BEFORE THE GEORGIA PUBLIC SERVICE COMMISSION

In the Matter of:	:	
Petition for Rule Nisi to Examine GEORGIA POWER COMPANY's Real Time Pricing Structure	:	Docket No. 11708-U

Room 507
47 Trinity Avenue
Atlanta, Georgia

Tuesday, April 4, 2000

The above-entitled matter came on for hearing pursuant to Notice at 11:30 a.m.

BEFORE:

ROBERT DURDEN, Chairman
DAVID BURGESS, Vice Chairman
LAUREN "BUBBA" MCDONALD, Commissioner
ROBERT BAKER, Commissioner
STAN WISE, Commissioner

* * *

APPEARANCES:

On behalf of the Commission Staff:

DANIEL WALSH, Attorney
Special Assistant Attorney General
Capitol Square
Atlanta, Georgia 30334

On behalf of the Consumers' Utility Counsel:

KRISTY HOLLEY, Attorney
Consumers' Utility Counsel
2 MLK Jr. Drive, Plaza Level East
Atlanta, Georgia 30334

On behalf of Georgia Power Company:

KEVIN C. GREENE, Attorney
THOMAS L. PENLAND, JR., Attorney
Troutman Sanders
5200 NationsBank Plaza
600 Peachtree Street
Atlanta, Georgia 30308-2216

On behalf of Georgia Industrial Group:

RANDALL QUINTRELL, Attorney
Sutherland, Asbill & Brennan
999 Peachtree Street
Atlanta, Georgia 30309-3966

On behalf of Georgia Textile Manufacturers Association:

PEYTON S. HAWES, JR., Attorney
Suite 1100, Candler Building
127 Peachtree Street
Atlanta, Georgia 30303

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P R O C E E D I N G S

CHAIRMAN DURDEN: This hearing of the Georgia Public Service Commission in Docket Number 11708-U regarding a Petition for Rule Nisi to examine Georgia Power Company's real time pricing structure will now come to order.

Let's enter appearances, please.

MR. HAWES: Peyton Hawes for GTMA representing the Petitioner; Randy Quintrell.

CHAIRMAN DURDEN: Mr. Greene, are you going to make an appearance?

MR. GREENE: I apologize, Mr. Chairman. Kevin Greene and Tom Penland on behalf of Georgia Power Company.

CHAIRMAN DURDEN: Who's representing Georgia Public Service Commission?

MR. WALSH: Mr. Chairman, Dan Walsh on behalf of Georgia Public Service Commission.

CHAIRMAN DURDEN: Consumers' Utility Counsel?

MS. HOLLEY: Kristy Holley on behalf of CUC.

CHAIRMAN DURDEN: Service Resources, Inc.

MS. BAULKMON: Jeane Baulkmon for Service Resources, Inc.

CHAIRMAN DURDEN: Is there any other party that's formally a part of the proceeding?

(No response.)

CHAIRMAN DURDEN: I understand we have several

public witnesses.

Mr. Hoke Shirley.

MR. GREENE: Before we begin, I'd like to interpose an objection to any public witness who is testifying as a member of GIG or GTMA. There was a Scheduling Order that required prefiled testimony in this case. So to the extent they're offering evidence, I'd like to prohibit that.

MR. HAWES: Mr. Chairman, every proceeding I've been involved in, public witnesses may be called. These witnesses are customers just as every other witness that appears here as public witnesses. They are not presenting expert testimony. There has always been an expression of concern about putting a face on exactly what is happening and what the complaints are. These witnesses are here and have been asked or these members are here and have been asked to limit their remarks to three minutes and to just give the experience of their company. They're not presenting expert testimony, although it is their factual situation.

CHAIRMAN DURDEN: Okay, I think since they are going to limit to three minutes, since they are not presenting expert testimony and since you will have the opportunity if you feel the need to, Mr. Greene, to cross examine these witnesses, that I'm going to allow it.

I would, however -- I think sometimes we inadvertently start down a road that can lead to hell fire and damnation of we're not careful. And I would caution the parties -- and I'm sure they'll follow this, all the parties -- that in the interest of good faith and keeping a proper proceeding that we not begin a trend here where we try to then get in information to avoid the prefiling rule.

With that in mind, the Commission then, of course -- each individual Commissioner will place whatever probative value he feels needs to be placed on the testimony, but I would hope the parties would not try to circumvent the rules with the public witness proceeding, either here or at any point down in the future.

So let's go ahead with our public witnesses. Mr. Shirley.

MR. SHIRLEY: Thank you. Commissioners Durden --

CHAIRMAN DURDEN: Can you hold on one second?

MR. SHIRLEY: Commissioners Durden, Burgess, McDonald, Wise and Baker, my name is --

CHAIRMAN DURDEN: Excuse me. Let me stop a minute.

MR. SHIRLEY: Yes, sir.

CHAIRMAN DURDEN: We've been a little inconsistent in the past, but I think most of us would feel more comfortable if we swore you in.

Would all the public witnesses raise their hands, please -- raise their right hands.

(Witnesses sworn en masse.)

CHAIRMAN DURDEN: Okay, you're all sworn.

Whereupon,

HOKE SHIRLEY

appeared as a public witness herein, and having been first duly sworn, was examined and testified as follows:

DIRECT TESTIMONY

THE WITNESS: My name is Hoke Shirley and I serve as the electrical engineer at Fruit of the Loom's Rabun Apparel Plant in Rabun Gap, Georgia. This plant is a combined spinning, knitting and dyeing plant that employs approximately 1100 people and is vital to the economy of this mountain county.

For the past eight years, Rabun Apparel has been on Georgia Power Company's RTP tariff. At its inception, the RTP tariff was a good rate for industry and soon became an incentive for industrial expansion in the state of Georgia.

For the first six years, '92 through '97, Rabun Apparel experienced very stable rates under the RTP tariff, with the yearly average being 2.27 cents per kilowatt hour. The highest yearly cost during this time was experienced in '95 and it was only 5.8 percent above the average.

Then in 1998, a very alarming trend started. The average cost per kilowatt hour jumped 43 percent above the stable average of the previous six years. This exponential trend continued, in 1999 there was a 58 percent rise above the previous average.

Rabun Apparel's average annual consumption of electricity for the last two years has been over 110 million kilowatt hours. The escalating prices of the last two years have driven up the power costs at our plant by more than $2.5 million. Budgeting power expenditures at Rabun Apparel has become almost impossible because each -- using the last two years' figures -- each one-tenth of one cent rise in the cost of electricity -- that's one-tenth of one cent -- costs us about $117,000 per year -- one-tenth of one cent rise adds that much to it. So it's very chancey to do any budgeting.

The high rates of '98-'99 have been attributed to hot summers and the deregulated spot market. If that were so, then we would expect a reduction of prices in 2000 if the weather is cooler. But to my alarm, the RTP prices for the first two months of 2000 are 24 percent higher per kilowatt hour than the same two months of 1999. 1999 was the highest price year since the inception of RTP, so it's very alarming to us.

Also, in the last week -- this is last week, I

pulled all these prices -- we saw extremely high prices for this time of year. During the five days of March 27 through 31, we saw eight hours over a nickel, 23 hours over four cents and 62 hours over three cents. Remembering each one-tenth of a cent spread over a year drives our prices up over $117,000.

Last year, Georgia Power approached us probably in the fall with several options to replace our -- or to supplement the current RTP that we have. Two were listed as higher than RTP -- that's kind of insurance hype -- and two were considered revenue neutral. We examined those, you know, spent quite a bit of time looking at them. We rejected both because there was no price relief in either offer. We didn't see the reason to do a great deal of work to end up paying the same price on something.

Gentlemen, we need relief from these high and unpredictable prices so that we can concentrate on the business of producing T-shirts and underwear instead of allocating so much of our resources to these unpredictable and unreasonably high energy costs.

Thank you very much for your consideration.

CHAIRMAN DURDEN: Thank you, Mr. Shirley. Do you have any questions, Mr. Greene?

MR. GREENE: I have just a few. Do you mind if I just stay right here?

CHAIRMAN DURDEN: That'll be fine.

CROSS EXAMINATION

BY MR. GREENE:

Q Mr. Hoke, do you know what your average RTP price was, or your average price was last year at your plant?

A Yes, I have all that. I have CBL, I have RTP and I have overall.

Q Okay.

A For all of last year?

Q Yes, sir.

A Overall price, 3.65 cents per kilowatt hour. RTP, 3.59 cents per kilowatt hour. CBL, 3.84 cents per kilowatt hour.

Q Do you know what those prices were in 1991?

A I don't think -- the plant wasn't there in '91.

Q Okay.

A They started up in the middle of '92.

Q Do you know what they were in 1992?

A I do have the yearly average and the high/low for '92.

Q Okay.

A The yearly average for 1992 was two cents, the high was 2.42 cents -- that was a month -- and the lowest month was 1.87 cents.

Q Do you know what the residential and commercial

rates are in the state of Georgia?

A Yes.

Q At this period of time?

A Yes.

Q What are they?

A About seven cents.

Q Are you on Georgia Power Company's service?

A Yes.

Q All right, that seven cents does not include fuel, does it?

A I thought all of it included fuel.

Q Fuel is added to the seven cents, isn't that correct?

A I'm not sure. I don't spend near as much time on my bill as I do the company's bill.

(Laughter.)

Q Would you agree, subject to check, that your residential rate is probably in excess of nine cents, including fuel?

A I think I calculated it last year and it was seven cents -- I thought it was, overall. That was my hours divided by the cost.

Q Now at 3.5 cents last year, you're still paying half of that seven cents, is that right?

A Yes. But my usage there is much flatter than it

is at the house and we're a much larger user. We have a very flat line, we run 24 hours a day, seven days a week, about 350 days last year. So that is the kind of rate that Georgia Power always gives the very lowest to.

The real problem is starting in '92 through '96, we had very stable rates, like I said earlier -- through '97 actually. It only varied about 5.8 percent up and about 11 percent down, it was almost flat. And then in the last two years, it's jumped huge jumps. That's the real concern, being able to budget the power has become virtually impossible. My boss man is an ex-lineman for N.C. State, so you don't need to walk in there and tell him too many times we need another half million to pay Georgia Power.

Q Mr. Hoke, I've just got one other question. You understand, don't you, that one of the options that Georgia Power Company brought to you end of last year and beginning of this year was what's known as RTP with adjustable CBL, where you could lock in your RTP rate for this year?

A Right, I tried to get them to lock in and they offered 3.5 cents, I wanted 3.35. The last conversation I had was that because we can't start until June, that it probably would be much higher than that because it would be through the summer months. If the 3.5 would be from June to the end of the year, I think it would be attractive because the high summer months would be included in that. But for

the whole year, that wouldn't even be near approaching the previous stable rates we had before.

Q Do you know how many hours a year last year you paid less than two cents a kilowatt hour for RTP?

A Last year, we paid several hours less. That's what I'm very concerned about this year when I was giving all those hours, I haven't seen an hour below two cents in a long time. And I look at it on the internet, that's what I do, that's my job, big part of my job, so I look every day about it. I even go on the weekends and check that because we run seven days a week. And I haven't seen but very few hours this year under two cents. If we don't have some under two cents, those hours when we get up around a dime this summer will kill us because the average will be very high.

MR. GREENE: Thank you.

COMMISSIONER McDONALD: Mr. Shirley.

THE WITNESS: Yes, sir.

COMMISSIONER McDONALD: What was your gross sales in 1993?

THE WITNESS: At Fruit of the Loom?

COMMISSIONER McDONALD: Yes, sir, in Rabun County.

THE WITNESS: We just make cloth and we actually spin, knit and dye and send to the sewing plants out of the country.

COMMISSIONER McDONALD: How much product was produced in 1993?

THE WITNESS: We produce --

COMMISSIONER McDONALD: Is that measured in yards or --

THE WITNESS: Pounds of cotton -- we do about a million and a half pounds of cotton a week and about a quarter million pounds of polyester a week.

COMMISSIONER McDONALD: And that was the same in '93 as it is in '99?

THE WITNESS: No, no, last year was our highest year in production, but all the cost trends I've noted have been cost per kilowatt hour, not anything to do with overall costs, cost per kilowatt hour, the actual cost we're paying for each kilowatt hour, is what everything I've listed here is. That way you can look apples to apples.

COMMISSIONER McDONALD: All right, sir.

CHAIRMAN DURDEN: Do you have anything, Mr. Hawes?

MR. HAWES: Yes, sir. I don't mean to belabor this because we've got something I've never seen before, which is cross examination of public witnesses, but I assume I can do rebuttal as well if we do that.

CHAIRMAN DURDEN: That's why we've let you stand up and begin to speak.

MR. HAWES: Thank you, sir.

REDIRECT EXAMINATION

BY MR. HAWES;

Q Mr. Shirley, has Georgia Power presented you anything to date that you thought you could overall save money?

A If the 3.5 cents were introduced in June through the rest of the year; yes, I could save money. But they said no, we'll have to recalculate using the high months and low months.

Q And do you have plants in other states other than Georgia?

A Yes, we have almost every southern state.

Q How do these rates that you pay Georgia Power compare with other states?

A Those that are with big power companies are -- most of them are cheaper than what we pay. Fayette, Alabama, 3.3 cents last year, where we were 3.65. Jacksonville, Alabama, 3.39; Winfield, Alabama, 3.17. There are some in Mississippi, but I don't have their information.

COMMISSIONER BAKER: Mr. Shirley, let me ask you, did -- due to the high prices the last couple of years, has your plant gone off system at any time when those prices, you know, were reflected? Did you go off system because of high prices?

THE WITNESS: Let me give you a little history. A

guy named Farley more or less ran Fruit of the Loom in the ground, we filed Chapter 11. When he was running the company, up until about Thanksgiving, when they moved him over, more or less. He just sent mandates down, you run this much this week. They didn't have any option. I would call my boss and say you'll pay a $30,000 premium to run today over what we would normally pay for power. He'd say I can't shut down. So we had no flexibility in that.

What we do have is a cogen unit, 4.3 meg maximum output cogen unit. On days when the power gets above a nickel, except last week, we were above a nickel five hours, our usage wasn't high enough in steam, I didn't do it then, but it was only just a few isolated hours. We normally would do what we call spin the generator, meaning we dump steam to produce more electricity that's offsetting cost as much as possible. That five cents -- there were a lot of hours last year we were over that, we actually had hours that were a $1.93 instead of five cents. So we spun the generator almost all summer. We used a lot of sawdust, it's a very large wood boiler and we almost burned our sawdust pile completely up trying to hold the generator.

COMMISSIONER BAKER: So at your plant, once prices get over a nickel, then you try to go to your backup generation?

THE WITNESS: Normally it has to be at a certain

usage level, we can only dump so much steam, but normally in the summer time when we're at high usage, we do it then.

COMMISSIONER WISE: Do you have other plants around the country?

THE WITNESS: Yes, sir, 30 I think.

COMMISSIONER WISE: And how do you stack up, energy-wise, against them?

THE WITNESS: I do a plant engineer comparison with the Alabama plants, the Mississippi plants and us. And we're probably -- on power -- there's one in North Carolina that's a small cooperative that's the worst. We're probably third worst I guess, pay the highest price. Most of them are cheaper than us.

COMMISSIONER WISE: And you're told that happens why?

THE WITNESS: They're Alabama Power, different companies. The one company in North Carolina is a small cooperative and they pay over four cents, but they're captive, they don't have an option. But the ones that are in big companies like Alabama Power and Gulf Power -- I think maybe there are some on Gulf Power, the ones in Mississippi and us on Georgia Power, I think we're third, including the one in North Carolina from the highest paid.

CHAIRMAN DURDEN: Does any other party or any other Commissioner have any questions of this public

witness?

MS. HOLLEY: Excuse me, Mr. Chairman, I just have a couple of questions.

CHAIRMAN DURDEN: Can you hear her?

COMMISSIONER WISE: Get her on up.

MS. HOLLEY: I can move to the front.

COMMISSIONER BAKER: Yes.

FURTHER CROSS EXAMINATION

BY MS. HOLLEY:

Q Kristy Holley with the Consumers' Utility Counsel. Early on in your comments, you gave some percentages, what was the percentage increase in 1999?

A Fifty-eight percent rise, based on a six-year average from '92 to '97. So your previous year was 43 percent rise, '98.

MS. HOLLEY: All right, thank you.

CHAIRMAN DURDEN: Any other party or any other Commissioner?

(No response.)

CHAIRMAN DURDEN: Okay, thank you, Mr. Shirley.

(Witness excused.)

CHAIRMAN DURDEN: I think in light of the experience I just had, what we will do henceforth for the rest of these public witnesses will be ask them to come up, take their seat in the witness stand, you've all been sworn,

and then after they've made their statement, any party or any Commissioner who has any question may ask that question.

Mr. Page, Jerry Page.

Whereupon,

JERRY PAGE

appeared as a witness herein, and having been first duly sworn, was examined and testified as follows:

CHAIRMAN DURDEN: You have already been sworn, Mr. Page.

MR. PAGE: Yes, sir, I have.

CHAIRMAN DURDEN: Please proceed.

DIRECT TESTIMONY

THE WITNESS: I am Jerry Page, Manager of Energy Services for Hon Industries. Hon Industries is a 1.8 billion dollar sales company that is primarily an office furniture manufacturer. However, we also own three major wood and gas fireplace manufacturing concerns. Hon Industries is the parent of the Hon Company, which is located in Cedartown. That's one of twenty-seven manufacturing plants in twelve states, plus we have two others outside the United States in North America. The Cedartown plant is limited only to office furniture. They make steel desks, vertical files and lateral files. Our 2000 employment will be approximately 750, which is up 15 percent in the last three years. Payroll during that same

period of time is up 22 percent. Since 1997 our electric demand has increased 43 percent, indicative of a growth plant. Energy is up 59 percent. During that same time our load factor improved 11 percent. Our annual electric cost increased 66 percent in that three year period of time, in spite of that load factor improvement. Now, one would think if energy goes up 59 percent, why, you would expect your total dollars to go up some comparable to that. In fact, they went up at a greater rate than did the electric usage.

Per unit cost in 1999 was 4.97 cents per kilowatt hour. This is above both the mean and the median for the 27 plants that are located in those 12 states in the United States.

I believe that consists of the data that I had to present.

CHAIRMAN DURDEN: Okay, does any party have any question of this witness?

(No response.)

CHAIRMAN DURDEN: Does any Commissioner have any question?

COMMISSIONER BAKER: Mr. Page, let me just ask, did y'all go off system -- have you gone off system because of these higher prices? And how many hours have you gone off system?

THE WITNESS: We're not an interruptible customer

and the reason we are as successful as we are in the office furniture industry is we have the shortest lead times for our product. When we accept an order from our customer, we tell them when they're going to have it. And we keep that promise 98 percent of the time. That means that our plants, for the most part, are non-responding on real time pricing.

It does, however, beg the question about what we do when we know that the price is going to go up. We do reduce load, that load that is not necessary during that particular production part of the day, we cut the air conditioning back, increase the thermostats. This year, due to what happened last year, the five days at the tail end of July and the first part of August last year killed us, we were paying $36,000 a day for a couple of those days for our electricity. That will not happen this year because of moves that we will make to alter the production cycle. But I don't see that impacting, at this point in time, under the current situation and the way RTP is applied to our account. I don't see that that's going to reduce our per-unit cost much this year, the ways thing are.

COMMISSIONER WISE: How can that not be, if you interrupt or curtail production at the two weeks when prices are at their worst, how will that not impact your average prices for the year?

THE WITNESS: Well, we'll simply shift kilowatt

hours certainly to hours when the price is slightly less. But '98 and '99 were almost exactly the same. And we probably had better response in '98 than we did in '99. Our business increased significantly at that plant in '99, and see no break in that this year. We can shift some production to third shift. But we're running three shifts now at that plant this year, so how they're going to shift production out of a cycle during that peak time of the day into the night hours, I'm not certain.

That's not my problem, but the critical overriding factor here in all of our manufacturing facilities will always be that they will not shift production if it means degrading their ability to ship that customer's product when they said they were going to ship it. When we accept an order from our best customer, we have a five-day lead time on desks and vertical files and lateral files for our best customers out of that plant. And if they deviate from that five-day shipment, it shows up against the performance of the plant, it also affects bonuses at the plant, it affects profit sharing at that plant. That directly affects all the production employees at that facility. So the tendency is not to shift unless they can do that in a way which does not degrade our business with our customer.

VICE CHAIRMAN BURGESS: Let me ask you, Mr. Page, do you know how much -- what percentage of your electric

costs are a total part of your overall production costs?

THE WITNESS: I do not, I'm sorry.

CHAIRMAN DURDEN: Any other questions?

(No response.)

CHAIRMAN DURDEN: Thank you, Mr. Page.

THE WITNESS: Thank you.

(Witness excused.)

CHAIRMAN DURDEN: Mr. Niland -- did I pronounce that right?

MR. NILAND: Yes, you did.

CHAIRMAN DURDEN: Okay.

Whereupon,

PATRICK NILAND

appeared as a public witness herein, and having been first duly sworn, was examined and testified as follows:

CHAIRMAN DURDEN: Mr. Niland, you've already been sworn so your testimony will be under oath.

DIRECT TESTIMONY

THE WITNESS: My name is Patrick Niland from Georgia Duck and Cordage Mill, I'm manager of business applications and administration. I'm representing the company in order to emphasize our feeling -- we're a member of the Georgia Textile Manufacturers Association and in full support of the non-competitive nature of the RTP tariffs.

Georgia Duck and Cordage Mill has been in

operation since 1903. Recently, in 1998, it was purchased by Unipoly, which is a British conglomerate. We are looking at growing the company, we employ 530 people in Scottdale, which is out by Decatur, and one of the keys to the growth of our company and the success of the company is to increase our margins so that Unipoly, our parent company, will be able to increase their investment in our company.

We have recently increased the number of employees and with Georgia Power's high rates, our margins have significantly gone down in the last few years. So that we're looking at relief from these higher tariffs. We're relying on the testimony of expert witnesses of GTMA in support of that appeal.

Unless we are able to reduce our operating costs, the ability to increase our machinery and to grow the company and reduce the cost, will really be impacted.

We appreciate the Commission looking into this aspect of the RTP tariff and the non-competitive nature of it.

That concludes --

CHAIRMAN DURDEN: Any party have any questions? Mr Walsh.

MR. WALSH: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. WALSH:

Q Are you an interruptible service customer as well?

A No, I'm not.

MR. WALSH: That's all the questions I have.

CHAIRMAN DURDEN: Does any Commissioner have any questions?

(No response.)

CHAIRMAN DURDEN: Thank you, Mr. Niland.

(Witness excused.)

CHAIRMAN DURDEN: Mr. Jerry T-h-e-y-s. I know that however I pronounce your last name, I will get it wrong. How do you pronounce it?

MR. THEYS: Theys [pronouncing].

CHAIRMAN DURDEN: I would have gotten it wrong. Whereupon,

JERRY THEYS

appeared as a public witness herein, and having been first duly sworn, was examined and testified as follows:

CHAIRMAN DURDEN: You've already been sworn in, so your testimony is under oath.

DIRECT TESTIMONY

THE WITNESS: My name is Jerry Theys, I'm the Vice President of Beaulieu of America. Beaulieu of America is a carpet and yarn manufacturer. We employ 7000 people in Georgia and have about 30 manufacturing plants, mostly located in the southeastern United States.

We are a Georgia Power RTP customer, we have interruptible service and firm service. The RTP rate is not competitive with our plants in Alabama, Georgia, Oklahoma or South Carolina. Our RTP-served plants averaged well over four cents for the last two years; first was 3.3 in South Carolina; 2.6 cents in Alabama; 3.2 cents in Oklahoma; 3.1 cents in Dalton, Georgia.

When we respond to high prices, we shut down our equipment and send people home. This represents a loss of income for Georgia residents.

The carpet manufacturing business has a low profit margin due to its extreme competitiveness. It's in a consolidation phase and we have closed plants and relocated operations and will do so in the future when required.

Power cost is very important to us and we track it very closely. We keep spreadsheets of all our power expenditures for all our locations, all our facilities, compare it weekly. Future investments will tend to go to locations with lower operating costs, that must result in loss of jobs in Georgia when power rates stay high.

That's all I had prepared.

CHAIRMAN DURDEN: Does any party have any questions?

MR. GREENE: No questions.

MS. HOLLEY: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MS. HOLLEY:

Q Do any of the 30 plants have a higher rate than the RTP Georgia average?

A I don't understand your question.

Q Any of the plants in other locations. You mentioned plants in Alabama, Oklahoma and South Carolina.

A I have no plants in Alabama, South Carolina that have higher rates. I do have one in Oklahoma that's higher rates.

Q Okay.

A I do have plants in Georgia that have higher rates than RTP.

Q And are there any plans to relocate those plants where the rates are higher?

A I can't disclose at this time whatever the plans are, but I can tell you that we have moved locations out of two locations that came with an acquisition, with Columbus Mills acquisition, and we have moved those operations. We have also made recently a decision to invest in Alabama and expand facilities there versus Georgia and there's as recent as '94 where we went through very extensive comparison process, including power costs, and looked at several Georgia locations and we decided to build the new plant in South Carolina that currently uses probably about 16

megawatts of power.

MS. HOLLEY: Thank you.

CHAIRMAN DURDEN: Does any other party have any questions?

(No response.)

CHAIRMAN DURDEN: Does any Commissioner have questions?

(No response.)

CHAIRMAN DURDEN: Okay, thank you, Mr. Theys.

THE WITNESS: Thank you.

(Witness excused.)

CHAIRMAN DURDEN: Mr. Mark Jarrell.

Whereupon,

MARK JARRELL

appeared as a public witness herein, and having been first duly sworn, was examined and testified as follows:

CHAIRMAN DURDEN: You've already been sworn, so your testimony is under oath, Mr. Jarrell.

THE WITNESS: Yes, sir.

DIRECT TESTIMONY

THE WITNESS: Commissioners, my name is Mark Jarrell, I'm a Vice President at Swift Denim and I represent Swift Denim in Columbus and our parent company, Gailey & Lord, who has a plant near Rome. In Georgia we employ over 2000 people.

Our companies use RTP rates at three southeastern investor-owned utilities. Up until 1997, Georgia Power's RTP rates were essentially competitive with those of other utilities in the southeast. Since 1997, in the last two years, Georgia Power's RTP rates have increased substantially each year, making them more and more uncompetitive. Georgia Power's base rates were already not the lowest in the region, so the uncompetitiveness is compounded upon.

I'm here today supporting the proposed remedies that GTMA and GIG have put forward in their petition, which can partially offset the increases we've seen in the last two years in RTP rates.

I did want to comment on the economic and business difficulties of making the decision to respond to exceptionally high RTP rate hours. Our plants can't automatically respond when the prices become high. We operate 24 hours, seven days a week and all of our production is scheduled for specific customers. Any interruption to our schedule will mean delays in deliveries to customers. We have to weigh that against the severe economic impact of high rates when those periods do occur.

As a customer of Georgia Power, we can't walk away from Georgia Power and go across the state line to get competitive rates, but our customers, if we do not make them

happy, can walk away from us.

I might note as well that when we do have to interrupt for high RTP rates, our employees go unpaid for those hours and there's no chance on our seven-day schedule, for them to make that up.

Our main concern is not with making these difficult business decisions because we have to make those on many issues. Our concern is that for the last two years, we've seen RTP rates increasing every month of the year, escalating, so that the average has gone up substantially during a time when Georgia Power has been making profits way beyond their top end of their regulated rate of return. Georgia Power has offered some RTP alternatives, they've all been described to us as revenue-neutral. Frankly, we're not interested in looking at a revenue neutral alternative. We'd certainly be glad to consider some alternatives that could save us revenue.

Commissioners, we appreciate the time you've taken to hear our comments.

COMMISSIONER WISE: Were the offerings that they made or the proposal that they made that you declared revenue neutral, would they have lowered your RTP rate?

THE WITNESS: No. My understanding is that they would be adjusted with factors so that they would be neutral. They might lower --

COMMISSIONER WISE: Well, revenue neutral means different things. To them, it means revenue neutral in the total picture.

THE WITNESS: Yes.

COMMISSIONER WISE: But if they lower your RTP rates, why are you concerned about whether they make a profit or don't make a profit or whether or not it's revenue neutral?

THE WITNESS: My understanding is that in our specific case, it would be neutral for us.

COMMISSIONER WISE: I see, thank you. I thought -- when I hear the term revenue neutral, I see it as Georgia Power-wide, not Swift Denim-wide.

THE WITNESS: I may be mistaken but that's my understanding.

COMMISSIONER WISE: All right. You mentioned two other investor-owned utilities that Swift does business with in the southeast.

THE WITNESS: Yes.

COMMISSIONER WISE: Are they part of the Southern Company system?

THE WITNESS: No, they are not, they are both in the Carolinas.

COMMISSIONER WISE: Representatives of the company I'm sure call on you -- Georgia Power being the company.

THE WITNESS: Yes.

COMMISSIONER WISE: Why do they tell you that you're paying a higher rate for RTP than these other IOUs?

THE WITNESS: Commissioner, I'm not an expert in that area, I can --

COMMISSIONER WISE: Well, you know, I'm not either.

THE WITNESS: I can reflect on arguments that I've understood about the weather in the last two years, but also about the decreasing margin of generation capacity to serve customers in Georgia.

COMMISSIONER WISE: But you know, again, isn't that happening all over the country, that margins and reserves are less?

THE WITNESS: Not to the point, with these other two utilities in the Carolinas, that it has gotten into regularly turning on high price generation, even in November, December and January, so that we're seeing steep escalations in RTP prices every month of the year -- no, sir, we have not seen that on the other RTP systems that we participate in.

COMMISSIONER WISE: Thank you.

VICE CHAIRMAN BURGESS: Let me ask you, so the other -- the Carolina states that you mentioned, you take service under an RTP type rate in those states -- do you

know whether or not there are key structural differences in those rates in the Carolinas versus the RTP rate that's available here in the state of Georgia?

THE WITNESS: There are some differences; yes, sir.

VICE CHAIRMAN BURGESS: Do you know what those differences are?

THE WITNESS: To say that they're key structural differences, I'm not qualified to speak to that, but they are not a major part of the RTP. The differences don't account for a major part of the RTP cost, the major part is the energy piece, which is calculated I believe similarly in all three cases.

COMMISSIONER WISE: Mr. Jarrell, could you provide us something for -- to help us in looking at this, could you provide us information about pricing and times of years both with these other two --

THE WITNESS: Commissioner, I do not have it today and I'm not sure with the confidentiality agreements with those utilities, to what degree I would be able to do that.

COMMISSIONER WISE: Okay.

MR. HAWES: If I could mention, they have confidentiality agreements with each of the utilities. If there is something they can provide regarding theirs, we would provide it under trade secret only to the Commission,

I think would be the appropriate way, but they'll have to check --

COMMISSIONER WISE: And that's certainly what I'm interested in, Mr. Hawes, so that our staff can look at it and review it as it impacts the customers in the state of Georgia as opposed to, say, somebody in North or South Carolina or Alabama, Mississippi. I'm interested in that, and Mr. Jarrell, if you can do that with consultation with Mr. Hawes and under trade secret and divulged only to staff --

THE WITNESS: I'll investigate whether we can do that and if we can, we'd be glad to, Commissioner.

COMMISSIONER WISE: Thank you.

CHAIRMAN DURDEN: Any other questions from any party or any Commissioner?

COMMISSIONER BAKER: Mr. Jarrell, how many hours or days last year did Swift have to go off system because of the high electric prices?

THE WITNESS: Of our two plants, only one was able to go off during the extremely high RTP price hours, the other one's full schedule didn't allow it to. And I believe on three separate occasions for a different number of hours, something on the order of four plus hours each time, we did go -- we shut down our facility. We're not able to take off a little bit of load. It's kind of like being a little bit

pregnant. We're very tightly balanced in the plant, so if we shut down, all of our production is affected.

COMMISSIONER BAKER: Have you ever explored with Georgia Power getting a firm rate for your plants?

THE WITNESS: No, sir.

CHAIRMAN DURDEN: Any party have any questions?

(No response.)

CHAIRMAN DURDEN: Any other Commissioner have any questions?

(No response.)

CHAIRMAN DURDEN: Okay, thank you, Mr. Jarrell.

THE WITNESS: Thank you.

(Witness excused.)

CHAIRMAN DURDEN: Now Mr. Hawes, you are ready to call your first regular witness, right?

MR. HAWES: We have one other, Mr. Stewart, I believe, Mr. Chairman.

CHAIRMAN DURDEN: Okay, Mr. Stewart -- my mistake.

Whereupon,

HENRY STEWART

appeared as a public witness herein, and having been first duly sworn, was examined and testified as follows:

DIRECT TESTIMONY

THE WITNESS: Thank you. My name is Henry Stewart, I work with J.M. Huber Corporation. We employ in

excess of 1000 people in the state of Georgia. We have about nine operational facilities in Georgia. We operate seven manufacturing facilities out of the state of Georgia. Within Georgia, we mine and process kaolin clay, calcium carbonate, we process aluminum trihydrate and we have an oriented strand board plant in Commerce, Georgia. Our plants are located primarily in what I would consider to be economically depressed counties such as Twiggs and Wilkinson Counties. These companies represent by far the better jobs in these counties.

We have to operate these plants where these minerals are located, we don't have the option of just going somewhere else where maybe we can find a cheaper rate. The kaolin is in central Georgia and that's where we have to operate. And if we get hit with higher costs such as higher energy costs, sometimes what we're having to do is simply lay people off, and in these economically depressed counties, if they lose a job with one of the clay companies, sometimes their livelihood will never recover.

We've taken advantage of every opportunity that we know of that Georgia Power has offered us to save money. We went on supplemental energy, we've been on real time pricing, are on real time pricing day ahead, time of use, multiple load management. We've put in 12 megawatts of generation. When we talk about high price signals, we start

turning our generators on at sometimes less than seven cents, but at seven cents, every generator we've got is on. We start getting prices hitting a dollar, we have to send people home. We shut down as much as we possibly can and it does work a hardship on us. But doing everything we've done in the last two years, our cost of electricity has still increased by 20 percent.

I heard a lot of discussion about the -- you know, what does power cost in different states, but the bottom line is that if your costs go up four-tenths of a cent, our weighted average cost per kilowatt hour, goes up four-tenths of a cent, that represents over a million dollar hit to the bottom line for our company. It's a huge number.

If your rate was 2.8 -- our rates were sometimes less than three cents a kilowatt hour. It's a great rate, I don't deny that. But now when this rate goes up to 3.3 and 3.4 over what you've been accustomed to paying, it represents a substantial hit to our bottom line and that's what concerns us.

I'm not going to argue with you about the rates in Georgia as much as I am about what the increase has done to us. Electricity in our industry represents about eight percent of our cost.

That's it.

CHAIRMAN DURDEN: Any Commissioners have any

questions?

(No response.)

MR. GREENE: Mr. Chairman, I have one.

CHAIRMAN DURDEN: Hold on just a second, Mr. Greene.

Okay, go ahead, Mr. Greene.

CROSS EXAMINATION

BY MR. GREENE:

Q Mr. Stewart, would you agree with me that the average kilowatt hour cost for J.M. Huber plants is lower today than it was in 1991?

A I can't answer that because I only took this over in 1994. I can't speak to that.

MR. GREENE: Thank you, that's all I have.

CHAIRMAN DURDEN: Does any other party have any questions? Mr. Walsh.

MR. WALSH: Thank you, Mr. Chairman.

FURTHER CROSS EXAMINATION

BY MR. WALSH:

Q Are you an IS customer, interruptible service tariff -- are you on Georgia Power Company's --

A No.

Q You're not?

A No.

MR. WALSH: Okay, thank you.

CHAIRMAN DURDEN: Any other questions?

(No response.)

CHAIRMAN DURDEN: Okay, thank you, sir, you can step down.

THE WITNESS: Thank you.

(Witness excused.)

CHAIRMAN DURDEN: Now, Mr. Quintrell or Mr. Hawes --

MR. HAWES: Thank you, Mr. Chairman. Just a couple of preliminary matters before the first witness is called.

One of the things that has been troubling is we need a fast schedule, which this Commission has accommodated in moving from testimony, brief, to decision and we appreciate that. What we'd like to ask is that if, prior to the decision, this Commission could allow us to try to pull this together with an oral argument of no more than a total amount of an hour for both sides, so that we could at least bring these issues and these points together in that forum. It's something I think has been done some with this Commission and it's something we would suggest ought to be done in this case.

CHAIRMAN DURDEN: I'll tell you what, I'm going to take that under advisement and let you know tomorrow or later this afternoon after I've had a chance to think about

it and discuss it with other Commissioners.

MR. HAWES: All right, sir. And there's one other matter that we'd like to address.

That is we -- staff filed a document request that was not responded to, that was asked for by I guess yesterday. We'd like to I guess find out if the company intends to respond to it and if not, if the Commission would entertain a subpoena for production of these by the end of the day today or tomorrow morning. It's workpapers supporting one of the contentions in their testimony.

MR. GREENE: It was filed.

MR. HAWES: We did not understand it had been filed. It has been filed?

MR. GREENE: It has been filed.

MR. HAWES: Okay.

MR. GREENE: I will point out that it was asked for on Thursday or Friday and we turned it around over the weekend. It's not a 30-day turnaround.

CHAIRMAN DURDEN: Okay.

MR. HAWES: It was the workpapers -- it was turned in. If it's in, fine, we'll try to get it that way.

CHAIRMAN DURDEN: Okay.

MR. QUINTRELL: Mr. Chairman, Petitioners call Mr. Jeffry Pollock.

CHAIRMAN DURDEN: You go ahead and swear him in,

Mr. Quintrell, and proceed.

Whereupon,

JEFFRY POLLOCK

appeared as a witness herein, and having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. QUINTRELL:

Q Mr. Pollock, did you prepare and have filed in this docket direct written testimony consisting of 33 pages in question and answer format, along with exhibits marked JP-1 through JP-9?

A Yes, I did, and Appendix A, also.

Q Appendix A which is your --

A Qualifications.

Q If I were to ask you here today each of the questions contained in that prefiled written testimony, would your answers be the same as contained in the written testimony?

A Essentially, yes, with a few errata.

Q Would you go through those corrections, please?

A Yes, I will. First change is on page 13 of the testimony, in three places, line 11, 13 and 19, there's a number 63 million. That should be $65 million. Again, that's on lines 11, 13 and 19. And the reason that number is changed, is because the number on line 20 which is

9,383,283 has also changed and should be 9,568,945.

Next change, on page 14, lines 1 and 2, again $63 million figure should be $65 million in both cases.

Q That's lines 1 and 2?

A That's lines 1 and 2, yes.

On page 23, line 3, reference to JP-5 should be JP-8.

Finally, page 25, in the table, two numbers need to be changed, both under scenario 2, the number that corresponds to the label Lambda Averaging, instead of 7.4 cents, should be 6.7 cents. And the Margin Above Cost, instead of 2.6 cents, should be 3.3 cents.

Finally, with respect to changes to the exhibits, my exhibits JP-4, two changes -- actually there are a number of changes that affect lines 4, 5 and 6 as well as line 8. We have, I think, an errata that will explain those changes. But essentially because of the change in sales, the number I mentioned before, going from 9,383,236 to 9,568,945, that also caused numbers in column 1 to change in lines 4, 5 and 6, with the bottom line being that line 8, the 1999 Excess Margins, increased to $64,698,617, which I rounded to $65 million.

Q Are those all you corrections?

A One more. Exhibit JP-6, line 2, Average 1998 and 1999 RTP Sales, instead of the numbers 9,100,922, again,

rippling from the previous change, should be 9,135,967.

Those numbers have only very, very minor rounding changes, the rest of the exhibit, but I would point out that on line 8, the calculation is not described correctly and line 8 should read "Line 6/Line 7".

Those are all the changes.

MR. QUINTRELL: Mr. Chairman, Petitioners move to copy Mr. Pollock's written testimony into the record subject to cross, as if it were read from the stand today.

And we also request that Exhibits JP-1 through JP-9 be labeled for purposes of the record as GIG/GTMA Exhibits 1 through 9.

CHAIRMAN DURDEN: Okay, they'll be so labeled and the testimony will be admitted, subject to cross.

(The documents referred to were marked for identification as GIG/GTMA Exhibits 1 through 9 and received in evidence.)

(Whereupon, the prefiled direct testimony of Mr. Pollock follows:)

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 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.

II. Why the Petition Was Filed

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.

II. Why the Petition Was Filed

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.

II. Why the Petition Was Filed

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~~ 65 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~~ 65 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~~ 65 million excess revenue, I multiplied the differential in the margins (0.68¢) by actual 1999 RTP sales of ~~9,383,283~~ 9,568,945 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~~ 65 MILLION OF EXCESS REVENUES IN PERSPECTIVE?**

A Yes. The ~~$63~~ 65 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).

III. The Requested Relief

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-8 (~~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.

Marginal Resources	Dispatch Cost per kWh	RTP Load (MW) Scenario 1	RTP Load (MW) 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¢~~ 6.7
Margin Above Cost		0.8¢	~~2.6¢~~ 3.3

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.

III. The Requested Relief

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.

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

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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BY MR. QUINTRELL:

Q Mr. Pollock, do you have a summary of your testimony?

A Yes, I do.

MR. QUINTRELL: Before you start that, let me -- we have compiled copies, Mr. Chairman, of the errata sheets and some of the exhibits that Mr. Pollock will use in his testimony, in the summary of his testimony. These are for the Commission to follow. We would like for this to be entered into the record as GTMA/GIG Exhibit 14.

CHAIRMAN DURDEN: Okay, you're moving its admission?

MR. QUINTRELL: Subject to cross.

CHAIRMAN DURDEN: Okay, any objection?

MR. GREENE: I haven't seen it yet.

(The document referred to was marked for identification as GIG/GTMA Exhibit Number 14.)

CHAIRMAN DURDEN: Let me ask you, Mr. Pollock, do you anticipate your summary is going to run more than five minutes?

THE WITNESS: Yes, sir.

CHAIRMAN DURDEN: Then I have a suggestion. I suggest, since we had planned to break for lunch at 12:30 and it is now 12:25, that we break for lunch at 12:25 and

come back at 1:25 and resume.

And I would encourage, Mr. Pollock, during that time that you consider ways to make your summary even more brief than it may be at this point.

THE WITNESS: Yes, sir.

CHAIRMAN DURDEN: Let me go ahead and rule on -- Do you have any objection, Mr. Greene, or does anybody have any objection to the admission of Exhibit Number 14?

MR. GREENE: No objection.

CHAIRMAN DURDEN: Okay, it's admitted subject to cross.

(The document marked as GTMA/GIG Exhibit No. 14 was received into evidence.)

CHAIRMAN DURDEN: And we are in recess until 1:25.

(Whereupon, a luncheon recess was taken.)

AFTERNOON SESSION

CHAIRMAN DURDEN: This hearing of the Georgia Public Service Commission in Docket Number 11708-U will now reconvene.

Mr. Pollock, you were in the process of getting ready to give us your summary, I believe.

THE WITNESS: Yes, sir.

CHAIRMAN DURDEN: So would you proceed, please, sir?

THE WITNESS: Thank you, Commissioners. GTMA and GIG appreciate your valuable time and your consideration of this very important petition, the serious economic consequences of this rate on companies that form the backbone of Georgia's economy. This matter is so important that many GTMA and GIG members have taken time from their busy schedules to attend these hearings.

What I am going to summarize is basically what this petition is all about and also what it is not about, describe the relief the GTMA and GIG are requesting from you, and provide the supporting evidence and why it is so important for you to act now to grant the requested relief, and why granting the request for relief will not violate the accounting order that you approved 16 months ago.

So, first, what is this petition all about. Simply put RTP is no longer a cost based rate. Cost based

means a rate that recovers operating expenses, provides a return of and a return on investment. The return on investment includes profit. In this case RTP customers are paying more than their fair share of the cost that RTP was designed to recover, which include incremental generation costs, which I will refer to as system lambda, and during certain hours the cost of reliability and congestion are added to the price, plus there is a profit, the purpose of which is to help lower the rates charged to other non-RTP customers.

As can be seen in exhibit 6, which is up on the view screen right now, what we are comparing to show that RTP is no longer a cost base rate is the production investment or capital supported by the margins or base revenues derived from RTP sales with the corresponding capital or average production investment of Georgia Power Company. These margins, as I call them, are really no different than how Georgia Power defines its base revenues, which is simply the difference between RTP revenues and the fuel cost rate. Thus, the analysis is designed to measure the capital contribution.

As can be seen in the chart, Georgia Power's net production plant investment is about $340 of kW as of the end of '98. If RTP was cost based, then the margin or the capital recovered from RTP would not be higher than this

number, but as you can see from the lines above, the capital contribution of RTP customers in total are $760 of kW, that's 120 percent above cost, and if we take the adders -- which I'll talk about in a minute -- out, the number goes down to $545 a kW, a kilowatt, but it is still 60 percent above cost.

Why have I chosen this standard? Well, first, RTP was designed to recover generation cost. All overheads, distribution, other fixed costs are recovered in the CBL, which is priced under the standard rates. Secondly, overall the company's rates are designed to recover their average costs plus a profit, no more, no less. Rates should never exceed embedded costs, but as you can see from this exhibit, the capital contribution from RTP customers is well in excess of the company's embedded cost of production plant.

Now, how can this be true if RTP was originally approved as a cost based rate in 1993 and subsequently in 1995? The answer is changing circumstances. When RTP was first implemented, Georgia Power and Southern Company had plenty of cheap baseload energy. The system lambda was only 2/10ths of a cent per kilowatt hour higher than the average fuel cost. They also plan for reserves in the 15 to 20 percent range. Since then the surplus has diminished. Capacity additions southern-wide have not kept pace with the growth. The planning reserve margin dropped to 15 percent

and then the last IRP, the company tried to lower that to 13.5 percent.

Another indication of the problem is when you look at the reserve margins on a southern subregion basis, of which the Southern Company is a major part of, you can see that as the utilities have reported to the government the reserve margins are substantially below the 15 percent planning reserve that you ordered for Georgia Power and certainly below the 13.5 percent margin that the Southern Company plans for, and Southern Company is responsible for the planning. In none of the years projected for the next 10 years will those reserve margins return back to the 13.5 percent level. What that means is the region is going to have to rely on more expensive purchased power in the wholesale markets to make up the difference. In fact, the company's IRP shows system purchases for the next several years. However, since FERC Order 888 was signed in 1996 wholesale markets have become price deregulated. The effects of this price deregulation began to be felt in 1998. You saw it in the Savannah Electric fuel case a couple of years ago in which I testified about the problems raising the fuel factor from about 2.1 cents to about 2.5 cents, and Savannah is back now before you looking for a further increase to about 2.7 cents. So in the course of just two years Savannah Electric is asking for half a cent increase

in their fuel factor, which is almost 30 percent.

Alabama Power has raised their fuel rate. Mississippi Power has raised their fuel rate, and Georgia Power is certainly not immune from the higher purchased power costs, which are the primary driver.

As you can see from this graph, which is a summary of the over-under collections under the FCR balance, when we started prior to the record hot summer of 1998, the fuel balance was about 20 million dollars over-collected. In only three months that over-collection went from 20 million positive to 28 million negative with a swing of 48 million dollars. The same pattern repeated itself in 1999, only now we have a larger under-collection, about 40 million, and we're not seeing that bounce-back that we usually see in the fall months either.

So we are starting the year 2000 with basically a 40 million dollar under-collection. So in less than two years the fuel balance is swung by a total of 60 million; plus 20 to minus 40.

My testimony further demonstrates how these rising purchased power costs in 1998 and 1999 have affected real time prices. The company said to us that really these prices in 1998 were a fluke because 1998 was the sixth hottest summer on record. However, in 1999, a year which had significantly fewer degree days than 1998, real time

prices reached astronomical levels, as high as six dollars a kilowatt hour. To put that in perspective, that's 80 times what an average residential customer pays for electricity. 1999 saw the highest average monthly prices in 9 out of the 12 months since the inception of RTP in 1993. The average price of 3.6 cents a kilowatt hour was substantially above what the company had projected in the last rate case of 2.7 cents.

Next slide. The difference between the company's rate case projection and the actual incremental margins in 1999 basically have contributed $65 million, 65 million out of 105 million of over-earnings that the company has reported for 1999, as shown in my exhibit 4.

So more than 60 percent of the 105 million can be traced to changes in margins derived under RTP because of the rising prices.

So the bottom line, instead of seeing a spread of only 2/10ths of a cent between system lambda and fuel, the spread has now grown to over 2 cents a kilowatt hour.

These trends have resulted in ever increasing margins from RTP sales -- that's the next slide. And again, you can see how the margins are compared to the rate cases assumptions.

And further, skyrocketing real time prices, as the next exhibit shows, RTP customers are the only customers on

the system that have seen prices rise, which on average that rise from 93 to 97, it's an average of about 7 percent a year. However, most of the increase as you can see from the chart occurred since 1997. That's a 44 percent jump in average prices in only two years. In my view -- and I've been doing this for 25 years now, believe it or not. Forty-four percent increase in two years violates every fundamental notion of fairness that I have ever seen in utility regulation and certainly violates the longstanding principle of gradualism, which means trying to avoid increases of this magnitude to customers. When you put these increases in perspective even the company promises 3.09 cents for this year, still represents at 28 percent increase from 1997. Hardly much relief. And this is why we are here.

Our petition suggests three possible ways to restore RTP to a cost based rate that is fair, just and reasonable. First, either reduce the adders by 50 percent or eliminate them. The choice depends on what you decide about the second and third issue, which I'll cover. Presently the adders are half a cent for RTP day-ahead and .45 cents for RTP hour-ahead. Since they are added to the real time prices in every hour, they don't affect price response. To put it in perspective, when the price is 10 cents a kilowatt hour, a half a cent is less than five

percent of the total price. It has no affect on price response. While the adders did serve a purpose when system lambda was only 2/10ths of a cent above fuel in 1993, they are no longer needed to enable the company to recover its cost as I previously demonstrated in exhibit 6. Today the adders provide windfall profit to the company. We have no qualms about the company profiting from RTP. We do have qualms about windfall profits because those hurt customers and are absolutely no benefit to the customers that have experienced these substantial increases in cost. But if you don't eliminate the adders, then we suggest you change the definition or calculation of system lambda. This is what is being illustrated on the chart on the view screen now.

Under the tariff, the company marginal cost of energy is based on incremental running cost of generation. It says nothing about purchased power. But, let's look at the practices the company has.

This hypothetical example basically says, we've got 1000 megawatts of real time pricing load in a given hour, and that load is served by an array of resources that range in cost from 3 cents all the way up to 7 cents. The most expensive resource is 7 cents a kilowatt hour. What's a system lambda under than hypothetical example? The system lambda is 7 cents a kilowatt hour. That's what all RTP sales are priced in that hour, 7 cents a kilowatt hour.

What did it actually cost the company to produce the energy on the margin to serve that load? Taking a simple average I tried to make the example somewhat easy. The average cost is 5 cents a kilowatt hour. That's a 40 percent markup between the selling price and the actual cost.

Now, just imagine what would happen if you added one more kilowatt of resource on top of this curve, and it cost 10 cents a kilowatt hour? What would the system lambda be then? It would be 10 cents a kilowatt hour. The cost would be essentially 5 cents a kilowatt hour, that's a 100 percent markup. Who gets to keep the money? We believe it goes right to the shareholders.

Although this is an illustration, we found several instances when the markup between the selling price and average purchased power cost was as high as 80 percent. So it is a conservative illustration in our view. With markups this high, who can blame the company for wanting to see ever increasing prices? It's your job to prevent this and provide a surrogate for competition that doesn't allow markups of 40 to 80 percent on the selling price. Lambda averaging, which means setting the system lambda at 5 cents in this example, rather than 7 cents, would move the price closer to actual cost while still maintaining a high enough level to encourage price response, and our petition asks for averaging of the entire resource stack to serve real time

pricing customers.

At least two utilities employ some form of this averaging. So lambda averaging is still pricing at marginal cost, it's just using a different calculation.

The next point is, we believe there is a problem with the way fuel is being accounted. My exhibit 9 uses the same hypothetical example, the selling price of 7 cents, while the company incurs 5 cents; an instant profit of 2 cents a kilowatt hour. The corresponding entry, when this happens, this is a 5 cent cost, that's fuel and purchased power. A corresponding entry is made in the fuel account to reflect that 5 cent cost. However, the company doesn't book that 5 cents, that cost, as recovery of fuel. They only book 1.4 cents as fuel recovery because everything above the FCR, everything above fuel is base revenue, or margin as I define it. So as a result of this practice, out of the total selling price of 7 cents, the company gets 5.6 cents. 1.4 cents stays in the fuel, basically as a recovery of fuel. What happens to the rest? Well, there's a fuel cost that is still in the fuel cost account, and it's going to be paid by somebody, and that somebody is all the other customers that support the fuel cost rate.

Our petition recommends that you credit the actual cost, 5 cents, toward the recovery of fuel rather than 1.4 cents. This will lower the fuel cost rate, it will lower

the balance and benefit all consumers.

Fourth, the petition requests you to require the company to disclose its energy procurement practices so that both you and the customers who are directly impacted by these practices can assess their prudence, their risks, and benefits of RTP. Presently the customers have no say over the procurement decisions that drive the real time prices. In my view that's taxation without representation. That's why we are here, to be represented.

As a result, the customers, not the company, the customers are bearing most of the price risk, for higher prices generate higher profits. So where is the incentive for the company to minimize the purchased energy costs? When retail customer choice happens, customers will have the say that they deserve, but until now it's your responsibility and we are asking you to regulate these costs to ensure that they are reasonable, necessary and prudent.

Finally, what is this petition not about? It's not about re-litigating the accounting order. The accounting order addressed any number of issues, major ones being allowing the company a return of 10 percent to 12.5 percent return on equity and defining some of the specific elements of the company's cost of service. Notably, neither GTMA or GIG appealed the decision even though we felt at the time that the company would earn more than 12.5 percent and

that every customer, all loads, all rates, should have been entitled to share in the rate reduction. Given that RTP is now contributing 60 percent of the current over-earnings, we would hope that you would allow these customers to share some of the benefits that they played a major role in creating.

But the accounting order did not address rate design. That's why we are here. We are here talking to you about the rate design associated with RTP. None of the things we've asked you, we believe, will violate the accounting order. We don't think the company's earnings will be affected much at all. Certainly not impair their ability to earn within the range that you authorized in the accounting order, and further we would remind you about the specific statement in that order that says, the Commission retains its jurisdiction to ensure that the company's rates are fair, just and reasonable. This obligation is not superseded by the accounting order.

The evidence that we've presented that I have shown you so far demonstrates that RTP is no longer fair, just and reasonable rates. The Commission must act now to restore this rate to a more competitive level, otherwise customers will have to wait until January 2002, at the earliest, to see any relief. That's too long for businesses and industries that are judged every quarter for their

performance. RTP has been an effective way to provide access to competitively priced electricity, but remember, the RTP prices only apply to about 34 percent of the total energy purchased by RTP customers. The rest is driven by the standard tariffs, which as you can see from my exhibit, in the case of Georgia Power, standard rates have ranked and continue to rank in the top third, being the most expensive industrial standard rates in the southeast.

Absent competitive prices under a cost based RTP, the company cannot provide the competitively priced electricity that customers, particularly GTMA and GIG members, need in order to remain viable.

GTMA and GIG members face every increasing global and domestic competition. Electricity is also a significant operating cost as you have heard here today. Thus your decision on this petition will have important ramifications on the economy of the State. Thank you.

CHAIRMAN DURDEN: Mr. Hawes, are you tendering him for cross -- Mr. Quintrell?

MR. QUINTRELL: Yes, he's ready for cross.

CHAIRMAN DURDEN: Mr. Greene.

MR. GREENE: Thank you, Mr. Chairman.

COMMISSIONER WISE: Before he starts --

CHAIRMAN DURDEN: Okay, hold on just a minute, Commissioner Wise has some questions.

COMMISSIONER WISE: Mr. Pollock, you talked about customer influence in the procurement. Isn't that the company's job?

THE WITNESS: It definitely is, but they don't have any say over how well the company does its job. And that's why we think the Commission should have a say to make sure that the company is doing an appropriate job.

COMMISSIONER WISE: So you're asking for -- when you make your comment about taxation without representation, you weren't implying that the Commission wasn't representing all consumers in the state, were you?

THE WITNESS: Not at all. We're asking the Commission to develop a tool to ensure that those costs are reasonable and necessary.

COMMISSIONER WISE: If you take the adders out, as you showed in your slide, what happens? What happens to the company, what happens to the other customers in the state? Certainly you comment about rate design, but rate design was built around those adders as well, so whether you like them, we like them, anybody likes them, that's how the rates were built. And so I wonder -- you know, certainly it behooves the large industrial and textile customers to take those adders out, but what does it do to the residential and commercial customers in the state?

THE WITNESS: That's a good question, and the

adders, as I said, did serve a purpose before, when the spread between system lambda and average fuel was very small. You take the adders out now, the company still generates I think more than enough capital contribution to support the rate. The adders generate about $45 million a year, basically in revenues, and that goes up as the RTP sales go up. How that translates into the company's bottom line is really going to be one of a whole host of things that will affect -- I mean, we're talking less than two percent of their base revenues. So whether or not that affects their future earnings, you know, nobody can really say for sure.

Now how does that reflect on other customers? To the extent that the company is earning within its allowed range anyway, it has no effect on other customers, except the ones that are directly impacted by RTP.

COMMISSIONER WISE: And I understand your point about the top of the lambda and how the seven cents comes in there. I still think that's how the rates were built, but your comment about that it goes directly -- the profits from that go directly to the shareholder -- doesn't under the accounting order -- aren't we seeing $70 million go back to ratepayers this summer?

THE WITNESS: Yes, you are.

COMMISSIONER WISE: So it's not really going to

the shareholders -- under the sharing arrangement, a portion goes to the shareholders.

THE WITNESS: That's correct. And to the extent they're over 12.5 percent, there's a sharing that goes on.

COMMISSIONER WISE: And $70 million of it goes back to ratepayers.

THE WITNESS: Yes.

COMMISSIONER WISE: I would have liked to have heard the whole story, not just the part where it goes back to the shareholders.

THE WITNESS: Of course, let me also tell you that none of this relief will affect the $70 million that goes back to all customers. So we're not asking you to apply this retroactively.

COMMISSIONER WISE: Again, -- and I asked some of the public witnesses this -- I understand the competitive arena and it's not Georgia versus Alabama or Georgia versus South Carolina. But I understand in these companies that they have other divisions that are in South Carolina and Alabama and if they're paying less for electric, that means their socks are cheaper, if they're paying a third or even 10 percent less, and electricity is a big part of whatever they're making.

So I mean what is your understanding on how Alabama could be charging less for electricity under these

types of rates or South Carolina does and not in Georgia?

THE WITNESS: That's a good question. Each utility has different costs and the rates, we hope, are trying to reflect what those costs actually are.

COMMISSIONER WISE: Does it go back to rate design?

THE WITNESS: In part, it goes back to rate design; I think also probably in major part, it's attributable to the cost structure of those other utilities. Alabama Power has got a lower cost structure than Georgia Power and that just is a fact. So their costs, therefore their rates, since rates follow costs, their costs are going to be lower.

COMMISSIONER WISE: Might it be subsidy from 100 years of regulation?

THE WITNESS: Subsidy to whom?

COMMISSIONER WISE: Residential.

THE WITNESS: Well that would tend to keep the rates above the costs and so, if for example, Alabama is charging three cents a kilowatt hour --

COMMISSIONER WISE: But if residential consumers in this state are subsidized --

THE WITNESS: Yes.

COMMISSIONER WISE: -- who would subsidize them?

THE WITNESS: Everybody else, by definition.

COMMISSIONER WISE: Yeah. So maybe that's how rate design gets done over time.

THE WITNESS: And in fact there are -- in Alabama, I know for sure there are subsidies that are going on, but even with those subsidies, the industrial rates in Alabama are less expensive than they are here in Georgia.

COMMISSIONER WISE: I didn't understand your testimony on the CBL and its relationship to RTP and that RTP basically is just the cost of the electricity and the CBL would be the profit part of that. Help me understand that.

THE WITNESS: There actually is profit in both elements, but let me separate them. The CBL is basically -- that's the baseline. That baseline load, those kilowatt hours are priced under the standard rates. The standard rates are designed to recover all of the company's costs of service -- generation, transmission, distribution, overheads and profit. Everything differentiating from the CBL, the RTP portion of the load, of the sales, is priced to reflect incremental generation costs. That's what the rate was designed to do, reflect incremental generation costs. There are no overheads reflected in that price --

COMMISSIONER WISE: So you're saying that the profit portion of that then has been increased beyond what it should be in the RTP rates?

THE WITNESS: Yes, because of the spread between lambda and average fuel, that generates more than enough profit from the rate, more than enough capital contribution from RTP sales, that you don't have to have the adder in order to make that profit.

COMMISSIONER WISE: So if that adder goes away, it goes back to what I asked earlier --

THE WITNESS: Yes.

COMMISSIONER WISE: -- who pays, shareholders or customers?

THE WITNESS: All other things equal, that could reflect a lower earnings for the shareholders. Whether that affects customers really depends on what earnings level the company is at in this year.

COMMISSIONER WISE: But if that last adder goes away and it takes it back to five, won't the residential and commercial customers in this state pay as well?

THE WITNESS: I don't see how, because all we're doing is basically taking a rate that is over-earning and bringing it more in line with the actual cost.

COMMISSIONER WISE: All right, that's all.

COMMISSIONER McDONALD: It would have an effect though on the over-earnings that were earned; i.e., in your comments, that were earned from RTP pricing, is that true?

THE WITNESS: Ultimately, if the company is

earning more than a 12.5 percent return plus $50 million this year, and you make this adjustment, and as a result, they're earning now 12.5 percent, then there's less over-earnings and less money that would come back to everybody.

COMMISSIONER McDONALD: So you kind of focused the over-earnings on the RTP pricing.

THE WITNESS: For 1999.

COMMISSIONER McDONALD: For 1999.

THE WITNESS: Right. Because there's a large increase in the assumptions that were built into the rates. We acknowledge the RTP revenues and the margins were an important factor in determining the company's cost of service and willingness to sell on the accounting order, but when you set that as a baseline and compare what's actually happened in '99 from that baseline, that's a $65 million swing, caused solely by RTP sales and by the widening profit between lambda and average. In other words, but for that increase in real time prices, the company's earnings would be about $65 million less in 1999.

CHAIRMAN DURDEN: Mr. Greene.

MR. GREENE: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. GREENE:

Q Mr. Pollock, on page 3 of your direct testimony, you identify three problems that you find with the RTP rate,

is that correct?

A Yes.

Q And on lines 4 and 5, you express concerns about the competitiveness of the rate, is that correct?

A Yes.

Q And I think on page 4 when you're discussing that a little bit further, you reference Exhibit JP-1, which sets forth various rate comparisons between Georgia Power Company's rates and other utilities generally in the southeast.

A Yes, the concern on page 3 was about the overall competitiveness of the company's rates and then the comparison is based on the standard rates.

Q Okay. JP-1 compares rates in 1998, 1999 and 2000, is that correct?

A Yes.

Q And the comparisons for 1999 and 1998 are for customers with a 68 percent load factor?

A That's correct.

Q Now the average load factor for RTP HA customers is about at 68 percent, is that correct?

A I don't know.

Q Okay. Do you know that the average load factor for RTP day ahead is closer to 50 percent?

A I don't know that either.

Q All right, you don't present rate comparisons for 50 percent load factor customers, do you?

A I have not.

Q And the comparisons for 2000 are for 90 percent load factors, isn't that right?

A Yes.

Q And again, we don't know what those comparisons would be for 68 percent load factors or 50 percent load factor customers in Georgia as opposed to other jurisdictions, do we?

A No, no. Since EEI hasn't issued the January survey, we don't know.

COMMISSIONER WISE: Mr. Greene, if I can, I want to ask Mr. Pollock, what's the impact of load factors then.

THE WITNESS: What load factor does is it -- the higher the load factor, the lower the average cost per kilowatt hour. So if we were to go back and take the comparisons on JP-1 and restate them at say a 50 percent load factor rather than 68 percent load factor, then all the bars would go up because you're taking the same amount of fixed costs and dividing them by a fewer number of kilowatt hours. That's what load factor basically means. So all you're going to do is raise all the bars.

COMMISSIONER WISE: And everybody's load factor is different.

THE WITNESS: That's right.

BY MR. GREENE:

Q So everybody's rate comparison is different.

A Each customer has its own average rate based upon its characteristics, its cost characteristics, load factor being one of several characteristics that determine what that average rate is.

Q And different utilities have different rates that affect different load factors differently, isn't that right?

A I would say they have different rates, yes.

Q Okay.

A And comparisons at different load factors might vary somewhat from what we've seen. That's why I've tried to present a broad enough range from 68 percent to 90 percent as an indication of whether or not that would change the company's ranking in either comparison.

Q Well, you didn't just differ between 68 and 90 percent, you also changed the years between -- within JP-1, didn't you?

A Yes.

Q Okay. Now none of these rate comparisons include the effects of RTP rates, do they?

A That's true in every case for every utility, even the ones that have RTP rates, that's not reflected in the comparisons.

Q And this is about the RTP rates, this case, right?

A This is about the overall competitiveness of the company's rates of which RTP is an important component of the overall competitiveness. As I said in my summary, about 34 percent of the sales to RTP customers are actually on the RTP rate, the rest is at the baseline which is priced at the standard rates.

COMMISSIONER WISE: Do we have more customers in this state that are eligible or participate under RTP than maybe customers in other states?

THE WITNESS: I'd say that's correct, you do, because the minimum qualification for RTP is very -- I think it's among the lowest threshold in the country that I'm aware of.

COMMISSIONER WISE: Does that perhaps impact the way pricing is done?

THE WITNESS: It only affects it in the sense that it gives access to price risk or lower prices for a broader array of customers than is the case for other utilities.

COMMISSIONER WISE: So somebody that may not be appropriate for RTP rates is tickled to death to be on it, but it might not be something that pleases the five or six energy buyers that we heard from this morning.

THE WITNESS: I don't know what pleases them other than lower costs.

COMMISSIONER WISE: I understand that.

(Laughter.)

THE WITNESS: Yes, so do I.

BY MR. GREENE:

Q Mr. Pollock, wouldn't you agree that Georgia Power Company has more customers on RTP than all other utilities combined?

COMMISSIONER WISE: Ask that question again.

BY MR. GREENE:

Q Would you agree that Georgia Power Company has more customers on RTP than all other utilities combined?

A I don't know that.

Q You wouldn't be surprised to know that though, would you?

A I suppose it would be no great surprise.

CHAIRMAN DURDEN: All other utilities in the southeast, all other utilities in the United States or all other utilities in the world?

MR. GREENE: In the United States.

CHAIRMAN DURDEN: In the whole country.

MR. GREENE: Yes.

THE WITNESS: And I think too that we're talking about RTP tariffs. Now remember that several states have now moved to customer choice and in fact all customers that are in customer choice are going to see rates that vary with

the market. So if that's functionally equivalent to RTP, then that statement is probably not the case.

BY MR. GREENE:

Q Mr. Pollock, we don't know what your JP-1 would show specifically with regard to these comparisons if we did comparisons that included RTP rates and used load factors comparable to the HA and the DA load factors, do we?

A No.

Q Okay. Now the staff has asked a data request asking for supporting data to this exhibit and asked you to compare prices paid by GIG and GTMA members in Georgia as opposed to prices paid in other states, is that correct?

A Yes, we received a data request of that kind.

Q All right, you received that on March 13, is that correct?

A I don't recall the date, but it was in March.

Q Have you answered that data request yet?

A No, because we don't know where all the GIG/GTMA members buy electricity from.

Q Well, they're your customers and your clients, aren't they?

A Well, they are for Georgia Power matters, that's true. And some clients I even represent in other states, but we don't have an exhaustive record of their costs in other states.

Q Well, when you say we don't, do you mean you as BAI don't, or we don't as in the group of GIG and GTMA customers?

A BAI does not have exhaustive records of every member, where they buy electricity from, from different utilities other than Georgia Power Company. Now there are some exceptions, but the rule is we don't have that data for any of the members for other utilities.

Q Have you asked the GIG and GTMA members for that information?

A Kind of funny you ask, we asked them to get information for Georgia Power and we have difficulty getting that information; but no, we did not specifically ask them to provide that information because they don't have to. They don't have to provide that information to us.

Q To --

A To BAI.

Q Okay. Is that to suggest that perhaps GIG and GTMA may not answer that data request fully and completely?

A I think the answer is we simply don't have the data to answer the questions.

Q Again, we as --

A BAI does not have the ability or the data -- or the ability to collect or coerce the data from the customers in order to come up with the numbers.

MR. QUINTRELL: Mr. Chairman, let me interject, I think it's only fair that it be stated on the record that the staff's data request asked for a response by April 12 and it's April 4 today.

BY MR. GREENE:

Q Mr. Pollock, you don't know whether that's going to be answered or not?

A I'll make the bold statement and say I don't think we can answer the question because there's no way humanly possible that we can collect all the information to do that, and there's no way that the customers are going to want to divulge that information.

Q I thought one of the premises of your testimony was that the RTP rates and the rates in general in Georgia were not competitive for GIG and GTMA members when you compare what they can buy in other states.

A That's true.

Q And now you're telling us that you don't have that information and can't coerce that information from your clients, and may not be able to give that information to us.

A Well, we presented the information in a different form. We've looked at the other rates that the other utilities are charging. You've heard testimony from a number of the clients today that says that their Georgia plants are paying more per kilowatt hour than plants in

other places.

Q Now these rate comparisons on JP-1 don't include the 5.75 percent rate reductions that the Commission ordered in the 1998 rate case either, do they?

A The '98 ones don't because the increase didn't go into effect until January '99. If the company reflected those numbers in its filing with Edison Electric Institute, then the '99 numbers should reflect that reduction and I'm certain the 2000 numbers do reflect that decrease.

Q You're certain that it does?

A Yes.

Q How are you certain of that?

A When we do the surveys, we call each utility and make sure that we have current rates in effect, including any riders. In the case of Georgia Power, my staff determined that there was a rider, the 5.75 percent reduction that you approved, and made sure that that reduction was taken into account in coming up with the cost.

Q Does it include the -- so you're speaking of the 2000, page 3 of 3, in JP-1.

A That's right.

Q Does that include the $79 million rate credits which customers will receive pursuant to the accounting order in 2000?

A No, because they haven't received them yet, as of

January 1.

Q Now the reason I asked all these questions about your comparisons is because you seem to suggest that Georgia Power Company's rates, whether including RTP or not including RTP over the past two years, have put some of your clients in jeopardy in terms of their national and international competitiveness. Do you think that's true?

A That's what I'm hearing from the clients.

Q Okay. Are you hearing that from GTMA?

A Yes.

Q Now what I'd like to show you right here is an exhibit I'd like to have marked as Georgia Power Company Exhibit 1 and I will represent to you that it is a letter to the editor which appeared in the March 16, 2000 Atlanta Journal-Constitution. I have the original paper here if there's any question as to where that came from. But it appears on page A-22.

Mr. Pollock, understanding that this letter was written, which is entitled "Textile Industry Still Going Strong" -- understanding that that was 10 days after you filed your direct testimony, I assume you weren't aware of this position by GTMA when you prepared your testimony, is that right?

A Yes, I was not.

(The document referred to was

marked for identification as GPC Exhibit Number 1.)

Q And you'll see that it was authored by a Ray Bowen, but because it is the President of GTMA, I assume you all can agree that it's Roy Bowen.

(Laughter.)

A Oh, yeah, we can agree on that.

CHAIRMAN DURDEN: You're not suggesting that the Atlanta Journal-Constitution might have made a mistake?

Q Well, I suspect that Mr. Bowen did sign his correct name and they typed it in wrong.

A I'm sure you can call him Ray.

Q I'm sure I won't.

Mr. Pollock, would you read this letter, please, out loud?

A Sure. [Reading] Textile Industry Still Going Strong --

MR. HAWES: Mr. Chairman, I believe he's asked him to read the excerpt of the letter printed in the paper rather than the letter.

MR. GREENE: That's fine, with that understanding, that'll do.

THE WITNESS: Okay. [Reading] We take exception to the editorial, "Big Tobacco's Welfare" March 10, which refers to the textile industry as "in decline," and suggests

that the state put greater emphasis on attracting newer high tech businesses and retaining workers for those jobs. Obviously, the editorial writers need to take another look at the textile industry, which is the largest manufacturing employer in the state, over 105,000 Georgians employed, and had record sales last year of more than $26 billion from Georgia textile and carpet manufacturers alone. The industry invests more than $700 million each year in new technology to increase productivity and improve quality. With computer-driven robots and lasers operating in the plants and computers linking the manufacturing facilities with suppliers and customers, the industry's investment in technology has made it a strong competitor in the global marketplace.

BY MR. GREENE:

Q Mr. Pollock, wouldn't you agree with me that Mr. Bowen believed what he said when he wrote this letter claiming that the Georgia textile industry in Georgia is a strong competitor in the global marketplace?

A I'll take the article at face value. I don't know what Mr. Bowen believed when he wrote the letter.

Q Let's move on to the second problem you raised with the company's RTP rates on page 3. Lines 6 and 7 of your direct testimony, you say that the RTP rates are being applied inappropriately because they include purchased power

costs.

A Yes.

Q Now when you testified in the 1998 rate case, did you raise this as an issue?

A No, as I said, rate design issues were not discussed at all in the 1998 case.

Q Well, you did advocate reductions in the RTP rate, didn't you?

A That's not really a rate design issue, that's simply a revenue distribution issue.

Q Was there anything that prevented you from bringing questions with regard to rate design into the case?

A None at all, other than the fact that the case was really about the company's earnings and the company's revenue requirements.

Q So when you tell me that rate design was not discussed in the 1998 rate case, what you're saying is is you didn't interject rate design into the discussion; isn't that a fair characterization?

A None of the parties did, as I recall. The reductions were either going to be spread across the board or were going to be spread to certain customers and not others. That's not a rate design question, it's not a rate structure question. None of the tariffs were ever changed in the last rate case.

Q Well, what prevented you from bringing that issue to the table in 1998?

A Principally because the problems associated with RTP really had not even come to the surface until after the summer of 1998 and we saw what happened to prices and then saw the summer of 1999, what happened to the prices even more so than what happened in 1998.

Q Are you telling me that you didn't know that purchased power was included in the RTP calculations until the summer of 1998?

A I'm not telling you that at all. I'm just saying it wasn't an issue that came to the surface. Given the issues that we had to address in the last case, was not an issue that we chose to pursue.

Q Now Georgia Power Company meets with GIG and GTMA several times a year to discuss many issues, including RTP, would you agree?

A Yes.

Q And you attend those meetings, don't you?

A Generally I do.

Q And I've been involved in them at least for the last six or seven years and I presume you've gone to them longer than that, is that right?

A Yes.

Q Now at any of those meetings, have you ever raised

the issue of whether or not RTP was inappropriately designed because it included purchased power costs?

A Not specifically that issue, but obviously the prices and the volatility of the prices and the level of the prices became a very important issue and was raised at a number of those meetings.

Q Now when you say on page 31, and as you just said, some of these problems didn't come to light until the summer of 1998, including purchased power in the RTP calculations was not a new problem that just came to light in 1998, was it?

A Well, since the company has been doing it all along, I take the company's testimony at face value. The real problem occurred when the cost of that purchased power exceeded even the highest cost of generation that the company incurs.

Q So it's the amount of the purchased power, not the fact that purchased power is included.

A It's clearly -- as I said in the testimony, the situation in the wholesale markets and the volatility in prices in the wholesale markets have tended to bring out problems with the rate that didn't exist until 1998 and 1999, and that problem is exacerbated by the way that purchased power affects the system lambda as I illustrated on Exhibit 8.

Q Now another problem that you point out in your testimony is the way in which the FCR is credited with average fuel for RTP hours. That wasn't a new problem beginning in 1998, was it?

A No.

Q And you talk about the adder and criticize the inclusion of the adder. That wasn't a new problem in 1998, was it?

A No. Again, all of these things have been accentuated by the dramatic increase in real time prices in '98 and '99.

Q Is it fair to say that your criticism is that the RTP prices just got too high in 1998 and it's not really that the RTP tariff is doing something inappropriate?

A Well, I think that it's a question of having the circumstances reveal a practice that heretofore we didn't feel was appropriate or inappropriate, it just simply -- the price was what it was. Now with the markets changing and particularly the price deregulation in the wholesale markets, now the way the rate works, it's charging prices that are well above the company's actual cost of service. And it's been those changes in the market, those changes in circumstances that have accentuated what I would consider flaws in the tariff.

Q That's an interesting concept that what's happened

is the deregulated wholesale marketplace is delivering a price which is higher than the regulated price the company otherwise charges, is that what's going on here?

A On occasion, it does that, yes.

Q Now --

A But the difference is at least the customers in a deregulated market can choose who they buy from. They don't have that choice now.

Q Now you would agree that sometimes purchased power costs lower your RTP price.

A Yes, it could.

Q All right. For instance, the IIC within the Southern Company oftentimes displaces native generation with cheaper generation somewhere on the system?

A Well, to the extent that that's considered purchased power. I don't think that really falls into the category that we're talking about here, because that's really just the use of native generation and a sharing of generation resources among the different Southern Companies which has been a practice at least as long as the IIC has been around.

Q Well, FERC considers it purchased power, doesn't it?

A Well, Georgia Power has to record that as purchased power for accounting purposes, but since you set

the real time price based on a Southern Company territory-wide basis, it's functionally the same as internal generation.

Q Well, what I'm trying to get at is what sorts of purchased power do you want excluded and what sorts of purchased power do you want included. Am I hearing that you want to exclude purchased power when it's too expensive, but you're okay including purchased power when it reduces the price?

A I think to the extent that it reflects the generation costs within the Southern Company system, that's fine, whether you call it -- or book it as purchased power doesn't matter. It's when you have to go outside your system because you don't have enough generation and have to pay 50 cents, a dollar, two dollars, four dollars, six dollars a kilowatt hour and pass that along in the rate that creates a problem.

Q What about back in those years when one of the things that kept RTP prices so low was purchased power from the Vogtle buybacks and the Scherer buybacks, would that have been okay to include that purchased power in RTP?

A Again, functionally speaking, those were equivalent to internal generation. You were not going outside of your system to buy power to replace generation that didn't exist.

Q What about Mid-Georgia and West Georgia PPAs, are those okay to include or should we exclude those?

A To the extent that those are certified by the Commission as resources by the company, they would be included as internal generation.

Q What about purchased power that is certified from other systems, like the Florida Power purchase?

A Possibly that too.

Q And the common thread of all those is that they reduce your RTP prices, don't they?

A Well, some of them probably increase them because some of those resources are more expensive than the average existing resources.

Q If we were to take out all purchases, spot and otherwise, over the last year, for instance, are you aware of the fact that it would have increased the RTP price 1.3 mills?

A I haven't done a study, so I don't know that.

Q I assume though that by taking out purchased power, you're okay keeping that 1.3 mills in reduced RTP price, correct?

A Like I said, I haven't done a study so I can't really comment on that.

Q Now the third problem you identified on page 3 of your testimony is that the RTP price is no longer fair, I

guess is a summary of lines 8 through 13, is that right?

A I think the summary is that it no longer reflects cost of service.

Q You did testify in the 1998 rate case.

A I did.

Q And you advocated a reduction in the RTP price in the 1998 rate case.

A I advocated a reduction to all rates and riders, including RTP, yes.

Q In the 1998 rate case, the Commission specifically said there shall be no reduction to RTP prices.

A That's what the order says, yes.

Q Now do you recall that Dr. Bowring testified on behalf of the staff in that rate case about three days before you did?

A I remember Dr. Bowring, yes.

Q And do you recall that he testified that according to his cost of service study, the industrial class was subsidized by the commercial class?

A I don't recall that specifically, but it wouldn't surprise me.

Q Would you agree, subject to check, that appears in the record transcript pages 1394 to 1396?

A I'll review the transcript.

Q And it's also his first exhibit that we spent a

lot of time talking about.

A I'm sorry?

Q It's also the first exhibit of his which was a focus of discussion during the 1998 rate case?

A Yeah, I don't recall that exhibit, so I'd have to check it.

Q Would you like to see a copy of it?

A Sure.

(A document was proffered to the witness.)

Q I'd just ask you whether that refreshes your recollection as to what that exhibit said.

(The witness reviews the document.)

A Yeah, this study shows that the residential and industrial rates are below system average rate of return based on the methodology that he employed in that case.

Q Okay. And in fact, he testified that the industrial class was further below parity than the residential class.

A That's what he testified to, yes, based on his allocation methodology.

Q And you recall that Dr. William Schaffer testified in the rate case right after you did?

A Yes.

Q And you recall he was a witness for GTMA and GIG.

A Yes, he was.

Q And do you recall that I only had one question for him in that rate case, and the question was "Dr. Schaffer, do I read your testimony correctly and conclude from it that in your opinion, the biggest impact on Georgia economy of lower rates comes when you give lower rates to residential customers and small business customers?" Do you recall that question?

A Vaguely.

Q I have a copy of the transcript if you want to check that, but will you accept it subject to check?

A I'll accept it subject to check.

Q And you recall what his answer to that question was?

A Your memory is better than mine.

Q Well, I looked at the transcript, it's not really a memory.

A Okay.

Q The transcript says, "Yes, that's right." Meaning that the biggest impact to the Georgia economy comes when you reduce residential and commercial rates. Do you recall that?

A I'll accept it subject to check if that's what the transcript says. I'm not sure he was answering the right question though.

Q In the 1998 rate case, the Commission ordered $262

million worth of rate reductions, isn't that correct?

A Yes.

Q And it reduced small business customers' rates 13.75 percent.

A Base rates, yes.

Q And it reduced them another $24 million beginning this year for a total of 16.1 percent.

A Base rates, yes.

Q And do you agree that that was one way in which the Commission could begin correcting the unfairness of the subsidies that Dr. Bowring may have found between commercial and industrial and on the other hand commercial and residential?

A Well, whatever it was, since I started testifying here, the commercial class has always been above cost of service. So it brought prices -- actually I think the rationale was to bring the commercial prices more in line with rates charged by other utilities. And I think there was evidence to support that.

Q Mr. Pollock, would you agree that all of your customers or clients; that is, all GIG and GTMA members, received at least a 5.725 percent reduction in the CBL portion of their bill?

A That's correct. That would be base rate portion. Total portion would of course be less because of fuel.

Q And you recall that pursuant to the accounting order, there will soon be refunds to all customers of about $79 million because of the earnings and revenues that came in because of the hot summer.

A Yes. We don't know how that's going to be distributed among the customers, but presumably there's a pot of dollars out there.

Q And I think you indicated in your summary that notwithstanding the dissatisfaction that GIG and GTMA has with that accounting order, you did not appeal that, did you?

A That's right.

Q Now on page 16 of your testimony, your direct testimony, you start talking about the five mill and the 4.5 mill adder, is that right?

A Yes.

Q And I think on line 12 of page 16, you say that every rate should provide some contribution to fixed costs as well as profit and that RTP is no exception.

A That's right.

Q Do you realize that when the company did its cost of service study for the 1998 rate case, it assigned no fixed costs to the RTP rate?

A The RTP class was not included as a class in the cost study, but the revenues collected from RTP, including

the five mill adder, were used to offset the revenue requirements of the other customers.

Q That's right, including the five mill adder --

A In effect, assigning five mills or assigning a certain dollar amount of fixed costs, including the difference between lambda and average costs, including that, to the RTP sales.

Q But in fact, RTP, as a rate, unlike other rates, has no fixed cost component associated with it; does it?

A No, and none should be assigned, because of the nature of the rate.

Q Well, you say that there should be some contribution to fixed costs. I suppose you do not agree with the way the company did it, which was it took the expected revenues from RTP and spread that across all other ratepayers in order to keep their rates lower.

A That's right, and that's the purpose of RTP collecting more than just the actual costs. Now the issue here is not that it should collect more than the actual cost, the issue is how much and how much is too much, and we think where it is today is too much.

Q Okay. And I think you said that as a result of the way RTP is calculated, there's some $60 million in what you characterized as excess revenues that have come in in the last summer.

A That's right. If you look at the assumptions from the rate case, just the thing that we were just talking about, and project them forward to '99 and compare them to what actually happened, which is what my Exhibit 4 does, it shows that RTP produced $65 million in excess revenues than what had been assumed in setting the rates for all the other customers.

Q And if the revenues are $120 million which are going to be split two thirds/one third, that's about half of the revenues that came in because of the hot summer, came from RTP sales.

A Yes.

Q And everybody else contributed the other half.

A Yes.

Q And all that $120 million pursuant to the accounting order is going to be split back among the customers, won't it?

A Which ones?

Q It's up to the Commission to decide that.

A That's right.

Q But at least the $79 million will be refunded to customers.

A Yes.

Q Including, I presume, GIG and GTMA customers, at least in the DBL portion of their bill.

A Again, we don't know what portion that's going to be.

Q Okay. Now when you call RTP load marginal, it's really only marginal since 1991, it's marginal for the 1991 rate case, isn't that right?

A I don't understand your question.

Q Well, there's a significant portion of RTP load which looks like firm load to the system, wouldn't you agree?

A The load looks the same regardless of what it is, the system sees a flow of power, it doesn't know whether it's RTP or any other rate.

Q Well, some RTP customers decrement their take or reduce their take given various prices, some customers don't, they just ride right on through, isn't that right?

A That's their choice, yes.

Q And so with regard to perhaps as much as half, if not more, of the RTP load, which never interrupts, that looks just like firm customers to the system, wouldn't you agree?

A It's not an interruptible service in the sense that the interruptible rate is an interruptible service, so yeah, it's a firm service. But it's a firm service that shifts a lot of the risk to customers in terms of what the prices are. So it's not really the same as standard, the

plain vanilla firm service. It's firm service but it's not a firm price.

Q You'd agree with me in concept, without regard to identifying the date, in concept at some point, marginal energy consumption becomes embedded or firm, would you agree with that?

A I don't know, I think all energy consumption that is not interruptible by the company or curtailable by the customer, that would be considered firm.

Q Okay. Now one way to have done the last rate case would have been to have taken all the energy consumption by all the customers on all the rates and divvied up the fixed costs to all those customers and had, in pure economic terms, no marginal energy taken during the test year. Wouldn't you agree that's one way to do this?

A Let me clarify what you're saying. Are you saying that what you would do is put RTP in a cost study and show it as a separate class?

Q Sure.

A And do a cost study on it?

Q Sure, that's one way to do it, isn't it?

A You could do that. I'm not sure why you would do that because RTP, unlike the other rates, is not designed to collect overhead costs.

Q Well, it's not designed to, but are you saying

that the customers who are taking on RTP, what is essentially firm power, are not placing any overhead costs on the company?

A They are, but they're recovering those costs from the CBL portion of their rate.

Q I thought the CBL portion was recovering the overheads created by the CBL portion of the rate.

A Creating the overheads that they caused the company to incur based on their load patterns before the time they got on the RTP rate.

Q Which is 1991?

A No, it could be later than that. New customers get on the rate every year. It's whatever the prior year load pattern is.

Q Well, some customers come on without establishing a prior load pattern, they're just assumed to have a certain load pattern, isn't that right?

A I think the company allows that, yes.

Q And as that RTP portion of the load goes on through the years and at some point, wouldn't you agree, that it creates overheads and that it creates distribution expenses and it creates transmission expenses?

A I think if that's the case -- and I don't agree with that, but I think if that's the case, then the rate should be redesigned to reflect those costs, if that's a

problem.

Q Or the CBL should be adjusted, right?

A You know, if the company can show that these RTP customers in total are not paying enough for their cost of service, then the rate should be redesigned. I don't think that's the case, but I think it's up to the company to come forward and modify a design if it feels it's not recovering the costs.

Q You haven't done a cost of service study with regard to the RTP rate, have you?

A Not in the traditional sense, no, because RTP is not a traditional rate. You don't have traditional firm customers whose prices fluctuate from one penny up to $6.00 a kilowatt hour. That just simply doesn't happen. A cost study doesn't reflect accurately what the cost of serving is for customers that have to bear that kind of fluctuation in their prices. And that's not the right tool, I would not use that tool, you know, to set the RTP rate. That was not the tool that was used to design RTP and it wouldn't be any more appropriate today, based on past experience.

Q Well why, on page 16 of your rebuttal testimony, do you point out the fact that Georgia Power Company hasn't done a cost of study by the RTP rate? Are you suggesting that one should be done? Stated another way, do you really want us to do one on the RTP rate?

A Well, I think the company has raised a lot of questions and we're getting into my rebuttal testimony, about oh, the adder is designed to include this cost and this cost and that cost, that are all brand new -- if the company really feels that way and they have cost evidence to show that the total costs that these customers paid, including the CBL doesn't recover this cost, this cost or that cost, then you ought to come forward with a study.

Q Mr. Pollock, you're the one that brought this petition, isn't that right?

A We did.

Q And you're the one making the allegation that it doesn't recover the costs, right?

A Yes.

Q And you haven't done a cost of service study to show that, have you?

A I did.

Q You didn't do a traditional cost of service study.

A And none is appropriate. The appropriate cost study for this case is Exhibit 6 which shows the capital contributions made by RTP customers in relation to the company's overall production capital.

Q Well, Exhibit 6 doesn't assume any distribution costs or any overhead costs or anything like that.

A None are included. RTP was not designed to

recover those rates or those kinds of costs.

Q Now the five mill adder does -- and the 4.5 mill adder -- it does contribute to fixed costs, doesn't it?

A Well, the question is how much is enough. How many fixed costs can you possibly cover, and the question is, is the coverage warranted by the costs. There's got to be a reasonable level in which you say enough is enough.

Q Okay, and enough is enough if we had taken away that five mill adder for the year 1999 -- for instance, if you had raised this issue in the 1998 rate case and it had been taken away in the 1998 rate case when rates were set, and the Commission had agreed with you that RTP rates should have been reduced, there would be now some $45 million less available for sharing to all the other customers, isn't that right?

A All other things being equal, that's correct.

Q Okay.

VICE CHAIRMAN BURGESS: Let me ask this question, Mr. Pollock. In the '98 rate case, how did you propose or did you propose how the Commission would accomplish a reduction of the RTP rate outside of some redesign of the rate?

THE WITNESS: Basically it would have been accomplished through the adders, by reducing the adders by the same base rate percentage as all the other rates. So

for example, I think we recommended about a 12 or 14 percent reduction in base rates, we would have applied that 12 to 14 percent to the adder and reduced that by that percentage.

BY MR. GREENE:

Q Mr. Pollock, on page 8 of your direct testimony -- excuse me, of your rebuttal testimony, you talk about wanting to limit the RTP price to 7.5 cents, is that right?

MR. QUINTRELL: Mr. Chairman, Mr. Pollock hasn't even presented his rebuttal testimony. This might be more appropriate if Mr. Greene has cross examination questions after he's presented that testimony.

MR. GREENE: Well, I'm trying to do this efficiently and I guess we can do it that way, although the rebuttal testimony doesn't raise any new issues with regard to anything that was raised in the direct, it's kind of just the same thing stated a different way. And all of these issues relate back and forth to each other. I won't ask this line of question again with regard to rebuttal, but I can ask it later. I'm just trying to do this efficiently.

CHAIRMAN DURDEN: Well, I think technically if he's going to object and he's going to stand on his objection, I think you're going to have to wait until rebuttal. I hate it because I think we'd probably get more accomplished doing it this way, but I'm going to sustain that objection.

MR. GREENE: Okay.

BY MR. GREENE:

Q Mr. Pollock, let's talk a little bit about the tight supplies that you think are developing in the southeast. You referenced those in your summary I think, is that right?

A Yes.

Q In fact, I think you talk about the 7.5 cents in your summary too, but I will honor the Chairman's ruling in that regard. The tight supplies that you talked about suggest that you think the Southern Company has lowered its planning reserve to 13.5 percent. You say that on page 12 of your direct testimony, is that right?

A Yes, that's my understanding.

Q Well, could your understanding be wrong?

A Sure, if you have evidence to show that it's wrong.

Q Well, the only evidence I have is the certification proceeding that just occurred, which you were an active participant in, in which the company was directed to maintain its planning reserve at 15 percent.

A Which company?

Q Georgia Power Company.

A We're talking about the Southern Company. Southern Company is responsible for the planning, not

Georgia Power Company.

Q Are you aware of the fact that in that docket, Georgia Power Company represented that Southern Company would maintain planning reserves at 15 percent?

A I don't recall.

Q Do you know as a matter of fact that Georgia Power Company doesn't maintain the 15 percent, it's the Southern Company that maintains the 15 percent?

A That's correct. That's what it should be.

Q And so that would change this analysis if you were wrong in that regard and it were true that Georgia Power Company, through the Southern Company was maintaining a 15 percent reserve.

A Regardless if it's 13.5 or 15, the point is that if you had enough generation, you wouldn't be paying purchased power prices as high as existed -- as high as occurred in 1999.

Q If you had more than 15 percent, you wouldn't have to pay as high --

A You may not have even had 15 percent in 1999, those numbers are planning reserves, we haven't looked at what the actual reserves were.

Q I understand that. You're the one that talked about planning reserves, is that right?

A That's correct.

Q Okay, so let's talk about planning reserves. If you plan to reserve more than 15 percent, it's your testimony you wouldn't need to make spot purchases as often as you do.

A That's possible.

Q Now when you plan to reserve more than 15 percent that means you build or long-term buy more than the company is doing, isn't that right?

A If you have a reserve in excess of 15 percent, like some of the other utilities do, that's right, you're going to have more assets to be able to call on and therefore, will have a natural hedge against the wholesale markets.

Q And while that has a beneficial effect on keeping RTP prices down, everybody else pays for that, don't they, through higher rates?

A I think everybody else is already paying for it right now, given where the company's earnings are, given the company's cost structure. I don't think the addition of any new capacity should cause the company to have to increase its prices, certainly not its non-fuel prices.

Q Have you done a study to see whether or not the purchases the company is making are less expensive than the installed capacity that it would otherwise make?

A The company has represented that it is able to

purchase power cheaper than what it is otherwise able to build itself, but the real analysis is what are the costs of those purchases compared to the existing resources. And if you add to your existing resources capacity that is lower in cost than what currently exists, you're going to lower your cost structure. That's what's happening with the company, the company's generation cost structure is going down because plant is being depreciated.

Q Mr. Pollock, don't we go through things called integrated resource planning and certifications to make sure that the company has the right balance to serve its customers?

A We do.

Q We don't focus on the RTP rate, do we? We focus on overall costs to customers, don't we?

A We try to. To the extent that the tools are there in the integrated resource plan case, and to the extent that parties have access to those essential tools, then that's the ultimate objective.

Q You're not suggesting that the Commission nor the staff have access or fail to have the appropriate access, are you?

A Clearly they do.

Q So you presume they're doing their job, don't you?

A I presume they are.

Q Now the same reason that you talk about having the 13.5 percent reserves or 15 percent, whatever that number ends up being, that includes MEAG and Oglethorpe and Dalton, Alabama Power, Mississippi Power, Gulf Power -- their public utility equivalents.

A Yes.

Q This Commission has no jurisdiction over them, does it?

A That's true, but the markets in the region and shortages in the southeast all depend upon what the market is, what supply and demand is region-wide. So the fact that there are low reserves in the region suggests that there are going to be times of very high wholesale prices. So if the company's capacity is not available or the company doesn't have enough capacity, same thing, they're going to pay those high prices.

Q You're not suggesting that the Georgia Power Company build or long-term buy, create a capacity in excess of 15 percent on the Georgia Power system or 14.1 percent that equates to 15 percent -- you're not suggesting that we over-build or over-buy just to keep the RTP price down because of what's going on in the wholesale markets, are you?

A I'm suggesting, and I think some utilities in Florida are now looking at the possibility of raising their

reserve margins. Now I'm not telling you that the company should build more capacity, I think there's a logical -- you have to look at that. I think the economics of building and buying need to be considered because the wholesale markets are what they are and because they sense a shortage of supply, can respond with very high prices. You need to reconsider that possibility.

Q Well, Mr. Pollock, we talk about reserve margins and certifications in IRP proceedings, don't we?

A We try to, to the extent that you have information available to be able to do that. But what you don't often talk about is what happens in the wholesale markets and I don't think the IRP, since we're looking at normal conditions, really focused on what's happened in the wholesale -- well, we haven't had an IRP -- the last one was 1998, so we really haven't looked at an IRP that focuses on what's been going on in the wholesale markets.

Q I thought we just certified less than a month ago, less than three weeks ago, the Wansley and West Georgia certifications in which we talked about the 15 percent reserve margin. You don't recall that?

A Yes, the certification; yes, that was a certification. But now we're talking about the resource plan which looks at over long term the resources needed to maintain reliability and minimize costs.

Q When the company and the staff were talking about the 15 percent reserve margin that was ordered by this Commission be maintained, did you raise any of these questions with regard to whether 15 percent was too low and it ought to be higher in order to keep RTP prices down?

A No, we agreed with the Commission's decision that approved a 15 percent reserve margin for Georgia Power Company.

Q Okay. So you could have -- you had in fact filed all of your testimony in this proceeding, hadn't you, when we were having those discussions, or you were preparing your testimony.

A In this proceeding?

Q In this proceeding, you were well down the path of knowing what the reserve margins were in the southeast, you were well down the path of knowing what impact that was going to have on RTP prices, and you didn't raise that issue when you were talking about a 15 percent reserve margin in the certification, did you?

A What issue, the 15 percent reserve margin?

Q Yes.

A Since the Commission had already approved a 15 percent reserve margin, I'm not clear what issue you're talking about that we should have raised.

Q Well, you should have raised the issue that it

should be greater -- you just went through a litany of telling me how some utilities are thinking about raising their reserve margins above 15 percent in order to keep pressure off of RTP prices, right?

A I didn't say it quite that way, I said in light of what wholesale market conditions have been, in light of other circumstances, some utilities are reconsidering whether or not their present planning reserve margin is appropriate. I don't think that's an appropriate place for a certification proceeding when we're dealing with here the resources that we've selected to meet that 15 percent criteria that had previously been approved in an IRP case.

Q Do you think it's better to raise it on page 12 of your petition for a rule nisi in an RTP challenge?

A When it affects rates, you bet it does.

Q Okay. Not in a certification proceeding when we're planning.

A Certification proceeding really does not look at what rates customers pay and whether those costs -- what those high purchased power costs do to customers.

Q Mr. Pollock, let me ask you a few questions here about the impact that RTP has on the GIG and GTMA members as a whole. Your page 8 of your testimony talks about changes in RTP prices since 1997, is that correct?

A Yes.

Q And that's shown also on your JP-2 exhibit.
A Yes.
Q Now RTP was adopted in 1992, is that right?
A The pilot program, yes.
Q Do you know what the average GIG price for energy was in 1991?
A I have no idea.
Q Would you agree, subject to check, that it was 4.54 cents?
A I have no way of checking that information.
Q So you won't agree to that, subject to check?
A If you want to show me the data, I'll be happy to check it, sure.
Q Well, GIG members are your clients, aren't they?
A Yes.
Q You could ask them what it was and aggregate that, couldn't you?
A I could.
Q So you do have a way of checking it.
A To the extent that they can uncover records from almost 10 years ago, I could, but the practicality is that the data won't be there.
Q Do you know what the average GIG price is today?
A I don't know what you mean by average GIG price because no customer pays the average price. Customers pay

their revenues -- they pay their revenues based upon prices that the company provides them. What that comes out in the form of an average cost per kilowatt hour depends upon the characteristics of the customers; the load factor, the size, the delivery voltage, the load shape, whether they're firm or interruptible and how much price risk they're willing to take. And there is no single customer that you can say represents that average characteristic because every customer is different.

Q Well, I appreciate it, Mr. Pollock, because that takes care of a lot of my questions about what is the purpose of JP-1 and JP-2, which appear to me to be average presentations of what's going on with the RTP price.

A They're simply -- JP-1 and 2? JP-1 is simply showing how Georgia Power's standard rates compare with other utilities, which determines on average two thirds of the total cost.

Q And --

A And that the purpose of RTP is to try to bring those high rates down to something that's more competitive.

Q Okay. Well, whatever averages you use to generate JP-2 and whatever averages you feel comfortable speaking about with regard to JP-1, do you know what the average GIG member pays on a cost per kilowatt hour basis, for energy today?

A The average revenue per kilowatt hour from a GIG member. That was responded to in the company's direct case.
Q I think it was 3.32 cents?
A I'll look.
Q Okay.
(The witness reviews the document.)
A That was in 1999?
Q Yes.
A Yes.
Q Okay, so between 1991 and 1999, the reduction for GIG members was 1.22 cents, is that right?
A I have no idea what the 1991 number was.
Q Okay.
A Of course, keep in mind too that all rates have gone down since then.
Q I understand.
A Base rates have gone down.
Q Do you know what the percentage decrease is between 1991, assuming it was 4.54 cents, to 3.32 cents?
A We can make a calculation.
Q Okay.
A Now we're just comparing prices per kilowatt hour, we're not taking into account changes in the quality of service, either interruptible service or price risks that the customers are doing, so all we're doing is comparing the

bare average, we're not considering how much risk the customers are bearing, either with respect to curtailments or high prices, right?

Q Right.

A Okay. I wanted to make sure that that was clear, that we're really not comparing apples and apples. But what was the number?

Q 4.54.

A And 3.32?

Q 3.32.

A That's 27 percent decrease in cost.

Q What other customers have seen a 27 percent decrease between 1991 and today?

A What other customers have experienced a quantum increase in the risk of their price for electricity?

Q I think the answer to my question, Mr. Pollock, would be none, is that right?

A None in terms of the actual price.

Q Okay.

A But if you would do a price/risk adjusted value, I don't think anybody has seen the kind of increases that RTP customers have seen.

Q Have you done a price/risk analysis?

A No, I haven't.

Q Okay. Now would you agree with me that the GTMA

average price has gone down in the same manner that we just talked about with regard to GIG since 1991?

A I have no idea. I didn't represent GTMA in 1991, so I have no idea what their average costs were.

Q And of course, these adjustments that we just talked about aren't inflation adjusted, are they?

A No.

Q So if you were to calculate in inflation, it would be a much more dramatic decrease than the 27 percent, wouldn't it?

A Certainly.

Q Now, JP-2 has no units of measure on the vertical axis, is that right?

A They're not shown.

Q Well, you show large business, small business, residential and I guess if we were to plug in the horizontal lines on the vertical axis, you're trying to show cents, is that right?

A Really trying to show changes. These are like indexes where we're basing -- the first year is like an index of 100 to measure the change from. The workpapers that I provided staff show the actual prices that went into the comparisons.

Q Well, if the average GIG rate was 3.32 cents last year on a kilowatt hour basis, would you agree with me that

the average residential rate was 7.24 cents?

A I'm not sure what the first has to do with the second, but I can calculate what the average residential rate was.

Q Okay. I'm just trying to get some sort of reference on this vertical axis on JP-2.

A Well, the vertical axis are not prices., the vertical axis represents rates of change, as I explained before. You're looking at, starting at 1993 as 100 and then equating the prices back to 1993.

Q Okay.

A So you can't actually derive prices from here, but as I said, I provided the -- will provide the workpapers to staff that shows how those numbers were developed.

CHAIRMAN DURDEN: Excuse me while Mr. Pollock is looking that up, let me do something I intended to do before we got started this afternoon and I kept waiting for an opportune moment but y'all were going at it so fast and furious -- Mr. Hawes had made a request for oral argument and I told him I would take it under advisement. I've decided that what we can do is allow both parties -- I had already announced to you five minutes -- after thinking about it, I think 10 minutes would be more appropriate -- 10 minutes following the conclusion of this hearing for each side to summarize his position. So that's what we'll do

when we get to that point.

THE WITNESS: The average residential revenue per kilowatt hour in a customer with much lower load factor, service at secondary voltage, is not at risk for interruption or at risk for price in wholesale markets, the average cost per kilowatt hour is 7.4 cents -- average revenue per kilowatt hour.

COMMISSIONER McDONALD: Residential.

THE WITNESS: Residential class only, with those characteristics.

BY MR. GREENE:

Q And you would add on top of that about 1.4 cents for fuel in order to get their full cost per kW?

A I took that from the company's operating report which I thought already had fuel built in.

Q We'll let Mr. Kubler answer that.

A That's fine.

Q I don't believe it does, but I'll let --

A I just divided one number by the other and I thought the number was total sales revenues.

Q Now when we were talking about the average GIG price, we were really talking about the average including the CBL and RTP loads combined.

A Right, you're looking at all -- a number of different characteristics among the GIG customers, not the

least of which is some that take RTP, some that take interruptible and RTP, some that buy transmission voltage, others that buy a distribution voltage, various other rates that these customers take service on, and so on, different sizes.

Q Do you know what the average RTP-HA price -- not the average -- yes -- do you know what the average RTP-HA price was in 1999?

A The average price?

Q Price paid.

A Well, okay, you're talking about if I took the average of 8760 hours of hour ahead prices or are we talking about taking the dollars of HA revenues and dividing it by the HA kilowatt hours? There's a difference, that's why I asked.

Q Why don't you give me both of them then.

A Give you both, okay. For which year?

Q 1999.

A '99, hour ahead?

Q Yes.

A Okay. 1999 average prices, that's if you take -- that's if you buy one kilowatt in every hour of the year, it's 3.609 cents per kilowatt hour. What the customers paid in average revenues, again, based largely on how they responded in 1999 was 2.874 cents a kilowatt hour.

Q Okay. Now on page 11 of your direct testimony, around lines 4 and 5, you start talking about some hours where the price in certain hours was above $6.00; do you recall that?

A Was as high as $6.00, yes.

Q And the statement you make on lines 4 through 5 is that no other retail customer will immediately see this $6.00 per kW price.

A Per kilowatt hour price, yes.

Q Okay. Do you know what the lowest RTP price was in 1999? I'll use the HA price.

A Sure. 1.49 cents.

Q So while no other customer receives $6.00 a kilowatt hour, no other customer receives 1.49 cents a kilowatt hour either, do they?

A As a total price? No. In fact, the RTP rate -- yeah, that's correct, 1.49 is the lowest price that was charged RTP in 1999.

COMMISSIONER BAKER: Mr. Pollock, wouldn't you agree that if any customer, who is taking power under the RTP tariff did not get off the system when it hit $6.00, they're really a firm customer, they're not RTP, are they?

THE WITNESS: Well, RTP is a firm rate. What you're saying is that they're not really responding to the price and shouldn't be on RTP.

COMMISSIONER BAKER: Right.

THE WITNESS: That may or may not be. They're not responding to the price.

COMMISSIONER BAKER: What would get your attention if $6.00 doesn't get your attention or causes a response.

THE WITNESS: Right, and the question really is should the price really be $6.00 or can you get your attention at 70 cents a kilowatt hour, as I think Mr. Stewart said. That gets his attention.

COMMISSIONER BAKER: But there are some customers out there taking service under RTP that it didn't get their attention at $6.00.

THE WITNESS: That's true, and -- but that's the customer's problem. What the issue here is is not how the customer -- whether they respond or not, the issue is whether the prices are reasonable. And is it reasonable to pass through a price in a deregulated market where the customers have no say on, is it reasonable to pass that price through and cause significantly higher rates to be paid by these customers, beyond any increase ever paid by any other customer on the system. I mean it's just a question of fairness, is it reasonable for the company to charge that price when it actually cost them maybe a dollar or less than a dollar to supply the kilowatt hours. That's the issue in the case, it's not about price response, it's

about charging a rate that reflects the actual cost. $6.00 is what the company paid for one transaction for maybe 100 megawatts of power, but they're serving over 1000 megawatts of load. It didn't cost $6.00 to serve 1000 megawatts of load. And that's the issue we're asking you to address. We think there can be a lot of price response even at 70 cents or a dollar. There was -- even when the price was 30 cents, the company reported that they had significant price response, but you can only respond -- you can only count on that price response to a certain degree. The more hot days you have, the more times that prices are above 30 cents, the less able the customers are able to respond, and this is a fact.

BY MR. GREENE:

Q Mr. Pollock, would you agree that one of the reasons why RTP customers may be willing to stay on rate that shows spikes every now and then of $6.00 a kilowatt hour is because for 1700 hours of the year in 1999, the price was below two cents?

A Yes, that could be.

Q That's 20 percent of the hours it was below two cents.

A At 20 percent and shrinking every year.

COMMISSIONER WISE: What shrinks, the price or the hours?

THE WITNESS: The hours that are that cheap. And that's a worry, that's a concern.

BY MR. GREENE:

Q Now the customers that don't respond to the high RTP prices are the ones that are setting the RTP price, wouldn't you agree?

A No, everybody that's on the system that the company has to serve in excess of the company's available resources are causing the company to go out and pay the prices when then in turn are declared to be the system lambdas which set the RTP price.

Q Well then if every customer out there is causing the purchases, as you say, then it's really not the RTP customers who are contributing to that $120 million in earnings over 12.5 percent, it's everybody.

A No, everybody is not contributing because everybody doesn't pay the $6.00 cost whenever the cost of purchased power is $6.00.

Q But likewise, nobody pays 1.48 cents either, do they?

A We don't charge everybody else based on a price that varies every hour except RTP customers.

Q Now I think you would agree, wouldn't you, that the RTP price over the last few years has become much more volatile than the years before.

A Yes.

Q And I think you will agree, as you say on page 11 of your testimony that at the end of the day you recognize the price volatility is driven by the fluctuations in the deregulated wholesale market.

A It's based upon that and the fact that the company has to rely on the wholesale market. If the company didn't have to rely on the wholesale market, we wouldn't see these prices.

COMMISSIONER BAKER: But tell me what the company can do to reduce its dependency on the wholesale market?

THE WITNESS: Needs to have more assets in the ground, more pre-arranged, more purchases in advance.

COMMISSIONER BAKER: I mean, when you say more assets in the ground, are you saying they need to have -- to go out there and build additional baseload capacity?

THE WITNESS: Not necessarily even baseload, in fact the company is out building peaking capacity for the wholesale markets to take advantage of these high prices. The point is that if the company had pre-arranged purchases, even if they had cost 10 cents a kilowatt hour, that would be a lot better than paying a dollar -- 10 cents is better than a dollar.

COMMISSIONER BAKER: Sure, I'll agree with that. What else -- are those the two steps they need to take?

THE WITNESS: They can take that step. Our group has submitted a proposal. They will go out and find power and take all the risk. We'll buy the power, we'll buy it at a constant rate and we'll pay less than we're paying today. And they're willing to take the risk to do that.

COMMISSIONER McDONALD: On average or on RTP?

THE WITNESS: Take their RTP load, go out shop it in the market, sign a contract, guarantee the load.

COMMISSIONER WISE: Didn't we talk about that concept before we decided that we'd go forward with these hearings on RTP?

THE WITNESS: I think that was your idea, Commissioner. And we submitted a proposal to the company to do that. In fact, probably just about a week after you brought that up.

COMMISSIONER WISE: I think it still has merit.

THE WITNESS: I do too, I agree with you. We haven't heard anything back from the company on it, however.

BY MR. GREENE:

Q Mr. Pollock, the company can also call IS for economic reasons and relieve the last 500 megawatts of purchases in these high priced hours too, couldn't it?

A Not without violating the tariff which basically says IS is for reliability reasons only. Now that's not to say you shouldn't modify the tariff if the cost and benefits

play out.

Q But if the IS is the CT of last resort, as witnesses testify to from time to time, then perhaps we ought to call that CT and make it equipment on the ground, wouldn't you agree?

A You would have to modify the tariff to do that. That's a possibility, I'm all in favor of looking at the costs and benefits of doing that. But you would have to modify the tariff.

CHAIRMAN DURDEN: Mr. Greene, I think at this point, we're going to take a five minute break.

MR. GREENE: I'm finished, I have no further questions.

CHAIRMAN DURDEN: Well, that's perfect timing then, we'll take five minutes and come back --

COMMISSIONER WISE: We would have asked for a break 30 minutes ago if we'd have know, Mr. Greene.

(Laughter.)

(A short recess was taken.)

VICE CHAIRMAN BURGESS: Does staff have questions of Mr. Pollock?

MR. WALSH: No questions.

VICE CHAIRMAN BURGESS: Consumers' Utility Counsel?

MS. HOLLEY: Thank you, Mr. Chairman.

FURTHER CROSS EXAMINATION

BY MS. HOLLEY:

Q On the second page of your summary, you present the four areas of adjustment, petitioner's relief adjustments, is that correct?

A You're talking about the executive summary?

Q Yes.

A Yes.

Q You've already addressed some of the effects of removing the adder on non-RTP customers, but for clarification, specifically what would be the immediate effects and the long-term effects on residential and small business customers of these proposed changes?

A I think ultimately, as I said, it really depends on where the company's earnings are, but it doesn't really affect the rates. I mean the company is supposed to be earning within the 10 to 12.5 percent range. As long as that happens you know, nothing changes.

Q Now the third request is to modify the fuel accounting. What would be the effect of that on residential and small business?

A It would lower the fuel cost rate and therefore would benefit residential -- in fact, would benefit all customers, even the RTP customers, for the CBL baseline portion of their bill.

Q I just want to make sure I understand the chart on I guess this is JP-1, the three page exhibit you have. What unit does each of these blocks represent, is that one cent? Each of the blocks that you have there, I guess you have 1, 2, 3, 4, 5, -- 8 blocks going across.

A You're talking about vertically?

Q Horizontal, the lines that go horizontally.

A Yes, each line horizontally represents a penny a kilowatt hour.

Q Okay.

MS. HOLLEY: I think that's all I have, thank you.

COMMISSIONER McDONALD: Mr. Chairman.

Mr. Pollock, you mentioned the fact that under the present order of the Commission, 10.5 to 12.5 percent, so it would not affect, should not affect residential rates saying that the company should be happy earning between 10.5 and 12.5, is that what you're --

THE WITNESS: That's what my understanding of the accounting order does.

COMMISSIONER McDONALD: They agreed to that stipulation, didn't they?

THE WITNESS: Yes, they did. And as long as they're earning within that range, that shouldn't be a problem.

COMMISSIONER McDONALD: And then your testimony on

page 12, you said that -- there was kind of a question that will marginal energy costs exceed embedded costs for the foreseeable future. And you answer that by saying yes.

THE WITNESS: The incremental energy costs are a lot higher than average, that's right. And that's what's generating the profit.

COMMISSIONER McDONALD: RTP rates, customers, would not want to go back to the average overall embedded and get away from RTP pricing, would they?

THE WITNESS: I --

COMMISSIONER McDONALD: Even if there was a range between 3.09 and 3.32 average price today with the industrial customers?

THE WITNESS: I don't think it would be their first choice, no, because they couldn't afford to operate at the rates that the company charges for its standard service. They wouldn't be here, or many would not be here. The benefit of RTP is that it brings the average blended cost down to a level that now is competitive with what competition is all over the southeast, what they get in terms of what their average costs are. But you don't get there without taking a lot of risk and that's -- you can't just compare and say ah, four cents here, three cents here. It's four cents here with absolutely no risk of any kind. In order to pay the low rate, the three cents, you've got to

take a lot of risk. And what we've seen is a tremendous amount of additional risk in the last two years. It's not for free.

COMMISSIONER BAKER: Mr. Pollock, have you done any study of your members to see at what point there is a significant impact as far as getting off the system once a price hits, I don't know, 10 cents, 25 cents, 50 cents a kilowatt hour, dollar a kilowatt hour -- where do you get a significant response based on price?

THE WITNESS: I haven't done a formal study for our group. I've read the literature that, you know, utilities have said here's what the price needs to be and we start to see a response. Based on that literature, I've seen a price as little as 30 cents a kilowatt hour that creates significant response. But the point is, is that if you have one hour or two hours or maybe eight hours at maybe 30 cents or higher, you're going to get one response. If you get 20, 30, 40, 50, 100 hours at that price, you're not going to get the same level of response, because there's not any way that any customer can respond to that price all the time for that entire duration. So you've got basically a finite resource there in terms of what customers can and are able to do, and at what price. And different customers will have different thresholds for responding, as you've heard.

VICE CHAIRMAN BURGESS: Do we have any cross

examination from Service Resources?

MS. BAULKMON: No questions.

VICE CHAIRMAN BURGESS: Any other questions by any Commissioners?

(No response.)

VICE CHAIRMAN BURGESS: If not --

COMMISSIONER BAKER: Well, let me ask Mr. Pollock -- I want to see, Mr. Pollock -- I've said it to everybody. I want you to make your case here, not in my office and I mean it.

THE WITNESS: Sure.

COMMISSIONER BAKER: So is there anything that you want to add? This is a soft ball, just -- I want you to put out everything, you know, you want in the record so that we have necessary information to make a decision in this case. Is there something that's been left out you want to re-emphasize, you want to elaborate on -- anything?

THE WITNESS: I wish I had known that ahead of time, I would have brought Mark McGuire with me to help me hit that soft ball.

But anyway, again, I think this case is really about the impact on customers which they have basically no say in determining the price. Their only avenue is to respond to the price. Some can respond more than others, others simply can't respond well enough to have any

appreciable effect. The issue is not what the customers do, the issue is the prices. The prices have to reflect the cost of service. What we've shown you is that the system lambda which is setting the $6.00 prices, the $2.00 prices, the dollar prices, is not the company's actual cost of service and all we're asking you to do is to adjust that calculation so it more closely reflects the actual cost of service because we think at that level the company is making enough money on RTP that they don't also need to add five mills to the rate. And that five mills will have nothing to do -- no impact at all on price response.

VICE CHAIRMAN BURGESS: Let me ask you, in order of priority, before revisions that you propose to this rate, how would you rank them in order of priority?

THE WITNESS: We've talked about that. I think that clearly the five mill adder has seen its day and is not necessary and that five mill adder I think can go away without any issue. I think though that if you decide that you just want to eliminate half of it, the petition says eliminate at least half, then I think you need to take the next step of lambda averaging and change the way those prices are calculated to reflect the actual incremental cost of the resources that are being used. And then the third thing would be the fuel, fuel accounting, which is a little bit more complicated because you've got to know -- you

basically have to have a fuel cost rate that is like a real time fuel cost rate, which you don't really have right now.

VICE CHAIRMAN BURGESS: I guess one thing I try to look at is long-term implications of the rates and the way that they're designed. The proposed modifications that you have made -- given these proposed modifications and given the way that -- your vision of where you see this market going, do you think the fixes you're proposing are long-term fixes or will we be back here again next year talking about RTP again saying we need to jiggle the rate a little bit more?

THE WITNESS: I sure hope not because I don't think my clients would want me to come down here again. To be perfectly frank though -- no, this is really a short-term --

COMMISSIONER McDONALD: Are you too expensive, is that the problem?

(Laughter.)

THE WITNESS: I don't know, I'll let them decide, they can complain to you if I charge them too much.

COMMISSIONER WISE: Don't open that door.

THE WITNESS: No, no, I'm going to close that door right now.

No, in all seriousness, I think that my clients, not just here but all over the country, feel that it's time

to allow choice. And I know that a lot of things have to happen here to do that. We've given the company a proposal that basically puts some of our load out on the market so that they can basically determine their destiny rather than have the power company determine their destiny. I would hope that we could make these adjustments to RTP as we proposed and that would be the end of it, and that the next thing that we did was talk about moving to customer choice, because I really think that that's where the market has gone, 24 states now embrace customer choice.

COMMISSIONER McDONALD: You should have been here a month ago and carried that across the street.

THE WITNESS: Ask my clients.

VICE CHAIRMAN BURGESS: I guess one final question I have is I think Commissioner Wise has raised this issue several times regarding pre-arranged power purchases --

THE WITNESS: Yes.

VICE CHAIRMAN BURGESS: -- do you think that is a real alternative to developing some stable RTP prices for the future?

THE WITNESS: Yes, I do. I think the company has done that to some degree but the problem with it is that they have to spend some money to buy the capacity to reserve it for the summer use. And those dollars get expensed, they don't get passed through the fuel clause, so naturally it

goes against their earnings to do more than they feel is necessary. We feel that when you're subjected to one dollar, six dollar prices, that they're not doing enough.

VICE CHAIRMAN BURGESS: Thank you. Mr. Quintrell.

REDIRECT EXAMINATION

BY MR. QUINTRELL:

Q Mr. Pollock, there were several questions on cross examination by both the Commissioners and Mr. Greene related to the company's -- each of the company's spot market purchases and you testified that the customers would be better off if the company locked up more power on a longer term basis ahead of time rather than waiting for the spot market; is that right?

A I think there's at least a good possibility with the kind of loads that these customers and other customers similarly situated have, that being able to go out in the market and guarantee a certain amount of load for customers, suppliers that would want to supply that load and would be able to supply that load. And I think they could achieve certainly a more stable rate and probably overall lower rate.

COMMISSIONER BAKER: Well, how do you make that financially attractive for Georgia Power to want to do -- to do that? I mean bottom line, everybody in this room is basically economic driven and you have to provide the right

incentives, economic incentives, to get a change in behavior. So how are you going to change behavior?

THE WITNESS: Well, the company has to be willing to say the W word -- willing. They have to be willing to get past the point where they're out on the market on the customer's behalf, the customer is making the decision which power to buy and they're reselling it to the customer. If they can get past that point, the economics are they get to keep all the load for the non-RTP portion, all the resource that would otherwise be used to serve the RTP load would be freed up and used for other customers and our proposal included a slight adder for them so that they would have an economic benefit on every kilowatt hour that they resold to this -- I'll call this this large buying group.

COMMISSIONER BAKER: Would that large buying group then waive any rights that it has to come back onto the system?

THE WITNESS: I think we'd have to talk about those circumstances. I haven't thought through the proposal to quite that detail, but that's certainly one of the concerns. And certainly they could not come back on the system in the middle of the year or the middle of a contract. Just as in other customer choice states, when you make a decision to choose a different supplier, that's usually a one-year decision or maybe a two-year decision.

And then you can come back only giving the proper notice. But again, those are details that we have not fully fleshed out.

BY MR. QUINTRELL:

Q Following up on that a little bit, what are the incentives and the disincentives from the company's perspective of buying ahead of the time and locking up power versus buying on the spot market?

A To do that, you have to basically pay a demand charge.

Q And how is that accounted for?

A Demand charge is just another expense. It's not a fuel cost, so it can't be passed through the fuel cost rate, so if you incur additional expenses to lock up the power, it basically reduces your earnings.

Q Versus --

A All other things equal versus buying it on the spot market, paying a dollar, two dollars, six dollars and passing all of it through.

Q Passing it through what?

A The fuel cost rate.

Q And who pays that?

A Everybody.

Q Including the RTP customer?

A For the CBL portion of their rate, yes. And they

pay it directly to the real time price.

Q So the company is better off from an earnings standpoint to buy on the spot market as opposed to locking up power ahead of time?

A Yes.

Q Mr. Greene asked some questions about some of the complaints that we've raised in this petition with respect to the structure of the RTP rate and his questions were why are we just now raising these concerns. When the RTP rate was designed back in the early '90s, what were the magnitudes of the system lambda that the company told us the RTP customer would be exposed to?

A As I recall the '92 testimony, it was basically any range from a penny to maybe up to 6.5 cents with an average of about a penny and a half. I could have those numbers not quite right, but 6.5 stuck in my mind as being the most that lambda would reach during a high cost, low capacity hour.

Q And what was the highest lambda that you recall from the information you've seen in 1999?

A It was over six dollars as opposed to six cents. That's 100 times higher.

Q Did the company buy energy purchases on the wholesale market in the early '90s?

A I'm sure they did buy economy power purchases,

that's routine. They're just simply not using their own generation, backing off the generation and replacing it with cheaper energy, which is what a normal utility practice would be under those circumstances.

Q How did the prices in the wholesale market compare in 1992 with those in 1998-'99?

A Well, obviously they were still regulated, so the prices were controlled and they were much lower. There were times when prices would get, you know, above three cents, maybe above four cents, but nowhere near the kind of prices that we're seeing now.

Q There were some questions about the rate case testimony, '98 rate case testimony, specifically cost of service study submitted by witness Bowring.

A Yes.

Q Did the company submit a cost of service study in that case?

A Yes, they did.

Q Was it consistent with the conclusions reached by Mr. Bowring in his cost study?

A Only in one respect, it showed residential rates being below cost. In the company's study in fact I think in just about every cost study filed, 1991 and prior to 1991 showed the industrials either at or above cost of service.

Q Did the Commission adopt any particular cost study

in its order in the '98 rate case?

A No.

Q Did witness Bowring have information concerning RTP rates in 1998 and '99 when he prepared his study?

A I doubt it because the first period one test year was 1997, period two was a projected weather-normal test year which had nothing to do with what actually happened in '98 and '99.

Q There were questions about the average price paid by the GIG and GTMA members for energy, both in 1991 and in 1999. Do you recall those questions?

A Yes.

Q What I didn't hear were questions about the company's cost to provide those kilowatt hours in 1991 versus 1999. Is that a relevant part of the analysis?

A Sure, you just can't throw rates around and say -- or prices around or average revenues per kilowatt hour around without looking at the cost of service.

Q Do you have any opinion as to whether the company's cost to provide kilowatt hours to industrial customers has increased, decreased, stayed the same, since 1991?

A Certainly since 1991 the company's cost structure has come down a lot and that was accelerated in '96, '97, '98 under the first accounting order where the company was

writing off lots of depreciation, lowering their rate base and reducing their cost, cutting expenses as well. The company has done a pretty decent job.

Q So that would indicate that the company's cost to provide a kilowatt hour now is lower than it was in 1991?

A I'd say so because you look at their net book value of production plant, it's come down pretty significantly since the '91 case.

COMMISSIONER BAKER: That's due to depreciation just over the years.

THE WITNESS: Exactly right. And that means lower cost because you have less rate base, less -- same amount of revenues will produce a higher amount of earnings.

BY MR. QUINTRELL:

Q There were also questions with respect to the -- I won't say questions, but there was a discussion early on about the company's response to a staff data request wherein the staff asked for the company's workpapers to support these average prices that the company says that GIG and GTMA members paid in 1998 and '99, do you remember that?

A Yes.

Q Have you had a chance now to review that data response?

A Just very briefly.

Q Could you draw any conclusions from your brief

review?

A Well, I mean, it shows that you really can't look at an average price and say this is what everybody pays because there are ranges there from less than three cents to I think over 10 cents a kilowatt hour, just depending on the type of service that the customer is taking. Further, I think the averages are driven a lot by the fact that you've got several very large members that pay very low average rates and you say why are they paying very low average rates. Well, let's see, they're on RTP and they take interruptible service, they're at high load factor and they're transmission level customers, I would believe.

COMMISSIONER McDONALD: Does that same explanation relate to Exhibit JP-1?

THE WITNESS: It doesn't quite because in JP-1 we've assumed everybody is the same characteristic, the same size and the same load factor. So we tried to compare -- we have compared apples and apples, the prices charged for a customer with 10,000 kW demand, 68 percent load factor for each utility.

COMMISSIONER McDONALD: But your explanation of Mr. Quintrell's question is not comparing apples to apples, is that what you're saying?

THE WITNESS: That's right, the comparison of looking at average revenues per kilowatt hour for GIG, GTMA

or any other group of customers is not an apples to apples comparison because each customer is taking a different type of service, has different characteristics, size, load factor, delivery voltage, absorbs different levels of risk. Some take interruptible service, some take real time pricing with the price risk. And you just can't put them all in a pot and say they're all the same, they're not all the same. That's why the average prices paid by some customers differ widely from what other customers pay. That's why residential rates are higher than commercial and industrial -- at least higher than industrial rates, because the residential class takes distribution level service at a low load factor and the customers are relatively small in size relative to large industrial customers.

COMMISSIONER McDONALD: What about small commercial?

THE WITNESS: Same thing there. Residential and probably small commercial customers are very similar in the sense that they take -- their characteristics are very similar, you see that seasonality of load, you see therefore a lower load factor, lower consumption per customer, service at secondary voltage, no price risk, no interruptibility. When you boil all those things away and look at each of the characteristics, which is what I've been doing for the last 25 years, there are reasons why different customers pay

different rates per kilowatt hour. And those are based on differences in the cost of service.

BY MR. QUINTRELL:

Q Could it be that -- first of all, about how many accounts were shown in the data response with respect to GIG members? About 300, wasn't it?

A Yeah, close to it, about 280 accounts.

Q Could it be that just a few large accounts could be driving the overall average that Georgia Power talks about in these proceedings?

A Clearly they have an effect. If you've got three accounts that account for almost a third or 40 percent or something of that nature of the average --

Q Is that what you saw in that data with respect to the GIG accounts?

A Let me refresh my memory. If you just take the three largest accounts, you know, which is about 30 percent of the total kilowatt hours for GIG, and you eliminate those, then the average goes up because those large accounts, by virtue of their characteristics, pay way less than the average per kilowatt hour amount than the rest of the accounts on this.

Q That's three accounts out of almost 300 that account for almost a third of all the energy?

A That's right.

Q That would tend to skew the overall average, wouldn't it?

A It would, yes.

MR. QUINTRELL: That's all, thank you.

VICE CHAIRMAN BURGESS: Thank you, Mr. Quintrell.

Any other questions by Commissioners?

(No response.)

VICE CHAIRMAN BURGESS: If not, the witness is dismissed. Thank you.

THE WITNESS: Thank you, gentlemen.

(Witness excused.)

VICE CHAIRMAN BURGESS: Mr. Greene.

MR. GREENE: Mr. Chairman, we have our panel of witnesses that we'd like to put at this time.

VICE CHAIRMAN BURGESS: Call them up.

Just for informational purposes, we plan on going to at least 6:00 this evening. So if anybody needs to make arrangements to pick up kids or something, do so, so we'll be here for a little while.

COMMISSIONER McDONALD: Thank you, sir.

(Laughter.)

VICE CHAIRMAN BURGESS: Anybody but you.

Would you swear your witnesses, please?

Whereupon,

RON HINSON

JONATHAN M. KUBLER

MICHAEL T. O'SHEASY

appeared as witnesses herein, and having been first duly sworn, were examined and testified as follows:

DIRECT EXAMINATION

BY MR. GREENE:

Q Mr. Hinson, would you give your full name and a brief description of your responsibilities at Georgia Power Company, for the record?

A (Witness Hinson) My name is Ron Hinson, I'm the Assistant Controller responsible for financial and regulatory accounting matters with the company.

Q Mr. O'Sheasy, would you do the same?

A (Witness O'Sheasy) I'm Michael T. O'Sheasy and my responsibilities is Manager of Product Design which are in the pricing area.

Q Mr. Kubler.

A (Witness Kubler) My name is Jonathan M. Kubler and I'm the Manager of Pricing and Rates at Georgia Power Company.

Q Gentlemen, did you cause to have filed with this Commission on March 17, 2000, 33 pages of direct testimony?

A (Witness Hinson) Yes.

A (Witness O'Sheasy) Yes.

A (Witness Kubler) Yes.

MR. GREENE: Mr. Chairman, at this time, I'd like to point out that what we plan to have introduced into the record, if it's acceptable with you, is the redacted version of the prefiled testimony. There is a trade secret version of the testimony which the staff has a copy of and which the petitioners have a copy of. It contains some fairly sensitive pricing information, some with regard to customers, some with regard to industry averages and that sort of thing. But what we would put into the record is the public disclosure version and that's what I'll be referring to here, if that's all right with everyone.

VICE CHAIRMAN BURGESS: If that's agreeable to all parties, that's what we will do.

BY MR. GREENE:

Q Gentlemen, did you also cause to have filed exhibits which were marked as HKO-1 through HKO-24?

A (Witness Kubler) Yes.

A (Witness O'Sheasy) Yes, sir.

MR. GREENE: And again, Mr. Chairman, with regard to the exhibits, the same holds true, that there are trade secret versions which are on file with the staff, but we'll introduce the redacted versions.

VICE CHAIRMAN BURGESS: So noted.

MR. GREENE: At this time, Mr. Chairman --

MR. HAWES: May I ask one question?

MR. GREENE: Sure.

MR. HAWES: Since I don't deal with this that often, the trade secret version will be part of the record but under seal, or will not even be introduced?

MR. GREENE: I suppose it's appropriate to make it part of the record under seal.

VICE CHAIRMAN BURGESS: Yes, traditionally the Commission has made them part of the record under seal.

MR. GREENE: Okay.

VICE CHAIRMAN BURGESS: And that's what we'll do in this case here.

MR. GREENE: All right, thank you.

I'd like to have those exhibits HKO-1 through HKO-24 marked for the record as Georgia Power Company Exhibits 2 through 25.

VICE CHAIRMAN BURGESS: So marked.

(The documents referred to were marked for identification as GPC Exhibits 2 through 25.)

BY MR. GREENE:

Q Gentlemen, are there any changes or corrections which you need to make to the prefiled testimony?

A (Witness Kubler) Yes, Mr. Greene, there are.

On page 19, line number 41, the first number there should be changed to 3.75 cents and the second number near

the end of the line should be changed to 3.32 cents.

And then in the exhibit or exhibits, on HKO-8, line number 12, for Duke Power Company, South Carolina should be changed to read 3.59.

COMMISSIONER McDONALD: Give me those first ones again, please, Mr Kubler.

WITNESS KUBLER: Line number 41, 3.75 cents instead of the 3.7 cents. And 3.32 cents instead of the 3.26 cents.

COMMISSIONER McDONALD: Thank you.

BY MR. GREENE:

Q Mr. Kubler, having made those changes, if I were to ask you the same questions here today under oath as are set forth in your prefiled testimony, would your answers be the same?

A (Witness Kubler) Yes, they would.

Q And were the exhibits which are identified as Georgia Power Company Exhibits 2 through 25 prepared under the supervision and direction of members of this panel?

A (Witness Kubler) Yes, they were.

MR. GREENE: Mr. Chairman, at this time, I'd like to move the admission of the testimony, that it be read into the record as if given here today; and move the exhibits subject to cross examination.

VICE CHAIRMAN BURGESS: They will be admitted

subject to cross.

(The documents, heretofore marked as GPC Exhibits 2 through 25, were received in evidence.)

(Whereupon, the prefiled testimony of Messrs. Hinson, O'Sheasy and Kubler follows:)

Direct Testimony of Ron Hinson, Jonathan M. Kubler and Michael T. O'Sheasy on Behalf of Georgia Power Company

Q. PLEASE STATE YOUR NAMES, TITLES AND BUSINESS ADDRESSES.

A. Ron Hinson, Assistant Comptroller, Georgia Power Company, 241 Ralph McGill Boulevard, Atlanta, Georgia 30308; Jonathan M. Kubler, Manager, Pricing and Rates, Georgia Power Company, 241 Ralph McGill Boulevard, Atlanta, Georgia 30308; and Michael T. O'Sheasy, Manager of Rate Research and Design, Georgia Power Company, 241 Ralph McGill Boulevard, Atlanta, Georgia 30308.

Q. MR. HINSON, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I hold an Associate of Science degree from Young Harris College, a Bachelor of Business Administration degree from the University of Georgia and a Masters of Business Administration degree from Mercer University. I am a Certified Public Accountant and a Certified Management Accountant. I began my employment with Georgia Power in 1979. I have held a number of positions in the Company's Accounting Department, including Financial Reporting Manager and Regulatory Accounting Manager, before being named Assistant Comptroller in 1995.

As Assistant Comptroller, I am responsible for the financial and regulatory accounting functions of the Company. My duties include maintaining the corporate accounting records in accordance with generally accepted accounting principles and various regulatory requirements; preparing and filing financial reports and preparing regulatory filings, including rate cases. I have previously testified before this Commission in the 1998 retail rate case and fuel cost recovery matters.

Q. MR. KUBLER, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

A. I received a Bachelor of Science degree in Electrical Engineering from the Georgia Institute of Technology and a Master's degree in Business Administration from Georgia State University. I am a Registered Professional Engineer in the State of Georgia. During my 38 years with Georgia Power Company, I have held the positions of Industrial Marketing Supervisor, Manager of Information Technologies, Assistant Plant Manager, and Manager of Commercial Marketing.

I was named Manager, Pricing and Rates in 1990. My responsibilities include managing the pricing and rates research activities of the Company and administering the Company's rates, rules and regulations. I direct my Department's efforts toward the development and implementation of new rates, as appropriate that meet the needs of our customers and the Company. Additionally, existing rates require continuous review and monitoring to ensure that the present applicability, structure and format are effective.

Q. MR. O'SHEASY, PLEASE SUMMARIZE YOUR EDUCATIONAL AND PROFESSIONAL EXPERIENCE.

I received a Bachelor of Industrial Engineering from the Georgia Institute of Technology in 1970. In 1974, I earned a Master's in Business Administration from Georgia State University. From 1971 to 1975, I was employed by the John W. Eshelman Company – Division of the Carnation Company – as a plant superintendent in their Chamblee, Georgia location. From 1975 to 1980, I worked for the John Harland Corporation initially as an assistant plant manager and then as a plant manager in their Jacksonville, Florida plant and finally as their plant manager in Miami, Florida. I joined Southern Company Services in 1980 as an engineering cost analyst and progressed through various positions in the Marketing and Regulatory Support Department, specializing in allocated cost of service studies. I became supervisor of the section and testified as a cost of service witness. In 1991, I joined Georgia Power Company in the position of Manager, Rate Research and Design.

My responsibilities encompass managing the rates research and design function. These activities include pricing strategy development and future rate planning; rate research, design and evaluation; and the preparation and filing of retail rates with the Georgia Public Service Commission.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of our testimony is to address the questions which have been raised by the Georgia Textile Manufacturing Association (GTMA) and the Georgia Industrial Group (GIG) regarding the Company's Real Time Pricing Day-Ahead and Hour-Ahead Tariffs (RTP-DA and RTP-HA, respectively).

Q. WOULD YOU PLEASE SUMMARIZE YOUR TESTIMONY?

A. With regard to each of the four proposals made by GTMA and GIG, we respond as follows:

1. GTMA and GIG argue that the risk adder (of 5 mills for RTP-DA and 4.5 mills for RTP-HA) be reduced. This is the same position they took in the last rate case which concluded less than 15 months ago and is the position which was rejected by the Commission in the Accounting Order. Plainly, the current GTMA and GIG position in this case is simply an attempt to relitigate the issue after the Commission has decided it. As importantly, the GTMA/GIG position has no merit. The adder remains an important component of revenues for the Company, which if it is not collected from RTP customers, would be collected from other customers.

2. GTMA and GIG argue that either (a) purchased power costs should not be included in RTP, or (b) the "lambda" which helps determine the RTP price should be averaged. Again, this position has no merit. While it is true that the 1998

Accounting Order left open the possibility that the Commission would examine the possibility of using a lambda based on an average of purchased power costs, that is not what GTMA and GIG seek here. They seek to exclude all purchase power costs, or average all lambda, including Company owned generation. Plainly, the Commission's Accounting Order correctly recognized that purchased power was part of the lambda that set the RTP price. Thus, the GIG / GTMA assertion that RTP was never intended to include purchases is without merit. And, the Commission's willingness to look at a lambda set by averaging purchases can not support the current attempt to average all generation and purchases. In fact, GIG and GTMA each rejected a proposal to average purchases after the Accounting Order went into effect. The rates which were set by this Commission to put the Accounting Order's rate reductions into effect were based upon the fact that GTMA and GIG had rejected purchased power averaging.

3. GTMA and GIG argue that the Commission should modify the fuel accounting to provide that the fuel account is charged with hour by hour costs and credited with hour by hour revenues, including virtually all RTP revenues when RTP prices are based on energy purchases. This is without merit. First, such a change in accounting practice would have no effect on the RTP price, which is the focus of this complaint. Second, it would be unlawful because it would allow recovery into the FCR dollars which are not for fuel or purchases. Third, it would distort and radically change the "average fuel cost" method that this Commission has used for years to set the FCR. Finally, it would merely shift base cost dollars that should be going to pay for power plants and to offset higher rates for commercial and residential customers, and it would lower fuel costs. But the lost base rate dollars would need to be made up in increased base rates of those same customers who now had lower FCR charges. The shell game would have no lasting effect on the cost of power, not even to GIG or GTMA members.

4. Finally, GTMA and GIG ask that the Company's power procurement practices be reviewed. On this point the Company merely shows that the Commission and its Staff have always had the responsibility to review the prudence of the Company's activities, including its fuel and power procurement practices. The Company has always been committed to working with the Commission and its Staff in this regard, and it did not take the filing of the GTMA/GIG petition to accomplish that.

For all of the reason set forth in our testimony, the Petition should be denied.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. We will present an overview of the RTP tariffs describing how they are composed and presenting a brief history of the tariffs. Then we will discuss the intent of the RTP tariffs including how the prices are affected by purchases and the response of customers to RTP prices. We will provide a discussion of the regulatory treatment of the RTP tariffs including how they impact the revenue requirements of the Company, how they were

dealt with in the Company's last rate case, and how fuel cost recovery is handled in the tariff. We will also discuss how RTP covers marginal costs and what would happen if purchased power costs were removed from RTP. We then will discuss whether RTP is appropriately structured for the future. We will discuss the competitiveness of RTP and industrial rates in general. We will also present alternatives to RTP that the Company has developed to meet the ongoing needs of our customers. Finally, we will address some of the most egregious errors and misunderstandings in the testimony submitted by Mr. Pollock.

RTP OVERVIEW

Q. PLEASE DESCRIBE BRIEFLY THE REAL TIME PRICING TARIFF (RTP).

A. RTP is an innovative and powerful tariff that blends embedded cost rates with a marginal cost rate. There is a customer baseline load (CBL) which represents a customer's historical hourly loadshape to which standard embedded rates such as Power and Light-Large (PLL) apply. Embedded rates collect variable and fixed cost incurred by Georgia Power Company (GPC). Marginal costs represent only those hourly costs that will change with relatively small changes in output. Therefore, the theory of the RTP tariff is that embedded cost (both fixed and variable) were incurred to serve a customer's historical load such that embedded rates should apply here while changes to this hourly historical loadshape can be priced at the hourly marginal costs which they cause. Therefore, there are two parts to an RTP customer's bill: (1) a "standard bill" which reflects a standard, embedded rate applied to his CBL; and (2) an incremental RTP portion which represents hourly changes from the customer's CBL priced at hourly marginal cost called the RTP price.

The hourly RTP price has 5 components to it:

1. Lambda which is the marginal cost of the last resource used to serve the last increment of load. The IEEE Standard Dictionary of Electrical Terms defines lambda to be "the additional cost of delivering another one MW of power to the load center". This marginal cost component could be from the last generating unit dispatched to serve retail load in this hour or it could be a purchase from another supplier. [Purchases are employed whenever a purchase is cheaper than dispatching an owned unit or if all available owned units are already dispatched and purchases are therefore necessary to serve additional load. We have historically purchased at any price in order to avoid customer interruptions; it is only when all possible purchases have been made that we have asked our interruptible customers (IS) to interrupt]. Lambda is the largest component in the RTP prices amounting to 75-80% of the average annual RTP price and is found in the price every hour of the year.

2. Losses which represent physical electrical losses in transmitting and distributing electricity. This is a small component amounting to 3-5% of the average RTP price and is found in each hourly price.

3. Risk adder of 5 mills/kWh for Day-Ahead RTP and 4.5 mills/kWh for Hour-Ahead RTP. This component is found in each hourly price and serves to cover GPC's forecasting risk (RTP prices are based on a forecast of marginal cost and are not trued-up) and provide a contribution to other fixed costs above marginal cost. It also accommodates other marginal cost considerations not in that tariff including unit commitment costs and Clean Air Compliance (SO_2) costs.

4. Marginal cost of transmission covers any marginal cost that may occur during critical hours. This component only arises in 200-300 hours per year (2.2 to 3.4 % of the total hours) and only amounts to 1-2% of the average annual RTP price.

5. Outage/reliability capacity cost which reflects the cost of the cheapest generation resource, a combustion turbine. This component is driven by the probability that the reliability of the system is in danger. It normally only occurs 50-100 hours (.6 to 1.1% of the total hours)and has been only 1% of the annual RTP price.

Q. IS THERE MORE THAN ONE RTP TARIFF AT GPC?

A. Yes, there is a day-ahead version (RTP-DA) and an hour-ahead version (RTP-HA). Both versions have the same components and structure, they simply are forecasted either a day ahead or an hour ahead. There are 1,526 customers on RTP-DA and 34 customers on RTP-HA.

Q. WHEN WAS THE TARIFF APPROVED?

A. There was a very successful pilot conducted in 1992-1993. The two tariffs were approved as permanent tariffs in 1994, with a couple of approved modifications authorized later.

Q. WHAT ARE THE MAJOR FACTORS WHICH INFLUENCE OVERALL RTP PRICES?

A. There are 6 primary factors which influence RTP: state of the economy, weather, fuel prices, wholesale markets, tie line availability, and unit availability. The weather and wholesale markets have the greatest effect of the six.

Q. CAN YOU PROVIDE US A HISTORY OF THE RTP-DA PRICES?

A. Please see Exhibit ___(HKO-1).

Q. IS RTP A COMMON TARIFF IN THE UTILITY INDUSTRY?

A. Yes. There are a lot of utilities that offer RTP, none however nearly as successful as GPC. In fact you could add up all the customers participating in RTP programs throughout the United States and the total would not equal that of GPC. Please see response to STF-2-17.

RTP TARIFF INTENT

Q. WHAT IS THE PHILOSOPHY AND INTENT OF RTP?

A. RTP is an important tariff in any progressive utility's pricing portfolio because it gives flexible customers an option to take on risk in order to obtain potential cost savings (see Exhibits___(HKO-2) and (HKO-3)).

Simply put, it is to provide an hourly price that reflects our expectations of the marginal cost of electricity. In most of the hours, these prices will be low although some hours can reach very high levels. Since electricity cannot be stored to any large degree, when the capability of the system to supply the customers' demand is constrained, risk is created and prices can reach high levels. Those customers who then have a high value of electricity can choose to buy. Those whose value of electricity is less than the RTP price can elect to reduce consumption. In fact if the RTP customer chooses to reduce consumption below historical levels (the CBL), GPC will pay the customer the RTP price for these reductions. Since the prices reflect the hourly expected marginal cost, the customer chooses whether to purchase, or not, based upon a comparison of the real, hourly cost of electricity to his current value of electricity.

Q. DOES RTP TRY TO CAPTURE THE AVERAGE COST OR TOTAL COST OF THE ENTIRE AMOUNT OF RTP LOAD?

A. Neither. The intent of RTP is and always has been to reveal the marginal cost of making marginal changes in load. Standard rates reflect the total cost changes over large increments of load changes.

Q. HOW IS THE COST OF PRODUCING ELECTRICITY COVERED IN THE RTP PRICE SINCE MARGINALLY SPEAKING THERE ARE SO MANY RESOURCES WHICH MAY BE PROVIDING ALL OF THE LOAD?

A. RTP is based upon the theory of capital substitution and the peaker methodology, which has been approved by many, including the National Electric Research Association (NERA). This theory states that if you charge the marginal running cost and the "cheapest" capital cost, then you should collect enough revenue to cover your cost. Please see Exhibit___(HKO-4) as to how a choice of two generating technologies could be combined to serve a system loadshape. Exhibit___(HKO-4) also shows how an RTP tariff combining the cheaper capital cost with the hourly running cost (lambda) would equal the cost to serve regardless of which technology was actually serving the load. In this simple example of a system, assume for illustrative purposes that RTP would be charging $30/kW representing the cheapest generating resource (a combustion turbine (CT)) and lambda of 6¢/kWh for the 1,500 hours in which the CT was the marginal unit and 2¢/kWh for the remaining hours of the year in which the base load coal unit was the marginal unit.

Q. IF SOME OF THE RTP LOAD WAS ACTUALLY BEING SERVED BY THE BASE LOAD COAL UNIT WITH A RUNNING COST OF 2¢/KWH, WHAT IS THE PURPOSE OF THE ADDITIONAL 4¢/KWH WHICH WILL BE CHARGED WITH A LAMBDA OF 6¢/KWH UNDER RTP?

A. That difference of 4¢/kWh above the actual running cost of the base load unit will pay for the "extra" capital cost of the base load unit. Remember the RTP tariff will only collect capital cost for the cheapest generating resource, in this case a CT, at $30/kw. By collecting an extra 4¢/kWh over 1,500 hours, there will be contribution of $60/kw thereby effectively covering the $90/kw capital cost of the base load coal unit. Its only fair that if an RTP customer is allowed to enjoy the lower economical running cost of this base load unit that he also contribute towards the higher capital cost of this unit.

Q. SO, DOES LAMBDA THEN CONTAIN NOT ONLY FUEL COST BUT ALSO A CONTRIBUTION TO THE CAPITAL COST OF A MORE EFFICIENT BASE UNIT?

A. Yes. It also contains variable operation and maintenance expense.

Q. IF YOU WERE TO AVERAGE THE RUNNING COST IN THOSE HOURS IN WHICH BOTH UNITS WERE RUNNING AND PRICE ACCORDINGLY, WOULD YOU COVER YOUR COSTS?

A. No. You would fall short in this example by $30/kw. You must charge the marginal lambda price coupled with the most economical generation capital cost to properly cover your cost. Otherwise, you violate the peaker theory and capital substitution logic.

Q. ARE PURCHASES A RESOURCE IN THE HOURLY DISPATCH OF RESOURCES?

A. Yes, they are correctly treated as another resource in order to minimize the cost of power to our all of customers.

Q. HOW DO PURCHASES IMPACT THIS PRICING MODEL BASED UPON CAPITAL SUBSTITUTION?

A. As mentioned earlier, we will purchase power whenever it can be obtained cheaper than dispatching its own units or when it has run out of its own units. Therefore the marginal unit can be a purchase and this purchase price can be more or less than the lambda of the last available owned unit lambda. This fact can be observed in Exhibit ___(HKO-5). The exhibit indicates there are hours in which the cheaper purchase will not contribute sufficient capital contribution necessary to pay for the high capital, base-load owned units serving RTP load. However the presumption is that hours in which the purchase sets a lambda higher than the most expensive owned unit will compensate for this deficit.

Q. HOW HAVE ECONOMICAL LOWER COST PURCHASES COMPENSATED FOR THE HIGHER COST PURCHASES SINCE THE INCEPTION OF RTP?

A. Prior to 1999, lower cost purchases compensated for the additional cost of higher cost purchases. During 1999, it appears that higher cost purchases were greater than the lower cost purchase effects. Over time the assumption is that this will average out.

Q. WHAT WOULD HAPPEN IF YOU ARTIFICIALLY REMOVED PURCHASES FROM THE LAMBDA CALCULATION IN HOURS WHERE PURCHASES WERE BEING MADE TO SERVE RETAIL LOAD?

A. Lambda would not reflect marginal cost and would send the wrong price signal to RTP customers. During high-priced hours, it would signal to an RTP customer a price that could encourage him to add load at a price less than the corresponding cost of electricity and vice versa in a low-cost hour.

Q. DO RTP CUSTOMERS RESPOND TO HIGH PRICES?

A. Yes. They do as an aggregate group. Some customers have specific trigger prices to which they respond consistently. Others change their response triggers as their business conditions change throughout the month and the year. As a result of this dynamic interaction of a large group of customers, GPC can depend upon a consistent level of response that effectively becomes the equivalent of a generating resource when conditions worsen and RTP prices rise. In GPC's most recent IRP filing, the RTP price response resource provided 328 MW's for a typical peak day response. During the very hot summer month of August 1999, the response in the highest priced hours was a phenomenal 864 MW's. This response provides a valuable resource no other utilities possess and prevents the need to construct similar MW's of new generation. Please see Exhibits___(HKO-6-1) and (HKO-6-2).

Q. HOW DOES GEORGIA POWER'S RTP TARIFF AFFECT THE COMPANY'S INTEGRATED RESOURCE PLAN (IRP)?

A. The Company's approved IRP contains approximately 1000 MW of Combustion Turbine equivalent capacity associated with our customers' load response to pricing signals and interruptible service. The RTP tariff effect is slightly less than half of this capacity.

Q. HAS THIS PRICING SIGNAL TO CUSTOMERS BEEN EFFECTIVE IN REDUCING THE NEED TO OBTAIN ADDITIONAL RESOURCES?

A. Yes. During the 1999 peak when the RTP prices included the higher cost of spot market purchases, the Company's capacity need was reduced by 864 MW. Since the prices paid for spot energy in 1999 were higher than the projected values used in the IRP, the customers load response was greater than projected. This response demonstrates that the concept behind the development of the RTP tariff is performing as it was intended.

Q. DOES THIS REDUCTION IN CAPACITY NEED BENEFIT THE COMPANY'S CUSTOMERS?

A. Yes. All of the Company's customers benefit from the RTP response. The customers receive near-term and long-term benefits.

Q. WOULD YOU EXPLAIN THE NEAR-TERM BENEFITS?

A. Yes. In the near-term, all customers benefit because the Company does not have to purchase additional high priced resources from the spot market. If the Company had to purchase the resources avoided by the RTP response, then the cost of these higher priced resources would be passed through to all of our customers. Also, these purchases would force the RTP prices to be even higher.

Q. WOULD YOU EXPLAIN THE LONG-TERM BENEFITS?

A. Yes. Due to the expected continuing RTP response, the Company's long-term capacity requirements are reduced. Our customers benefit from the avoided resources costs that would have been incurred if this capacity had to have been built or purchased and included in future rates.

Q. CAN YOU GIVE AN EXAMPLE OF THIS AVOIDED COST?

A. Yes. The IRP projects approximately 500 MW of RTP CT equivalent capacity in 2003. Using the installed cost of a generic CT to replace this 500 MW of capacity, our customers would be responsible for this increase in cost of $17.6 million. Since the RTP response is assumed to continue through the IRP plan, this avoided cost adjusted for inflation and market pricing would be an annual avoidance.

Q. DO DIFFERENT CUSTOMERS CAUSE DIFFERENT FUEL COST EFFECTS ON GPC DEPENDING UPON WHEN THEY CONSUME ELECTRICITY?

A. Yes, they do. However, this Commission has determined that it is appropriate to account for fuel cost on an average basis across all hours for all customers.

Q. WOULD RTP CUSTOMERS' FUEL COST BE DIFFERENT FROM SIMILAR CUSTOMERS ON OTHER RATES?

A. Probably so, and this is another advantage of RTP. When fuel costs are high during a specific time period, a standard-rate customer using the FCR mechanism does not sense that fuel costs are high at this time since his bill is predicated on this average FCR rate. An RTP customer on the other hand is sent an RTP price signal which reveals the high cost of fuel during this time period, and the customer often times reduces consumption accordingly. This not only lowers the RTP customer's bill by reducing consumption but also has a dampening effect upon the fuel clause since now expensive fuel cost will not

have to be incurred as it would have, had this RTP customer been on a standard rate with the FCR price signal.

Q. CAN YOU ELABORATE ON THE DIFFERENT COMPONENTS WITHIN LAMBDA BESIDES FUEL COST?

A. Yes. The two common additional components are 1) variable operating and maintenance expenses, and 2) capital substitution contribution mentioned earlier in the discussion on the definition of lambda. Even the fuel cost itself for the unit varies as the unit ramps up from cold start to maximum output. For instance the average fuel cost per mile of an automobile running at 10 miles per hour (mph) is greater than when it is operating at 45 miles per hour. The point here is that if in a 30-minute cycle, an auto sped up from 10 mph to 45 mph, you could not measure the cost of fuel at the 10 mph speed and allege that this would be the actual cost of fuel for the entire 30-minute period.

Q. ARE THESE TWO ADDITIONAL COMPONENTS WITHIN LAMBDA ALLOWED TO BE COLLECTED THROUGH THE FUEL CLAUSE (FCR)?

A. No, only fuel cost and related purchased power are permitted. The FCR tariff defines costs permissible in the FCR and does not allow these.

Q. SHOULD THESE TWO ADDITIONAL COMPONENTS BE ALLOWED IN THE FCR?

A. No. The proper way to account for fuel cost according to this Commission is the FCR, and the RTP methodology of removing fuel cost responsibility as defined by the FCR is correct. If one were to credit lambda (or anything other than the FCR), revenue would be flowing into the fuel clause that was non-fuel cost related creating an inequality. This accounting error would be compounded in that the resultant revenue flowing to base cost recovery would be diminished creating a likely under-recovery of non-fuel expenses. It would move the important capital substitution component from base rate recovery to the fuel account. The FCR rate might go down, just like if revenues were removed from any other base rate component and moved over into the FCR. But the capital substitution component would still have to be recovered from somewhere – either residential, commercial or some other customer group with higher base rates resulting.

Q. CAN LAMBDA IN ANY PARTICULAR HOUR EVER BE LESS THAN THE FCR RATE (WHICH IS CREDITED TO THE FUEL CLAUSE)?

A. Yes, it can and does for a couple of reasons. Since the FCR is an average of all hours of the year, the marginal unit with its lambda during some off-peak hours can easily be below the FCR rate. In addition, the FCR includes fuel cost related to unit commitment while unit commitment cost is not currently included in the lambda component of RTP.

Q. IF LAMBDA IS HIGHER THAN THE FCR RATE THAT IS CREDITED TO THE FUEL CLAUSE, DOES THIS DIFFERENCE FLOW DIRECTLY TO GPC EARNINGS?

A. Absolutely not. There is no separate accounting for revenue received from an RTP customer's bill than that of any other GPC customer. For example assume that a PL customer paid a bill of $10,000 to GPC at an overall average rate of 5¢/kWh including the FCR. Furthermore assume that an RTP customer likewise paid a bill of $10,000 to GPC at an overall average of 5¢/kWh (this incorporates both his standard bill portion and the incremental RTP bill with all the components in the RTP price). In both cases, GPC will remove fuel cost revenue defined by the FCR (assume that rate is 1.4¢/kWh). In both cases the remaining revenue (3.6¢/kWh in this simple example for both customers) flows to pay for non-fuel embedded expenses. If after contributing towards these non-fuel costs, there is still some revenue remaining, then in both cases the remaining revenue contributes to earnings. As a matter of fact, in almost all cases, the PL customer's cents per kWh contributed will be higher than a similar RTP customer's cents per kWh, such that the resultant contribution to non-fuel embedded expenses and any resultant contribution to earnings will almost always be greater for the PL customer.

In addition, we must remember that GPC is a weather sensitive, summer peaking utility. Hot summers like 1998 and 1999 result in increased annual revenues even as they place greater costs on the utility. Whether one is talking about Power and Light, or residential rates, or RTP, a hot summer will likely result in an increase in annual revenues. This increase in revenues through rates is then credited against correspondingly higher costs. In hot years, the increase in revenue contributions from all rates produces an increase in company earnings. Likewise, a milder year reduces revenues and resultant earnings. Since tariffs are designed based on the cost to serve in a typical weather year, there will always be some years with higher earnings and some with lower earnings.

REGULATORY TREATMENT OF RTP TARIFFS

Q. HOW WERE REVENUES FROM THE RTP TARIFFS REFLECTED IN THE COMPANY'S 1998 RETAIL RATE CASE FILING?

A. The base and fuel revenues associated with the RTP tariffs were calculated according to the terms of the tariffs and were explicitly included in the overall determination of test period revenue requirements. The RTP revenues are specified in the Commission's minimum filing requirement F-4 found in Appendix Volume 1, Exhibit 2 of the GPC filing in Docket 9355-U.

Q. **ARE THERE OTHER EFFECTS ON REVENUE REQUIREMENTS AS A RESULT OF THE RTP TARIFFS?**

A. Yes. RTP tariffs are a component of the Company's Integrated Resource Plan (IRP). The expected customer response to the RTP price signal is reflected as a resource in determining GPC's available supply. Therefore, the operation of the tariffs directly

impacts the need for additional capacity resources. The amount of RTP reflected in the IRP directly affected the level of purchased power expense included in calculating the test period revenue requirement. 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 through either purchased power expense or new generation.

Q. WAS THE EFFECT OF THE RTP TARIFFS ON TEST PERIOD REVENUE REQUIREMENTS ULTIMATELY CONSIDERED IN THE 1998 RETAIL RATE CASE DECISION?

A. Yes. The Commission Staff and other parties of record conducted an exhaustive review of the Company's test period revenue requirement calculation, including revenues from all existing tariffs. No party, including the GTMA and the GIG, took issue with the determination of RTP revenues as reflected in the filing. Also, the effect of RTP tariffs on the Company's IRP was properly considered in prior IRP proceedings. The Commission, based on the Company's test period expenses and revenues, and other evidence presented in Docket 9355-U, concluded that the rate reductions included in the modified stipulation adopted as the "Accounting Order Alternative Rate Plan" resulted in rates that were "fair, just and reasonable".

Q. DOES THE COMMISSION'S ORDER IN DOCKET NO. 9355-U SPECIFICALLY REFERENCE RTP TARIFFS?

A. Yes. The Order in paragraph 5, page 4 of 7, which discusses the allocation of rate reductions, specifically states that "Georgia Power's Real Time Pricing rates will not be reduced."

Q. WOULD YOU PLEASE SUMMARIZE THE GENERAL TERMS OF THE COMMISSION'S ACCOUNTING ORDER ALTERNATIVE RATE PLAN.

A. The Accounting Order reduced rates $262 million effective January 1, 1999 and an additional $24 million effective January 1, 2000. The Order requires the Company to record $85 million per year in accelerated amortization of regulatory assets. The Company's earnings are evaluated against a retail return on equity (ROE) range of 10.0% to 12.5%. In 1999, two-thirds of any revenues above the 12.5% ROE are used for additional rate reductions, with the Company retaining the remaining one-third. In 2000 and 2001, the first $50 million of any revenue above the 12.5% will go to additional accelerated amortization of regulatory assets, after which any remaining amounts will be subject to the aforementioned sharing mechanism.

Q. WOULD THE CHANGES TO THE RTP TARIFFS PROPOSED BY GTMA & GIG IMPACT THE OPERATION OF THE ACCOUNTING ORDER?

A. Yes. The proposed changes to the RTP tariffs would reduce base revenues billed under the RTP tariffs. A reduction in base revenue would impact the sharing provision of the Accounting Order and the ability to accelerate amortization of regulatory assets. A

reduction in rates paid by RTP customers could result in smaller rate reductions for other customers (through the sharing mechanism), less ability to accelerate amortization of regulatory assets and a reduction in the Company's earnings.

Q. IS THE COMPANY CORRECTLY ACCOUNTING FOR THE FUEL ASPECT OF THE RTP RATE?

A. Yes. GPC is accounting for fuel in the RTP tariff exactly as this Commission has approved on at least three occasions and it is specifically prescribed in the RTP tariffs.

Q. HOW IS FUEL COST HANDLED IN THE RTP TARIFF?

A. Fuel cost incurred when generating electricity out of our plants is accounted for and recovered separately from other GPC costs, as dictated by Georgia State law and this Commission. This separate accountability for fuel cost is deemed the Fuel Clause Recovery (FCR) mechanism. Non-fuel costs are recovered through base rates. When electricity is purchased from other suppliers on a per-kWh basis, these costs also flow through the FCR. The FCR is a cost pass through mechanism with no profit feature. All retail customers of GPC whether residential, commercial, or RTP customers have the same fuel cost responsibility (broken down into 3 distinct voltage levels of service). This average costing mechanism has been deemed a fair way by this Commission for the strict collection of fuel cost and related purchase power expenses.

With most GPC tariffs, there is a separate, distinct FCR component. This component is produced by multiplying the customer's monthly kWh consumption times the current applicable FCR rate. This procedure is also performed on the standard bill (CBL) portion of an RTP customer since a base rate is applied to the CBL. However, with the incremental RTP portion of the bill, there is already a component (lambda) in the RTP price which collects for several costs, one of which is fuel. So to prevent double recovery, the FCR rate does not show up as an additional component in the incremental RTP bill. And to continue with the precedent of equal and average fuel cost accountability, an equivalent FCR rate is removed from the incremental RTP rate revenue and credited to the fuel clause. This procedure ensures that equal fuel cost accountability is maintained.

Q. IS IT APPROPRIATE UNDER THE ACCOUNTING ORDER TO CHANGE THE RTP TARIFFS AND FUEL ACCOUNTING TREATMENT AS PROPOSED BY GTMA & GIG?

A. No. As stated earlier, the Commission concluded in the 1998 rate case that the Company's tariffs, as reduced by the Accounting Order, are fair, just and reasonable. The Commission made that determination based on an extensive review of test period expenses and revenues and other evidence presented in the rate case. The fuel accounting is being performed correctly. To now selectively change the RTP tariffs and reduce base revenues would be contrary to the multi-year Accounting Order concept. The Commission made its determination and allocation of rate reductions based on the

evidence presented in the case. The sharing mechanism approved by the Commission recognizes that actual revenues will vary based on weather, sales growth, and general economic conditions and accordingly provides a balance of benefits to our customers and the Company. In requesting these changes to the RTP tariffs GIG and GTMA are simply trying to supercede the Commission's allocation of rate reductions in the 1998 rate case and the balancing of customer and Company interests through the sharing mechanism.

CURRENT MARGINAL COST COVERAGE

Q. DOES THE CURRENT RTP PRICE ADEQUATELY COVER MARGINAL COST FOR GPC?

A. Yes it does. With the inclusion of the present risk adder, lambda definition and overall tariff structure, any additional cost risk can be covered adequately.

Q. YOU MENTIONED "ADDITIONAL COST RISK." WHAT ADDITIONAL COST RISKS ARE THERE WHICH ARE NOT CURRENTLY COVERED IN THE RTP INCREMENTAL PRICE?

A. There are several:

1. As mentioned previously, unit commitment costs are not included in the RTP price signal. Unit commitment costs are fuel and variable Operating and Maintenance (O&M) cost experienced when a unit is run out of economic dispatch (i.e. at a time when it would not normally be running if it were not needed for a future time in order to achieve overall total cost minimization) in order to most optimally serve load in a future period under a goal of overall cost minimization. These fuel costs are recovered through the FCR. However, since unit commitment costs are incurred when the unit is "out of economic dispatch," it does not show up in the lambda during these out-of-dispatch hours, but does later actually lower the lambdas in those hours it is planned for in cost minimization. So, the RTP customer gets a lower lambda later without paying for the cost experienced earlier, which allows the later benefit. An enhancement to RTP would be to add onto the later hours to which the unit is committed a cost reflecting this pre-commitment expense.

2. Also mentioned earlier, Clean Air Cost, which is the value of SO_2 emissions allowances, is emissions allowances that the SES has been granted for designated units. The revenue from these sales can be credited to the FCR thereby lowering everyone's FCR rate. Currently this clean air cost for corresponding units is not reflected in the RTP hourly price even though it has a "revenue/cost" effect. If these units are not run, these allowances can be sold in the marketplace. This clean air cost effect could easily be added to lambda in order to signal to an RTP customer the true economic effect of his decision to consume a kWh on the margin.

3. The RTP price has a marginal cost component for generating and transmission (G&T) expenses. These are included because a decision by a customer to consume a kWh on the margin can have a direct effect upon G&T costs. On the other hand, there is nothing within the incremental RTP price for distribution or overheads. The reason for this omission is that these costs do not vary directly with a customer's decision to consume a kWh on the margin, but do so more in an indirect manner. The original RTP design assumed that existing distribution and overheads would be compensated for through the CBL mechanism and any incremental effects would be small enough that they could be accommodated by GPC through the approved contribution effect of the RTP rate. But as customers have been on RTP for 5-7 years enjoying load growth from these economic RTP prices, they have indirectly influenced additional distribution and overhead cost to the extent that the present approved contribution effect of RTP must remain in place to provide the appropriate cost contribution.

4. In spite of the petitioners' allegations, there is still forecasting risk to GPC. Even though there now is 6-7 years experience forecasting RTP prices, as the petitioners point out, the last 2 years have experienced extreme price volatility. This has made it even more difficult to predict our hourly marginal cost and be assured we will cover our cost. As shown in the Company's response to Staff data requests, for the 1999 year, we actually under-forecasted our actual lambda for RTP-DA. Also contrary to the petitioners' allegations, this can have a damaging effect on eventual earnings even with the FCR in place – this fact is clearly revealed in response to Staff data requests.

Q. WHAT WOULD BE THE EFFECT OF REMOVING PURCHASED POWER FROM LAMBDA IN SETTING THE RTP PRICE?

A. If this change were made to the RTP price, it would no longer be a marginal cost rate. Lambda is the marginal cost consequence of a marginal consumption decision much like Last-In-First-Out (LIFO) is used with inventory evaluations. RTP would no longer signal to an RTP customer what the true cost consequences are of his making a marginal change to his consumption. This, therefore, would then violate the original intent of the rate.

Q. WOULD THE OVERALL RTP PRICE GO DOWN IF YOU WERE TO REMOVE PURCHASES?

A. Because economic purchases are often made rather than dispatching more expensive owned units in addition to the times when expensive purchases are made when we are out of owned units, in a normal year the RTP might actually go up. It is highly likely that it would have gone up during the early years of RTP. 1999 was a hot year across the United States such that had purchases been removed the overall 1999 RTP price would likely have been less than it actually was. But one must realize that had this been done in 1999, RTP would not have reflected marginal cost, resultant prices would likely have been lower, resultant RTP price response would have been less thereby requiring even more expensive purchases, and possibly impairing the reliability of the system such that

Interruptible Service (IS) customers would have to have been interrupted even more than they actually were during 1999.

Q. HAVE THERE BEEN SOME QUESTIONS ABOUT INTERRUPTIBLE SERVICE (IS) BY THE COMMISSION STAFF ABOUT HOW "IS" CUSTOMERS ARE CALLED AND THE IMPACT ON RTP CUSTOMERS. PLEASE ELABORATE ON THIS?

A. Yes. "IS" customers have contracted with GPC to interrupt their interruptible load with at least 30 minutes notice whenever requested up to 240 hours per year. As compensation, customers are paid an IS credit of up to $45/kw-year, plus an energy credit of 3.22¢/kWh. Historically, these calls have been strictly for reliability purposes when the system is in jeopardy. Please see Exhibit___(HKO-7) for a history of "IS" calls. However, with the recent advent of very high wholesale power prices, if the "IS" resource were also called for economics (i.e. whenever wholesale purchases exceeded a threshold), there would be a significant drop in the resultant RTP price. The threshold could be set high resulting in few economics calls but significant cost savings to the system and lower RTP prices would result. For instance, the expected average RTP-DA price for 2000 is 3.09¢/kWh assuming "IS" is called only for reliability purposes. If "IS" were also called for economic reasons at a threshold price of $350/mWh (35¢/kWh), there would be only 6 additional hours of expected calls, and yet the expected RTP price would fall from 3.09 cents per kWh to 2.9 cents per kWh, almost 2 mills/kWh.

Q. THE PETITIONERS CLAIM THAT PURCHASES HAVE JUST RECENTLY SURFACED IN RTP. IS THIS TRUE?

A. No. Purchased power has been influencing RTP since its inception. It has been a major influence in keeping RTP prices down during the early to mid-90's. It has always been within our stack of resources, which is why when we refer to "generation", it naturally applies to owned units and purchases. It is very common for utilities such as Kansas City Power and Light along with Virginia Power Company to include purchases in their "generation" component of RTP. Kansas City Power and Light Company states in its RTP tariff "Marginal Cost = Projections of the hourly running costs of incremental generation and wholesale prices, ... so that the algorithm for our RTP price calculation includes market prices so as to best approximate opportunity cost on the transaction." (KCPL rate name – "Schedule RTP") Purchases are merely another resource similar to a generating unit. This is why when we refer to "generation," we're referring to all generation resources, which naturally includes purchases.

COMPETITIVENESS OF RTP PRICES AND INDUSTRIAL RATES

Q. WHAT SOURCES ARE AVAILABLE TO SEE HOW COMPETITIVE GEORGIA POWER RATES ARE AS COMPARED TO OTHER UTILITIES IN THE SOUTHEAST?

A. There are many sources of utility pricing information. The Edison Electric Institute (EEI) and the Department of Energy (DOE) routinely publish information on utility prices. Many private firms, such as Regulatory Research Associates (RRA) and Resource Data International (RDI) also publish utility pricing information. I review each of these sources.

Each source uses their own methodology and should be carefully evaluated before being adopted as a sole criterion.

Q. DESCRIBE THE PUBLICATION BY THE EDISON ELECTRIC INSTITUTE?

A. EEI publishes several comparisons of investor owned utility prices. One of these is EEI's Typical Bills and Average Rates Report, which is published twice a year and covers all classes of customers and usage levels. Although the information for the typical bill report is prepared and submitted by the utilities themselves, there are variations in how each utility prepares its information.

This is particularly true for industrial customers who have rate options and riders such as interruptible service and real time pricing riders.

Q. DOES THIS MEAN THAT THE NUMBERS PUBLISHED IN THE EEI TYPICAL BILLS REPORT ARE WRONG?

A. No, the numbers are not wrong, but they are not always done the same way by each utility. For example, in GPC's case, our calculations are based on our standard tariffs such as our Power and Light (PL) rate and do not include any usage under GPC's Real Time Pricing rider or interruptible service credits.

While comparisons in EEI's report of small and medium sized commercial customers and residential customers do not suffer from these drawbacks, comparisons of industrial customers can be quite misleading, depending on what riders and rate options were used by each utility.

For example, Georgia Power's RTP hour-ahead (HA) customers rely on RTP for over 32% of their total usage. Therefore, to rely on standard tariffs alone for these customers is to leave out 32% of their usage in determining what these customers actually pay for electricity. RTP's day-ahead (DA) customers rely on RTP for almost 36% of their total usage. Customers with load factors over 80% can often rely on RTP for even more of their usage.

When a customer evaluates energy usage and cost it is much more appropriate to look at what the customer actually pays in total, rather than just a portion of his usage. This is particularly true for Georgia Power since a large portion of our industrial load is served under the RTP tariff. Looking only at the standard bill portion would leave out a large portion of our industrial customer's usage. In fact, in 1999, energy sold to customers

under Georgia Power's RTP tariff would have amounted to almost 35% of total industrial class usage.

For these reasons the comparisons in the testimony filed in this docket for GIG and GTMA customers made using standard tariffs alone form an incomplete and in fact misleading picture of a group as unique as GIG and GTMA.

Q. CAN APPROPRIATE COMPARISONS BE MADE USING OTHER SOURCES?

A. Yes, they can. Similar information is also published each fall by the Department of Energy's Energy Information Agency in its Electric Sales and Revenue report. This report is in fact available publicly at no charge on DOE's web site -- WWW.EIA.DOE.GOV.

Q. WHY DO YOU CONSIDER THESE COMPARISONS APPROPRIATE?

A. These comparisons include prices for all pricing options used by industrial customers, therefore giving a complete picture of what industrial customers are paying for their total usage. Further, the report includes examples of industrial prices in other regions of the country as well as the national average for all industrial kWhs sold in 1998.

Q. HAVE YOU MADE THESE COMPARISONS?

A. Yes. We routinely review prices for all classes of customers on both a regional and national basis in the normal course of business.

Exhibit___(HKO-8) 1998 Industrial Price per kWh Comparisons, summarizes information obtained from DOE's 1998 Electric Sales and Revenue, the last year complete information is publicly available. This exhibit lists the total average price per kWh paid by industrial customers for utilities in the United States.

Q. WHAT DOES THIS EXHIBIT INDICATE?

A. This exhibit indicates Georgia Power ranks 10th out of 19 investor owned suppliers in the southeastern United States. A line item was added to show Georgia Power's 1999 average industrial price per kWh which reflects the effect of the most recent rate reduction implemented in January 1999.

Additionally the prices all GIG and GTMA customers paid on average in 1998 as well as 1999 was added to this exhibit as a reference point. GTMA's 1999 overall average price was 3.7 cents per kWh and GIG's 1999 overall average price was ~~3.26~~ 3.32 cents per kWh, well below almost all suppliers on the exhibit and certainly much lower than portrayed in the comparison offered by Mr. Pollock in his testimony filed in this docket.

The exhibit also indicates GPC's average industrial price is almost 7% below the national average.

It should be noted that if you look outside the southeast, that Georgia Power's average industrial price is at least 50% below those in states such as California, Pennsylvania and Massachusetts who are in the process of deregulation.

Q. ARE PRICES IN THE SOUTHEAST LOWER THAN IN THE REST OF THE UNITED STATES?

A. Yes, prices are quite low in the southeast. Many utilities in our region have industrial class prices well below the national average. Our region has a number of very price competitive utilities.

The joint efforts of the public utility commissions and the utilities are responsible for this. Clearly, economic development in our region has been and continues to be positively influenced by low prices for industrial manufacturers.

Q. SHOULD WE BE MORE CONCERNED ABOUT PRICES WITHIN THE REGION OR ACROSS THE COUNTRY?

A. Both comparisons are important. It is appropriate to continue to examine and compare prices not only among southeastern suppliers but also to national averages and other regions.

The state of Georgia and our industries compete in a national marketplace. We should always be aware of how competitive we are on a national basis.

Q. PRICE COMPARISONS WITH THE TENNESSEE VALLEY AUTHORITY ARE NOT INCLUDED, WHY?

A. It is inappropriate to place TVA in the same category as investor owned utilities that are subject to state and federal tax codes and must compete for investor's capital. The Tennessee Valley Authority (TVA) is a major electric supplier in the southeast. TVA is an entity created by the United States government and in its initial stages was funded entirely by United States government backed capital. Even today TVA pays no federal income taxes and is not subject to any regulatory body; its sole oversight is by the United States Congress.

Q. ARE MARGINAL PRICES HIGHER THAN EMBEDDED PRICES?

A. No. The annual average marginal prices are below annual average embedded prices. In testimony sponsored by GIG and GTMA for this docket on page 12, Mr. Pollock incorrectly states that marginal costs are significantly higher than embedded costs. As a simple example, a 100% load factor load shape priced on RTP-DA in 1999 would be priced at 3.57¢ per kWh. This same load shape would cost an average of 4.1¢ per kWh or 15% more on our embedded rate PLL with the Off Peak (OP) rider. Another example is a customer with a 75% load factor load shape. In 1999, if a sample customer had 70%

of their load on RTP and 30% of their load on our embedded PLL rate, then the total average annual price would have been 4.60¢ per kWh. If the entire load shape was priced on PLL/OP it would have been 4.96¢ per kWh.

Q. WHAT WERE THE AVERAGE PRICES PAID BY RTP CUSTOMERS IN 1999?

A. Because RTP customers respond to RTP prices differently and because they have different load shapes, the average price paid is always different from the prices offered. In 1999, the RTP-HA customers paid an average of **(Redacted) per kWh (1999 RTP-HA average paid price)** as compared to the offered price of **(Redacted) (1999 RTP-HA average offered price).** (See Exhibit___(HKO-9)) The RTP-DA customers paid an average of **(Redacted) per kWh (1999 RTP-DA average paid price)** as compared to the offered price of **(Redacted) (1999 RTP-DA average offered price).** (See Exhibit___(HKO-10)) This of course is due to the fact that these customers bought slightly more kWh on-peak than off-peak.

Q. WHAT WERE THE AVERAGE PRICES PAID BY GIG AND GTMA RTP ACCOUNTS FOR 1999?

A. There are 64 GIG and 68 GTMA accounts on RTP tariffs. The average incremental RTP-DA price paid by GIG and GTMA was 3.39¢ and 3.61¢ per kWh respectively. For RTP-HA the average incremental price paid was 2.90¢ per kWh for GIG and 2.98¢ per kWh for GTMA.

If you combine the incremental energy with the energy in the Customer Baseline Load (CBL), the average price paid by all GIG RTP accounts was 3.26¢ per kWh and the average price paid by all GTMA RTP accounts was 3.70¢ per kWh. These prices are well below Georgia Power's average 1999 industrial price of 4.19¢ per kWh, and approximately 50% below average residential price of 7.27¢ per kWh and the average commercial price of 6.44¢ per kWh.

Q HOW SUCCESSFUL IS THE CURRENT RTP PROGRAM AT GEORGIA POWER?

A. It is extremely successful for both our Customers and the Company and it is working the way it was designed.

The RTP Program has 1560 Commercial and Industrial customers ranging in size from 250 kW to 145,000 kW. We are adding, on average, 10 accounts to the program each month and since 1992 less than 20 customers have left the rate.

For the year 1999, the average paid by all RTP-DA customers for all energy was 4.10¢ per kWh and the average price paid by all RTP-HA customers for all energy was 3.05¢ per kWh, both of which are lower than their costs would have been under other firm tariff rates. During the month of August 1999, 18 customers received a negative bill because

the credit they received for being below their CBL was greater than the standard bill for the CBL portion of their rate.

The customers and the Company have both benefited from the shift in load and price response. During 1999 customers responded to high RTP prices and established a need for less generation or purchased power. (See Exhibits___(HKO-6-1) and (HKO-6-2)). On the highest priced day the total load response from the RTP customers was 864 MW's, providing a significant savings to all customers of Georgia Power.

Q. WHAT HAS BEEN THE IMPACT OF VOLATILITY ON RTP PRICES?

A. During both 1998 and 1999, the marketplace has seen a change due to FERC Order 888, which was issued in 1996. The Order established the ability for power marketers to buy energy from and sell energy to utilities. No longer were utilities just selling to utilities. Now there was a third party setting the price. During 1998, the Southern Company was not exposed to the extreme market prices, and the most expensive energy purchased was $500 per MWh or 50¢ per kWh. During 1999, however, there were a few hours in which the Southern Company did purchase power at $6,000 per MWh or $6.00 per kWh. The number of hours with these high prices are very few as compared to the total number of hours in a year (8,760 hours). Also this extreme volatility observed in 1999 is not forseen in 2000 or 2001 as new generation has come on-line in the Southeast.

For RTP-DA in 1999, there were only **(Redacted) hours (1999 RTP-DA hours over 40.0¢ per kWh)** in which the price exceeded 40.0¢ per kWh and if the customer responded down to their CBL for these hours, their average RTP costs for the year would have been **(Redacted) per kWh (1999 RTP-DA average price for response during hours over 40.0¢ per kWh).** For RTP-HA in 1999, there were only **(Redacted) hours (1999 RTP-HA hours over 40.0¢ per kWh)** in which the price exceeded 40.0¢ per kWh and if the customer responded down to their CBL for these hours, their average RTP costs for the year would have been **(Redacted) per kWh (1999 RTP-HA average price for response during hours over 40.0¢ per kWh).** Exhibit___(HKO-11) shows the impact of responding to prices for 50 hours or more for the year 1999.

Even greater reduction in average prices would be achieved if the actual response was below the CBL.

RTP STRUCTURE FOR THE FUTURE

Q. IS RTP, AS IT IS CURRENTLY STRUCTURED, APPROPRIATE FOR THE FUTURE?

A. Yes. RTP is working in the way it was designed to work. It will continue to do so if unaltered. RTP was designed to signal marginal cost to a customer in the event of a marginal consumption change. It continues to do so. The problem is not in the structure of the tariff; the problem, simply put, is that marginal costs have risen over the life of RTP, especially the last two years. RTP customers have enjoyed the benefits of marginal

cost pricing for years and can continue to enjoy them. And, RTP will continue in the long run to be a cheaper alternative than an embedded rate (see Exhibit___(HKO-12)), and it should since it shifts risk from the utility to the customer. (Note there may be some years when RTP is greater than the alternative embedded rates, but in the long run it should be cheaper.)

However, the gap between embedded rates and RTP in the near future may not be as great as it was during the early to mid-1990's when there was excess base capacity and greater reserves in the industry. But this simply reflects a capital intensive industry in which there are broad swings in surplus and deficit capacity. To merely compare a period of large surpluses like the early 1990's to one of tight conditions like now and ignore the wisdom of cycles is foolhardy. It would be similar to a knee jerk reaction to the recent run-up in gasoline prices at the pump. Once again, the problem is not in the tariff structure and its designed purpose, the problem is that the gap between embedded costs and marginal costs has narrowed, and RTP is correctly revealing this.

Q. CAN THE CURRENT ADDER IN RTP BE LOWERED?

A. No. The current adder is reasonable and necessary, and there are several reasons why it should not be lowered:

(a) The adder helps cover forecasting risk. The wholesale market has become MANY times more volatile over the last two years making it more risky to forecast marginal cost than ever before. For 1999, the RTP-DA lambda (which was forecasted a day ahead) was almost 2 mills/kWh less than the actual lambda incurred the next day. In addition, forecast risk occurs in the other three components of the RTP prices.

(b) To reduce the risk adder could negatively impact non-RTP customers (through the Accounting Order) and the Company. The adder, like all components of all tariffs was included in the revenue projections in the Accounting Order. In that docket, the petitioners wanted the rate reduction applied to the adder, but the Commission decided there not to reduce the RTP tariff.

(c) GPC actually credits the entire RTP, including the adder, for decrements. This is done for simplicity purposes since it makes no logical sense for GPC to also credit the adder, thereby giving away its profits for a customer's non-consumption. To reduce the adder would lower customer's credits for reductions below the CBL.

(d) As inflation has increased RTP prices, the adder has remained constant since 1992, thereby becoming a smaller and smaller component of the overall price, and indeed a smaller benefit to GPC in terms of current economic value.

(e) The current risk adder helps lessen the pressure to include clean air and unit commitment cost in RTP, and also contributes to any distribution and overhead costs driven by incremental RTP sales.

(f) The equivalent mark-up in non-RTP rates is considerably higher. The minimum PLL mark-up is 6.5 mills/kWh.

(g) RTP adders by other utilities are typically equal to or higher than GPC's:

i. Duke's RTP (Schedule HP) is 5 mills/kWh
ii. TVA's RTP (ESP Options D&E) is 8 mills/kWh
iii. SCE&G's RTP (Large Power Service RTP-Rate 27) is 5 mills/kWh.

Q. WILL THE RTP PRICE INCREASE OBSERVED IN 1998 AND 1999 CONTINUE IN 2000?

A. It could for a particular year if that year is extremely hot like 1998 and 1999. But, if future years return to normal weather, RTP will not rise dramatically and will be below those levels observed in 1998 and 1999. In fact, our expected RTP-DA price for 2000 is **(Redacted) cents/kWh (2000 RTP-DA expected price),** which is **(Redacted) (percentage reduction in RTP-DA price for 2000)** below the 1999 actual. (Please see Exhibit___(HKO-13)). And, with some of the new rate alternatives included in this filing, we are willing to assure our RTP customers who take these options that this will be the most they will have to pay for any RTP load that they want to place on the alternative.

Q. DO YOU EXPECT THE RTP PRICES TO CONTINUE TO REMAIN HIGH OR MODERATE?

A. Since the high RTP prices are related to: extreme weather conditions; unit outages; regional reserves; and the spot market price of purchase, we expect that RTP prices will moderate over time. The reason for this is simple. Since the current high spot market prices are a result of a tight supply market, we believe that the industry and independent developers are responding to this tight market by adding significant amounts of new capacity in the Southeast and around the nation. As these new resources become available to the market, the prices paid in the spot market should moderate and be lower cost in real terms. Thus, the RTP price signals should reflect this change as well.

Q. MR. POLLOCK STATED THAT 1999 WAS NOT THAT HOT A YEAR, AND YOU'RE SAYING THAT HOT WEATHER DID CAUSE THE HIGH 1999 PRICES. HOW DO YOU EXPLAIN THIS?

A. While it is true that the summer of 1998 was hotter on average than the summer of 1999, the summer of 1998 heat was spread throughout the summer months and not concentrated in any one period. On the other hand, the period between July and the end of August 1999 had more extreme weather than any comparable period in 1998. For instance, August 1999 had 21.5% more cooling degree days than a normal August. This 21.5% difference in cooling degree days was higher than the difference between actual and normal weather for any summer month in 1998. This concentration of extreme temperatures in late July and early August drove the peak load to record levels day after day, thus contributing to record-level wholesale spot market prices and extreme RTP prices.

An indication of the difference in the concentration of heat during 1999 can be seen in the energy weighted maximum temperatures. Georgia Power Company uses seven weather stations located across the state. These hourly temperatures of weather stations are weighted based on energy consumption for the area surrounding each station. This weighting provides an hourly temperature that is representative of Georgia Power's entire service area. During 1998, the maximum hourly weighted temperature for the year was only 96.2 degrees. However, in 1999 the maximum hourly weighted temperature for the year was 98.8 degrees, a difference of almost 2.6 degrees. Moreover, 1999 had a period of about a week with such extreme temperatures. Even though over the course of the entire year, 1999 was slightly cooler than 1998, the extended high temperatures in 1999 had a very significant impact on peak demand and RTP prices.

We are a summer peaking utility. Each individual hour is critical and its load must be served. As a utility becomes constrained, its hourly marginal cost accelerates at a non-linear, exponential rate. In other words, a one degree temperature change in a summer afternoon day averaging 95ºF can have an extraordinary influence on load, while a one degree temperature change when the temperature is averaging 85ºF can have a very mild influence. (One-degree change when temperatures are in the 90's can add 750mW's of load to the SES). One cannot merely look at overall heating degree and cooling degree days for the year to ascertain if weather has influenced load and prices. If during one hour the actual temperature were 84ºF instead of the expected 85ºF, and in another hour the actual temperature were 96ºF instead of the expected 95ºF, Mr. Pollock's methodology would ask you to believe that you had normal weather over these two hours, and therefore, loads and prices should be normal.

Q. WERE THERE SPECIFIC CRITICAL TIME PERIODS DURING 1999 WHEN TEMPERATURES AND LOADS WERE EXTRAORDINARILY HIGH?

A. For the first 6¾ months of 1999, the weather was somewhat normal, and prices were near expectations. Then on July 23 a heat wave came across the U.S. and lasted through August. The cooling degree days (CDDs) from 7/23/99-8/31/99 in the territory that we serve were the hottest ever recorded, amounting to over 20% above the average of the past 20 years! Loads skyrocketed with the SES setting numerous all-time peaks along with many other utilities (some of these other utilities even experienced blackouts). As a result, wholesale prices and RTP prices skyrocketed during this period. The result was average RTP prices for July and August at extremely high levels (note the one hot week in July caused prices that week that more than offset the relatively mild RTP prices for the first three weeks of July). The average RTP price for 1999 was greatly influenced by these two months. The 1998 peak was exceeded for a total of 64 hours during late July and early August. The bottom line is, we don't expect extraordinary weather patterns like this to continue. We have RTP price expectations reflecting this belief, and we're willing to offer RTP Alternatives that will assure the customers of these prices.

REAL-TIME PRICING (RTP) ALTERNATIVES

Q. WHAT IS THE PURPOSE OF THE RTP ALTERNATIVES?

A. The RTP Alternatives are excellent pricing solutions for RTP customers who have a need for additional control over their exposure to RTP prices. The purpose of the RTP Alternatives is to allow RTP customers to manage, reduce or remove price risk associated with RTP. While many RTP customers will prefer to stay on the RTP tariff, others will have the opportunity to move to an alternative that will provide more stability and certainty than RTP alone. They are not to replace RTP or to suggest that RTP is not a good tariff that is doing what it was designed to do.

Q. WHY HAS GPC FILED AND OFFERED THE RTP ALTERNATIVES?

A. First of all, many customers want more pricing options and more control over their electricity costs. GPC always desires to meet the needs of our customers with innovative pricing products. For example, GPC has supported the offering of Price Protection Products to RTP customers for several years. The portfolio of new RTP Alternatives will successfully meet the needs of RTP customers to mitigate RTP price risk. The Alternatives provide fair, reasonable and competitive rate options. They are excellent pricing solutions for RTP customers.

Second, customers have requested the development and offering of these specific rate alternatives. The W.A.N.T. Project (What Are The Needs Today; see Exhibit___(HKO-14)) was a year-long Georgia Power initiative in 1999 aimed at developing innovative pricing products to meet the needs in our marketplace. In this extensive market research project, we surveyed and interviewed many RTP customers to understand their needs. We designed the Alternatives around their needs and tested the Alternatives with those customers. Customer feedback on this package of Alternatives has been clearly positive and favorable because of the Alternatives' ability to alleviate risk at fair and reasonable prices.

Q. BRIEFLY DESCRIBE THE RTP ALTERNATIVES.

A. A general analogy to illustrate the value of the RTP Alternatives would be home mortgage rate options. A prospective homeowner's alternatives for paying the mortgage company for the loan service include a range of choices, from purely adjustable rates to 30-year fixed rates. The adjustable mortgage rates obviously represent RTP in this analogy, and the range of other alternatives, which could be part-adjustable/part-fixed options or completely fixed options, represent the new RTP Alternatives. With the adjustable mortgage rates and RTP, you take on more risk to get access to the lower cost. With the fixed mortgage rates and the RTP Alternatives, you agree to pay a little more to lock in an attractive rate and protect yourself against possible increases during some periods of time.

GPC proposes the following four RTP Alternatives. A tabular summary is provided as well as a brief written description on each of the Alternatives. In addition, a "scorecard" on specific attributes is shown on Exhibit___(HKO-15).

Alternative	Description
RTP with Adjustable CBL	Raise or lower CBL at expected RTP prices
RTP with Price Protection Products	Financial hedge contracts (CfDs, Caps, Collars and Index Pricing)
Variable Incremental Pricing	Time of Use (TOU) pricing; interruptible for reliability and economics
Fixed Incremental Pricing	TOU pricing

1) **RTP with Adjustable CBL**

RTP with Adjustable CBL allows an RTP customer to manage RTP price risk. The customer may adjust the Customer Baseline Load (CBL) once a year to manage the level of exposure to RTP prices. The customer may select to raise the CBL for a twelve-month period in order to lock in expected RTP prices for some or all of the incremental load. Or the customer may select to lower the CBL for a twelve-month period in order to apply RTP prices to more load. The monthly Standard Bills will be recalculated to reflect the adjustment to the CBL. See Exhibit___(HKO-16-1) and (HKO-16-2) for illustrations. Refer to Exhibits___(HKO-16-3) and (HKO-16-4) for copies of the tariffs.

2) **RTP with Price Protection Products**

RTP with Price Protection Products (PPP) allows a RTP customer to manage RTP price risk. PPPs are separate financial hedge contracts (Caps, CfDs, Collars and Index Prices) that may be used to achieve price stability during specific time periods. GPC has offered PPPs on a limited, pilot basis in the past and seeks to improve and expand the program to more customers with more products. See Exhibits___(HKO-17-1) and (HKO-17-2) and (HKO-17-3) for an example. Refer to Exhibit___(HKO-17-4) for a copy of the tariff.

3) **Variable Incremental Pricing**

Variable Incremental Pricing (VIP) allows a RTP customer to reduce RTP price risk. VIP provides TOU pricing in most hours for the incremental load, that is, load in excess of the CBL. The incremental load is interruptible for both economic and reliability considerations. During the economic and reliability periods the customer may choose to "buy through" by paying RTP-HA (Hour Ahead) prices and RTP-HA plus $3.50/kWh, respectively. VIP should be thought of as a non-RTP rate alternative. In fact, it is similar to PL plus the SE rider, but with a lot of improvements. See Exhibit___(HKO-18-1) for an illustration. Refer to Exhibit___(HKO-18-2) for a copy of the tariff.

4) **Fixed Incremental Pricing**

Fixed Incremental Pricing (FIP) allows an RTP customer to remove RTP price risk. FIP provides simple, fixed, firm Time-Of-Use (TOU) pricing for those customers who prefer a stable price. To simplify the pricing and billing under this tariff, all of the customer's usage is actually priced at the FIP TOU energy charges, and a fixed charge is developed

to cover the fixed costs of serving the customer. This economic TOU tariff should also be thought of as a non-RTP rate alternative. It is a simple, economically priced TOU rate. Refer to Exhibit___(HKO-19) for a copy of the tariff. Refer also to Exhibit___(HKO-20) for an updated version of the Large Business Reduction Rider (LBR-2) which now includes FIP. See Exhibit___(HKO-21) for an example.

See Exhibit___(HKO-22) which shows a menu of RTP Alternatives. See Exhibit___(HKO-23) which illustrates cost versus price risk for the RTP Alternatives.

Q. HOW MANY CUSTOMERS ARE EXPECTED TO GO ON THE RTP ALTERNATIVES?

A. The following table describes the possible participation rates for each alternative.

Alternative	Possible Participation Rates
RTP with Adjustable CBL	200- 400 customers
RTP with Price Protection Products	200- 400 customers
Variable Incremental Pricing	50-200 customers
Fixed Incremental Pricing	100-300 customers
Remain with Standard RTP Tariff	600-1000 customers

Q. WHAT ARE THE BENEFITS OF THE RTP ALTERNATIVES?

A. There are many significant benefits of the RTP Alternatives to customers, the Company and non-participants. Some of them are:

- Improves customers' operating budget stability
- Allows customers to transfer more or additional price risk to Georgia Power
- Allows customers to lock in profits from their products and services
- Insures customers against extreme weather and other events which drive RTP prices up
- Improves customer satisfaction
- Provides simplicity (e.g., FIP)
- Maintains competitive pricing
- Maintains efficient price signals which will retain on-peak load response

Q. DESCRIBE GPC'S EXPERIENCE WITH PRICE PROTECTION PRODUCTS.

A. The Company has completed very successful pilot programs with Price Protection Products. Informal surveys of account representatives and customers have revealed significant interest in PPPs. Customers who have purchased PPPs are very satisfied, and it is highly likely they will use them again. Many customers who have not purchased PPPs have indicated that it is highly likely they will purchase them in the future if they are available. Some customers would like to see more options, and all customers need more time prior to the summer to complete their decision analysis. Therefore, it is

important that the company be able to have firm plans from year to year to offer PPPs in order to help customers plan for upcoming periods. It is very difficult for a customer to plan if they are not sure whether or not PPPs will be available.

Customers appreciate the options and have shown significant interest in PPPs as demonstrated by the following information. In 1996, 13 contracts were signed (9 Caps and 4 CfDs). The company collected $343,000 which was driven by the relatively mild summer weather in 1996. In 1999, 64 contracts were signed (49 CfDs, 12 Caps and 3 Collars). The company collected $337,000 and paid out $2,166,000. The payouts were driven by the severe heat in late July and early August. In summary, PPPs have been very successful for both the customers and the company, and RTP customers have expressed their desire that the program continue and be expanded.

Q. HAVE YOU ASKED YOUR CUSTOMERS WHETHER THEY WOULD BE INTERESTED IN POTENTIAL PRICING PRODUCTS?

A. Yes, and we have found a lot of excitement and eagerness on our customers' part to get them approved. There will be a considerable number (maybe 1/3 to 2/3) of the present RTP population who will choose to stay on the RTP tariff since, as previously stated, in the long run RTP should be the cheapest option. In fact, a number of the customers represented by GIG and GTMA may remain with RTP for this reason, but a considerable number may volunteer for the Alternatives.

SPECIFIC ERRORS AND MISSTATEMENT IN PETITIONER'S TESTIMONY

Q. DID MR. POLLOCK CORRECTLY CALCULATE THE REVENUE VARIANCE ASSOCIATED WITH HIGH REAL TIME PRICES IN 1999?

A. No, the $63 million figure calculated by Mr. Pollock is incorrect. Actual RTP revenues during 1999 were $48,976,678 above the forecasted revenues. Since total 1999 Georgia Power revenues were $131.7 million over the forecasted revenues, the RTP revenue variance was about 37% of the total, instead of 60% quoted by Mr. Pollock. For comparison, 14.5% of the revenue variance was supplied by residential customers and 50% of the revenues variance was supplied by commercial customers.

Q. DO YOU AGREE WITH MR. POLLOCK WHERE HE STATES THAT RTP IS NO LONGER A COST-BASED RATE BECAUSE OF GPC'S "...APPARENT UNWILLINGNESS TO PROTECT ITS CAPTIVE CUSTOMERS FROM THE EXTREME HIGH PRICES AND VOLATILITY CAUSED BY TIGHT CAPACITY SUPPLIES..."?

A. No. This is not a true statement, but demonstrates a misunderstanding of the difference between marginal costs and average costs. Rates based on real time system lambda (system incremental cost) are inherently both marginal cost based and volatile. System incremental cost, as calculated in real time, is highly sensitive to the available system

generation mix (which is subject to resource outage variations), load variations (which are in turn highly sensitive to weather variations) and various congestion factors, all of which can be and are monetized for use in the calculation of RTP prices. This is distinctly different from average cost methodology where volatility is averaged out over time.

Mr. Pollock states that "... the RTP tariffs do not allow purchased power costs to be included in the hourly price..." This is not true. The original RTP tariff was developed based on the resource stack concept utilized by Southern Company for economic dispatch and unit commitment. Power purchases were considered a part of the resource stack and included in the calculation of system incremental costs at the time RTP was developed as they are today. They were not nearly as common at that time, but they were part of the stack. The Resource Stack concept was used at Southern Company and throughout the electric utility industry considerably prior to the development of the RTP tariff. In this concept, all dispatchable resources, including both generation and purchases as well as (potentially) economically driven interruptible customers, are included in a resource stack that is ordered on an economic basis. Resources are drawn from the stack to serve system needs as required and the economic point in the stack from which the resource is drawn effectively sets system incremental cost or lambda. All dispatchable resources are included in the stack unless specifically excluded for contractual or technical reasons.

Q. CAN YOU COMMENT ON MR. POLLOCK'S COMPLAINTS ON THE INCREASE IN RTP PRICES?

A. There is no doubt that 1998 and 1999 RTP prices have been higher. One must be cautious however in presuming that the most recent two years are absolute indicators of the future. Please see Exhibit___(HKO-24) for the RTP price increase over the first 5 years. As we have stated earlier, the last two years have had extraordinary weather conditions when compared to the past 20 years. In addition, the cycle of this capital intensive industry in terms of capacity is very relevant. Exhibit___(HKO-25) shows an expected RTP price growth rate from inception to expected year 2000.

Q. IS MR. POLLOCK'S ANALOGY OF "SELLING A LOT FULL OF FORD AUTOMOBILES AT A MERCEDES PRICE JUST BECAUSE ONE MERCEDES HAPPENS TO BE PARKED ON THE SAME LOT" A FAIR ANALOGY?

A. No, absolutely not. Whether a kWh is generated by a base load unit, a combustion turbine, or a purchase, that kWh is identical in make-up. To use his construct you have a lot full of identical kWhs. The fact is that the last kWhs that you added to the lot are expensive, in fact the most expensive on the lot and indicative of what you will have to pay to add additional kWhs to your lot and possibly the future cost to replace any kWhs currently on your lot. So the products are sold on your lot at this recent cost (much like an accountant uses last-in-first-out --LIFO—for inventory valuation).

Q. IS MR. POLLOCK'S ALLEGATION ON PAGE 19 STATING THAT RTP SALES COULD SUPPORT PRODUCTION INVESTMENT 123% HIGHER THAN GPC'S NET PRODUCTION PLANT CORRECT?

A. No, and it contains numerous flaws. For one thing we have clearly shown previously that what Mr. Pollock is using as margin is not purely production plant margin. Mr. Pollock's testimony calculated "margin" as the difference between the total selling price and the associated Fuel Cost Rate (FCR). However, a margin should be calculated as the difference between the selling price and the costs of production. His approach ignores several key issues: (1) FCR recovers the total average fuel costs for all of the energy supplied by Georgia Power Company. The correct method of calculating RTP margin would include subtracting marginal fuel and purchase power costs from RTP revenues. (2) Subtracting certain transmission costs associated with RTP. (3) Subtracting certain generation reliability costs associated with RTP. (4) Subtracting risk cost associated with RTP. In addition, there are clean air, commitment costs, additional distribution plant, and incremental overheads that "margin" must cover.

The RTP rate was designed to provide customers with the benefits of marginal pricing while capturing marginal cost associated with serving RTP loads. It is incorrect to assume that fuel is the only marginal cost associated with RTP load and it also incorrect to assume that RTP fuel costs are equal to average fuel costs for the entire company.

Second, even if you performed the computation correctly, you certainly could not compare this marginal cost margin to GPC's "net production plant, which has a book value of about $340 per kW...". Marginal cost are distinctly different from net plant book value, just like replacement cost are very different from vintage cost. The SES could certainly not replace its production plant today at $340 per kW. Finally, if Mr. Pollock's idea here is to compare a "margin contribution" from RTP after removing the FCR, even if one thought this were a reasonable exercise, the fact is that CT investment cost is recovered through the outage cost component. This so-called lambda contribution above FCR is not necessary for recovery of CT cost per kW. Therefore, one should remove CT cost from the $340 per kW before making a comparison using this line of reasoning.

Q. PLEASE EXPAND ON MR. POLLOCK'S DEFINITION OF LAMBDA AS EXCLUDING PURCHASE POWER.

A. His definition applies to unit lambda only, not to system lambda. Lambda, as it applies to individual, fuel fired generating units per the IIC, includes:

- Unit Incremental Heat Rate at output P (b + 2cP)
- Marginal Fuel Cost (FC)
- Incremental emissions cost (EC, excluded from GPC RTP lambda)
- Fuel Handling Cost (FH)
- Variable Operating and Maintenance Cost (VOM)
- Transmission Penalty Factor (TPF)

The equation for Unit Lambda is:

$\lambda_u = [(b + 2c)(FC + EC) + FH + VOM]TPF$

Note, however, that unit lambda does not a system lambda make. System lambda is the incremental cost to serve the next MWH of load on the system. If it is served by fuel fired generating units, then the equation above is essentially correct, although somewhat simplistic (there are over one hundred units, each with its own unit lambda that go into the calculation of system lambda). However, if the next MWH of generation is being supplied by other than a fuel fired generating unit, then the incremental cost of that resource is used and not the equation above. This is typically the case for purchases at the top of the loading stack, but can apply equally well for nuclear resources at the bottom. Thus, as stated earlier, system lambda is set by the incremental cost of the resource being utilized from the resource stack, which may or may not be a fuel fired generating unit.

Q. ARE THE PURCHASE DECISIONS OF THE TRADING FLOOR INFLUENCED BY COST RECOVERY CONSIDERATIONS?

A. No. The trading floor seeks to obtain the most cost effective short-term products for the Operating Companies, with due regard for reliability and risk mitigation. Retail cost recovery considerations are not a motivating factor in the trading floor's decision making process. As explained in response to Staff Data Requests, the following are the general principles followed when making purchases and sales.

- Direct the lowest cost off-system energy available to territorial customers if it can reasonably be expected to result in savings.
- To extent energy from retail jurisdictional resources is marketed elsewhere, the transaction will be treated as an economy sale.
- If energy from resources that are not retail jurisdictional is marketed elsewhere, all losses or gains will be directed to the wholesale jurisdiction.
- Energy from retail jurisdictional resources, which have been replaced with lower cost energy, may be marketed elsewhere with impacts being direct to the wholesale jurisdiction.

SUMMARY RESPONSE TO PETITION

Q. WOULD YOU SUMMARIZE YOUR RESPONSES TO THE MAIN ISSUES RAISED BY THE PETITIONERS?

A. With respect to the issues raised by GTMA and GIG, it is Georgia Power Company's position that:

1. RTP should continue to be based upon marginal cost reflected in the last resource to serve the last increment of load.

2. The fuel clause should continue to be credited at the prevailing fuel cost recovery (FCR) rate.
3. The present risk adders of 5 mills for RTP-DA and 4.5 mills for RTP-HA are appropriate, reasonable and necessary.
4. The RTP tariffs were properly considered in prior IRP proceedings and in the Company's last retail rate case and the Commission determined that the rate reductions included in the modified stipulation adopted as the "Accounting Order Alternative Rate Plan" resulted in rates that were "fair, just and reasonable". Those tariffs should not be modified now.

Q. IN CONCLUSION SHOULD THIS COMMISSION MAKE ANY CHANGES TO THE RTP TARIFFS BASED ON THE PETITIONERS' DEMANDS?

A. No. The Commission should deny the requests of the petitioners and leave the RTP-DA and RTP-HA tariffs intact as they are. Also the Commission should approve the RTP Alternatives to allow for implementation for this summer.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MR. GREENE: And at this time, I believe Mr. Kubler is available for a brief summary of his testimony before cross examination.

WITNESS KUBLER: Commissioners, we're here today to address the issues that have been raised by Georgia Textile Manufacturers Association and Georgia Industrial Group pertaining to the real time pricing tariffs.

Contrary to what GTMA and GIG have said, as well as Mr Pollock, real time pricing is working well at Georgia Power Company. Since its inception in 1992, 1600 customers have come onto the tariff and in that same period of time less than 20 customers have actually left the rate.

When we went through the process of designing the real time pricing tariff, customers said they wanted flexibility in the way in which they could buy electricity and that's exactly what the rate provides to them.

Customers have been responding to the price signals that we have been sending out, and when that happens, everybody wins. Just by way of an example, in the integrated resource plan due to RTP price response, we recognized about 500 megawatts worth of price response from RTP. If you were to have to build a facility, make an investment to cover that price response, it would be $200 million and of course tens of millions of dollars cost to our customers annually.

Secondly, RTP covers marginal costs. System lambda, not to be confused with unit lambda, is the largest component in the RTP price. It comprises about 75 to 80 percent of the price. And it contains fuel, variable O&M and contributions towards capital. In the generation component costs, it does include native generation as well as purchased power. It does not include clean air and commitment costs.

If we were to average lambdas as proposed by GTMA and GIG, we would not be able to achieve full recovery of our marginal costs. And if that happens, who pays? All customers end up paying.

Third, purchased power is appropriately included in the RTP price calculation. Those purchases help to keep our RTP prices low. There are times when we do buy power that is actually less expensive or less costly than our native generation, and when we do, it does go into the overall calculation and does reduce the overall RTP price from what it would be otherwise. So, it is a generation resource and it is a cost in the generation dispatch.

We also have historically purchased power whenever it was available in order to prevent from having to interrupt our customers.

Next, fuel accounting under RTP is being done correctly. The changes proposed by GTMA and GIG would shift

base rate costs from the RTP customers to all other customers. This change that they are proposing is not consistent with the current statutes that are in place for the state of Georgia. Crediting fuel with the RTP revenue will not change the RTP price one bit. And after all, what I have been hearing this morning is that the RTP price is the issue, and this will not change the RTP price one bit.

We are doing it correctly, the fuel cost clause has been in existence for 20 years, this Commission has had numerous occasions to adjudicate fuel issues and we have been doing it consistently the way the Commission has ruled and the way the Commission has acted.

Next, the adder component of the RTP price is set at the appropriate level and is necessary. We still have risk on our system. As Mr. Pollock indicated, the prices were quite volatile during 1999 and as a result of that, we under-forecast, and that was one of the main reasons why that risk adder was put in there, to help us offset under-forecast conditions. It also is there to lessen the need to collect for clean air and commitment costs as well as any incremental distribution costs or administrative and general costs that we might incur as a result of serving this incremental RTP load.

Other RTP programs have an adder added. Duke Power Company, for example, uses five mills, just like

Georgia Power Company does. TVA, eight mills; South Carolina Electric & Gas, five mills.

And we would also submit that in the 1998 rate case, all rates were reviewed by this Commission and found to be just and reasonable. We were ordered to reduce our rates by $262 million in 1999 and an additional $24 million in the year 2000-2001. And the order specifically said there would be no reduction in the RTP prices. What it appears is that we're really trying to right now undo what the Commission had previously ordered.

Customers have and will continue to receive benefits from the procurement practices employed by Southern Company. Our practices continue to be available to the Commission for review, but we are very sensitive to the confidential nature of this information. It does result in commercial value if this information did find its way into the marketplace.

There are incentives put in place for us to go out and secure the cheapest power available. An example of those incentives would be attracting economic development to the state of Georgia.

The company has worked with our customers and the Commission to design tariffs that do lower rates.

VICE CHAIRMAN BURGESS: Hold on just a second.

(Brief pause.)

WITNESS KUBLER: The company has worked with our customers and the Commission to design tariffs that help lower our rates. What we are doing in this case in our filing is that we are recommending four alternatives. These alternatives we propose will help our customers mitigate price volatility, improve their budget stability within their companies, it will transfer more risk to the company and away from the customer and it will protect the customer from extreme weather.

The RTP adjustable CBL and the price protection products will help customers manage that risk. The variable incremental pricing product will help reduce that price risk. And the fixed incremental pricing will eliminate that price risk altogether.

We've heard an awful lot about rates and comparisons to other companies and other jurisdictions, but what I'm showing you here is really what the record is for the state of Georgia. 1991 we're using as a base year because RTP did not exist at that point in time. What this is showing is the prices paid and yes, while things do vary on a customer-by-customer basis, the best we think that you can see what is happening is to make these average type comparisons.

In 1999, you can see that we have reduced residential, we have reduced commercial and we have reduced

industrial rates overall. You can see in these three years what the DA customers paid, not just on their RTP purchases, but on their CBL purchases together. You can see that the RTP-HA customers likewise for '97, '98 and '99.

And yes, we did go through the process of looking at the GTMA members and we did look at all of their accounts. We looked at their outdoor lighting accounts, we looked at their general service accounts, and still they came up to be these average cents per kilowatt hour.

COMMISSIONER BAKER: Do the average prices for the residential, commercial and industrial include fuel costs or is --

WITNESS KUBLER: Yes. All of these numbers take into account fuel because the RTP prices and all have fuel already figured into the RTP price. So all of these numbers do include fuel.

So we've worked with our customers, we've worked with the Commission to produce some innovative tariffs and I think that's a pretty impressive record.

GTMA and GIG will tell you that the years 1998 and 1999 were bad years for RTP. But I'm here to remind you that 1993, '94, '95, '96 and '97 were excellent years for the RTP customers. And the year 2000 is expected to be better than 1999.

VICE CHAIRMAN BURGESS: Let me ask you, Mr.

Kubler, how many customers have you added to the RTP rate during 1998 and 1999?

WITNESS KUBLER: Mr. Commissioner, I don't have an exact number, but I do know that we're averaging about eight to ten customers per month.

VICE CHAIRMAN BURGESS: And how does that compare to '97 -- between 1991 and 1997?

WITNESS KUBLER: We've continued to add customers. When we first started this program, Mr. O'Sheasy and I thought we'd have about 250 accounts and we're now up to 1600. So we continue to add customers to this rate.

VICE CHAIRMAN BURGESS: One of the other things that you mentioned too was the economic development. I think that's something that this Commission is very in tune with and it's very important to this Commission. And I want your assessment of, given some of the changing conditions that we do see in this industry, what impact -- do you believe that this rate will continue to be a competitive rate to help expand existing business or create new business here in this state?

WITNESS KUBLER: Yes, I do. The RTP tariff is the lowest tariff that we have, and to the extent that we're trying to attract industry to the state of Georgia, it affords us the best opportunity to price our product in such a way that we can attract industry.

COMMISSIONER McDONALD: But does it attract the expansion of existing industry in our state rather than them looking at one of the sister states that supposedly, or it has been testified here today, that have a cheaper RTP price rate than what we presently have in Georgia?

WITNESS KUBLER: You have heard, just as I heard today, that there was a company that made the decision not to locate here because of electricity prices; but there are customers that do. So it's really on a customer or situation by situation.

In summary, this hearing is really not about the RTP structure, it's really about lowering rates. Do our customers ask for lower rates? Yes, they do, they all do, and they always will.

The Commission looked at this situation 15 months ago, 16 months ago, and the decision that they made was a good decision. Even though the revenues for 1999 were more than expected, the money, the vast majority of that money, two-thirds of it, is going to be returned to our customers and is going to lower or cause these prices for 1999 to be even lower.

So the company is just asking the Commission to look at the RTP alternatives that we are offering as being the best possible solution to the issues that have been raised by GTMA and GIG.

COMMISSIONER McDONALD: Mr. Kubler.

WITNESS KUBLER: Yes.

COMMISSIONER McDONALD: Would you mind backing up just a bit and revisiting the risk adder component and kind of bring me up to speed on your interpretation of the company's risk in that area.

WITNESS KUBLER: I can, but I would really like to defer to Mr. O'Sheasy.

COMMISSIONER McDONALD: That's fine.

WITNESS O'SHEASY: Commissioner, when we originally set that five mill adder for day ahead and 4.5, what we were looking for was a adder that would afford us a reasonable profit while encompassing the risk of the tariff itself. It did just that, it fit nicely with what adders were for similar tariffs throughout the country and that's why it was selected. And it continues to be the appropriate adder, as it is today.

Let's talk for just a few moments about is there still risk in RTP that an adder would be necessary. Yes, there is. Mr. Kubler was indicating that there's still forecasting risk with RTP. Whether you have a fuel cost recovery program or not, if we misforecast our lambdas, then it harms us. There's a staff data request, I believe it's 2-12, where I went through a simple exercise to show how Georgia Power loses if they underforecast the true lambda

that they incur.

The adder itself also contributes to the fact that there are some other marginal cost considerations that have arisen since the original rate was put into place, and Mr. Kubler was referring to clean air and commitment costs. Those are marginal cost considerations that are not in the current tariff, that can be accommodated with the current adder the way it is. In other words, Georgia Power can absorb those additional risk components with the current adder like it is.

That adder, by the way, which is five mills, is the lowest adder we have on any rate at Georgia Power Company. The nearest comparable rate to RTP for large industrial customers would be PLL. The adder for that is about 6.5 mills a kilowatt hour. That five mills is similar to the risk adder that you'll see other utilities with RTP programs currently experiencing.

So the adder is entirely appropriate. It has not changed at all since 1992. To the extent the RTP price has risen from 1992, as petitioners have pointed out, that adder is a smaller component of the overall price than it ever was. In terms of real value to the company, to the extent there's been inflation, it is a smaller contribution to the company. So in our opinion, it is entirely adequate the way it's currently structured.

VICE CHAIRMAN BURGESS: Mr. Greene.

MR. GREENE: Mr. Chairman, the panel is available for cross examination. And at this time, just as a matter of housekeeping because I tend to forget, I don't think I moved the admission of GPC-1 and I'd like to do that at this time. That was the newspaper article that we talked about during cross examination.

VICE CHAIRMAN BURGESS: It will be a part of the record.

MR. GREENE: Thank you.

(The document, heretofore marked as GPC Exhibit Number 1, was received in evidence.)

COMMISSIONER WISE: Mr. Kubler, you mentioned Duke's adder is at five mills. Why, if the adders are the same, would the RTP rates be higher in Georgia than they would be in Duke's system?

WITNESS KUBLER: The simple explanation is that the resources used by Duke Power Company, they're long in their resources as opposed to the Southern system being short in their resources. So Duke Power Company did not have to go the market and purchase power the way Georgia Power Company had to do.

COMMISSIONER WISE: So there's something to what Mr. Pollock said then about reserve margins.

WITNESS KUBLER: Well, the reserve margin that we were talking about is planning reserve, and as you go through the actual operation and establish your operating reserves, we are dependent on a number of issues, one of which is hotter weather. So in calculating the planning reserve level, if you used a temperature of 95 degrees as your temperature for your planning reserve, and the temperature was actually 96 degrees, that would add about 750 megawatts worth of load to our system. As temperatures get even higher, you can see that the amount of load on our system increases.

So when you couple the planning reserves to what actually happens in real time, then you do get these phenomenons where you have to go out on the market and buy power and buy purchased power.

WITNESS O'SHEASY: Can I add to that also, you have to look at the mix of capacity that a utility has over a period of time and the reserve level that we oftentimes refer to is really how much capacity do you have available that you don't think is going to be necessary to serve the peak demand. But there are many other hours of the year in which you may or may not have capacity in a particular mix that's necessary. You obviously have to do maintenance all year around, or at least in the non-summer, in order to minimize costs. And so utilities go through cycles where

they're longer in certain types of capacity than other periods of time. In the early '90s when we first came out with RTP, we were long in baseload capacity. As a result, our lambdas were quite small and we didn't have to go to the wholesale market as often as we do now. Duke may be caught in a situation like we were earlier in the '90s where they are basically longer in their mix of capacity than we are, but it's part of the process.

VICE CHAIRMAN BURGESS: Any other questions by Commissioners?

(No response.)

VICE CHAIRMAN BURGESS: If not --

COMMISSIONER BAKER: Well, let me follow up with Mr. O'Sheasy's comments. Do you disagree that the general trend that we're seeing in the industry now or at least in Georgia is that -- I mean that we don't have the margin of capacity that we did in the early '90s, it's shrinking or being reduced.

WITNESS O'SHEASY: Commissioner, I would agree with that, but we're doing it in a least cost manner. As we put together our IRP, we find out that a 15 percent reserve level is the least cost consequences for all customers. So we're doing it for the right reason.

I would also like to add that as the wholesale market has deregulated and these sky-high wholesale prices

have occurred, we are seeing entrepreneurs come and build new production plants in the southeast -- all over the country for that matter -- so we're hoping that like cycles in any industry that is heavily capital intensive, these new additional generating plants in the southeast will have a dampening effect on the market price in the wholesale arena. So what I'm saying is even if the reserve levels for the Southern Company drop to 15 percent or remain at 15 percent, that doesn't mean we're going to continue to experience these high wholesale prices just because of the economics of entrepreneurs being attracted to that market.

COMMISSIONER BAKER: All right. But right now, in calculating the system lambda, there is -- a larger percentage of the system lambda now is produced or dependent upon purchased power arrangements than they were say back in '91 and '92 -- that's a trend.

WITNESS O'SHEASY: Yes, sir, that is correct, but it's also the optimal amount. If we were to go in and build capacity to reduce that, it would not be being done in an overall least cost manner. It would lower the marginal RTP price, but it would not lower the overall cost to serve all customers in the state of Georgia.

COMMISSIONER BAKER: Are you saying that we're sort of in that time period between when the price signals are being sent to the marketplace, to the IPPs or to the

developers of new power plants, to give them the incentive to build this new capacity and that we're waiting to see if they do respond and bring additional capacity into the marketplace which theoretically would help reduce the cost of purchased power that would have to be factored into RTP?

WITNESS O'SHEASY: Yes, sir, it's my belief that new capacity is coming to the southeast right now. And it will indeed have a dampening effect on RTP. We are -- our forecasted RTP, as Mr. Kubler was saying earlier, is about 14 percent below what we experienced in 1999. And in fact, we're willing to guarantee that with some of the alternatives that Mr. Kubler was indicating. And our forecasts past the year 2000 show relatively small increases in the expected RTP price, which, as I said before, with some of these alternatives, we're willing to guarantee.

VICE CHAIRMAN BURGESS: So based on -- this upcoming forecast, based on last year's forecast, as a comparison, is the projected price for RTP higher or lower?

WITNESS O'SHEASY: I believe we projected last year that the DA price, the day ahead RTP price would come in at 3.44. I believe that the DA actual was 3.59. What we're willing to guarantee, what we're expecting for the year 2000, we're willing to guarantee, is 3.09, which is 14 percent below the actual for '99 and I think it's around 10 or 11 percent below the forecast for '99.

WITNESS KUBLER: And contrary to what has already been talked about as far as January, February and March, the actual prices are on target with that projection of 3.09.

VICE CHAIRMAN BURGESS: Mr. Hawes.

MR. HAWES: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MR. HAWES:

Q Sometimes it's easier to start in the back and go forward, so let's just start with your summary. I think Mr. O'Sheasy, in response to a question from Commissioner Baker about the gap that we now experience that may be filled later on by Georgia Power, the RTP customers bear the entire risk of that gap at this time, is that not true?

A (Witness O'Sheasy) No, I don't think that's true. I think to the extent that we have to purchase on the wholesale market and those prices go up, those cost consequences are felt by all customers.

Q The consequences of going off and purchasing power are passed through to the RTP customers, are they not?

A (Witness O'Sheasy) Yes, sir.

Q So they are the ones paying those prices?

A (Witness O'Sheasy) They are paying a portion of it, but to the extent that we have to purchase power for the residential customer, the FCR can go up.

Q The FCR can go up?

A (Witness O'Sheasy) Yes, sir.
Q The rate stays the same?
A (Witness O'Sheasy) The base rate stays the same, but the FCR would go up.
Q But the rate the RTP customer pays goes up directly as you buy that, right?
A (Witness O'Sheasy) As long as that is the marginal purchase, yes, sir, you are correct.
Q You mentioned that the -- I believe -- I'm not sure who this was, who talked about the price and risk --
A (Witness O'Sheasy) I think I did.
Q That it is so much smaller as a percentage these days and hasn't changed since '91. Basically as established earlier, isn't it true that the cost of the company -- the company's cost structure has gone down in this period, right?
A (Witness O'Sheasy) Well, not the marginal cost, which is what RTP is based on. Our marginal cost have risen. Now, if you are referring to embedded cost --
Q Right.
A (Witness O'Sheasy) -- I don't have any numbers to substantiate it one way or the other, but I would suspect that embedded costs have gone down.
Q And you say it is a smaller component, meaning what? Because prices have gone up?

A (Witness O'Sheasy) Yeah, let's say for example that the average RTP price in '93 was 2.4, and I don't know the exact number, but let's assume it is, and let's assume that the average RTP price in '99 was 3.5. So my point was that .5 divided by 3.5 is a smaller percentage than .5 divided by 2.4.

Q What is the .5 and 3.5 percentage-wise?

A (Witness O'Sheasy) Well, that's about 14 percent, I guess, off the top of my head.

Q So it is still a fairly substantial profit margin, is that right?

A (Witness O'Sheasy) Well, it's not all profit. It's covering risk in addition to profit.

Q The forecasting risk that you mentioned, do you know how many hours, for instance in 1998, which is the number I've got, that Georgia Power over forecasted the hour-ahead?

A (Witness O'Sheasy) No, I don't. It seems like what I tried to do, I believe, in one of the data requests, was estimate the average lambda that went into the hour-ahead versus the average lambda that we incurred, and I think with the hour-ahead, it was .3 of a mil over forecast actual, and I think with the day-ahead, it was 2 mils per kilowatt hour, the forecast under. If that helps.

Q Well, it's not totally responsive. Would it be

correct that in the hour-ahead that you over forecast over 5400 hours out of the year?

A (Witness O'Sheasy) I don't -- I can't corroborate that, but I won't take exception to it. That's possibly reasonable. I'm not sure.

Q How many hours in the year are there?

A (Witness O'Sheasy) 8760 in a standard year.

Q So that's over 50 percent of the time there? A good bit?

A (Witness O'Sheasy) Yeah, and I think 50/50 on either side is probably reasonable for forecasting.

Q And what about a day-ahead in '98? What about 4981 hours out of the year?

A (Witness O'Sheasy) That could very well be the case. I'm not sure.

Q Over forecast.

A (Witness O'Sheasy) Uh-huh.

Q And that's over 50 percent also?

A (Witness O'Sheasy) Uh-huh.

Q So, when that happens and you over forecast, who pays the price when the price is less than what you forecast?

A (Witness O'Sheasy) Well, any time that you -- whatever price is forecast is what the customer ends up paying.

Q Right.

A (Witness O'Sheasy) So to the extent that one hour you over forecast, that's what he pays; to the extent one hour you under forecast, that's what the customer pays. So in my opinion what you have to look at is over the course of the year the over forecast or under forecast, and that's the consequences that we were talking about in terms of forecasting error.

VICE CHAIRMAN D. BAKER: But wouldn't it also depend on the degree to which you over and under forecast during a particular hour and the amount of kilowatt hours you sold during that period of time?

WITNESS O'SHEASY: Yes, sir, Commissioner. To do it exactly right what you would want to do is take on an hour-by-hour basis the kilowatt hours that were sold at RTP times the under or overage and then sum it up for the year to see. We -- When we first started thinking this issue through, we started developing a monthly report, which we've shared with the Commission and the staff that will track that one issue.

BY MR. HAWES:

Q But to finish that line, just one more question, if you over forecast, which you did in over 60 percent of the time -- this is '98 --

A (Witness O'Sheasy) Right.

Q -- that's what the customer pays?

A (Witness O'Sheasy) Yes, sir.

Q If it is over forecast and you paid less, you just keep the difference?

A (Witness O'Sheasy) Yes, sir.

A (Witness Kubler) It's also true that if we under forecast, we have to eat the difference.

Q If you under forecast and -- let's say when purchased power is used -- and we are speaking of purchased power now as opposed to generation -- you buy that purchased power, it goes straight in fuel to be recovered, doesn't it?

A (Witness Kubler) Yes, it goes in fuel cost to be recovered, yes.

Q You don't eat it?

A (Witness Kubler) It's the marginal cost though of the system at that particular hour.

Q You don't eat that, do you?

A (Witness O'Sheasy) Yes, we do. Imagine that in the fuel clause right now, the way we set it -- Let's assume the fuel clause is 1.4. In order to get that 1.4, we forecast what we thought our fuel costs were going to be. Now in that assumption was that we were going to be buying some power at a certain price. Now, to the extent that when the actual purchases occur, let's presume for the sake of discussion that our forecast was right on so that 1.4 is

indeed our true cost of fuel. Okay? Well, day-ahead, if by chance we miss the mark -- in other words, when I am looking to tomorrow's purchases, I under forecast what it actually is, we eat that.

Q Let's look at this just a moment if we might. I guess, Mr. Kubler, that was your chart. These rates that you are showing here for day-ahead and hour-ahead, et cetera, just so we are sure we understand, those are blended rates, are they not? Those are base line and the RTP?

A (Witness Kubler) Yes, that's correct. They are blended.

Q So basically what those are reflecting is that for those customers, the result of the rate case which was a five point something percent reduction in base rates was offset by increase in RTP, is that right?

A (Witness Kubler) That's correct.

Q And that's true for all those I guess in green pretty much, whereas opposed to the overall status of customers just continued to come down?

A (Witness Kubler) Yeah, that's correct. There's a number of reasons why the prices have come down since 1991, and the 1998 ruling by the Commission is one of the reasons why this happened.

COMMISSIONER BAKER: Do you know how many hours a year the RTP rate is over, let's say, a nickel an hour? So

we can get some kind of perspective about...

WITNESS KUBLER: The answer is, yes, I do, but I do not know what it is off the top of my head. I can find that out for you if you would like to know.

COMMISSIONER BAKER: Well, could you give me a ballpark? I mean, what was it, 8760 is the total number of hours in a year that y'all --

WITNESS KUBLER: That's correct.

COMMISSIONER BAKER: What's a good --

WITNESS KUBLER: Well, I can tell you some of the things that I do know. At 7.5 cents, the number of hours that are over 7.5 cents was, I think, 400 hours for HA for 1999. That went to 1100 hours -- this would be subject to check -- 1100 in 1998, 3000 in 1997, just to give you, you know, a ballpark of what we are talking about here.

COMMISSIONER BAKER: So it's been going down? Am I missing something here?

WITNESS KUBLER: Yes, the number of -- the number of hours above 7.5 cents --

COMMISSIONER BAKER: Has been going down since '97?

WITNESS KUBLER: No, I will have to be corrected on that. What I was giving you was not those hours. I will have to find out what it is and let you know. I can't remember what it is.

COMMISSIONER BAKER: Okay. Well, what about -- this may by, hopefully, in your mind -- how many hours did the RTP rate hit -- the system lambda hit $6.00 an hour?

WITNESS KUBLER: One hour.

COMMISSIONER BAKER: Okay.

WITNESS KUBLER: And during that one hour, it was for the HA customers and the HA customers responded to the price, and in that hour they did not pay $6.42. They received a credit of $6.42 for a total of 700 thousand dollars' worth of credit under RTP for avoiding that $6.00 price. That's why I said that RTP pricing in Georgia is working. When the price got to $6.00, customers responded to the price and got off and they were rewarded for doing that.

And that is the reason why the HA customers there have achieved 3.1 cents for 1999, it's because of their price response. In 1998, they responded, but they didn't have to respond near as much because the prices weren't that high. The highest price in 1998 was about forty-something cents, 50 cents per kilowatt hour, so they didn't have to respond near as much to achieve that reduction.

BY MR. HAWES:

Q You said in your summary and again in your response to this question, everyone -- well, you didn't say it in response to this question, but you did say everyone

wins when there's a response. Is that right?

A (Witness Kubler) That's right.

Q Does the worker who is sent home win?

A (Witness Kubler) I think that what I was referencing to, to answer your question, I wasn't making reference to the worker. So if the worker is being sent home because of the company, that's a decision that the company is making in how to respond to the price.

Q Not your responsibility?

A (Witness Kubler) Not my responsibility.

Q What about the company that loses orders because they had to shut down? Did they win?

A (Witness Kubler) If the price of electricity was above what their economic value was that they were going to achieve from taking those orders in, yes, they do win. It's their choice. That's what RTP is. It's the -- the customer has the choice to either buy or not buy in that particular time based on their economic value of electricity at that moment in time.

Q And you're setting an economic price that they have no choice but to either take it or shut down?

A (Witness Kubler) That's what they asked for, and that's correct.

Q That's the system we've got now, right?

A (Witness Kubler) That's correct. Otherwise, they

could go to a firm tariff rate, and they'd know exactly what it is, or secondly, they could take one of the RTP price alternatives we're offering and lock into what that cost would be.

Q Both of those options, I believe -- I don't know if it's been said today, but it's been said often -- those are revenue neutral, are they not?

A (Witness Kubler) You would really have to look at how one defines revenue neutral. I think what we have indicated is that we're expecting the price to be a lot lower in the year 2000 than they were in 1999. So if you want to make it revenue neutral to 1999, no it's not. It's not revenue neutral.

A (Witness O'Sheasy) Let me also add, if I could, that Mr. Pollock was making a valid point that you have to consider not only price, but risk, and that's really what RTP is all about is that relationship, but these so-called revenue neutral alternatives that we're talking about, they are revenue neutral with what we expect RTP to be in 1999, but on the other hand, they guarantee it -- excuse me, the year 2000. I'm sorry, thank you. They are revenue neutral with 2000 expected prices, but they guarantee it. In other words, they transferred the risk back to the utility. So, one could argue if price and risk both need to be considered, that they are not revenue neutral.

MR. HAWES: Mr. Chairman, we have something here that I need to use, which is a trade secret exhibit that is being filed in that fashion. I've got it in pink so none of them will get out, but what I would suggest, I guess, if the procedure is all right, is of course to give it to the company, but give it only to the Commission and to the witnesses. We won't talk the specific numbers but just the relationship.

VICE CHAIRMAN D. BAKER: That'll be fine.

MR. HAWES: May I approach? And I will state for the record that this is the same as HKO-1 to Georgia Power's prefiled testimony, but the trade secret version of it will be filed with the Commission.

BY MR. HAWES:

Q Gentlemen, is this a correct copy of an exhibit that was filed with this prefiled testimony by the company?

A (Witness O'Sheasy) It appears to be.

Q And what does it represent?

A (Witness O'Sheasy) What we tried to demonstrate was the average monthly RTP day-ahead price and the annual number from 1993 through 1999. This is the price offered.

Q Now, looking at the sheet, the bottom of that sheet, would it be correct to say not just in the months of the stack, but in all other months the prices are going up?

A (Witness O'Sheasy) Well, there are exceptions to

that, but it is probably in general true, what you are saying.

Q Well, I'm just looking at the numbers and, of course, we can't talk the numbers here specifically, but just looking at the relationship, each month as we go through the years, those prices are gradually creeping up, are they not?

A (Witness O'Sheasy) In general that's probably true.

Q So it's not just the $6.00 an hour that we are here about at all, is it, if the overall rate being paid is being determined by increasing prices in all months?

A (Witness O'Sheasy) I would say in general that that's probably true and it is reflecting the fact that our marginal costs are going up in all months of the year.

Q And translated that means you're serving this out of higher priced resources, right? Closer to the margin, closer to your -- the edge?

A (Witness O'Sheasy) The cost of those resources is going up. It might be the same resource, it's just the fuel cost could be higher.

Q Could be, but generally speaking, as you see these increases -- and I'm just looking at the numbers on your chart, from '93 through '99 it's showing a steady and -- well, until we get to the last two years and then a dramatic

increase in those years, right?

A (Witness O'Sheasy) Well, they are months that I would not describe as dramatic increases. I would say that the overall annual price has gone up considerably in '98 and '99.

Q And as the person or one of the people dealing with this, doesn't that show to you that you are serving that load all year-round, the more expensive resources and therefore probably higher than the stack, so to say?

A (Witness O'Sheasy) I'm not sure it is higher than the stack, but the cost of the resources to serve the load is going up.

Q You heard testimony by one of the public witnesses this morning that so far in January and February, the year 2000, which normally would be considered to be lower cost months, would they not, that this is the highest prices they've ever seen? Yet again, coming into 2000. Did you hear that?

A (Witness O'Sheasy) Yes, I did, and when he said that, what I then did was I compared to what we forecast would happen in the year 2000 when we came up with that 3.09, and basically those January, February, March actuals are right at what we forecast them to be in order to achieve a 3.09 for the year.

Q Well, looking at the numbers that you've got in

front of you, 3.09 is still a substantial increase over the levels for '93 through '97, is it not?

A (Witness O'Sheasy) I guess substantial is a relative term to the beholder, but it is an increase that I wish weren't there, but it is a fact of life with our marginal cost.

Q Well, since I guess -- I'm trying to think, what's on the table, 3.09 is on the table. Well, how much of an increase, you're saying, it depends on the eye of the beholder. How much of an increase was there between, say, 1997 and the 3.09? What percentage increase is that, you say?

A (Witness O'Sheasy) Do you have a calculator?

MR. GREENE: Mr. Chairman, I'm not sure if we can do that calculation without backing into what 1997 was, and that's part of the trade secret information.

MR. HAWES: All right. I'm trying to avoid that.

MR. GREENE: I think the numbers are available for everybody who is interested in this conversation who is available to see under the confidentiality agreement. I think the numbers are there.

MR. HAWES: Okay.

BY MR. HAWES:

Q Well, let me just ask you, since the Commissioners are looking at the number that you're testifying about it

depends on the eye of the beholder, if the price went from what we are looking at in 1997 to what you are talking about at 3.09, do you know any businessman that would not consider that a substantial increase?

A (Witness O'Sheasy) Well, I think you'd have to consider the industry that you are working in, but I would agree that that is a substantial increase.

Q And that's just what you project to be your average this year?

A (Witness O'Sheasy) It is, but we do have alternatives that will guarantee it.

Q Well, we won't go there right now. It's really not a guarantee, is it?

A (Witness O'Sheasy) Yes, it is.

Q So, when a customer looks at a rate they should be able to expect that rate to be based on the company's cost, is that your understanding how the regulation should work?

A (Witness O'Sheasy) Yes, and there's two different ways to define cost. It's embedded cost, which standard rates are based on, and there is marginal cost which RTP is based on.

Q So if the company agrees that this Commission should regulate them so they recover their actual cost and give them a profit on their cost, why have we spent all day talking about what price somebody is paying as opposed to

what cost is generated by the company?

A (Witness O'Sheasy) I'm not sure I understand the question, but bottom line is --

Q I'll repeat it another way, if you like? The question is, if the purpose of regulation is to let the company recover its cost plus a profit, and we consider that cost of service, why have we spent this whole day talking about what price somebody pays? Shouldn't we be talking about the cost?

A (Witness O'Sheasy) Well, I think that the problem is not in the rate structure itself. The problem is that Georgia Power, the Southern system's marginal cost have risen dramatically since this rate was first introduced. It's still -- and the rate correctly reflects that. It creates a problem, however, with our customers because the cost of their product, electricity, is going up, but for the right reasons. Our marginal costs are going up.

COMMISSIONER McDONALD: Mr. Hawes, would your question there be in the frame work of price reflecting on the RTP customer and the reflection of cost being the whole gamut of customers in the whole system? Am I missing that?

MR. HAWES: I don't think you are missing it. Obviously the whole gamut of customers are supposed to pay cost plus the reasonable rate of return. There can be some variation between class, but --

COMMISSIONER McDONALD: When you asked the question about why are we today talking about price, we're talking about RTP price, isn't that correct?

MR. HAWES: That's correct, we are.

COMMISSIONER McDONALD: But when we talk about costs and how it reflects in the 10.5 to 12.5, we're talking about the entire system cost, is that --

MR. HAWES: No, sir, that's not what I understand. These rates should, not perfectly reflect cost, but should have a fairly close relationship to cost, and just to say that a price is X or Y or Z does not tell you anything about what that price should be based on, cost analysis. Whether it be RTP, PL, residential, whatever, it just doesn't tell you that. That's why I'm so -- I don't understand why everybody wants to focus -- or the company wants to focus on price if it is not related to cost.

COMMISSIONER McDONALD: Well, see, I'm just trying to catch up with you and see where --

MR. HAWES: Yeah, that's what -- My whole purpose here this afternoon has been to show that this is no longer cost related. It's generating excess profits. And to keep focusing on price and not cost of the company, is not the appropriate way to get the answer to that question. We understand why they do it, but we're just trying to make a point that that is not what the Commission should be looking

at, not the price but the cost of the company.

If that answers the question --

COMMISSIONER BAKER: Okay. Kind of brings a question in my mind. We're talking about -- Mr. O'Sheasy is talking about marginal cost have increased dramatically for the company, and the thought goes through my mind, I mean, how many megawatt hours are we talking about that are really -- I mean, if you had available today 500 additional megawatt hours, would that eliminate the need to go to a spot market or go to a purchase power market and buy that expensive energy, or is it 1000 megawatts that we are talking about. I mean, what -- what segment of the RTP demand is driving the rate into the higher cost area?

WITNESS KUBLER: We determined that we have about 2000 megawatts worth of RTP incremental purchases during normal price times. As the price increases, load leads, and we saw 864 megawatts worth of load leave the system when the price got to $1.73 for DA and $6.42 for HA. So, if you take those numbers and make the subtraction, we still had to go out into the marketplace and buy power even with that price response. If you made -- If we had another 100 megawatts worth of price response, we probably would not have had to buy the $6.00 price energy. So it does depend on a specific incident, but that's kind of a snapshot of what happened on that particular day that it reached $6.42.

COMMISSIONER BAKER: Well, I mean, Mr. Pollock used something like that as an example of the unfairness of the using -- calculation of the system lambda in his testimony saying that that 100 megawatts that had to be purchased out there in the spot market that then drove up the cost astronomically, that that does not really fairly reflect what the actual cost was, or even come close to what the actual cost was overall to the company for having to meet that additional 100 megawatt demand that had to be met.

WITNESS O'SHEASY: Let me offer a few things that might help. What you need to know is how many megawatts are you buying at those high prices, and we don't have that information here in front of us, but we have supplied some information that might be helpful. One is, I think we supplied or we've indicated to others that in 1999 if the average RTP price was 3.55 the day-ahead, we've indicated that if customers had responded to X hours, what would that price have been? And do you remember what that first break was, John?

WITNESS KUBLER: At 50 hours it was 3.12 cents.

WITNESS O'SHEASY: So 50 hours -- If 50 hours of high prices had been removed, the 3.55 would have been 3.1, did you say?

WITNESS KUBLER: 3.1.

WITNESS O'SHEASY: 3.1. Okay. Another antidotal

bit of information, if for example in the year 2000 we were able to -- we had permission to call interruptible service for economics, we could reduce that expected RTP price that I quoted of 3.09 by almost 2 mils a kilowatt hour and only have to call IS an additional six hours. So I can't address your question specifically, but I'm saying there's not a whole lot of hours involved in reducing prices on RTP significantly.

COMMISSIONER BAKER: Maybe -- Are we too liberal in defining who can participate in the RTP rate structure?

WITNESS KUBLER: Well, the tariff structure says, at the very beginning it says, customers on this tariff must be able to respond to RTP prices in order to get on the tariff. It doesn't say they have to. It just says they must be able to. And I think that customers rightly make the choice as to what they want to do depending on what the price is and what their value of electricity is. Every RTP customer has to have at least indicated by a past history or by demonstration what they are capable of doing.

COMMISSIONER BAKER: So basically every RTP customer wants the other RTP customer to get off the system so they can stay on the system and get the lower price.

BY MR. HAWES:

Q You've got 1600 customers on RTP. How many of those are commercial customers?

A (Witness Kubler) About half of them are commercial and half of them are industrial.

Q Do those commercial customers respond regularly?

A (Witness Kubler) Some do.

Q And how do they do that if you've got a department store running and your heat goes up?

A (Witness Kubler) Some of them have generators. Some of them choose to reduce load in the plant for certain hours and not for other hours. Every customer has the ability to make the choice. If it is a large enough commercial establishment that has emergency generators, they can use that to respond to it. Some customers have allowed the chill water temperature in the building to rise. Some of turned off air equipment, some have turned off outdoor lights, outdoor signs, there's a whole gamut of things that customers can do, commercial customers can do to respond to price.

Q Just out of curiosity, how much response did you get from them last year?

A (Witness Kubler) I did not divide the number that way. I looked strictly at the DA customers which gave us a maximum of 414 megawatts and the HA customers which gave us about 450 megawatts.

Q Looking at -- just a question of how the price problem is caused, the purchase of the high prices. Now,

when prices -- when you get a hot day, and I think that's what has been causing this, right, the July, August that we had last year on this particular issue -- you said one degree day causes you to have to have how much more in the way of capacity?

A (Witness Kubler) 750 additional megawatts worth of capacity.

Q So every one degree is 750 megawatts additional over and above what you plan for?

A (Witness O'Sheasy) As long as the temperature is hot. If it is 82 degrees, one degree is not going to make that much difference.

Q Now, who uses that -- who causes the need for that other 750 megawatts from the peak that goes from '96 to '97?

A (Witness O'Sheasy) Well, it's hard to -- you can't say. It's like Mr. Pollock was saying, it's the system load that causes you to have to go out and make that purchase. We don't break the system load into who causes it.

Q I understand you don't do that, but I mean, intuitively it's air conditioning, right? Primarily?

A (Witness O'Sheasy) I would think so.

Q And most or a lot -- well, I won't try to characterize it. Industrial customers are a pretty steady load, aren't they? They're mostly processed.

A (Witness Kubler) Your large industrial customers that have a process.

Q So air conditioning is more sensitive to, what, residences and malls or whatever? Air conditioning? They go heavy on the air conditioning?

A (Witness Kubler) In general you find that your residential customers are weather sensitive, commercial customers weather sensitive.

Q Sure. And so when that drives that need up and you have to go off system and purchase -- let's just say you've got to purchase 700 megawatts because of that, that price that you paid goes to the RTP customer, doesn't it?

A (Witness Kubler) Sure.

Q Sure. They are paying for everybody else's stack?

A (Witness Kubler) Well, I was going to say that while I agreed with your assessment that residential and commercial customers are weather sensitive, there are things that industrial customers do as well that contribute to the load in that particular time. For example, a textile facility, if they are air conditioned, they are going to -- that air conditioning is going to be driven by -- the load is going to be driven by the weather, just as an example.

A (Witness O'Sheasy) But I wanted to add also that those residential and commercial customers who are weather sensitive, we do indeed reflect their load shapes and their

cost to service and their prices are higher. These relatively -- 7.4 cents per kilowatt hour for residential and higher rates than that for commercial reflect the fact that we are going to have to provide power for them during summer times when their prices are higher commensurately.

Q We're not complaining, we're just trying to keep the record straight as how it happens.

Now, if the day-ahead price is set by you in advance, right? You set it a day in advance?

A (Witness O'Sheasy) Well, I hate to say that one of us sets it. The Southern -- the dispatch center in Birmingham provides the cost characteristics that are converted into the price.

Q And that's going to be the price regardless of load, what it costs?

A (Witness O'Sheasy) It's our forecast of costs that we guarantee, we lock into. We don't true-up.

Q So it doesn't matter what the customer does or doesn't do, they are going to pay that price, even if --

A (Witness O'Sheasy) I'm not sure. If he does do something to respond, he's not going to pay that price.

Q If he is not on the system.

A (Witness O'Sheasy) Correct. In fact, if he goes below a CBL, we'll give him credit at that price, which is a big savings.

COMMISSIONER BAKER: Let me just clarify. You said that over 800 a year RTP are commercial customers?

WITNESS KUBLER: It's about 50/50.

COMMISSIONER BAKER: When we are talking commercial, we're talking like shopping malls?

WITNESS KUBLER: There are some shopping malls on there. There's also large office buildings in downtown Atlanta.

COMMISSIONER BAKER: Okay.

MR. HAWES: Mr. Chairman, I would like to use a hearing exhibit for comparison purposes, which have already been introduce in -- Well, one is JP-12. I'm sorry, it hasn't been introduced yet. It will be. And one is HKO-8, which was introduced -- No?

VICE CHAIRMAN D. BAKER: Mr. Hawes, this might be a good time. We're going to take about an eight minute break. Come back here at 5:00.

(A short recess was taken.)

VICE CHAIRMAN D. BAKER: Let's go back on the record.

MR. HAWES: Mr. Chairman, one of the soft colored exhibits that you have here is one that is -- two exhibits, one is HKO-8, and the other one is JP-12. I want to ask a series of questions on the two exhibits, if I may.

BY MR. HAWES:

Q Gentlemen, looking at page 1 on the JP-12.

A (Witness O'Sheasy) Excuse me, sir, may we have one?

Q Oh, I'm sorry, I thought you did. Looking at the top of the page, this is the revenue for kWh comparisons of the industrial class by the list of utilities. Do you agree with those numbers? Many of them are on your own second page there. But the different ones included?

A (Witness Kubler) At this particular point in time I would agree with them subject to check.

Q Subject to check. And so the difference being that you've listed 19 and we've listed 33. And you made the correction I believe where Duke Power, rather than 4.59 is really 3.59?

A (Witness Kubler) That's correct.

Q That's a major competitor for a lot of this load. One of the things, in talking about the price, I think, some of this has been touched, but I want to be sure we get it all in context. When you look at a price per kWh comparison, and we'll look at page two, which is HKO-8, which you all filed -- Georgia Power, excuse me, filed. And you are showing the variations from Georgia Power, which is at 4.19 for industrial kWh. Now, look at Savannah. Savannah you're showing at 4.03 and they don't have lower rates, do they? That's just the way their price works out?

A (Witness Kubler) Yeah, this is really, as you've indicated, nothing more than taking the average -- the revenue paid divided by the kilowatt hours to come up with a cents per kilowatt hours, but it's not addressing the issue of rate structure per se.

Q And so to look at that you can intuitively say that Savannah Electric has probably got fewer but larger industrial customers and that would account for why the average kWh is lower?

A (Witness Kubler) Could be.

Q And going to the way that these rates are determined. All of the rates that serve the GTMA and GIG members recover costs, do they not? You don't lose money on them?

A (Witness Kubler) Right, including RTP.

Q Right. Especially RTP. So the fact that they are lower than industrial average is going to indicate, I believe, as Mr. Pollock testified that these are operating characteristics of size, load, voltage, delivery, transportation delivery, these things affect their rates and lower them, do they not?

A (Witness Kubler) That's absolutely correct. Everything for a unique customer depends on the characteristics for that particular customer in coming up with what their average price is. This analysis, as any

analysis you might do is just merely an indicator of what the rates would be. I think from purposes of this Commission what I've shown there on the chart is the most important thing to look at because of the fact that that's what this Commission has jurisdiction over, not any of these other utilities that I mentioned here.

Q But you mentioned, let's see, -- you changed the number I think, but I'll just use the one I had -- 4.19 is the industrial average. Is that still --

A (Witness Kubler) Well, 4.2.

Q 4.2, okay. Did you have any occasion to look at the information that was supplied us at lunch on the -- trade secret -- billing determinants on GTMA and GIG members?

A (Witness Kubler) Yes.

Q And that's where you got your -- let's just use GTMA, I looked at first -- 3.76.

A (Witness Kubler) Rounded to 3.8.

Q Now, do you approximately how many accounts you gave us information on there?

A (Witness Kubler) For GTMA?

Q Yes, GTMA.

A (Witness Kubler) I'd have to look at it to count them up to find out, but it's over 200.

Q About 220?

A (Witness Kubler) About 220.

Q Subject to check. So 220 accounts. Do you know how many of those 220 accounts have average rates over the industrial average, not just what you show on exhibit 8, but over the industrial average?

A (Witness Kubler) No, I don't know.

Q Would 155 sound right?

A (Witness Kubler) Subject to check.

Q Subject to check.

A (Witness Kubler) And those would probably be things like your outdoor lighting account, your general service account. No doubt in my mind it could be that many.

Q And we don't know what they are because we ask for and got this by account number --

A (Witness Kubler) Sure. Right. Or by rate. Do you have the rate? I don't think you have the rate on there.

Q Yes, sir, we do -- But -- So 70 percent, 155 is about 70 percent. So 70 percent of these industrial or textile customer are paying higher than 4.1. Now, we're not saying anything about the size. I understand your point there. I can't tell. Do you have any idea --

COMMISSIONER McDONALD: Let me get something clear right here. Is it -- Is this including the outdoor lighting in all of this, embodied, or is that in the actual

manufacturing portion of it per se?

WITNESS KUBLER: The number up there for GTMA and GIG includes all their outdoor lighting accounts, all of their general service accounts, all of their power and light small accounts, all their power and light medium accounts, all their TOU accounts, as well as their RTP accounts. So it's all in that number there.

BY MR. HAWES:

Q And the information that we received today is just by account. So I don't have it for instance by -- at this point by company. I think I have a pretty good idea of it, but I don't have it here that I can ask specific questions because that's not the way the information was provided. So, yes, some accounts are large, some accounts are small, the point being -- and I think it's been made before -- is that the average can be heavily weighted and generally is by a few large customers that bring the average down, but if you look at a mean or medium, you'll get an entirely different thing.

A (Witness Kubler) In your particular case with GTMA, of the 220 accounts there are 64 RTP accounts that is contained in that number, in addition to the outdoor lighting accounts, the power and light, small general services.

Q But this number here -- I'm sorry, when I say

here, HKO-8, this is all rates, not just RTP, is that right?

A (Witness Kubler) That's correct.

Q So we're looking at apples and apples when we look at it all and not just RTP rates?

A (Witness Kubler) Correct.

Q And would you agree, subject to check, that a very small percentage -- say another 25 percent of the textile companies -- we'll say companies, now -- are paying at or less than the average you've got in here of 3.7? 3.721 or something?

A (Witness Kubler) I'll agree to it subject to check. I don't know.

Q Have you ever looked at that when you came up with this number as to --

A (Witness Kubler) Oh, yes. If you go through the process, we're looking at every individual account for every individual customer and you are looking at the ones that are above and below the average, but I didn't count them.

Q But did you notice how few of the customers are paying at or less than this price that you put on this exhibit?

A (Witness Kubler) Again, I went through the process of looking at them, but I did not count it up, so I can't tell you how many or how few there were.

Q Can we agree on a maximum with 25 to 30 percent?

Would that be too hard to do?

A (Witness Kubler) I mean, subject to check and subject to us sitting down and actually calculating it out, if that's what you want us to do, we can do that.

Q Well, we've got a little problem with trade secret here. So I mean, --

A (Witness Kubler) Sure.

Q -- you understand that, and I do too, but I just want to be sure there is no misunderstanding. You didn't intend that these numbers would tell this Commission or even imply that a majority of the textile members have prices of 3.76 or under?

A (Witness Kubler) When you say textile members, I mean, you've already indicated there are 220 accounts. How many members do you have that comprise that 220 accounts?

Q Subject to check about 53.

A (Witness Kubler) Fifty-three. So you indicated that 25 of those members were paying -- did I understand you correctly -- were paying less than the average?

Q Twenty-five, no. Twenty-five percent.

A (Witness Kubler) Okay.

Q Say around -- It's your testimony you never looked at these kind of --

A (Witness Kubler) Not statistics the way you are describing them, no. I mean, I can tell you what the

average is for those, I can take the 60-some odd RTP accounts and I can tell you the average for those 60 accounts is 3.7 cents, but as far as which accounts are above and which accounts are below that average, no, I can't tell you that.

Q Well, I know you can't, and I'm not really asking you to do that. I can't do it either right now, but just the relationship of the numbers. That's all I'm trying to look at. Way more above that number than below it.

A (Witness Kubler) Well, if you are strictly looking at numbers, I would agree that there are probably more accounts that are above the average than below because you are looking at strictly numbers rather than size. If you look strictly at numbers, there are 1600 RTP accounts, but there's only 132 RTP accounts represented by GIG and GTMA. So if you want to look at numbers of accounts, we can do that, but I think you really are wanting to look at the arithmetic average of the load and the revenue that these customers pay.

Q You understand when you say, just looking at numbers, that what we are really talking about is, we're looking at the price that the company pays? That's what the numbers to you --

A (Witness Kubler) That's what these numbers represent.

Q That is a very significant --

A (Witness Kubler) I am very aware of that. I've spent numerous hours in front of your membership talking with them about the prices and about the rates that we have. We spend a considerable amount of time with our customers talking to them about these alternatives, and these alternatives, back in 1999, were what the customer said would be the things that would help respond to the volatility in RTP prices.

Q So the numbers that we are talking about, that you are talking about, these are the prices that these customers of yours pay and, if it is correct, shows out that over 70 percent of them pay above this, they may have a problem with this number that you put out there, right?

MR. GREENE: Mr. Chairman, I think I'm going to have to object. I think his question has been asked and answered several times. We are here to talk about RTP accounts and RTP prices, and Mr. Hawes keeps asking about TOU rates and all the 1600 rates. This witness isn't, I don't think, prepared to talk about the whole rate structure, but I think he is trying to answer the question.

MR. HAWES: I'll withdraw the question and move on.

VICE CHAIRMAN D. BAKER: Yeah, let's move on.

BY MR. HAWES:

Q But that is not just RTP numbers?

A (Witness Kubler) Correct.

Q I just need to clarify something. We didn't get into the rate structure of RTP in the 1998 rate case, did we?

A (Witness Kubler) I believe that there was mention of RTP from the standpoint of a rate structure, and number one, not receiving any reduction. Number two is, I think the order commented on the fact that at some future time that we would get back together and talk about averaging purchase power lambdas. So, yes, to answer your question specifically, yes, it was discussed in the '98 rate case.

Q Do you remember cross examination of your, page 2663, transcript? Have you got that? Question, the first question to you on cross examination -- Let me see if I can't find a way to quickly limit what I need to ask you about, speaking to you. Georgia Power is not asking for any change in this docket in IS or RTP, are they? No, we're not. And there was no testimony put in by Mr. Pollock on that subject either, was there?

A (Witness Kubler) Correct.

Q And then later I believe Ms. Hingst was on the panel with you, and I asked the question, and you indicated we would want to address that in the future?

A (Witness Kubler) That's correct.

Q And this is the future, isn't it?

A (Witness Kubler) Sure.

MR. GREENE: That was IS and RTP for the response?

MR. HAWES: RTP or IS.

BY MR. HAWES:

Q And so just so we are all on the same page, then we have that statement in the stipulation that the RTP would not be reduced in any amount. It only asks for the same amount as any other rate, right? And it just added a stipulation and the Commission approved the stipulation, and we were not part of the process of writing that stipulation, were we?

A (Witness Kubler) I only know that from hearsay, and the answer to your question is, no, you weren't.

Do you want to respond?

A (Witness O'Sheasy) GIG and GTMA did not sign the stipulation. They were the only ones that opposed the stipulation.

THE REPORTER: I'm sorry, I couldn't hear you.

WITNESS O'SHEASY: GIG and GTMA did not sign the stipulation. They were the only party in the case that opposed the stipulation.

BY MR. HAWES:

Q So basically the record as far as any discussion

of how you'd go about structuring or address problems with this rate was not anywhere in that record? It just came out in the stipulation?

A (Witness Kubler) I would agree. To the detail that you are talking about it today, no, it wasn't.

A (Witness Hinson) You're talking about in the stipulation and in the Commission order --

Q Right.

A (Witness Hinson) -- there are findings of fact.

Q Going back to a question I forgot to ask on the trade secret number one. You talked about what the price should be of the rate. If you took, as suggested, the two hottest months that you indicate, I think, caused a lot of problems in this last year or last two years, you would still have, would you not, greatly increasing -- I say greatly increasing -- you'd have an increasing rate over the last two years. Now, you've said you would offer a 3.09 for the coming year. That's no longer on the table because we've ended three months, right? So it wouldn't be 3.09. It would be something more than that, we don't know what.

A (Witness Kubler) Well, it actually would be based on the file that we put together showing what the hourly prices were for the year 2000. That's what we would go through the process of using for the alternatives. Yes, three months have gone by, so as you take the remaining

hours that are left in that file and average them, then you would get a number higher than 3.09. But it is still all consistent with the price file which generated the 3.09 price for a full 12 months.

A (Witness O'Sheasy) So effectively what would happen, if you incorporated the three months of actual with the nine months that we are willing to commit to, you'll get around 3.09.

Q If you took 1999 numbers that's shown on the trade secret exhibit and you substituted the 1998 two months of July and August, which is where the issue arose, you'd have a rate less than 3 cents, wouldn't you? Just take '99 numbers for 10 months and just put in '98 two months --

A (Witness O'Sheasy) July and August of '98? Well, you've probably done the math, so subject to check, you're probably right. I'd have to run through the numbers.

Q (Inaudible) Mr. Greene would not like it.

A (Witness O'Sheasy) I don't have the ability up here to do the math right now, but it's quite possible, what you are saying.

Q And if you took '97 for those two months, and plugged them into the '99 other 10 months -- you know, the 10 months of '99 except for July and August, you get well below three, don't you?

A (Witness O'Sheasy) It appears that you would.

Q So you can understand why we've asked for some accountability on what does 3.09 means?

A (Witness O'Sheasy) Uh-huh -- Well, I'm not sure exactly what question you were asking just then. To me, the accountability with 3.09 is a fact, we're willing to guarantee it.

Q Well, I think we've heard a lot of people discuss those and whether or not there is any guarantee, just a whole other issue than we've got on the table right now. So I won't pursue it. But, I'm just trying to understand, you know, you came to a 3.09, but if you took your actual '99 prices that you pay and just took out the two months and put in July and August of other years, '97, '98, you're going to get under 3. So you can understand why the question would be ask, why should we have faith in 3.09?

A (Witness O'Sheasy) I'm sorry, but I don't understand the connection.

Q Okay, well --

A (Witness Kubler) What this chart is indicating, what you are looking at is, in 1999 there were two months that looked out of skew, the months of July and August, with previous Julys and Augusts. If you look at 1998, you see the months of June and July as being kind of out of skew with other Junes and Julys for previous years. So what it boils down to is, we have four months in 1998 and 1999 that are

problematical from a pricing standpoint and when Commissioner Baker asked earlier how many prices would be above a nickel, and I told you I didn't have that number, but I do have the 7.5 cents number, and for 1999 the HA prices, there were 390 hours above 7.5 cents, and in 1998 there were 452 hours that were above 7.5 cents. So, yes, it did increase, and you will find that the numbers are about the same for the DA prices for the same two years.

MR. HAWES: Your Honor, we have prepared a hearing exhibit that we will not introduce it -- Well, I guess we will introduce it under trade secret protection. GIG/GTMA Exhibit 15.

(The document referred to was marked for identification as GTMA/GIG Exhibit No. 15.)

BY MR. HAWES:

Q Without using any of the numbers on this chart which are trade secret protected -- and this, we'll represent, is a chart that we prepared. It's not something that you prepared, other than the numbers. Looking at this, is this a reasonable depictation, for instance, looking at the column to the left, and I guess I can use July 30 of '99, that column going across, this represents purchases that you actually made on that day? I know you can't testify specifically about purchases, unless you can, but

subject to check.

A (Witness O'Sheasy) These don't look unusual. I wouldn't be surprised if these didn't come from our records. I think what this top page here is showing, the specific hour of that day --

Q It is.

A (Witness O'Sheasy) -- not all the purchases that day.

Q Absolutely, and I want to make that clear. In the top left-hand corner is the date and the hour for those purchases at that time, and it does not depict anything more than just a snapshot of these times. And to the right-hand part where it says lambda day-ahead, hour-ahead, these would be the forecasted prices that you charged your customers on that day?

A (Witness O'Sheasy) It could very well be. I presume that is correct.

Q And subject to -- I'm sure these will be checked, so subject to check do you think you could make that... And then we have the column lambda average, which shows the amount of megawatts and this would be the average price?

A (Witness Hinson) You mean the row.

Q Yes, row. Lambda average.

A (Witness O'Sheasy) That appears to be the average of the purchases in that hour.

Q And if you subtract the average price from the actual price you charge for that, which is up at the top, you get a difference between lambda and lambda average, don't you?

A (Witness O'Sheasy) You get a difference in the lambda that was forecasted for the RTP price and you get a difference in this averaged lambda that you've computed.

Q And that's what the customer would pay if he had to pay, what had been forecasted and what he had been notified was the price?

A (Witness O'Sheasy) That is correct.

Q And so it would generate then -- in the next round is the revenues it would generate, which is simply a multiplication of the megawatts by the price? Is this kind of the way it would work so far? I just want to be sure the methodology is right. Subject to check of the numbers.

A (Witness O'Sheasy) I think what you are saying is, you took the RTP price and you multiplied it by the megawatts in the schedule, is that correct, to get the revenues?

Q Took the price the customer pays, which is the day-ahead lambda, times the megawatts?

A (Witness O'Sheasy) Well, I don't know for a fact that the RTP customers bought this quantity. They bought all the purchases. They may have bought more, they may have

bought less. We purchase for the system, not just for RTP. I cannot agree that the revenues of those that would have come in from RTP customers because I don't know the quantity that was being bought in that out.

Q Are you saying that without RTP that you would have been up into those purchases at that point?

A (Witness O'Sheasy) Yes, sir. In fact, that's an excellent point, I'm glad you made it. If it weren't for RTP I suspect we would have been even higher than that. I would suspect looking at the lambdas that you are indicating here that there was significant price response. Had these same customers been on PL, they would not have seen the significant price response. The loads in the system would have been significantly higher and the purchase prices would have been much higher than even this.

Q Yes, grand response. Leave that aside for the moment.

A (Witness O'Sheasy) Okay.

Q People who could not respond or did not respond, whichever, I won't try to argue that point, would be paying these prices. It wouldn't be paid by a residential customer, would it?

A (Witness O'Sheasy) It's embedded in the residential rate. The quantity that you are showing for purchase, let's assume for the sake of discussion that half

of that came from RTP customers, then that half would be paying the lambda price that you see there. The other half, the cost of that would be embedded in the other rates.

Q Embedded in the other rates. I'm not sure. I apologize.

A (Witness O'Sheasy) Okay. Let --

Q You're putting it into fuel, is that what you are saying?

A (Witness O'Sheasy) We do put it -- It would in effect go into fuel if these purchases were made to go through the fuel clause.

Q And they would, wouldn't they? Purchased power?

A (Witness O'Sheasy) I suspect they would. If these happen -- some of these happen to be long term purchases that I think we were talking earlier this morning about if there were a demand charge in there they might not be going through the fuel clause, but presuming these are spot purchases per kilowatt hour, then I think it is likely that they would go through the fuel clause.

Q And then the energy would, wouldn't it?

A (Witness O'Sheasy) Yes. Let me just --

Q That's what you mean when you say it would be put in others?

A (Witness O'Sheasy) Correct, it could. Let me also add another clarifying factor here. When we present

our purchases for a particular hour, these are our total system purchases in that hour for the system, and it is not necessarily purchases for retail load. They could be purchases for wholesale transactions, they could be purchases for off system sales. We don't have a way of going into each one of these purchases necessarily and break him out and say, this one is going to a wholesale requirement, this is going to a retail requirement.

Q You think you gave us some wholesale information?

A (Witness O'Sheasy) I'm saying I could, I don't know. If we gave you a list of all the hourly purchases that we made last summer, I guarantee you some would have been wholesale. I can't speak to this specific hour.

Q But if we assume that these are high-priced purchased power hours, this is the way the price in which that you would recover on that purchase would be set?

A (Witness O'Sheasy) Yes, sir, I think that is a safe statement.

Q And if -- In all three pages that you are looking at here, without referencing the number, look at the green price column which is about in the middle of the page. Now, these -- just as a hypothetical to show how the system works, and these are the true purchases you made that day, that top number in each one of those pages would be the lambda -- would set the lambda for that entire stack, is

that right?

A (Witness O'Sheasy) In a perfect world, that should be the case. The problem that we have here, and I think where you are going with this is there is a discrepancy between the actual highest purchased power price and the lambda that is in the RTP price, and if that is where you are going, let me just address that now. These RTP prices are, in the case of hour-ahead are forecast two hours ahead. On the case of day-ahead, they are forecast a complete day ahead. So we are trying to forecast what we think our purchase prices are going to be. Now, what you have in the column under the purchase, what the purchases actually were, and to the extent that we were right or wrong in our forecast of purchases, you may see things like this. Now, there's another phenomenon that's going on here that you need to be aware of and that is, with the hour-ahead, you should be much closer to the actual purchase price with the hour-ahead than you should with the day-ahead for the time limits of it, but some of the things that we have experienced, even two hours ahead, when prices are changing quickly in a volatile market, it's very difficult to forecast. In addition to this, we tried to do some analysis like this ourselves, and you've got to be a little careful to make sure that you line up the hour of the purchase with the hour of the price to make that comparison that I think

you want to make. For example, most of the time these purchases are in Central time, and you are forecasting your hour-ahead based on Eastern time two hours ahead. So be careful that you synchronize them correctly.

Q I'm not sure I ever could. But the question wasn't really going there. But thank you for that answer.

(Laughter.)

A (Witness O'Sheasy) Well, I withdraw my answer.

(Laughter.)

Q The question really was, looking at -- we'll just say the first top page of that, we'll use that one. That's the very top purchase, the number of megawatts and the price of that is only a fraction of what is the total number of megawatts which is down in the lambda average column. But you price all of it -- the system lambda is set at that very top number for that whole stack?

A (Witness O'Sheasy) It looks to me like that top purchase is about 25 percent of the total purchases in that hour.

Q And that sets the lambda?

A (Witness O'Sheasy) That is correct.

Q And that is what you charge?

A (Witness O'Sheasy) That is correct.

Q And look over to the second page and it gets a little more extreme, doesn't it?

A (Witness O'Sheasy) It looks like the second page is I guess around 12 percent. It looks like the last page is somewhere in the range of, I don't know, 22, 23 percent.

Q So you priced 100 percent at what 22 percent cost you? Is that the way you testified?

A (Witness O'Sheasy) That is the way the marginal cost rate works.

Q But you can work it another way, right?

A (Witness O'Sheasy) It wouldn't be marginal cost if we did.

Q Essentially be called averaging of the lambda?

A (Witness O'Sheasy) Correct.

Q Other utilities do that, don't they? Average lambda?

A (Witness O'Sheasy) I think I read in Mr. Pollock's testimony where he found a couple of other utilities that do that?

Q Like TVA maybe?

A (Witness O'Sheasy) I believe he mentioned that, and I think he also mentioned Florida Power and Light.

Q One question on this -- I feel like it's still not quite clear. When you say that the response shifted is -- not response -- that the price or the cost is shifted to other customers, this is through the fuel clause, right?

A (Witness O'Sheasy) Yes, sir. I think you were

referring to the purchases, and I said if all the purchases aren't being employed by RTP, then the FCR is going out for other customers.

Q And so, if you were even left with any power there, it would still go to the ratepayers? It would not cost you anything because it would go through the fuel clause?

A (Witness O'Sheasy) That is correct. The cost of those purchases would go through the fuel clause.

Q No risk there at all?

A (Witness O'Sheasy) Well, I hate to say -- Risk is a strange word. You have to be careful with it. Every time Georgia Power's prices go up, whether it is RTP or the FCR standard rates, I don't think that's a good thing. I think we run the risk of losing additional sales. So, to me, it's a risk any time prices go up that you disadvantage your competitive position.

Q Now, we've offered to correct that problem so there would be no such shift, hadn't we, by our fuel clause solution?

A (Witness O'Sheasy) Well, that's not a workable solution. That won't work.

Q Well, that will be up to the Commission, won't it?

COMMISSIONER BAKER: Can I just get a clarification? On that second page, July 30th, 4:00 p.m.,

looking at the -- the 1118 hours purchased, purchase power --

WITNESS O'SHEASY: Megawatts.

COMMISSIONER BAKER: Megawatt hours, okay. And those were all, I assume, sold to customers at the top price of the --

WITNESS O'SHEASY: No, sir. If those hours lined up correctly --

COMMISSIONER BAKER: Right.

WITNESS O'SHEASY: -- the price that was sold to RTP customers in those hours, if you look to the right of that top line, you see the day-ahead price, and to the far right you see the hour-ahead price.

COMMISSIONER BAKER: So what I'm seeing here to the left of that number though are not the actual prices, two hours behind or --

WITNESS O'SHEASY: These I think are supposed to represent the actual purchase cost. The numbers to the right are the actual price on RTP --

COMMISSIONER BAKER: At that time.

WITNESS O'SHEASY: -- at that time if they've lined up correctly.

COMMISSIONER BAKER: So the purchases that were made at 4:00 p.m. on July 30th were then sold at 6:00 p.m. or am I missing -- or 2:00 p.m.?

WITNESS O'SHEASY: That's what I'm saying, it's hard to line up. Let's imagine that what you are saying is true. In other words, we made these purchases at 4:00 p.m. Well, what we would be doing, you'd have to go back two hours in time. It's a -- Say some time between 1 and 2 p.m. that day, we would have been forecasting for hour-ahead customers what we thought purchases were going to be.

COMMISSIONER BAKER: Right.

WITNESS O'SHEASY: And that's what would have gone into the hour-ahead lambda that set the price for that hour that RTP customers paid.

COMMISSIONER BAKER: Okay. But then -- All right. But let's say then, just for -- we have 1118 megawatt hours that were purchased in this example right here. Those were all sold, and those were sold at the highest marginal cost for the purchased power at that particular time.

WITNESS O'SHEASY: What I was trying to indicate is, I cannot promise you that RTP load in that hour, that quantity --

COMMISSIONER BAKER: Took out the entire 1118?

WITNESS O'SHEASY: Right. We purchase on a system basis to serve the load. We don't know who was creating and who is causing it, so I was just fictitiously imagining -- let's say half the load you see purchased there was going to RTP customers, then half of that would have been priced at

this, the remaining half would be going through the fuel clause, and let me add that these purchases, I'm sure in these hours here, had to be made in order to either keep the lights on or prevent us from calling interruptible customers. In other words, we've run out of our own resources.

COMMISSIONER BAKER: Sure, sure, I understand that. But, I mean, what you then sold those megawatt hours at, I mean, you recovered your cost fully, correct?

WITNESS O'SHEASY: Yes.

COMMISSIONER BAKER: I mean, you got everything back, plus you got a healthy return.

WITNESS KUBLER: But the cost associated with that RTP price is covering more than fuel. It's covering variable O&M costs, and it's making a capital contribution to the units that are generating the lower prices so many hours of the year. So it's not -- it's not just fuel that you see in this lambda number here that's being portrayed on this sheet. And the other thing I would say is, we not only priced it to our customers at that price, we bought it from our customers at that price. If this is the hour that he is portraying here, we actually bought power from our HA customers at this price. We did not sell to our HA customers.

COMMISSIONER BAKER: Well, let me ask, I mean,

would you like to make a little change in that arrangement too with your HA customers?

WITNESS KUBLER: No, because it elicits price response which is a positive thing and is a good thing for all of our customers.

COMMISSIONER BAKER: So if I was a RTP HA customer of yours, I would have to still be on the system at the time that these prices kicked in?

WITNESS KUBLER: Correct.

COMMISSIONER BAKER: And if I got off the system at 4:00 p.m. on that day, you would cut me a check for however many megawatt hours I normally use?

WITNESS KUBLER: Figuratively speaking, yes, it would show as a credit on your bill for going below your CBL, going below your baseline load. In other words, we are buying back from you what you have already paid for in your CBL at this rate. At that point in time, if that's what the price is in the marketplace, I mean, we would either be paying our customers for it or we would be paying another utility for it, and to the extent that we can pay our customers for it, again, it creates very much of a win-win situation.

COMMISSIONER BAKER: But it sounds like from what the Petitioners are saying is that they are willing to forfeit?

WITNESS KUBLER: It kind of goes back to the statement you made earlier, some RTP customers want the other RTP customers to respond to price to keep the price down.

COMMISSIONER BAKER: Sure.

BY MR. HAWES:

Q This is something I overlooked, Mr. Kubler, just a straight question. You said in your testimony that purchased power has always been reflected in the prices. Did you actually, since the beginning of this rate from '92 on, did you actually put purchased power through rate as you are doing today or would that change at some point in time?

A (Witness O'Sheasy) It's always been done this way.

Q Always done exactly the same way?

A (Witness O'Sheasy) Yes, sir.

Q The point I guess I'd like to make, and I want to be sure that this is -- this point is not lost, because I don't understand when you said some of this may not go to RTP customers, but that last unit sets the price for everything RTP customer pays, though, doesn't it?

A (Witness O'Sheasy) Yes, sir, you are correct.

Q So it is still going to be that number that they are going to buy it?

A (Witness O'Sheasy) That's correct.

Q And looking at that number, there is a great deal of spread between the bottom and top of what you're buying?

A (Witness O'Sheasy) I think what I was trying to say was that quantity of purchases that you see there, I don't know that that is exactly the amount of RTP load that is being bought in that hour.

Q Well, even then, let's ask even a more different -- maybe different. Let's say you also serve a -- not just -- I'm going to look at page 1 and we'll make it simpler. The amount of megawatts you are buying there, your RTP load is much greater than that, isn't it?

A (Witness O'Sheasy) It may not be in that hour.

Q How much do you say it is? When we ask the question, what is your megawatt load?

A (Witness O'Sheasy) I think what we normally talk about is the RTP load probably runs in the range of 1000 to 2000 megawatts on the average. Okay? And what you've got to remember is the RTP load is not 100 percent load factor load. It has a shape to it also. So, in a particular hour, let's imagine that the RTP load is 1200 megawatts. Well, if you get 800 megawatts of response, then the remaining RTP load being bought in that hour is less than those total purchases. Q So, just for the sake of what we are talking about, we don't know exactly in any given hour what's on, but it generally averages between one and two

thousand?

A (Witness O'Sheasy) As long as prices aren't real high like the prices you are showing here, I'd say that's probably a safe statement.

Q Now, if you can just assume with me for the moment that you had more than -- in this case more than the megawatts shown that were taking power in that hour on RTP, and you then, whatever would be needed more than this, you would be getting from your native generation -- what is your lambda on your native system? 7.5 cents?

A (Witness O'Sheasy) That's probably a reasonable number. I think it can get up around 10 or 11, but there's not a whole lot of resources at that, so 7.5 is probably a reasonable number for the sake of our discussion right now.

Q So those people who were taking RTP at that hour, that were served by this, were being served by native generation that was costing you maybe a maximum of 7.5 cents to produce and you were selling it at that top number?

A (Witness O'Sheasy) In terms of the fuel cost, you are correct. Like Mr. Kubler was indicating, the delta there, the difference in the selling price and the resultant FCR is contributing to factors in addition to the fuel cost.

MR. HAWES: No further questions.

VICE CHAIRMAN D. BAKER: Thank you.

VICE CHAIRMAN BURGESS: Mr. Walsh.

MR. WALSH: The staff just has a couple of questions.

COMMISSIONER BAKER: Take your time.

FURTHER CROSS EXAMINATION

BY MR. WALSH:

Q I'll address my questions to the panel and whoever among the panel wants to answer the questions may. First, earlier today there was some testimony regarding the interruptible service tariff. Is it true that IS is called by Georgia Power Company based on reliability?

A (Witness Kubler) Currently that's correct, based on reliability.

Q Okay. Do you agree with -- I don't want to mischaracterize his testimony, but I understood Mr. Pollock's testimony earlier to say that it would require a change in the IS tariff for Georgia Power to call an IS based on an economic --

A (Witness Kubler) We don't believe that there would be a requirement to change the tariff and the reading of the tariff. It gives -- it does not specify exactly the reasons for calling the interruptible. So from our position we would not have to change the tariff. You know, we would be looking for direction from this Commission in order to be able to do that.

Q Thank you. There was also some discussion with

the public witnesses concerning comparable rates for RTP in the Southeast. I think Alabama Power was mentioned specifically. Do you recall that discussion?

A (Witness O'Sheasy) Yeah, I think I do. I'm not sure that when we were comparing them to Alabama we were comparing them to Alabama RTP rates. We may very well have been. I just know we were indeed comparing prices in Georgia to prices in Alabama.

Q I wasn't sure myself if there was the actual comparison between total bill or just RTP. But would the Alabama RTP rate be different from the Georgia Power RTP rate?

A (Witness O'Sheasy) Well when we're talking Alabama, I'm sure we're talking about Alabama Power Company because there are other utilities there.

Q That's what I was referring to.

A (Witness O'Sheasy) Right. The Alabama Power RTP rate, they really have two major -- two basic types of tariffs over there. They have one which is a two-part, like Georgia Power's, but that has very few customers on it. In fact, the last time I looked, they only had one customer on it. Then they have what's called a one-part RTP, where basically they will take their marginal cost and apply a multiplier to them so that's where they can collect their embedded cost. So they will have a one-part rate, and

that's where the majority of their RTP customers are. I think they probably have 35 or 40 customers on that application. So to answer your question, I'd say that the majority of RTP prices in Alabama are driven by an RTP rate that's somewhat different from Georgia Power's.

Q You used the terms one-part and two-part. What was Georgia Power's RTP rate?

A (Witness O'Sheasy) Two-part.

Q Two-part. Is it true that the higher the RTP rate, the higher the revenues to Georgia Power Company? Is that a true statement?

A (Witness O'Sheasy) No, not necessarily. You have to -- in order to get revenues, obviously you have to multiply the price times the quantity. We can actually have reductions of quantity at high prices such that the total revenues go down.

Q And what incentive does the company have to keep the RTP rate low?

A (Witness O'Sheasy) Numerous incentives. Customer satisfaction is very important to Georgia Power Company. We want our customers to be satisfied with their electric supplier. We talked about economic development. We do indeed want new business to come to Georgia. This is the tool we use. Customer choice. As you know, any new load in the state of Georgia that's over 900 kW connected is

competitive. We want those customers to sign up with us. We make five mills per kilowatt hour on our day-ahead price. If we keep a low price, we can sell more units at a low price, and so the five mills per kilowatt hour is multiplied by more units. There are just numerous reasons why we indeed want our prices to remain low.

Q Thank you. Could you refer to page 8 of your testimony, lines 6 through 12.

(Brief pause.)

Q Are you there?

A I think so.

Q Okay. You discuss the collection of capital costs from coal units through RTP rates, is that correct?

A (Witness O'Sheasy) Yes, sir.

Q Do you agree that the capital cost of coal units is a fixed cost?

A (Witness O'Sheasy) Well, I would -- I'm not trying to be trite with you, all costs are incremental in the long run. But for the sake of your question, yes, I would agree that coal costs should be considered as fixed.

Q Okay. Have fixed costs always been something that the RTP rate intended to recover?

A (Witness O'Sheasy) Yes, sir, to make a contribution towards. In other words, the RTP rate was always envisioned -- that it would have a component that

would contribute towards fixed cost.

Q Okay. I'd like to ask a couple of questions on the risk adder. I think in your testimony you say that the risk adder accommodates other marginal cost considerations that are not in the tariff, is that correct?

A (Witness O'Sheasy) Yes, sir.

Q Are these cost considerations stated anywhere else? I guess I'm just -- when you say cost considerations that are not in the tariff, what cost considerations are we talking about?

A (Witness O'Sheasy) Okay, clean air, for example. Commitment costs are another example. Any distribution costs, or A and G costs that arise because of the incremental RTP load would be additional cost considerations.

We also talked earlier today about marginal load that's been around possibly since 1992, '93, '94. I think a question becomes when does marginal cost become embedded cost, and the adder would help accommodate that. So these are some of the other considerations that I would say the adder currently adequately addresses.

Q Thank you. Also on the risk adder, how much of the total RTP price does the adder compose? Is there a range that it would compose?

A (Witness O'Sheasy) Well let's say that we talk

1999. The average DA price was 3.55 and the adder for day-ahead was 5 mills. So I think the math on that's about 14 percent.

Q Is that representative of an average year?

A (Witness O'Sheasy) No, that was a high year. Let's --

Q It's normally a lower percentage?

A (Witness O'Sheasy) No, it normally would be a higher percentage than that. If you were to go back to say 2.8, okay. Take 5 divided by 2.8 and you would get a higher percentage.

Q Will you refer to page 9, lines 1 through 6 of your testimony.

A (Witness O'Sheasy) Yes, sir.

Q You're discussing here the higher cost purchases of 1999?

A (Witness O'Sheasy) We were discussing purchases in general.

Q Okay. And it says that during 1999, it appears that higher cost purchases were greater than lower cost purchase effects?

A (Witness O'Sheasy) Yes, I see the sentence that you're referring to.

Q Okay. And is that -- is something that would affect purchases for all customers, not just RTP customers,

or is that just something for RTP customers?

A (Witness O'Sheasy) No. To the extent that there are high purchases, then that cost ripples through -- impacts all customers, not just RTP customers. And let me say that these high cost purchases were made for reliability purposes. They were made to keep the lights on. They were made to keep us from calling IS customers. It was a wise thing for us to do. In other words, to make those purchases.

Q Finally, I just -- I know that there are some -- there have been some questions on how the different rates have worked together. I take it not all RTP customers are IS customers?

A (Witness Kubler) That's correct.

Q Is there -- are most RTP customers IS?

A (Witness Kubler) No. The only customers that are eligible for IS are the RTP-HA customers, and there are 34 of those customers, and then there's 560 -- excuse me, 1,560 DA customers. So the HA customers are the only ones who are eligible for IS. Then you have other IS customers that are on other tariffs like PL.

Q Okay. Go ahead.

A (Witness Kubler) I was going to say, there's a total of 170 IS customers.

Q And what about the TOU rates? Are all RTP

customers on TOU?

A (Witness Kubler) No. The CBL, or baseline load, for an RTP customer depends on the rate they were on before coming on to RTP. So if they were a PL customer, then that's the rate that they're billed on for their standard bill. If they were a TOU customer, that's the rate they're billed on for their standard bill.

MR. WALSH: Mr. Chairman, that's all the questions I have.

VICE CHAIRMAN BURGESS: Thank you.

CUC?

MS. HOLLEY: We don't have any questions.

VICE CHAIRMAN BURGESS: All right.

Service Resources?

MS. BAULKMON: No questions, Mr. Chairman.

VICE CHAIRMAN BURGESS: Thank you.

COMMISSIONER BAKER: Does the company ever do any kind of reassessment of the RTP customers to see if they meet the criteria that makes them eligible to be an RTP customer as far as price responsiveness? Has anybody ever been kicked off RTP?

WITNESS KUBLER: No one has ever been kicked off of RTP once they went on the rate. We leave it up to them to make the choice as to whether or not they respond to price or don't respond to price. So we don't go back and

retest them.

WITNESS O'SHEASY: Let me also add that I don't think that would be a good thing to do. I think leaving the choice in the customers' hands is the right thing to do. But if we were to, if we were to take customers off of RTP and move them to another rate where they didn't see these price signals, if these are non-responders, the load itself on the system is not going to go down. In fact, it could go up because the comparable rate might be flat. So you're not going to lower RTP prices per se by moving non-responders off of RTP on to another rate in my opinion.

VICE CHAIRMAN BURGESS: Let me ask a question. Now on the CBL, it's set once and set for in perpetuity?

A (Witness Kubler) No, Commissioner, it's not. If a customer goes through the process of removing load from a system that was there when the CBL was set, then we will make a corresponding adjustment to the CBL to reflect that, otherwise, if they don't make any change at all, it is set for perpetuity.

VICE CHAIRMAN BURGESS: Well let me ask you this question: For those customers that don't respond, year to year, and you don't make an adjustment in the CBL -- I guess I'll ask the question, you know, should you, if you know that -- continually they're just riding through those high priced hours, and that's looking more and more like firm

usage for that customer. Shouldn't you look at that customer and say maybe we ought to readjust his CBL? He needs to be taking more of his power usage under the, you know, traditional tariffs instead of having him on RTP for that level above, which now appears to be almost like firm load for that customer.

WITNESS O'SHEASY: That's an interesting question. Some utilities write that into their RTP tariff, that every so many years they have the right to adjust the CBL upwards for those reasons that you alluded to. We personally think with the current rate structure that we have with RTP, with the lambda pricing, with the FCR account that we have with the five mill adder, that the price structure is adequate to compensate for the need that you were alluding to. That we don't need to update the CBL because of the current pricing structure. If you got away from that current pricing structure, I'm not sure what our needs would be.

COMMISSIONER BAKER: Also, if lambda averaging were adopted, could that theoretically increase load demand because essentially there would be lower cost to customers, and give them less an incentive to conserve energy, to get off the system or make any kind of modification in their usage pattern?

WITNESS O'SHEASY: Yes, sir, for sure. These handouts that we were looking at here -- I forgot the exact

exhibit. I think it's 61 and 62, trade secret exhibits. You could take the prices that you see there, and let's just assume that lambda averaging dropped the prices in half, then go to those graphs and say okay, at that price, that half priced, what was the response that you got. I think you'll notice that there would be hundreds of megawatts of response that would no longer be there, that we would have to go out and buy at these same high prices, or even higher prices because we put greater demands on the Southeast.

COMMISSIONER BAKER: And driving up the marginal cost even further.

WITNESS O'SHEASY: That's right.

COMMISSIONER BAKER: Unless the marketplace saw an increase in capacity -- available capacity.

WITNESS O'SHEASY: Right. And I don't know why it would, if it hadn't already, at that moment in time.

VICE CHAIRMAN BURGESS: Mr. Green.

MR. GREEN: I just have a few questions on recross -- redirect.

REDIRECT EXAMINATION

BY MR. GREEN:

Q Mr. Kubler, Mr. Hawes was asking you a question about this JP12. It was in the -- it was right in that discussion where he was asking you why we were talking about prices if you really ought to be discussing about cost, and

then he showed you this which appears to be prices from other utilities around the Southeast. Do you recall that?

A (Witness Kubler) Yes, I do.

Q Is it your understanding that these price comparisons do not include the impacts which RTP has on various utilities?

A Since it's documented down there at the bottom as the source of the information being the Department of Energy, that's filed information that they gleaned or got this from, the same as we did, so yes, it does reflect, you know, the prices and revenue collected from our customers.

Q Okay. Now let me ask you if we really were talking about cost instead of prices, Mr. O'Sheasy, is it your opinion that RTP is a cost based tariff?

A (Witness O'Sheasy) Yes, sir, that's my opinion.

Q We discussed here this exhibit, which was -- I forget what it was marked.

MR. HAWES: Fifteen, I believe.

BY MR. GREEN:

Q Fifteen. It was the one that had the spot purchases for July 30th, 1999. Sixteen hundred was one of the -- I think that's the second sheet.

A (Witness O'Sheasy) Yes, sir.

Q Without discussing particular prices, if you look on the second sheet, would you agree with me that slightly

less than 200 megawatts were purchased in three separate purchases, but all roughly clustered at a point which was dramatically above all the purchases which had been made to that point?

A (Witness O'Sheasy) I think you're right. I'm not sure -- you're saying that --

Q It's on the second sheet.

A (Witness O'Sheasy) Right.

Q It's on the second sheet, 1,600.

A (Witness O'Sheasy) Right.

Q There appear to be three separate purchases. I don't know if that's accurate.

A (Witness O'Sheasy) And if you sum up those megawatts, you'll get approximately 200 megawatts, is that what you're saying?

Q No. Wouldn't you get slightly less than 300?

A (Witness O'Sheasy) Excuse me, 300. Yeah, approximately 300 megawatts.

Q Right. And the purchases for that is where the dramatic step -- took from what appeared to be a gradual rise to then a dramatic step?

A (Witness O'Sheasy) That is correct.

Q Mr. Kubler or Mr. O'Sheasy, do you have an opinion as to whether or not an additional -- if an additional 300 megawatts of RTP load had responded to that high price, do

you think that would have avoided the need for that high price?

A (Witness O'Sheasy) Oh absolutely. Not only RTP but IS. Any reason for the load to have gone down 300 megawatts would have made those purchases disappear and not ever happen.

Q Okay. That was going to be my next question. Do you have an opinion as to whether or not if IS had been called -- less than the 500 total, if only 300 of the IS had been called, that would have avoided that need also, wouldn't it?

A (Witness O'Sheasy) Correct.

COMMISSIONER MCDONALD: What is that level of availability to call? Is there -- isn't there a ceiling or something?

MR. GREEN: Well the witnesses -- I think they used 500.

COMMISSIONER MCDONALD? Five hundred?

WITNESS KUBLER: We have 500 megawatts worth of IS load in the state of Georgia for the Georgia system. There is more than that if you consider the entire Southern system, but 500 megawatts for Georgia.

COMMISSIONER MCDONALD: What would happen if that were increased to 700? What effect would that have on pricing?

WITNESS KUBLER: Well it certainly would drive the prices even down lower.

WITNESS O'SHEASY: Let me also add an important factor. We dispatch as a system. We use IS as a system resource. So when Mr. Kubler was saying we have 500 in Georgia, we have 1,600 system wide. We believe we have 1,600 megawatts of system IS resources right now. If Georgia Power, for example, were to call for economics, then I think we could also talk to our sister companies about doing likewise, so the total resource calling for economics would be considerably more than 500 megawatts as it currently exists today.

COMMISSIONER MCDONALD: I may have missed it, but how much call is made, or is it really volunteers?

WITNESS KUBLER: Oh, it's -- we give a customer 30-minutes notice and then he's expected to respond within 30 minutes. If they don't respond within 30 minutes, there's penalties in the tariff for non-response.

COMMISSIONER MCDONALD: So there is an ongoing call during these high-need times -- peak times?

WITNESS KUBLER: Not now, no. For reliability, yes, but not for economics. We have not called for economics under the current situation.

COMMISSIONER BAKER: In '98 and '99, how many times was IS called for reliability purposes?

WITNESS KUBLER: In 1999, it was called for 12.5 hours, and I believe in 1998 it was only called for like two or three hours.

BY MR. GREEN:

Q Mr. Kubler, when you do the analysis to determine the appropriate level to be paid for IS interruptions, what assumption do you make with regard to IS calls that you're going to make during the year?

A (Witness Kubler) The assumption is made that that number could be, according to the tariff, as high as 240 hours per year.

Q Okay.

A (Witness Kubler) 240 hours a year.

Q Now, Mr. Kubler, do you have a recollection as to whether or not this July 30th, 4:00 p.m. description on the second page of this trade secret exhibit was the hour that was the highest priced hour in 1999?

A (Witness Kubler) It was the highest priced hour in 1999.

Q All right. This, I believe we indicated earlier set a price of about $6.42 cents?

A (Witness Kubler) That's correct.

Q How many times did this situation occur at $6.42?

A (Witness Kubler) Only one hour.

Q Do you have a recollection as to whether this was

the hour in which you got about 840 -- 864 megawatts of day-ahead response?

A (Witness Kubler) It is the hour in which we got that much response.

Q All right. And do you have an opinion as to whether you would have seen that kind of response if the averaging of lambdas had been used as proposed by GTMA and GIG?

A (Witness O'Sheasy) I think as Mr. O'Sheasy indicated earlier, that as you start to reduce the price, if you were to reduce it in half, then you would see a far less response than what we got with the prices that are indicated here.

Q If we assume that we had only gotten half of that 864 megawatt response, let's say we had gotten 432 megawatts of response, that would have left an additional 432 megawatts that you would have had to go out and buy, is that right?

A (Witness Kubler) That's correct.

Q And we really don't have any idea what price that would have been purchased at given the dramatic steps this has taken and the 300 megawatts that was actually purchased?

A (Witness O'Sheasy) That's correct, if it was available at all.

Q That was going to my next question. We don't even

know whether that would have been available or not?

A (Witness Kubler) That's correct. One of the things that we have not really discussed is the fact that importing power into the state of Georgia requires the use of a transmission system, and you have to reserve capacity on the transmission system in order to bring load into the state unless you prearrange for this purchase. It might not have the ability to bring it in, or it might not be available elsewhere.

Q I think you indicated that some of the HA customers were in fact paid $6.42 a kilowatt hour when they went below their CBL?

A (Witness Kubler) That's correct.

Q Do you know whether or not as a result of the purchases that were made during the summer of 1990, whether any of the HA customers actually saw negative bills?

A (Witness Kubler) I don't remember specifically about the HA customers, but I can tell you that all RTP customers -- there were 18 customers during the month of August that received a negative bill because of their response. Some of them were HA and some of them were DA.

VICE CHAIRMAN BURGESS: But you have to net that against the fact that they're not making product at that time though, right?

WITNESS KUBLER: Oh, definitely. I mean,

remember, it only takes a few hours at those higher prices to create a pretty sizeable credit.

VICE CHAIRMAN BURGESS: Right.

WITNESS KUBLER: So it's not like they were down for the entire month.

VICE CHAIRMAN BURGESS: Right.

BY MR. GREEN:

Q And, Mr. Kubler, the fact that they dropped below their CBL doesn't mean that they're not making product. Some of these have generators that they can put in place to keep making some of their product?

A (Witness Kubler) Yes, that's correct.

Q In fact, I think some of the questions you were asked about commercial customers being on RTP and having the ability to respond, are you aware of any office buildings in downtown Atlanta that, in fact, have generators to supply themselves when RTP prices get too high?

A (Witness Kubler) Yes, I do. The First National Bank Building, downtown Atlanta, setting in their garage are generating units that they crank up whenever the price gets to a certain point, and they are providing their energy from those generators as opposed to us under RTP.

Q So sometimes -- would you agree that sometimes this balance is not between making product and not making product or keeping the lights on and not keeping the lights

on, it's the difference between what can I, as a customer, generate it for myself versus what I can buy it from the company at?

A (Witness Kubler) Correct, an economic decision.

Q Now there are hours that -- we talked about one hour here that was $6.42 and was represented here at 4:00 o'clock in the afternoon on July 30th. Do you recall how many hours in 1999 customers paid less than two cents a kilowatt hour?

A (Witness Kubler) I believe it's 733 hours. The piece of paper that I was using escapes me, but it'll be able to tell you exactly what that number was.

Q Do you recall with regard to HA whether it was 1,700 hours?

A (Witness Kubler) I have it. For 1999, prices less than two cents, 733 hours; for HA, prices less than two cents were 1,715 hours.

Q So if we've got one hour here at $6.42, we've got 20 percent of the hours that are less two cents for HA customers?

A (Witness Kubler) Correct.

Q And if you'll look again at the sheet we were referring to, it shows here the day-ahead lambda and the hour-ahead lambdas, and understanding that we've got Central Time versus Eastern Time and that sort of thing, but using

this merely as a representative example, Mr. O'Sheasy, would the amount listed in the day-ahead lambda be an example of where you had forecast ahead -- a day ahead a certain price that because of contingencies on the system was -- maybe represented 25 percent of what the actual lambda was?

A (Witness O'Sheasy) Correct.

Q And in that situation that would be a forecasting error, correct?

A (Witness O'Sheasy) Correct.

Q Now you actually charged that customer the day-ahead price -- even though you had to go out and buy it for that customer -- the actual price that was agreed to?

A (Witness O'Sheasy) Correct.

Q Mr. O'Sheasy, are you aware of any independent sources, or sources which you may have contributed to, which are -- give us a publicly discussed description of what marginal cost is?

A (Witness O'Sheasy) Well I was reading through the petitioner's prefiled testimony and they were quoting an EPRI manual, which I was one of the contributing authors for it. I believe it was a 1995 edition, which I have here with me. We -- the inputs that I put into that manual were fundamental, not only for the manual, but also the RTP rate that we have today, such as discussing marginal costs as small increments of load changes that create marginal

changes in cost. So the answer to your question I think is the EPRI manual.

Q That gives you the definition that you then followed for --

A (Witness O'Sheasy) Correct.

Q -- for establishing your RTP rate?

A (Witness O'Sheasy) Correct. And also, the definition that was established for several other utilities. We've consulted with South Carolina Electric and Gas, Duke Power Company, Public Service of Oklahoma, numerous utilities that have used and adopted these same definitions.

Q Does that same document give us any publicly discussed information with regard to adders and what those should be and what those should be used for?

A (Witness O'Sheasy) Yes. That's one of the reasonable components that the document indicates should be seriously considered in your RTP price signal as an adder, so that the utility will have the profit incentive just like they do in any other rate.

Q Okay. And finally, let me ask you, we haven't heard a whole lot of discussion about the price guarantees that have been offered here. I know that Mr. Hawes said that that's a whole other issue than what we have here on the table, but I think that is something we have on the table. Didn't you file that as one of your proposals?

A (Witness O'Sheasy) That's correct. That's one of our alternatives.

Q All right. Mr. Hawes kept not wanting to let you tell him that it was a price guarantee. In your opinion, is it a price guarantee?

A (Witness O'Sheasy) It is most definitely a price guarantee.

Q And if the price guarantee, calculated on the year as expected, is 3.09 cents, is that, in your opinion, a guarantee of 3.09 cents on the average customer?

A (Witness O'Sheasy) For an -- yes, it is. For an equal amount of load in every hour, that is a guarantee of 3.09.

Q All right. And the company makes a projection of every customers' RTP price for the year, isn't that right?

A (Witness O'Sheasy) Yes.

Q All right. And when you make that prediction with regard to any particular customer, is the company willing to guarantee that price for that particular customer?

A (Witness O'Sheasy) We're willing to guarantee, or offer, to any RTP customer that they can purchase an equal amount of RTP load in every hour at that price.

Q Okay.

A (Witness O'Sheasy) Now, I want to make sure that -- Mr. Hawes was indicating some issues that I don't want to

ignore, and that is, we were hoping to have this particular alternative in place January the 1st, the year 2000. That did not come about. If it had, we could have indeed guaranteed 3.09 for that equal amount of load for the entire year. Now the point being made here is, if that particular alternative does not become effective until -- we'll say June 1, for example, the 3.09 would not -- would not be the resultant price because we would have missed several months of low prices in that guarantee. I think the resultant June through December would actually be around 3.34.

But the point I was trying to make earlier was, the January/February/March actual RTP prices are right at what we forecast that went into the 3.09. So if, for example, you were to make the new alternative effective March -- excuse me, April 1, then if you were to couple that with the actual prices RTP customers face, the equivalent number for the whole year comes right back to 3.09.

Q And the reason that it's 3.34, if we start in April, is because you've got a higher percentage of higher cost months --

A (Witness O'Sheasy) That's exactly right. If, in theory, we have four high priced summer months, June through Sept, that's one-third, obviously, of a standard year, but if we go from June to December, then it would be a much higher -- the number of summer months would be a much higher

percentage.

WITNESS KUBLER: I would like to also add that while we're talking about this being a guarantee, we have not eliminated the possibility of a customer responding to prices and getting even a lower cost than 3.09 cents. So built into the alternative is still the incentive for the customer to give us the price response which we have talked about is so important to us.

MR. GREEN: I have no further questions.

MR. QUINTRELL: Mr. Chairman, if I could have one minute of recross on this last point that they raised? They raised some questions with respect to the RTP alternative.

MR. HAWES: We had divided it out where Mr. Quintrell was going to handle alternative measures but I forgot about it.

VICE CHAIRMAN BURGESS: I'm going to do this because I don't want to get involved in another round of recross and re-redirect. That's why we're providing parties with 10 minutes a piece to summarize arguments at the end of the case. I would much rather that any specific points you have to make on the issue, you just make them in your closing comments.

MR. QUINTRELL: That'll be fine.

VICE CHAIRMAN BURGESS: If there are no other questions of this panel you may be excused.

(Witnesses excused.)

VICE CHAIRMAN BURGESS: I'm going to go forward. Commissioners are y'all willing to -- we've got Mr. Pollock's rebuttal testimony and 10 minutes of arguments from each side.

COMMISSIONER BAKER: Well, you know, this is an important case and I hate to rush it just because we don't want to have to come back here tomorrow morning.

COMMISSIONER MCDONALD: We won't get to see a lot of these people tomorrow if we don't finish today.

MR. GREEN: If it helps any, I will not consider rushed. I only have cross examination on the rebuttal witness. I think we can get done even with the -- assuming a five or ten-minute summary and my cross of 15 minutes, we can still be done within half an hour or 45 minutes. That would save coming back tomorrow, but I can come back tomorrow, too.

COMMISSIONER BAKER: Okay. I need to make a call.

VICE CHAIRMAN BURGESS: I tell you what, we'll take a 10-minute recess and we'll come back and finish.

(A short recess was taken.)

VICE CHAIRMAN BURGESS: We're ready to go back on the record.

Just let me say this before we get started. I don't want anybody to have the impression that we're trying

to run you out of here and rush you out of here, take the time that you need. This is a very important case. I don't think you would have seen the Commission entertaining at this late an hour this case if we didn't think it was important. So I don't want anybody to take that impression out of the room that we're just simply trying to get you out here and be done. You take the time that you need to complete your case and present the evidence in the case.

MR. QUINTRELL: Mr. Chairman, along those lines -- I'm just inquiring, is there going to be another time later on this week or early next week, when the Commission is already going to be assembled for another matter, when we could do the oral argument? I mean, I think it would be productive and helpful, particularly since we've got two commissioners that aren't here. Oral argument is the time to sort of synthesize and organize and present your ideas in a cohesive fashion, and I'm afraid that what we're going to have, at least with respect to the oral argument today is going to be just a recitation of what we've already heard since we haven't had time to sit down and think and organize.

VICE CHAIRMAN BURGESS: What I would suggest you do is, the Chairman ruled -- he made his ruling and he's no longer here. I think it's appropriate that if you want to have a separate oral argument set later on, that you request

that of him. I think it's appropriate that he make that ruling because he told the parties what his ruling was before he had to go today. I don't mind not doing it today. I believe it would serve everybody better if we did have a little bit more time to do it. That's fine with me, but I think the request needs to go through the Chairman to have a separate oral argument.

MR. HAWES: If he says no, are we just going to --

VICE CHAIRMAN BURGESS: I think he's accommodating. Once again --

COMMISSIONER MCDONALD: Mr. Vice Chairman.

VICE CHAIRMAN BURGESS: Yes, sir.

COMMISSIONER MCDONALD: With all due respect though -- I mean, are we going to hear it twice?

VICE CHAIRMAN BURGESS: No, we're not going to hear it twice, we're going to hear it one time.

COMMISSIONER MCDONALD: Are we going to hear it now?

VICE CHAIRMAN BURGESS: What I'm hearing from Mr. Quintrell is, he would rather hear it later.

Let me hear from Mr. Green. Have you got a preference?

MR. GREEN: We would respond to a request for oral argument, we have no objection to it. We think briefing is perfectly fine. I'm prepared to -- if Mr. Quintrell's

request for oral argument is granted at another time, we'll show up. I'll respond today if he wants to have it today, if he doesn't, I won't insist on having one today.

VICE CHAIRMAN BURGESS: Thank you. This is what we'll do, we'll schedule oral argument and I'll have the Executive Secretary send out an order notifying you when that date will be. So we'll come back and have separate oral arguments.

MR. GREEN: Thank you, Mr. Chairman.

MR. QUINTRELL: The Petitioners recall to the stand Mr. Jeffry Pollock.

Mr. Pollock, let me remind you that you're still under oath.

Whereupon,

JEFFRY POLLOCK

was RECALLED as a witness herein, and having been reminded of his oath, was examined and testified further as follows:

DIRECT EXAMINATION

BY MR. QUINTRELL:

Q Mr Pollock, did you prepare and file in this docket written rebuttal testimony consisting of 25 pages of questions and answers in Exhibits JP-10 through JP-13?

A Yes.

Q If I were to ask you those questions here as you sit on the stand today, would your answers be the same as

reflected in that prefiled written testimony?

A Yes, it would.

Q Do you have any corrections or additions to your prefiled rebuttal testimony?

A Only one. There's a typographical error on page 11 of the testimony, line 22. Actually I'm not sure what line it's on. But in any event, it's the line that begins -- it says accelerated deprecation, it should say accelerated depression.

Q I'm glad you caught that one.

A That's not a Freudian thing.

MR. QUINTRELL: Mr. Chairman, the Petitioners move a copy of Mr. Pollock's rebuttal testimony into the record as if read from the stand here today, of course, subject to cross exam. We also request that Exhibits JP-10 through 13 be marked and reflected in the record as Exhibits GIG/GTMA 10 through 13, and also be entered into the record subject to cross.

VICE CHAIRMAN BURGESS: Subject to cross examination, the testimony and exhibits will be made a part of the record.

(The documents referred to were marked for identification as GIG/GTMA Exhibits Number 10 through 13, and received in evidence.)

(Whereupon, the prefiled rebuttal testimony of Mr. Pollock follows:)

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 of Jeffry Pollock

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.

BY MR. QUINTRELL:

Q Mr. Pollock, would you please briefly summarize your rebuttal testimony?

A Certainly. Although I do not respond to everything that's in the Georgia Power direct testimony, that should not be interpreted as an endorsement of the company's position. I do address four issues. Let me just summarize those real briefly.

Mr. O'Sheasy says that RTP is still a cost-based rate and obviously we disagree. RTP is not a cost-based rate. The mark up on the RTP cost, the differential between the price charged, the system lambda being the most expensive power on the system, and what it actually costs the company ranges anywhere from 40 to 80 percent, and that makes that part -- the way that system lambda is set means that it is not based -- does not reflect what the company's actual cost is. So based on that mark up, the rate is not cost based.

Secondly, when the company adds five mills, it hasn't really provided any cost evidence to suggest that five mills is an appropriate adder. It does compare the five mills with other utilities. In fact, other utilities -- some utilities do charge five mills. One even charges six. What the company doesn't tell you is the one utility that they modeled their rate after, which was Niagara

Mohawk, only charges two mills for an adder. And besides which, the utilities that charge five and six mills also have lower standard rates than Georgia Power does.

With respect to other issues on the adder, the company says that there's some marginal cost considerations that need to come into play and they speak of three things, unit commitment costs, emission allowances and distribution costs and overheads.

First of all, the unit commitment costs and the distribution costs are being fully recovered by all customers. If there's a problem with the price signal, because it doesn't reflect distribution costs, that's simply a cost allocation problem, it's not a rate problem. None of Georgia Power's rates precisely reflect cost of service. As we talked this morning, residential rates are below cost, industrial and commercial rates are above cost. There's no difference. But besides that, unit commitment costs are in fuel. Everybody pays fuel costs. Distribution costs are in base rates. As long as the company's earnings are within the range prescribed in the accounting order, those costs are fully recovered. And furthermore, the distribution element does not affect customers that take service at transmission voltages. So the company's arguments, while assuming that they apply to distribution level customers -- some RTP customers, it certainly doesn't apply to all of

them. Most of the RTP-HA customers are at transmission voltage.

With respect to the issue of price response, lambda averaging, as I said in my direct testimony, will make the rate reflect cost of service. And yes, instead of seeing 4 and $5, or a dollar, the prices will be lower, but the company is still going to get the amount of price response that they projected. In their IRP case, the projection was somewhere between 300 and 400 megawatts of price response. I think we'll all agree that last year they got double that because of the serious prices. The point here is, you have to balance price response with setting prices that are reasonable. Price response is not the sole objective of RTP, it's sending of an appropriate price signal that reflects changes in the company's cost of service. If you lambda averaged, as we suggest, those prices may not be as high as 4 and $5, or a dollar, but they will be high enough, and just as high as they've been -- in fact, higher than they've ever been in the past and will send proper price signals.

Mr. O'Sheasy referred to the EPRI guide with respect to real-time pricing. It's interesting to note in that particular guide the company reported seeing price response even when the price was as high as 30 cents a kilowatt hour. I continue to believe that customers will

respond to prices of that magnitude. Which again, 30 cents a kilowatt hour is more than any other customer pays as an average rate.

Finally, let me address the other point in the company's testimony. In looking at -- particularly the chart that you see now, comparisons of average revenues per kilowatt hour basically mean nothing. Different customers have different characteristics, load factor, size, delivery voltage, willingness to interrupt and price risk. Willingness to take price risk. Those characteristics are not reflected in that, yet the company's rates are cost based; therefore, to the extent there are differences in average revenues, I submit that those differences reflect differences in cost of service.

Finally with respect to the company's analysis of revenue per kilowatt hour comparisons, I point out in my Exhibit JP-12 that there are several utilities that were omitted that are in fact providing lower average revenues per kilowatt hour. And further, that the prices charged for service where a customer doesn't have to assume interruptibility, doesn't have to assume firm -- doesn't have to assume price risk are lower for other utilities of comparable size and load factor as these customers. The point is is that GIG and GTMA members, contrary to what the company would have you think, really are not getting the

best deal. There are other deals out there that their competitors are getting that they can't get.

That concludes my summary.

VICE CHAIRMAN BURGESS: Mr. Green.

CROSS EXAMINATION

BY MR. GREEN:

Q Mr. Pollock, I notice that nowhere in your prefiled rebuttal, and certainly nowhere in your summary here did you even discuss or address the four new tariffs that the company has proposed as a way of attempting to deal with some of these RTP problems, is that correct?

A That's correct. In my direct testimony, though, I did address the same issue. The alternatives are designed to address price volatility, and as I indicated in my direct testify, it's the price, not the volatility that the customers are concerned about.

Q Okay. Is the 1.4 cents that's the low price for 1999, that's not a problem for you, is it?

A I don't have a problem with it, no.

Q Okay. And you don't have a problem with the 1,700 hours that are less than two cents either, do you?

A I have a problem in the sense that those number of hours keep shrinking and that the hours above five cents keep growing. That is a concern.

Q Well, in fact, didn't -- did you hear Mr. Kubler

when he explained that the hours above 7.5 cents were actually less in 1999 than they were in 1998.

A Oh, I heard that, too, but the prices -- the extreme prices in 1999 were obviously a lot greater. You didn't have prices over a dollar in 1998.

Q Now you have proposed in your rebuttal testimony capping system lambda at 7.5 cents, is that right?

A No.

Q Okay. That's not on page 8 of your rebuttal testimony?

A Well what I said was, if you set system lambda only at incremental generation cost, you would still a price as high as 7.5 cents a kilowatt hour. I haven't said that you should cap the rate at that, no.

Q Okay. Nor have you suggested that a floor be put under the rate for -- to avoid customers from getting the advantage of those less than two cents a kilowatt hour, have you?

A No, I'm not suggesting any limitations. All I'm suggesting is that the rate -- the prices that are charged reflect the actual costs.

Q Now in 1999 the company, because of the hot weather and other reasons, has about $120 million to share pursuant to the accounting order.

A That's what I understand.

Q All right. And would you agree that for every dollar that you reduce RTP revenues by because of rate restructuring --

(Loud sirens on the street.)

A That's not me.

Q Are they coming to your aid or my aid?

A I don't know.

(Laughter.)

Q For every dollar that you reduce RTP revenues because of a rate reduction, you would be taking 66 cents away from residential and commercial customers?

A I would disagree with that because our proposal is not going to affect the distribution of over earnings in 1999, this year. And I would also say that whatever the company earns, the company is going to earn. Earnings are affected by a lot of things, revenues, expenses, a lot of which can be managed. Who knows what the earnings are. I think the best analogy is, if we're worried about trying to get money back in the customers' pockets, I think that's really the wrong worry. The real concern is to make sure that the rates and the prices -- I'm sorry, I'm having trouble talking. The rates and the prices reflect the actual cost and the consequences will fall where they fall. Whether that's money back in customers' pockets or not, I don't know. If a burglar cleaned me out, took everything

that I had and said well gee, if I have too much, I'll be able to, you know, give you back a table and chairs or something like that, I wouldn't be any happier getting back the table and chairs if I'm already, you know, out all of my possessions. I mean, if that's the whole purpose of the exercise, what's really the point?

Q Well you're not suggesting that the 1998 accounting order was a burglar effort on your customers are you?

A Well I'm saying if the company is allowed to earn consistently above 12.5 percent there's something wrong, because the accounting order says you have an opportunity to earn between 10 and 12.5 percent, and it's not the purpose of the accounting order to allow you to earn more than that.

Q Well let me see if I can get you to agree, you've read the accounting order, haven't you?

A Certainly.

Q Doesn't the accounting order say that the company is allowed to earn between 10 and 12.5 percent and keep one-third of all earnings over 12.5 percent?

A Except this year and next year, which the company gets the first 50 million above the 12.5 percent.

Q And that's a provision in the accounting order?

A Yes, it is.

Q And that was litigated in the accounting order?

A Honestly, litigated, I think that was all developed in a stipulation of which we were not a party to. So we didn't litigate that part. If we had of had an opportunity, we would have litigated that part.

Q I thought your testimony dealt specifically with some of these very issues in the 1998 rate case.

A Which issue was that, the accounting order?

Q The accelerated depreciation being continued.

A Our testimony addressed the cost of service elements, that's correct.

Q Did you not address the issue of the accelerated depreciation in your testimony?

A Yes, we did.

Q Okay. Did not Mr. Hawes and Mr. Quintrell argue to this Commission that they shouldn't allow that?

A Yes.

Q Okay. The accounting order specifies where every dollar about 12.5 percent goes, isn't that right?

A Yes.

Q And it specifies what rate reductions will occur between 1998 and the year 2000, doesn't it?

A It specifies rate reductions?

Q Yes. There is a rate reduction that's been --

A Oh, I'm sorry. Yes, that's correct, '98 and '99.

Q And the accounting order specifies having

considered RTP, that RTP rate shouldn't be reduced?

A That was part of the stipulation which GTMA and GIG were not a party.

Q Well, I don't mean to be too precise here, but I think we ought to be too precise. That was part of the accounting order itself, signed by the Commission?

A The Commission adopted the stipulation, but they did so without our concurrence.

Q And they did after considering your objections?

A I'll allow the attorneys to answer that. I don't know what they considered.

MR. GREEN: I've got no further questions.

VICE CHAIRMAN BURGESS: The staff?

MR. WALSH: No questions, Mr. Chairman.

VICE CHAIRMAN BURGESS: CUC?

MS. HOLLEY: No questions.

VICE CHAIRMAN BURGESS: Service Resources?

MR. CLARKSON: No questions.

VICE CHAIRMAN BURGESS: Mr. Quintrell.

MR. QUINTRELL: Just briefly some redirect.

REDIRECT EXAMINATION

BY MR. QUINTRELL:

Q Mr. Pollock, Mr. Green asked you about the RTP rate alternatives --

A Yes.

Q -- that Mr. Kubler talked about. You just testified a minute ago that those were designed to address volatility, is that correct?

A That's correct.

Q They were not designed to address the average RTP price?

A That's right.

Q It's kind of like an insurance policy against the real high prices we've been seeing the last couple of years, is that right?

A That's right.

Q And like insurance, they've got a cost, don't they?

A They have a cost and there's some risk that the customers are going to have to take in order to take advantage of the alternatives.

Q The 3.09 cent guarantee that the Georgia Power panel testified about, is that -- what does a customer have to do to really get that guarantee?

A In order to get that guarantee, a customer has to increase his baseline load by an equal amount for the entire year. Now what that implies is that if a customer doesn't have a perfectly flat load, there are going to be some hours of the year that aren't going to be covered by that guarantee. As a result, the hours that aren't covered by

that, the customer is going to pay whatever it is.

On the other hand, there's another option that says you can do your entire load -- move your load shape up and lock that in. The problem with that is, when you adjust your CBL up and you suddenly have -- or subsequently have a downturn or something that causes you to use less, then that price is not a guarantee. You're basically going to be stuck paying a price for energy that you're not using.

Q So the alternatives that they're talking about really don't do anything to reduce the average price? In fact, Georgia Power's witnesses, they come right out and say that in their testimony, don't they, that most customers expect to stay on RTP because in the long run it's going to be the cheapest alternative.

A Two of the four alternatives basically are straight out higher prices. The other two are basically trying to address the volatility issue, but don't really get at the price level that the customers are paying on average.

Q And none of the RTP alternatives or the price-protection products, or any of that address the problems that we've identified with respect to the way system lambda is calculated or the fuel cost accounting is done and the way the adder was charged?

A That's correct. It's all based on the same pricing platform which we believe needs to be changed.

MR. QUINTRELL: Thank you. That's all I have.

VICE CHAIRMAN BURGESS: Thank you. Any further questions of this witness?

(No response.)

VICE CHAIRMAN BURGESS: Thank you, Mr. Pollock. You may be excused.

(Witness excused.)

VICE CHAIRMAN BURGESS: Mr. Hawes?

MR. HAWES: I would move the introduction of GTMA Exhibit 15.

VICE CHAIRMAN BURGESS: It'll be a part of the record.

(The document heretofore marked as GIG/GTMA Exhibit Number 15, was received in evidence.)

VICE CHAIRMAN BURGESS: If there is nothing else to come before this Commission, the Commission will notify all parties when the oral arguments will be held. Thank you for your participation here today. Thank you.

(Whereupon, the hearing was concluded at 6:51 p.m.)

C E R T I F I C A T E

I, Peggy J. Warren, do hereby certify that the foregoing pages represent a true and accurate transcription of the events which transpired at the time and place set out in the caption, to the best of my ability.

Peggy J. Warren, CVR-CM, CCR A-171