revenues are now (and will continue to be) well above the level needed to enable GPC to recover its actual cost of service and to earn a reasonable profit. In fact, as I have previously stated, GPC is recovering excessive profits from RTP customers.

2. RTP Pricing Structure

Q GPC WITNESSES HAVE ASSERTED THAT REMOVING PURCHASED POWER FROM LAMBDA IN SETTING THE RTP PRICE WOULD NO LONGER MAKE RTP A MARGINAL COST RATE. DO YOU CONCUR?

A No. This is an overstatement. Incremental generation costs determine real time prices during the vast majority of hours. Expensive purchases are only required when the Company does not have sufficient generation to meet territorial loads. As it is the Company's objective to always have sufficient resources to satisfy customers' needs for reliable low cost service, the instances where expensive power purchases set the real time price should be the exception and not the rule. Trends would indicate the opposite.

Limiting the system lambda to include only incremental generation cost would continue to send marginal cost-based price signals to customers. This is because incremental generation costs can range from 1.2¢ to as high as 7.5¢ per kWh. As low-cost base load energy is exhausted and new resources are added that are fueled with more expensive natural gas, these higher costs will immediately be reflected in the hourly real time prices. This is consistent with sending marginal cost price signals.

Q DO YOU HAVE ANY CONCERNS ABOUT WHETHER THE COMPANY WILL HAVE SUFFICIENT GENERATION TO SATISFY CUSTOMERS' NEEDS?

A Yes. The Company mentions that new capacity additions will help to reduce real time prices. My concern is that the projected capacity additions will barely keep pace with projected load growth. As I demonstrated in Exhibit ___ (JP-3) attached to my Direct Testimony, the projected reserve margins in the Southern Subregion are currently well below a 15% planning reserve. This means that the utilities must add more resources than projected load growth in order to restore a 15% reserve margin.

Q WOULD LAMBDA AVERAGING ALSO SEND MARGINAL COST PRICE SIGNALS?

A Yes. Lambda averaging is just another way of quantifying marginal cost. As I stated in my Direct Testimony, there is no universally accepted definition of system lambda. Some utilities, like GPC, define system lambda as the cost of the next kWh generated. Other utilities use lambda averaging. Thus, the issue is not which definition reflects marginal cost because both GPC's lambdas and lambda averaging are marginal cost-based.

The real issue is which definition of lambda best tracks the actual cost to provide RTP service. As I demonstrated in my Direct Testimony, lambda averaging more closely reflects the actual incremental cost to serve RTP loads. This is precisely the reason why the Commission should adopt full lambda averaging in this proceeding.

Q THERE IS CONSIDERABLE DISCUSSION IN THE GPC TESTIMONY ABOUT THE PRICE RESPONSIVENESS OF RTP CUSTOMERS. IS THIS PRICE RESPONSIVENESS A RECENT DEVELOPMENT BECAUSE OF THE EXTREMELY HIGH SPOT MARKET PURCHASES, OR HAVE RTP CUSTOMERS ALWAYS BEEN PRICE RESPONSIVE?

A It is my understanding that RTP customers have always been price responsive, even prior to 1998. For example, in GPC's 1998 Integrated Resource Plan, the Company estimated a 330 MW reduction to peak demand in 1997 as a result of customer responsiveness to the RTP rate.[3] Average RTP prices were much lower in 1997.

[3]Georgia Power Company, "Budget 1998 Load and Energy Forecast 1997-2022," prepared by Georgia Power Company, Southern Company Services, Inc., September 1997, pages 7-9.

Q WOULD HIGHER PRICES NECESSARILY RESULT IN A GREATER PRICE RESPONSE?

A No. According to an EPRI-sponsored study on RTP:

> "Customers facing high prices for prolonged periods of time may become less flexible in their response because sales losses attributable to postponing production deadlines are likely to become an overriding factor in not responding regardless of the level of price. *Even if high prices persist for only a very short time, a customer facing a very tight deadline will not be any position to respond to high prices.*"[4]

As the Study indicates, there are finite limits in both the magnitude and duration of price response under RTP. Customers that can respond will do so. Other customers may not always respond to price signals because of competitive or other economic concerns.

Q GPC WITNESSES CONTEND THAT ANY CHANGES TO THE RTP TARIFFS THAT REDUCE THE DEGREE OF CUSTOMER RESPONSE WILL REDUCE THE AVAILABILITY OF THIS RESOURCE AND RESULT IN INCREASED REVENUE REQUIREMENTS. HAVE THESE WITNESSES ATTEMPTED TO QUANTIFY THE CHANGE IN PRICE RESPONSE AS A RESULT OF GTMA'S AND GIG'S LAMBDA AVERAGING PROPOSAL?

A No. The only analysis provided by GPC showed the change in real time prices under a more limited form of lambda averaging, where only bottom-of-stack purchases were removed.[5] According to the Company's analysis, limited lambda averaging would lower average real time prices between 0.06¢ (based on year 2000 projections) and 0.29¢ per kWh (based on actual 1999 conditions).[6] The Company failed to quantify the impact of these price changes on price responsiveness. However, these changes are much

[4]Christensen Associates, "Real Time Pricing Quick Start Guide," prepared for Electric Power Research Institute, Final Report dated August 1995, page 204. (emphasis added)

[5]The GTMA and GIG have recommended full lambda averaging, which includes averaging the marginal costs of all incremental resources serving RTP loads. However, GPC refused to provide the impact of full lambda averaging.

[6]GPC's response to Data Request No. STF-2-1.

smaller than the 0.6¢ per kWh reduction in day-ahead real time prices that the Company is projecting for the year 2000.

Q SHOULD PRICE RESPONSE BE THE SOLE OBJECTIVE OF REAL TIME PRICING?

A No. There must be a balance between price responsiveness and ensuring that the prices charged by a utility are fair, just and reasonable and reflect the utility's actual cost of providing service. This balancing of interests is the only way that the Commission can protect customers' interests by fulfilling its role as a surrogate for competition.

Q GPC ACCUSES YOU OF UPSETTING THE BALANCING OF CUSTOMER AND COMPANY INTERESTS ESTABLISHED IN THE 1998 RATE CASE. WOULD CHANGING THE PRICING STRUCTURE OF RTP ADVERSELY AFFECT NON-RTP CUSTOMERS?

A No. As I stated in my Direct Testimony, the proposed change in the RTP fuel accounting practice would reduce the FCR. This would benefit all customers.

Q GPC ALLEGES THAT NON-RTP CUSTOMERS WILL BE HARMED BY THE PROPOSED CHANGE IN THE FUEL ACCOUNTING PRACTICE BECAUSE THE REVENUE SHIFT FROM RTP BASE REVENUE TO THE FCR ACCOUNT WOULD REQUIRE THE COMPANY TO INCREASE BASE RATES. UNDER WHAT CIRCUMSTANCES CAN THE COMPANY INCREASE BASE RATES?

A Under the Accounting Order, base rates cannot be increased as long as the Company's earned ROE is within the 10% to 12.5% range. Since 1995, GPC has consistently earned at or above this range. As GPC's rate base continues to decline, due to accelerated deprecation, there is every reason to believe that the Company can achieve similar returns in 2000 and 2001.

Q WHAT CONCLUSIONS DO YOU DRAW FROM THE COMPANY'S POSITION THAT THE ACCOUNTING ORDER PREVENTS ANY CHANGES IN THE RTP TARIFFS?

A The Company is attempting to evade regulation by telling this Commission that it no longer has the right to safeguard customers' interests even when evidence is presented which demonstrates that the prices being charged for RTP service are no longer fair, just and reasonable. Contrary to its claim, the Company has no entitlement to extract each and every dollar it possibly can from its customers regardless of the circumstances. In other words, the Commission is obligated to continue regulating all of the Company's tariffs, and this obligation is not affected by the Accounting Order. Neither the proposed changes in the pricing structure nor eliminating the adders will violate the Accounting Order.

Q GPC ALLEGES THAT YOUR ANALYSIS, WHICH SHOWS THAT GPC COLLECTED $63 MILLION OF EXCESS REVENUES FROM RTP SALES IN 1999, IS INCORRECT. DO YOU AGREE?

A No. The Company has mischaracterized the $63 million amount calculated in Exhibit ___ (JP-4), attached to my Direct Testimony. However, the Company also concedes that RTP sales contributed $49 million of the total excess revenues generated in 1999. Although I do not dispute the Company's statement about 1999 actual versus forecasted revenues, this does not correctly describe the analysis that I made.

Q HOW WAS YOUR ANALYSIS DIFFERENT FROM GPC'S?

A The analysis in Exhibit ___ (JP-4) is a comparison of base revenues, or margins, between the assumptions made in GPC's last rate case and what actually occurred in 1999. In other words, if GPC had accurately projected real time prices based on its rate

case assumptions, it would have recovered $63 million less in margins from RTP customers during 1999.

Q HAVE YOU REVIEWED EXHIBIT ___ (JP-4) SINCE IT WAS ORIGINALLY FILED?

A Yes. After reviewing my workpapers, I found that I had understated actual 1999 RTP energy sales and incremental revenues. As a consequence, the excess margins in 1999 were also understated. The corrected amount is $65 million, as shown in Exhibit ____ (JP-11).

3. RTP Adders

Q THE GPC WITNESSES ALLEGE THAT THERE ARE OTHER RISKS/COSTS NOT REFLECTED IN THE CURRENT RTP PRICING STRUCTURE. DO YOU AGREE WITH THESE ALLEGATIONS?

A No. The Company claims that there are three new components that must now be reflected in the adder, since they are not currently covered in the RTP incremental price. These include:

- Unit commitment costs;
- Distribution and overhead costs associated with RTP load growth; and
- The value of SO_2 emission allowances.

The Company also identifies forecasting risk. However, the Company's claims about forecasting risk are not new. I shall demonstrate later that, even without the adders, customers are already bearing this risk.

Q IS THE COMPANY BEARING THE ADDITIONAL COST RISKS AS ITS WITNESSES ALLEGE?

A No. The GPC witnesses concede that unit commitment costs are treated as fuel and recovered through the FCR. Similarly, distribution and overhead costs are part of GPC's standard embedded cost tariffs, which determine the CBL portion of an RTP customer's bill. Because the Company's earned return on equity has always been at the upper end or above the 10% - 12.5% range allowed by the Commission under the Accounting Orders, there is no question that these additional costs have been fully recovered. Thus, the Company is not bearing any cost risks.

Q DO THE COMPANY'S CONCERNS ABOUT ADDITIONAL DISTRIBUTION AND RELATED OVERHEAD COSTS APPLY TO ALL RTP CUSTOMERS?

A No. Many RTP customers take service directly from the transmission system. In fact, the larger GIG and GTMA members that take service on RTP-HA are almost entirely at transmission voltage. GPC does not invest in distribution equipment to serve the needs of transmission-level customers. Thus, even if the Company's concerns were valid, it would not justify collecting the same revenues from all RTP customers because many of these customers – especially larger GIG and GTMA members – are served directly at the transmission level.

Q ARE UNIT COMMITMENT COSTS ONLY INCURRED TO SERVE RTP CUSTOMERS?

A No. These costs are incurred whenever the Company must start-up a generating unit in anticipation of serving loads that are expected to occur the next day. Typically, this occurs during off-peak hours. Unit commitments are generally required because of time-of-day variations in load. Day-time loads are typically much higher than night-time loads. Adequate generation must be available to meet these day-time loads. The problem is that many generators cannot be turned on and turned off to instantly respond to changes in load. Units must be committed ahead of time (usually on the previous day or night) to meet projected daily demands.

Thus, unit commitment costs are a system-wide cost. They cannot be solely attributed to RTP customers. However, if any attempt were made to allocate unit commitment costs to specific customers, then they should be allocated relative to on-peak usage because on-peak usage causes unit commitment costs to be incurred.

Q ARE RTP CUSTOMERS PAYING UNIT COMMITMENT COSTS AND DISTRIBUTION AND OVERHEAD COSTS?

A Yes. RTP customers are already paying distribution and overhead costs through the CBL portion of their bill. They are also paying unit commitment costs through the FCR.

Q HAS THE COMPANY PRESENTED A COST STUDY TO DEMONSTRATE THAT RTP CUSTOMERS ARE NOT PAYING THEIR FAIR SHARE OF UNIT COMMITMENT COSTS AND DISTRIBUTION AND OVERHEAD COSTS?

A No.

Q SHOULD RTP CUSTOMERS BE SEPARATELY CHARGED FOR THE VALUE OF SO_2 EMISSION ALLOWANCES?

A No. The value of SO_2 allowances is not a cost of service. What the Company omits is the fact that the SO_2 allowances that it says it might potentially sell were either given to the Company (at no cost) or bought and paid for by customers through higher fuel prices for low sulfur coal. Given these circumstances, the Company's proposal to include SO_2 allowances in the hourly real time prices is absurd.

Q ARE GPC'S FORECASTING RISK ARGUMENTS CORRECT?

A No. The Company has overstated the impact of forecasting risk. Although complaining that it actually under-forecasted system lambdas for RTP-DA in the year 1999, the Company conveniently ignores that it over-forecasted the 1999 RTP-HA lambdas.[7]

[7] GPC response to Data Request No. STF-2-2.

Q HOW DID GPC'S 1998 FORECASTS COMPARE WITH ACTUAL SYSTEM LAMBDAS?

A During 1998, projected RTP-DA lambdas were higher than actual lambdas in 4,981 hours. This is more than 50% of the total hours. On average, the projected day-ahead lambdas exceeded actual lambdas by .02¢ per kWh. Similarly, projected RTP-HA lambdas exceeded actual lambdas in 5,408 hours, or 62% of the total hours. The average projected hour-ahead lambdas were .05¢ per kWh higher than the actual lambdas.

Projected lambdas, not actual lambdas, set the prices paid by RTP customers. Thus, actual experience demonstrates that the RTP customers are bearing forecasting risk. Further, the magnitude of the forecasting risk is no where near the 0.5¢ and 0.45¢ adders to every RTP kWh sold.

Q GPC SAYS THAT THE ADDERS SHOULD BE RETAINED IN ORDER TO COVER THESE ALLEGED ADDITIONAL COSTS/RISKS. DO YOU AGREE?

A No. The Company has not provided any quantitative evidence supporting the adder. Further, the so-called additional cost risks are either illusory (e.g., value of SO_2 emissions) or are already being recovered in its standard rates, which apply to nearly two-thirds of the loads of RTP customers (e.g., distribution and overhead costs, unit commitment costs, forecasting risk). The Company has not shown that RTP customers are not paying their fair share of the actual costs caused by these customers.

Finally, my Exhibits ____ (JP-6) and ____ (JP-10) demonstrate that, even without the adders, the RTP rates collect more than GPC's embedded generation costs. Thus, the adders should be eliminated.

Q WOULD ELIMINATING THE ADDERS VIOLATE THE EARNINGS SHARING PROVISION OF THE ACCOUNTING ORDER?

A No. It will have no impact on the sharing of earnings during calendar year 1999 since the results of this case will not be applied retroactively. As I stated in my Direct Testimony, GPC's future earnings will depend on a variety of factors, including how well the Company manages its operating expenses. Absent a severe economic reversal, a resurgence of inflation or other unknown event, there is every reason to believe that, based on past performance, the Company's earnings will continue to generate refunds for all customers.

Q WOULD ELIMINATING THE ADDER ADVERSELY AFFECT THE PRICE RESPONSIVENESS OF RTP?

A No. Price responsiveness is a function of the hourly marginal cost. The adder is not a marginal cost associated with generation, it is simply a constant amount added to the hourly real time price. This is in contrast to the other RTP components that vary each hour depending on system operating conditions. Changes in these components, which result in corresponding changes in hourly real time prices, convey the appropriate price signals and encourage customers to respond accordingly. The adder, unlike the other RTP cost components, is nothing more than pure profit to GPC. GPC does not need this additional profit to fully recover embedded generation cost from RTP customers.

4. Revenue Comparisons

Q HAVE YOU REVIEWED THE 1998 INDUSTRIAL PRICE PER kWh COMPARISONS PROVIDED WITH THE GPC TESTIMONY?

A Yes. GPC's comparisons are shown in Exhibit ____ (HKO-8).

Q ARE THE COMPARISONS SHOWN IN THIS EXHIBIT A VALID ANALYSIS?

A No. First, the Exhibit is mislabeled. Contrary to the label, these comparisons do not represent actual prices paid by individual customers. This is because the numbers were derived by dividing average revenues paid by industrial customers by the total kWh sold to industrial customers in 1998. Actual price comparisons were provided in Exhibit ____ (JP-1) attached to my Direct Testimony.

Second, GPC made an error in the average revenue for Duke Power Company South Carolina. The correct number is 3.59¢, not 4.59¢.

The Exhibit also gives the mistaken impression that Savannah Electric's industrial rates are cheaper than Georgia Power's, when the opposite is true. It just so happens that Savannah's industrial customers are six-times larger than GPC's average industrial customer. As explained later, it is much less costly to serve larger customers on a per kWh basis. When more energy is sold at a lower price, the result is to lower the average revenue per kWh for the entire class. Consider the following example:

	Utility A		Utility B	
	Sales	Price	Sales	Price
Rate 1	50	3.00¢	450	3.25¢
Rate 2	150	4.00¢	50	4.50¢
Average Revenue per kWh		3.75¢		3.37¢

As can be seen, Utility B has higher prices than Utility A. However, because Utility B sells more energy at a lower rate (Rate 1), its average revenue per kWh is lower than Utility A. This example demonstrates how average revenue per kWh comparisons can be misleading.

Q WHY ELSE ARE GPC'S COMPARISONS MISLEADING?

A Including GIG and GTMA average cost per kWh information is a classic apples and oranges comparison. It is simply wrong to compare a select group of GPC's customers to the average per kWh revenues paid by all industrial customers served by other southeastern electric utilities.

Notwithstanding the apples and oranges nature of the per kWh comparisons, GPC selectively omitted Kentucky Power Company, TVA and several other low-cost utilities. It is no coincidence that the average revenues per kWh derived from industrial sales by the utilities that GPC selectively omitted are below the amounts shown for GIG and GTMA members. The complete listing for all Southeastern utilities is provided in Exhibit ___ (JP-12). These are the same utilities used in the "apples-to-apples" price comparisons shown in Exhibit ____ (JP-1), page 3.

Finally, average revenue per kWh comparisons mask fundamental differences in the usage and other characteristics that determine the per kWh cost of providing service.

Q DOES GPC PRESENT ANY VALID REASON FOR EXCLUDING TVA FROM ITS REVENUE COMPARISONS?

A No. TVA is a major competitor to GPC. This conclusion is not altered by the fact that TVA has a different financial and tax structure than GPC.

Q CAN ANY LEGITIMATE CONCLUSIONS BE DRAWN BY COMPARING THE GIG AND GTMA AVERAGE REVENUES PER kWh WITH THE CORRESPONDING AVERAGE INDUSTRIAL REVENUES OF CUSTOMERS SERVED BY OTHER UTILITIES?

A No. By their very nature, averages mean that some customers pay more per kWh for service, while other customers pay less. Closer examination of the average revenues per kWh charged by other utilities to selected industrial customers reveals that GIG and GTMA members are not getting the best deal, contrary to the false impression created by GPC's Exhibit.

For example, average revenues per kWh sold to Rate HLF customers served by Alabama Power Company (GPC's affiliate) are only 3.01¢ per kWh. Another GPC affiliate, Mississippi Power Company, recovers only 2.56¢ per kWh from its Rate LPO industrial customers. Louisville Gas and Electric, which was omitted from GPC's Exhibit, recovers 3.10¢ per kWh from its special contract customers and only 3.50¢ per kWh from its large industrial time-of-day customers. Although some industrial rates are higher than the examples shown above, it is clear that GPC is not the lowest cost supplier in the Southeast to customers like GIG and GTMA members.

Q DO GPC'S COMPARISONS PRESENT A COMPLETE PICTURE OF CURRENT RATE AND COST RELATIONSHIPS?

A No. The examples presented earlier demonstrate the fallacy of comparing average revenues between selected customer groups and broad industrial class averages. What is missing from GPC's analysis is evidence that compares the actual cost of providing service to industrial customers similar to individual GIG and GTMA members.

Q WHAT WOULD A COST STUDY SHOW?

A A cost study would show that it is common practice to charge lower rates for customers that operate at a higher load factor, take service at a higher delivery voltage, consume more electricity per meter, who are willing to either curtail service or assume price risk and whose load shape is more off-peak in nature.

Q WHAT IS LOAD FACTOR?

A Load factor is a measure of how customers use the capacity that they impose on the utility. A high load factor customer uses capacity steadily around the clock and throughout the year. A lower load factor means that electricity is used more intensively during certain times of the year (e.g., the hot summer months for air conditioning load). In general, the higher the load factor, the lower the cost to serve per kWh.

Q HOW DOES DELIVERY VOLTAGE AFFECT AVERAGE REVENUES PER kWh?

A Customers that take service at a higher voltage level are less costly to serve for two reasons. First, GPC does not have to incur lower voltage distribution costs to serve transmission-level customers. Nor does GPC incur as many losses to serve a transmission-level customer. With less investment and lower losses, service provided at transmission voltage is less costly on a per kWh basis.

Q HOW DOES SIZE AFFECT THE PER kWh COST TO SERVE?

A Larger customers require more expensive metering, and billing and customer accounting costs are generally higher per location than for smaller customers. However, these costs are not proportional to the amount of kWh consumption. Thus, customer-related costs to serve larger customers are lower on a per kWh basis.

Q IS THERE EVIDENCE THAT GEORGIA POWER'S INDUSTRIAL CUSTOMERS HAVE DIFFERENT COST CHARACTERISTICS?

A Yes. Exhibit ____ (JP-13) is a summary of the cost characteristics for GPC's industrial class. It shows demand, energy, load factor, number of customers and average consumption (size) separated by delivery voltage.

The Exhibit demonstrates that industrial customers are served at a wide range of delivery voltages: from 115 kV transmission lines to distribution line transformers. There are also differences in load factor as a function of delivery voltage. Similarly, larger customers tend to be served at the higher voltages (e.g., transmission lines and substations). Finally, although the majority of the industrial load is served at higher voltage, the vast majority of the industrial customers are served at distribution voltage. (All residential and most commercial customers are also served at this distribution level.)

These different characteristics suggest that it is inappropriate to compare average industrial revenues on a per kWh basis. Such comparisons must also consider differences in the characteristics that result in differences in the actual cost to serve per kWh.

Q DO AVERAGE REVENUE PER kWh COMPARISONS BETWEEN BROADLY DEFINED CLASSES REFLECT DIFFERENCES BETWEEN FIRM AND NONFIRM SERVICE?

A No. Nonfirm or interruptible customers take a lower quality of service than firm customers. This is because the utility can require nonfirm customers to curtail their service so that sufficient capacity is available to enable the utility to continue meeting the needs of its firm customers.

Q IS NONFIRM SERVICE LESS COSTLY THAN FIRM SERVICE?

A Yes.

Q DO AVERAGE REVENUE PER kWh COMPARISONS REVEAL DIFFERENCES IN PRICE RISK?

A No. These comparisons do not differentiate between standard embedded tariffs and real time pricing, which places customers entirely at risk for changes in system operating conditions and costs.

Q DO RTP CUSTOMERS THAT HAVE DIFFERENT LOAD SHAPES PAY THE SAME AVERAGE REVENUES PER RTP kWh SOLD?

A No. These differences are illustrated in GPC's Exhibit ____ (HKO-16). For example, Customer X, which has a completely flat load shape, would pay an average RTP price of 3.09¢ per kWh. Customer Y, whose load shape is more summer peaking, would pay 3.25¢, which is a higher average price per kWh than Customer X. Similarly, Customer Z, who has a more off-peak load shape, would pay only 2.95¢ for RTP service, which is a lower average price than either Customer's X and Y pay.

Q WOULD THESE CHARACTERISTICS EXPLAIN IN LARGE PART WHY GIG AND GTMA CUSTOMERS PAY LESS PER kWh THAN DO OTHER GEORGIA POWER INDUSTRIAL CUSTOMERS?

A Yes. Both the GIG and GTMA customers are among the largest loads served by GPC. This means that average customer costs per kWh are lower for these customers than for smaller industrial loads. Many GIG and GTMA customers take service at higher delivery voltages. This means that GPC incurs less investment and lower losses to serve these customers, resulting in a lower average cost per kWh. Most GIG and GTMA members

normally operate either multiple shifts or around the clock. Thus, they generally have higher load factors than most industrial customers. This further reduces the average cost per kWh. Several of the larger members take interruptible service. Interruptible service is less costly than firm service on a per kWh basis. Finally, many GIG and GTMA members take real time pricing. RTP is more risky than standard service. This additional risk, coupled with the generally more off-peak load shapes of these customers, further justifies the lower average revenue per kWh from GIG and GTMA members.

Q DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A Yes, it does.

Exhibit ____ (JP-10)

GEORGIA POWER COMPANY

Assessment of RTP Margins
During the Years 1998 and 1999

Line	Description	As Billed (1)	Excluding Recovery Factor (2)	Excluding Recovery Factor and Transmission (3)
1	Average 1998 and 1999 Margins	$189,781,336	$ 144,950,023	$ 131,359,047
2	Average 1998 and 1999 RTP Sales (MWh)	9,136,967	9,136,967	9,136,967
3	Margins in Cents per kWh (Line 1 / Line 2)	2.08	1.59	1.44
4	Hours in the year	8,760	8,760	8,760
5	Margins per kW (Line 3 X Line 4)	$ 182	$ 139	$ 126
6	Less: Fixed O&M per kW at $30	$ 152	$ 109	$ 96
7	Annual Fixed Charge Rate	20%	20%	20%
8	Equivalent Investment per kW (Line 6 / Line 7)	$ 760	$ 545	$ 480
9	GPC Net Production Investment per kW	$ 340	$ 340	$ 340
10	**Excess Margins per kW**	**$ 420**	**$ 205**	**$ 140**

Exhibit ____ (JP-11)

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	$337,142,805		
5	Less: Fuel Recovery	$131,285,919		
6	Margins	$205,856,886	9,568,945	2.15
7	**Excess over Rate Case**			0.68
8	**1999 Excess Margins**	**$64,698,617**		

Exhibit ____ (JP-12)

GEORGIA POWER COMPANY

1998 Industrial Class
Revenue per kWh Comparisons

Line	Utility	Cents per kWh
1	Kentucky Power Company	3.01
2	Tennessee Valley Authority	3.03
3	Southwestern Electric Power Company, TX	3.46
4	Entergy Gulf States, Inc. - TX	3.48
5	Appalachian Power Company, WV	3.52
6	Appalachian Power Company, VA	3.53
7	Duke Power Company, SC	3.59
8	Mississippi Power Company	3.62
9	Louisville Gas and Electric Company	3.66
10	Central Power and Light Company	3.71
11	Virginia Electric and Power Company	3.77
12	Gulf Power Company	3.81
13	South Carolina Electric & Gas Company	3.88
14	Texas Utilities Electric Company	3.91
15	Alabama Power Company	3.95
16	Monongahela Power Company, WV	3.97
17	Southwestern Electric Power Company, LA	4.02
18	Savannah Electric	4.03
19	Entergy Louisiana, Inc.	4.04
20	Houston Lighting & Power Company	4.07
21	Entergy Gulf States, Inc. - LA	4.15
22	Central Louisiana Electric Company, Inc.	4.16
23	Duke Power Company, NC	4.27
24	Georgia Power Company	4.29
25	Tampa Electric Company	4.48
26	Carolina Power & Light Company, SC	4.64
27	Entergy Arkansas, Inc.	4.83
28	Florida Power Corporation	4.90
29	Ameren Corporation-UE, MO	4.94
30	Carolina Power & Light Company, NC	4.98
31	Florida Power & Light Company	4.99
32	Entergy New Orleans, Inc.	5.10
33	Entergy Mississippi, Inc.	5.40
34	**Average**	**4.10**

Source: Electric Sales & Revenue 1998,
Department of Energy, Energy Information Administration

GEORGIA POWER COMPANY

Industrial Class Characteristics
Test Year Ending July 31, 1999

Line	Delivery Voltage	12 CP Demand (kW) Amount (1)	12 CP Demand (kW) Percent (2)	Energy Sales (MWh) Amount (3)	Energy Sales (MWh) Percent (4)	Load Factor (5)	No. of Customers (6)	Avg MWh Usage per Customer (7)
1	Transmission Lines 115 kV	16,917	1%	163,357	1%	110%	2	6,807
2	Transmission Substations	1,204,092	42%	10,248,113	45%	97%	139	6,144
3	SubTransmission Lines 38 to 69 kV	42,998	1%	321,500	1%	85%	7	3,827
4	Distribution Substations	370,049	13%	3,101,321	14%	96%	290	891
5	Primary Distribution 25 kV and lower	412,513	14%	3,319,103	15%	92%	225	1,229
6	Line Transformers	837,983	29%	5,622,868	25%	77%	8,504	55
7	Total Industrial Class	2,884,552	100%	22,776,262	100%	90%	9,167	207

Source: Cost of Service Study Filed in Docket No. 9355-U and Responses to Various Staff Data Requests

Exhibit ____ (JP-13)

CERTIFICATE OF SERVICE

This is to certify that I have this day served a copy of the foregoing Rebuttal 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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This 24th day of March, 2000.

Peyton S. Hawes, Jr.