BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In The Matter of	DOCKET NO. 891345-EI
Application of GULF POWER COMPANY for an increase in rates and charges.	HEARING EIGHTH DAY EVENING SESSION
	VOLUME - XXIII
	Pages 3392 through 3618

FPSC Hearing Room 106
Fletcher Building
101 E. Gaines Street
Tallahassee, Florida 32399

Wednesday, June 20, 1990

Met pursuant to adjournment at 1:10 p.m.

BEFORE: COMMISSIONER MICHAEL McK. WILSON, CHAIRMAN
COMMISSIONER GERALD L. GUNTER
COMMISSIONER THOMAS M. BEARD
COMMISSIONER BETTY EASLEY

APPEARANCES:

(As heretofore noted.)

REPORTED BY: JOY KELLY, CSR,RPR
SYDNEY C. SILVA, CSR, RPR
Official Commission Reporters
and
LISA GIROD-JONES, CPR, RPR
Post Office Box 10195
Tallahassee, Florida 32302

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WITNESSES

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EXHIBITS

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EVENING SESSION

(Transcript follows in sequence from Volume XXII.)

CROSS EXAMINATION

BY MR. BURGESS:

Q Mr. Haskins, isn't one of the -- isn't the reason that you disagree with Mr. Wright's method for determining time-of-use demand charges that a customer who is able to shift most of the load off peak would end up being subsidized?

A A customer that is able to shift all of or a major portion of his load off peak would pay very little demand charge. In fact, on his proposal he would only pay for the local facilities and would pay no production and transmission related demand charge, and I don't believe that's appropriate for him to get a free ride on that. And so to that extent he would be being subsidized by the remaining customers.

Q So it's correct, then, that even if all usage is off peak, there is still some production and transmission costs incurred by Gulf Power?

A Yes.

Q Then is it fair to say that even if usage is entirely off peak, it, nevertheless, causes the Company to incur some production and transmission costs?

A If usage is entirely off peak, there is still a need for production and transmission cost to provide service to that customer.

Q So it causes -- usage entirely off peak, nevertheless, causes the Company to incur production and transmission costs?

A Yes. (Pause)

Q Isn't one of the reasons for Gulf's opposing higher industrial rates the fear that you'll push some of your industrial customers to cogenerate?

A That, as well as the fact that industrial customers might either leave Gulf's service territory or not come.

Q Cogenerate, leave or simply not arrive in Gulf service territory?

A That's correct.

MR. BURGESS: Thank you, Mr. Haskins. That's all we have.

MAJ. ENDERS: Thank you, Mr. Chairman.

CROSS EXAMINATION

BY MAJOR ENDERS:

Q Mr. Haskins, on Page 5 of your rebuttal testimony you state "Mr. Wright's proposal is a brief theoretical discussion, which has no regard for the effect implementation of his proposal might have on the

affected customers." Why do you say that?

A Because he has run no calculations of the effect his rates would have on individual customers to see what percentage increase they might get, to see what the effects might be on their individual bills and the effect on other rates that would be adjacent rates, if you will, to those classes of customers.

Q What, if any, calculations or what rates has Staff proposed in this regard?

A To my knowledge they have not proposed any rates that would look at this aspect of rate design either.

Q Similarly, on Page 8 you're discussing Mr. Wright's alternative method for determining energy charges, and I guess your answer is about the same as it was to the previous question.

A Yes, it's an interesting theoretical discussion, but with regard to the actual effect on the customers in Gulf's territory, he's made no determination of that.

Q Mr. Haskins, you said Dr. Johnson's proposed LP/LPT rates would take the class down to .95 index of return. .05 below parity, is that correct? I believe you said that in your summary.

A Yes.

Q Would you agree with me that there are intraclass subsidies within the LP/LPT class?

A I will agree to that to the extent that within any class of rates that has more than one customer in it, there may be an intraclass subsidy because no rates are precise in recovering the costs from individual customers within a large class.

Q But is a subsidy more aggravated in this class than say the other classes?

A I don't believe it's any more aggravated in that class than it might be in another class

MAJOR ENDERS: I have no further questions.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Mr. Haskins, to follow up on Mr. Burgess' question.

When you build a generating station or a transmission line, you pay the money to build it and then you incur what they call "fixed capital costs." You've got to pay off the mortgage, and you have depreciation expense, and taxes and so forth. And those continue to run on peak and off peak, don't they?

A Yes, sir.

Q So if a customer didn't buy electricity during the off-peak period, do your banks forgive you

the mortgage payments during the off-peak period?

A I guess you're using banks giving the mortgage payments as a representative of our financing situation.

Q Yeah.

A And the cost of those plants continues regardless of whether there is off-peak usage or not.

Q And the tax collector doesn't reduce your taxes, does it?

A No.

Q They continue to wear out, don't they?

Q And the shareholders in your company still want a return?

A That's correct.

Q Now some production and transmission costs go away, those costs that would be variable operating costs. But the fixed costs stay whether the customer is buying electricity or not?

A That's right.

Q So when you design things like the SE rate, that's a way to get in or encourage people to buy electricity during the off-peak period in order to pay for the fuel and get some additional contribution to your capital cost?

A That's correct.

Q And I presume those are people who might not buy electricity otherwise and people you can kick off the system if your other customers need that power, isn't that right?

A That's right. They have that understanding.

Q Now that SE service, that's available to every person that can take advantage of it, I guess, in the industrial class, or who is it available to?

A It's available to all customers in the LP/LPT. PX andPXT classes, which is everybody above 500 kilowatts.

Q And when they buy that electricity, it's beneficial to your Company?

A Absolutely.

Q Now if you have a cogeneration customer who -- I guess it's not -- you don't have a pure -- generally you don't have a pure cogeneration customer who either is solely standby, but you have people who have mixed use. Some of them, they serve part of their load with cogeneration and part with buying electricity from Gulf, is that correct?

A We have customers that have mixed use, and we actually, on our system, have one customer that is 100% standby.

Q I see. And one of these mixed use customers,

for their regular load they have SE service available to them; they can use more electricity during the SE period, is that right?

A That is correct. And some of our customers that have mixed generation and purchase power, if you will, are signed up for SE and some are not.

Q Okay. Now, if one of the customers is eligible for SE also has cogeneration, and he loses a cogenerator during an SE period, he's got -- at that point in time he can't use SE, anymore, is that the deal?

A He becomes a standby customer at that time.

Q And so to that extent, the industrial customer or the cogeneration is cut off when an industrial customer who doesn't have cogeneration could continue to buy SE power, he's cut off unless he's willing to pay more for standby power?

A That's correct.

Q When you contested Mr. Kisla's math, I guess, and he gave a hypothetical, and on Page 26 of your rebuttal, Mr. Kisla, in his Exhibit 610, assumed that supplementary service contract capacity cannot be used as a substitute for standby service capacity. Is that what he assumed?

A That appears to be what he assumes, yes.

Q Did you hear Mr. Kisla's testimony that the scenarios portrayed in Exhibit 610 represent average conditions and not necessarily peak conditions?

A I really did not hear that particular part of his testimony. I heard some of it, but I didn't hear that particular part of it. But if you say he --

Q Are you contending he didn't say that or -- sometimes it passes over me.

A No, I'm not contending he didn't say that. And if you say he did, I'm sure he did.

MR. McWHIRTER: Subject to check.

COMMISSIONER EASLEY: Is that factual or mathematical?

Q (By Mr. McWhirter) Well, let's assume a cogeneration customer has a supplementary contract of 15 megawatts and the customer routinely uses 15 megawatts during the month. If the customer sustains an outage, as a result, the customer then imposes 20 megawatts of demand during the outage period, is it your testimony that the customer has used more than five megawatts of standby power, if that customer is a cogeneration customer?

A If he has been running 15 megawatts, he has a supplementary contract of 15?

Q Yeah.

A And he loses generation?

Q Uh-huh.

A And he goes to 20 megawatts?

Q Yeah.

A What, just to have the complete picture so we'll have all the cards we have to deal with, what was his standby contract and how much generation did he lose?

Q Well, say he had a standby contract for 15 and he had cogeneration of 10. And he lost 10.

A He lost 10.

Q Uses 20.

A And he used 20?

Q Uh-huh.

A And that's -- and so he must have had five megawatts of load reduction at the time that he lost the 10, or he would have gone up -- if he was using, if his load was 15 and he had 10 megawatts of generation, that means the plant load was 35 megawatts.

Q Let's use your Schedule 6 and that will be easier to follow. And that scenario, he had self generation of 14 and 5, 14.5?

A Okay.

Q Well, I guess in this one he had cogeneration of 26.5 and lost a cogenerator, is that what's

happening? Or he had 27 and then lost the cogenerator? Explain your schedule to me.

A Are you looking at Kisla's exhibit, or are you looking at mine?

Q No, I'm looking at your Schedule 8, in your rebuttal exhibit.

A Okay.

Q Let's just take Column A and the winter outage.

A Okay. Column A and the winter outage, his self-generation is 14.5. His supplementary is 10. And his standby is 12.5. And he has a load reduction, as we were talking earlier, of five megawatts. Leaving the sum of 42, as Mr. Kisla had in his table.

Q Now his contention in his exhibit, I believe, was that he only had 7.5, he had only triggered 7.5 megawatt of standby, and you say he triggered 12.5? Is that where you reach your dispute?

A That's correct. Because he took an additional supplementary capacity up to his contract capacity as supplementary rather than taking standby for that. And under the present rules, that's not allowed.

Q That was the problem, I think, we were having with it. He said, "If I have a contract of

supplementary power for 15 megawatts, why do I only get credit for 10 megawatts in your schedule, rather than 15 that I actually have a contract for?"

A Because supplementary and standby, in essence, stand alone. And he cannot use any additional capacity available to him under his supplementary contract as standby.

Now, you know, if he were allowed to do that, he would pay for it just that month and would not pay for it in the future. But under the standby tariff, and as the standby rules are structured, standby is standby and he cannot dip into his supplementary contract in order to take care of his standby. They stand alone.

Q So what you're telling me is if he has a contract for 15 megawatts and pays each month for 15 megawatts of supplementary power under that contract --

A He doesn't pay for 15 megawatts under the contract unless he uses it.

Q Okay, say he has used it during the month.

A Okay.

Q And so he's triggered the demand for that month. He's got to pay for that, but he only gets credit for 10 of the 15 that he's paid for in the event he loses a cogenerator.

A Well, if his max demand for the month was already -- or supplementary -- was already established at 15, that's what he would pay for for supplementary.

Q That's right. But it wouldn't reduce his standby charge, and he'd still have to pay for 12.5 of standby rather than 7.5, wouldn't he?

A That's correct.

Q You would only give him credit, in calculating standby, you would only give him credit for 10 of the supplementary he paid for.

A That's correct.

Q So in that month he got to pay twice for the same five megawatts, once as standby power and once as supplementary power?

A He took it at different times. He set his peak demand where he established the 15 megawatts at one time during the month, and his standby service, by definition, had to occur at some other time or he would not have been able to have that much load.

Q What is --

A Standby is done on an interval-by-interval basis, whenever it occurs throughout the month. Whereas supplementary, under the tariff, is based on the peak demand established during the period when standby is not taken.

COMMISSIONER EASLEY: Could I ask a question?

MR. McWHIRTER: Yes, ma'am.

COMMISSIONER EASLEY: Is there a period of time at which he will never be able to actually utilize all of the power available to him either under stand by or supplemental because of this stand-alone part of it?

WITNESS HASKINS: No, there is no time when he cannot use all the power that's available to him. And he will pay for it either under supplementary or standby during that month. But he may -- and I think the difficult situation to conceive of is that supplementary billing demand is based on the maximum demand established during any 15-minute period of the month, regardless of when it occurs.

COMMISSIONER EASLEY: Okay.

WITNESS HASKINS: Unless he's taking standby during that time. And then during this period a customer has declared he's taking standby --

COMMISSIONER EASLEY: For that 15 minutes?

WITNESS HASKINS: Yeah, for that 15 minutes or any combination of the 15 minutes, the standby tariff then prevails.

COMMISSIONER EASLEY: All right. The only way then he gets to the supplemental is having used up the 15 minutes of standby?

MR. McWHIRTER: I don't think that's quite right.

WITNESS HASKINS: No.

COMMISSIONER EASLEY: It's getting very confusing the way you two are doing this.

WITNESS HASKINS: Well, that's because it is.

COMMISSIONER EASLEY: Oh, okay.

WITNESS HASKINS: Don't feel badly.

Q (By Mr. McWhirter) Let's look at it from the view of the demand on your system. And during the month, using supplemental service, he puts 15 megawatts of demand on your system. So now he's going to pay for that 15 megawatts for the rest of the month?

A He's going to pay for it for that month.

Q For that month. Okay. Then he comes along and he drops a generator. And I'll use a hypothetical because I can't quickly run through the math. He drops a generator and he also reduces his load, so that the demand he places on your system continues to be 15 megawatts. Is he going to trigger, in addition to the 15 megawatt supplemental demand charge, now a standby charge for whatever it was he dropped in that generator, less whatever he could reduce it by, his load reduction?

A To try to clarify that, let me see if I can

take just a minute and construct what would take place on the billing for an interval where he had this standby situation you're talking about. (Pause)

In a period of time when you have SS declared and in your case where you had 15 megawatts was the supplementary, and maybe he was running 15 megawatts at supplementary just before he had an outage, and if his load went up to 20 megawatts, then the customer declares standby and tells us how much standby he's taking, because you see, we have no way of knowing how much standby he is taking. The customer has to tell us that, because the standby is a combination of what his outage was and the load reduction that he accomplishes. So the customer tells us how much standby their taking.

Q Does he tell you how much standby he's taking, or does he tell you his generator was down?

A He does both. He tells us the generator is down and then he has to notify us how much he is taking as standby.

Q Let's visualize. He's taking 15, and he loses a generator. So he reduces his plant operations to the degree that he's still only taking 15.

A Okay, and he lost a 10-megawatt generator?

Q He's lost a 10-megawatt generator, and he's never incurred any standby requirement before. He

tells you at that point in time, "I have lost my generator, but I don't want to declare standby because I haven't placed anymore than 15-megawatt demand on your system." In that scenario, as I understand it, you would still charge him a reservation fee based on 10 megawatts.

A No, that's not correct.

Q Okay.

A If his load does not go up, he does not have any standby.

Q Okay. What if he's load went up by -- he dropped a 10-megawatt generator and his load went up by five megawatts, would you charge him for five more, or would you charge him for ten more on standby?

A He would report standby of five megawatts.

Q Even though he dropped a 10-megawatt generator?

A Because he would have a load reduction of five megawatts that would offset that. And that's an opportunity that he has. The standby service that he's taking is just that. It's the standby service taken. It's not how much the generator outage is, and I think that's an important consideration.

One of the things in the standby rate docket was that cogenerators were concerned about load

following generation, but the other side is also true, that the amount that they're able to reduce their load when they have an outage to minimize their standby.

COMMISSIONER EASLEY: Wasn't one of the glitches that came in the testimony, though, that he didn't know he had to notify you or request standby, and that was --

WITNESS HASKINS: In that particular case.

COMMISSIONER EASLEY: And that was part of the confusion as well, I think, in getting to this error factor, isn't that correct?

WITNESS HASKINS: Because I think that in this particular case, the customer that we were -- Mr. Kisla was talking about, that if they had realized how it worked, they could have curtailed some load in the plant to minimize the amount of standby that they had to declare, whereas they --

COMMISSIONER EASLEY: How much does that affect, though, the discussion, because we are trying to come back to that five megawatt error, and does that affect trying to get back to that?

WITNESS HASKINS: If the customer's load goes up five megawatts as a result of a 10-megawatt generator outage, because he was able to reduce his internal plant load by five megawatts, then all he pays

for is five megawatts at standby, because that's all that hit our system. If he's able to take 10 megawatts off, when he loses a 10-megawatt generator, then he has no standby to pay for it at that time.

Q (By Mr. McWhirter) Let me give it to you one more way.

A All right.

Q Go to your Schedule 6 and look at the winter outage columns. Stone would purchase between 12-1/2 megawatts and 17-1/2 megawatts at standby power, is that correct?

A Yes.

Q Now, if Stone had already, during that month, imposed a 15-megawatt supplementary demand on your system, as it regularly does, would Stone be charged for 27-1/2 megawatts, which would be the 15 that it had previously been charged for a supplementary service, plus the new 12-1/2? (Pause) Stone has reduced its load to 10 from the regular 15. (Pause)

A I think that one of the things that you have to consider in looking at this is that it's our understanding of Mr. Kisla's exhibit, he was not talking about a previous time period, as something that happened in that same month. If you look at what happened at this time period at this hour of this

interval, his supplementary at that time was 10 and he had an outage, and so his standby was 12-1/2.

Q What if it was 10 because he had reduced his load by five?

A If it was 10 because he had reduced his load by five, then -- I'm consulting with my billing expert here. (Pause) I think the thing that we're missing on the standby calculation is that looking at what happened at that moment, there is no way for us to tell the amount of standby that the customer is taking at any interval without looking somewhere else.

Q Yeah.

A And he has to tell us how much that is at that time, and there's no other way to do it.

Q So what you're telling me is that at -- at Column A there under winter outage, the demand his placed on your system is only 22.5, 10 supplementary and 12-1/2 standby?

A That's right.

Q And if he tells you that the standby is not 12-1/2, but is only 7-1/2 standby and 15 supplementary, and you're only going to charge him for 2.25, but if he tells you that, "My 12-1/2 megawatt generator is down," but forgets to tell he's reduced his load, otherwise, you're going to charge him that month for 27.5, because

he previously incurred 15 megawatts in supplementary service?

A I'm not following your proposition.

Q Too many ifs?

A Yes.

Q You wouldn't want to charge him for more than 22-1/2 megawatts, if that's all the demand --

A In this particular interval?

Q Yeah.

A That's correct, here. We would charge him -- we would charge 10 megawatts supplementary and 12-1/2 megawatts of standby, and we would not charge him 15 megawatts of supplementary and 12-1/2 megawatts of standby.

Q These are one of the communication problems.

A That's right.

Q So what's happened is a 12-1/2 megawatt generator went down, but he could have told you, as he should have if he had known the rule, that, "I've only used 7-1/2 megawatts of standby power, and I want you to charge the other to my supplementary service since I've already incurred a 15-megawatt demand during this month," and that would okay?

A No, he has to tell us how much his generator went down and how much load reduction was so that --

and we know how much his standby was. Now, we may be getting to the same place, but that's not the way -- the numbers are going to come out the same, but that's not what he has to tell us.

Remember, we have the power going through one meter, and all we know is what that meter records. And we have to have the customer tell us what his standby requirements are, notify us of an outage, first notify an outage, how much the standby requirements were and how much the load reduction was. And we have one other piece of information that we then use at the end of the month to make a reasonableness test on that, and it is we have the generation meter.

COMMISSIONER BEARD: Let me try this from a different angle, and I understand the math he's doing. At the point in time that he's talking about where you've got -- they were using 15 megawatts, they had this 12.5-megawatt outage, they reduced their supplementary use by five megawatts. You've now got 22.5 megawatts of demand going through that meter.

WITNESS HASKINS: Right.

COMMISSIONER BEARD: Okay. A combination of supplementary and standby. Now, previous in that month, when they were just trucking along and everything was peachy keen, they had put a previous

supplementary demand of 15 megawatts, okay?

WITNESS HASKINS: That's right.

COMMISSIONER BEARD: Would be their high supplementary demand for that month. Now, at the end of the month, okay, how are you going to charge them for demand?

WITNESS HASKINS: They're going to pay for 15 megawatts of supplementary based on what happened at a time when their generator was not out, because they took that as firm service, which they're obligated to pay for just that month under the tariff. Then we look at the interval where -- or the intervals in demand where they had the outage.

COMMISSIONER BEARD: Uh-huh.

WITNESS HASKINS: And we make a stand-alone calculation there as to how much standby they owe us for that period of time.

COMMISSIONER BEARD: And the net effect of that is that they will pay you for 15 megawatts of supplementary demand and 12.5 megawatts of standby demand, based on that stand-alone, 22.5 minus the 10?

WITNESS HASKINS: That's right.

COMMISSIONER BEARD: So the net effect is they pay you in that month for 27.5 megawatts of demand, if you sum the two?

WITNESS HASKINS: Yeah, that's correct, because there's two different classes of service.

COMMISSIONER BEARD: Did I get you there?

MR. McWHIRTER: That's it exactly.

WITNESSD HASKINGS: It's two different classes of service.

COMMISSIONER BEARD: I understand that, and I'm not sure -- I'm still not sure you aren't doing apples and oranges because you're summing the two.

MR. McWHIRTER: I'm what?

COMMISSIONER BEARD: You're summing the two, 15 plus 12.5, okay? And they're two different classes of service. Is the reservation charge for the 12.5 megawatts exactly the same as the supplementary demand charge?

WITNESS HASKINS: Absolutely not. It's much less than that. The reservation charge is 10%. It's based on 10% of the demand cost.

COMMISSIONER BEARD: So you would not sum the two?

WITNESS HASKINS: No.

COMMISSIONER BEARD: Okay, which is what you were doing.

MR. McWHIRTER: No, the maximum demand he would have placed on your system during that month, if

we look at your side of the meter, is 22-1/2 megawatts, but because of the peculiarities of the tariff, you will charge him for 15 megawatts of supplementary service and 12-1/2 megawatts of standby service, so he will pay for 27-1/2 megawatts of service of demand?

(Simultaneous conversation)

COMMISSIONER BEARD: Let me finish my thought, because I have been listending to you guys, and I really would like to go on. The 15-megawatts supplementary demand -- you pay 15 megawatts of supplementary demand. You correct me if I am wrong, Jack. If the 12-5 megawatts associated with a reservation charge, you're telling me that that is actually based on 10% of demand of 12.5 megawatts?

WITNESS HASKINS: It's based on a 10% -- 10% of the unit cost because it's 10% probability of being on peak, so it's discounted to 10%.

COMMISSIONER BEARD: So you take the typical demand charge that you would have, and you discount it to 10%?

WITNESS HASKINS: No.

MR. McWHIRTER: You're getting into a pricing concept there.

WITNESS HASKINS: It's the unit cost of production and transmission.

COMMISSIONER BEARD: I'm trying to get down to what you've got to pay. Okay, that's what you care about, isn't it, how many dollars come out of your pocket?

MR. McWHIRTER: That's right.

COMMISSIONER BEARD: I thought so.

MR. McWHIRTER: And you have to pay it for 23 more months.

COMMISSIONER BEARD: And all I want to know is, is based on the standby 12.5 megawatts, the cost of that to the customer as opposed to 12.5 megawatts of supplementary demand; what's the difference?

WITNESS HASKINS: The supplementary demand for the PXT rate is -- or the PX rate -- is $7.55 per kilowatt.

COMMISSIONER BEARD: Okay.

WITNESS HASKINS: The reservation charge is 98 cents per kilowatt.

COMMISSIONER BEARD: That's 13%. So you're paying 13% of the demand, typical demand charge?

WITNESS HASKINS: And what you do is you take -- you calculate the reservation charge, which is times the contract capacity, maybe 15 megawatts of backup, and times 98 cents, and you take a daily demand charge for -- this class of customer would be 42 cents per

kilowatt per day. So, actually, he uses -- if he used that standby only one day, he would just pay 42 cents per kilowatt. And if he used it two days, he would pay 84 cents per kilowatt. Until he then -- so you can see after three days, he's up to where he's better off to pay the reservation charge. But, the price is discounted.

Q (By Mr. McWhirter) Unless he has incurred that reservation charge, he pays it for how many months?

A 23 months.

Q But the demand on your system is not 27 megawatts; the demand on your system would only be 22-1/2?

COMMISSIONER BEARD: That's right.

WITNESS HASKINS: That's right. That's right.

Q (By Mr. McWhirter) I handed you a copy of Exhibit 611, which Mr. Kisla used and said reflected that event in September of 1989, where we had the mistake problem.

A Right.

Q And as a result of that, you'll see there the peak, at the bottom of this exhibit you'll see a line, that's the SE period.

A Right.

Q And then you'll see a peak about halfway over on that exhibit where he went to the 22 megawatts, and for that he said he paid $60,000.

If the Staff's proposal is correct, for that one-time use for -- what would be the duration of that use according to that graph? A couple of hours?

A Let's see. These are -- I can't see the indicator there.

Q 15-minute intervals at the bottom.

A It looks like it's probably a couple of hours.

Q And that inadvertent use under the Staff analysis would cost them around $300,000, the 60 plus another 249,000?

A I don't -- the $249,000 doesn't sound right. We made a calculation of that for the --

Q Prehearing Order I saw something about $249,000 in revenues that you didn't book, they were charging you for. That's not this $249,000?

A Let me check that. (Pause)

There are two aspects of that. The original bill under rate PXT was -- and I'm looking at my deposition exhibit, Late-Filed Exhibit No. 15, hearing Exhibit No. 289. The original bill for September of 1989 was 381,894.87. The -- for the month of -- and

the new PXT bill for that month, actually goes down because part of it becomes standby to 351,099.63, along with a standby service bill of 13,826.42. And if you consider the effect of that SS demand that is then established in that month, you know, as a result of 20/20 hindsight and some degree of speculation, I guess, the total revenue effect in 1989 for September, October, November and December is $17,011.52. And then for 1990 through the first three months is 16,325.35. So I really don't know where that $240,000 came from.

Q What does the Staff want you to deduct your revenues by as a result of not collecting money from those customers, was what I was trying to get at.

A Well, based on this exhibit, it would be a total of about $33,000.

Q Okay. And that's because through our mistake.

A Right.

Q I have no further questions.

CHAIRMAN WILSON: Mr. Palecki.

CROSS EXAMINATION

BY MR. PALECKI:

Q Mr. Haskins, correct me if I'm wrong, but in your earlier testimony in this proceeding, I believe you stated that if time-of-use customers shift all

their use off peak, they are not paying their fair share of cost because there is some production in transmission costs associated with off-peak usage. Is that correct?

A No, I didn't say that with regard to my rates. I said that with regard to the rates that Mr. Wright would propose.

Q Do you agree with that as a statement of philosophy that if time-of-use customers shift all of their use off peak, they are not paying their fair share of costs because there is some production and transmission cost associated with off-peak usage?

A No, I would not agree with that.

Q And why not?

A As I --

Q What was it that you testified to earlier? I thought that's what you had said earlier in your testimony.

A I said that with regard to Mr. Wright's rate design where he included no production and transmission cost in the off-peak pricing. In our rates we do have some demand-related production and transmission cost in the off-peak period.

Q And why did you say Mr. Wright's proposal was inappropriate?

A Because he has no -- as I understand his proposal, he has no production and transmission related cost in his off-peak price. He would only charge what's equivalent to our proposed local facilities charge.

Q And in your rates as you've designed them, you don't have any similar situation?

A No.

Q Isn't it true that the SE PXT customers don't pay any costs for production, transmission and distribution plant for off peak that is used -- that is off peak during the SE periods?

A If you look at the months billing, they always pay a demand -- a full allocated demand charge for production, transmission and distribution plant as appropriate during any billing month. Because we never have a month that is entirely SE. There is always some time during the month where they will establish a non-SE demand to be used for billing of the standard tariff.

Q Well, that's my point. There is no demand charge in the SE, the off-peak hours, correct? And if a customer were able to design their use so that they were within all of those hours, those off-peak hours, the SE hours, they would pay absolutely no demand

charges, is that correct? They pay nothing at all for transmission, distribution, production plant?

A If you had such a strange customer that they were able to, by some magic, tailor their loads such they were always only in SE periods, recognizing that SE periods are flexible time periods, solely at the discretion of the Company. In that extreme hypothetical that would be the case. But the SE was not designed on that premise; it never took place during the entire two-year test period and it has not taken place since, and we never expect it would, and if it happened, we probably would want to make some modification to that.

Q Can you reconcile your position on rate design with respect to off-peak costs for time-of-use customers with set off-peak hours versus those with flexible off-peak hours?

A Keep in mind that the flexible time periods are just that and are solely at the option of the Company, whereas -- and they are unpredictable from the customer's viewpoint. Whereas, the fixed time period time-of-use rates that the Company has are predictable to the customer, and I suppose it is somewhat more conceivable that a customer could tailor his operation purely to match the time-of-use periods in our

time-of-use rates, then he could under the SE tariff. However, I think that, too, is very likely; but, nevertheless, since that is predictable, known in advance, then it is conceivable that the customer could do that.

Q Would it be true that if demand charges are set below unit cost in this docket, that a portion of the demand-related transformation cost would be recovered through the energy charge under the rate?

A Yes.

Q Therefore, in order to develop proper voltage discounts, the energy charge would also need to be discounted in order to reflect the transformation cost being allocated by the energy charge, correct?

A Yes, it would. And you just reminded me of something, too, with regard to the SE rate.

To the extent that demand charges on the standard rate -- or demand costs, rather, on the standard rate -- are recovered through the energy price, then even your hypothetical, very extreme SE customer that was all in the off-peak period would be paying some -- excuse me, in a non-SE period. No. The hypothetical customer that was all in SE periods would still be paying some portion of demand charges because he pays the full energy charge. There is no reduced

energy price for SE customers. It only is demand price forgiveness. (Pause)

Q Isn't it true that for the PXT the demand charge has been set at the full demand unit cost?

A I don't believe that's correct, but before I give a definitive answer I'll need to take a look at the, you know, cost sheet.

Q Wouldn't you have to look at the unit cost sheet from the last rate case?

A Which one are you asking about, the last one or this one?

Q Well, the rates haven't been set yet in this particular case.

A We'll look at the urit cost sheet for present rates. (Pause)

The present -- just look at proposed. I don't have the present rate unit cost sheet handy.

The unit cost for a PXT is $8.59 for demand, and our proposed rates filed are -- under the no migration study, that's the cost of service unit cost you have been locking at -- is $8.26. So you've got the difference between 8.26 and 8.59 in the energy price.

Q That's based on this filing, correct, not on the unit cost from the last filing?

A That's correct. This is the case we're in now.

Q On Page 21, Line 7 through 12 of your rebuttal testimony, you state that "An increase in a specific rate does not lead to the conclusion that differences between voltage classifications should increase accordingly."

Has Dr. Johnson made this assumption in his testimony? (Pause)

A Did you ask a question?

Q Yes. The question was, has Dr. Johnson made that assumption in his testimony?

A No. Dr. Johnson did not make that proposal.

Q What is the impact of this assumption?

A Well, that would say, for example, if you were proposing to change a demand charge from $6.25 to $8.50, that whatever that percentage increase is you would increase your voltage by the same amount without any regard to the cost basis for the voltage discounts. And we don't think that's appropriate.

MR. PALECKI: Thank you. We have no further questions.

CHAIRMAN WILSON: Any on redirect?

CHAIRMAN WILSON: Any on redirect?

MR. STONE: Briefly

REDIRECT EXAMINATION

BY MR. STONE:

Q Mr. Haskins, you were asked an extensive number of questions regarding your Schedule 6. Was your testimony in your calculation of the numbers in Schedule 6 meant to demonstrate what would be required under Commission policy and rules?

A Yes.

Q Is it necessarily the position of the Company that this policy or these rules are the best policy for this situation?

A No. It's not. It's what we're having to deal with now; and it has been an evolving process as to how to determine the appropriate standby capacity. And I don't think we are at the best policy.

Q I would now like to direct your attention to Exhibit 611. I believe Mr. McWhirter handed you a copy of that exhibit. Do you still have it with you?

A Yes.

Q Mr. Wright testified that SE would not constitute an interruptible rate as that term is defined by this Commission. I assume you agree with that statement?

A Yes. As very narrowly defined by the Florida Commission.

Q Does this exhibit demonstrate the curtailable aspect of the SE rider, based on the economics?

A Yes. It does. It demonstrates the economic switch that we have talked about where, as you can see, at the end of that SE period that occurs just to the left of the center of the page that when the customer was notified that SE was going to be terminated and got to the point where it was terminated, he reduced his load drastically in about a half-hour period of time there, it looks like.

Q And what was the reason for -- what typically is the reason for declaring the end of an SE period?

A Typically, it is based on predictions of increased load on the system such that a system peak or a Southern peak might be established.

Q Based on the typical reason for curtailing or ending an SE period, would the load of this customer, as demonstrated by Exhibit 611, have been on the Company -- Gulf's or Southern's -- system peak, whichever was coming into play when the period was declared to be at an end?

A No.

Q Does that mean then that the demand established during the SE period did not contribute to Gulf's or Southern's system peak?

A It means very definitely that demands did not contribute to the peak.

Q The demands during the SE period?

A During the SE period, that's right. Because it is operated so that it cannot and this is a demonstration of that.

Q And in terms of the issue regarding recovery of production plant, I believe you have testified that, in fact, the energy rate during an SE period is the actual full energy charge that would be incurred at any other time?

A That is correct.

Q Does that include the component for production plant?

A It does to the extent that the full demand charge is not recovered -- excuse me, the full demand cost is not recovered through the demand component of the rate.

Q Does this overcome the problem that you have identified with Mr. Wright's proposal for time-of-use rates?

A Yes.

MR. STONE: That completes our redirect. I'm sorry, one last question.

Q Mr. Haskins, are you familiar with the

Commission's rules for the determination of cost effectiveness in terms of the conservation program?

A Yes.

Q Is it -- what is your understanding regarding the majority of the benefit as far as whether it's on demand savings or energy savings?

A It is my understanding that it is primarily under the current situation on demand savings.

MR. STONE: Thank you, that completes my redirect.

CHAIRMAN WILSON: Thank you. Nothing further, he may be excused. Thank you very much, Mr. Haskins. Call your next witness.

(Witness Haskins excused.)

MR. STONE: The next witness would be Mr. Parsons. (Pause)

MR. BURGESS: Commissioners, if we're not on a break, I might as well try to take care of this little piece of business. As I understand it, the exhibit that's attached to Mr. Wright's rebuttal testimony was not identified with an exhibit number at prehearing, I think. And therefore, I would ask that it be given an exhibit number and entered into the record.

CHAIRMAN WILSON: That would be Exhibit No.

616. Do you think it's been numbered already?

MR. BURGESS: Okay.

MR. VANDIVER: I'm not certain.

CHAIRMAN WILSON: Wait just a moment, Mr. Pruitt, we'll check it.

MR. BURGESS: I couldn't find it in the Prehearing Order.

MR. VANDIVER: No, we don't have it.

CHAIRMAN WILSON: That would be Exhibit 616. Without objection, it's admitted into evidence.

(Exhibit No. 616 marked for identification and received in evidence.)

MR. HOLLAND: And, Mr. Chairman, while we're doing that type thing, I can't recall and Mr. Burgess does not either whether I had, in fact, moved in Exhibit 583, which was the composite exhibit relative to have Plant Scherer. I'd like to move that at this time.

CHAIRMAN WILSON: I don't believe you did. All right.

MR. BURGESS: I told him he had and not to worry about it. (Laughter)

CHAIRMAN WILSON: Without objection, that is admitted into evidence, 583.

(Exhibit No. 583 received in evidence.)

CHAIRMAN WILSON: Any time you're ready.

EARL B. PARSONS, JR.

appeared as a rebuttal witness on behalf of Gulf Power Company and, after being previously duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. HOLLAND:

Q Mr. Parsons, you have been previously sworn and have previously testified, have you not?

A Yes. I have.

Q And have you filed in the docket rebuttal testimony entitled, "The Rebuttal Testimony of Earl B Parsons, Jr."?

A Yes. I have.

Q Do you have any corrections to that testimony?

A No, sir.

Q If I were to ask you the questions today contained in that testimony, would your answers be the same?

A Yes.

MR. HOLLAND: Mr. Chairman, we would ask that Mr. Parsons' rebuttal testimony be inserted into the record as though read.

CHAIRMAN WILSON: His testimony will be so

NOTE: Page No. 3436 inadvertently omitted in numbering.

inserted into the record without objection.

MR. HOLLAND: I think all his rebuttal exhibits have been premarked and already entered

(Exhibits previously stipulated into evidence.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal of
Earl B. Parsons, Jr.
In Support of Rate Relief
Docket No. 891345-EI
Date of Filing May 21, 1990

Q. Are you the same Earl B. Parsons, Jr. who testified earlier in the proceeding?

A. Yes, I am.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to rebut the testimony of Mr. Schultz, Mr. Larkin, and Mr. Rosen and the positions taken by them with respect to issues raised in this proceeding.

Q. Mr. Parsons, the Commission Staff and Office of Public Counsel have taken the position that Plant Scherer Unit 3 capacity should not be included in rate base. What is your response?

A. Gulf is deeply disturbed by the position taken by the Staff regarding exclusion of Scherer 3 capacity in the rate base. Also related to Scherer, Mr. Rosen has filed testimony for the Office of Public Counsel that, if followed by this Commission, will prove extremely

detrimental and harmful to the long-term best interests of the customers which we serve in Northwest Florida.

I have been at Gulf Power Company since early 1978, when the Scherer capacity was first considered as a cost-effective alternative to continuing construction at the Caryville site. I personally participated in the October 1978 workshop before the Florida Public Service Commission at which time we presented our proposal for cancelling Caryville and acquiring the capacity at Scherer.

I have presented extensive testimony to this Commission in four rate cases and attended a number of Planning Workshops and Planning Hearings at which our plans have been fully discussed with the Commission. In every one of these instances, there has never been any concern expressed on the part of the Commission regarding the prudence of acquiring Scherer. If there was a concern, it was that we might not be able to acquire the Scherer capacity. The Commission felt so strongly that we should make this purchase that it held, subject to refund, our write-off of the Caryville cancellation costs approved in Order No. 9628, pending completion of a contract with Georgia to acquire Scherer. Order No. 9628, Docket No. 800001-EU, Order No. 10557, Docket No. 810136-EU, Order No. 11498,

Docket No. 820150-EU and a follow-up order issued on May 15, 1984 address these issues.

We have on any number of occasions, both formally and informally, presented our plans regarding our capacity expansion and our off-system sales before the Commission. It has been shown from the beginning that Scherer capacity would eventually come back to our territorial customers. Some of that capacity is available for use by our territorial customers now.

The Scherer capacity was acquired for the long-term benefit of our territorial customers. It was not purchased for purposes of unit power sales. All of our actions regarding this acquisition have been prudent. If the Commission follows the prehearing recommendation of its own Staff or that of Mr. Rosen in his prefiled testimony and disallows cost recovery for capacity which the Commission itself has agreed was prudent to acquire, it will break the regulatory compact which has been established with Gulf. While Mr. Howell will fully review the details of our concern in his testimony, I simply want to emphasize how strongly the Company feels that disallowance of the Scherer capacity in rate base would be a detriment to our customers and send an extremely negative signal to

the Company regarding what constitutes prudence in its decisions.

The long-term benefits of the Scherer capacity were valid when we made the decision to invest, and are still valid today. The new unit power sales, for which Gulf contracted in 1988, will allow us to capture even more savings for our territorial customers in the long term.

As Mr. Howell will cover in his testimony, Gulf had two choices - either participate in Scherer or not. Participation requires at least a 40 year commitment to the capacity and, therefore, cost-effectiveness must be viewed over the long term. If the Company were to follow the philosophy suggested by the Staff and Mr. Rosen, it would cease making decisions based on long-term cost benefits and make decisions based on one-year, short-term analysis. This would create an extremely unreliable and costly electric system for our customers. Mr. Howell will cover in detail how the Scherer decision is a long-term benefit to our customers, and how we have done everything reasonable to minimize the impact of the Scherer capacity in the test year. I ask the Commission to approach this issue with an open mind, carefully consider the strong

evidence which we will present, and allow cost recovery of the Scherer capacity.

Q. Mr. Parsons, do you agree with Mr. Rosen's recommendation of an 18 percent reserve margin for Gulf?

A. No. The 20-25 percent range for planning reserve margin guideline utilized by Gulf and Southern has been adopted by the Commission as reasonable. Since the criteria was last established, there has been no need to commit to additional capacity on the system. As indicated in Mr. Howell's testimony, the criteria was last reviewed and deemed appropriate by the Commission's consultant in Docket 860004-EU. As the time approaches when there will be a need to commit to new capacity, we believe it is appropriate to review this criteria. Such a study is now under way. Although the operating companies of Southern have determined to maintain a minimum 20 percent planning reserve margin guideline, commitments for capital expenditures in 1990 for capacity additions have been limited based on a 16 percent reserve margin until the detailed study is completed, hopefully, later this year. The consequences of committing these large capital expenditures which may be later deemed to be

imprudent, with 20/20 hindsight, are too great to justify moving forward without this additional detailed examination of capacity requirements.

Short lead time demand side options and short term capacity purchases will be utilized, if necessary, to provide adequate reserves during the test year.

Q. On page 17 of his testimony, Mr. Larkin suggests that the Caryville site should be excluded from rate base because there is no plan to build a generating unit on the Caryville site. Is he correct?

A. No. Caryville is still a viable, certified site for future base load coal capacity in Gulf's system. As I have previously stated, the Commission agreed with Caryville's inclusion in rate base as plant held for future use in Docket Nos. 800001-EI, 810136-EU, 820150-EU and 840086-EI. For example, in Order No. 9628, the Commission supports this decision by stating, "We agree with the Company that its plans for the site are sufficiently definite to warrant its inclusion, and that to deny the request would be to the disadvantage of ratepayers in the long run." Inclusion of the Caryville site in rate base for plant held for future use is still a prudent decision by the Commission.

Q. **What is the value of this site to the customers of Gulf Power?**

A. An extensive site selection study was undertaken in the late 1960's and early 1970's when Gulf projected the need for a new generating plant site. Caryville was determined to be the most viable of all the sites analyzed. Because of the extreme difficulty in certifying new sites due to stringent environmental requirements, Caryville may well be the only available site on which to locate future generation in Northwest Florida; future generation which will be required as our customers' needs grow.

Q. **Is the present property owned by Gulf Power Company at Caryville of a sufficient size to accommodate its future generation needs?**

A. No. The Caryville site was originally certified during 1976 for the initial construction of two 500 mw low sulfur coal units. Again, as I have stated in my direct testimony, changes in environmental regulations since that time now require that flue gas desulfurization equipment or scrubbers be installed on any base load generating units constructed at the site. Additional space will be required for the scrubbers, limestone storage and the waste by-product. Additional

space will also be required for 500 kv transmission lines and substations rather that the 230 kv systems certified.

Q. Why is the additional land purchase important at this time?

A. Again, as I have previously stated in my direct testimony, since the units are not needed immediately, Gulf can secure property adjacent to the Caryville site as it comes on the market at a much lower price than if we were to wait until construction begins. The extreme difficulty anticipated in acquiring and certifying sites in the future makes it necessary and prudent to proceed with the purchase of additional property as it comes on the market in order to enhance and protect the viability of the site for future generation needs.

Q. What action will Gulf take if the Commission excludes the site from the rate base?

A. This would indicate that the Commission does not believe that this site has future value to Gulf's customers. We would have to consider possibly selling the property. A Commission decision such as this would have a significant negative impact on Gulf's ability to meet long-range generating capacity needs at a

reasonable cost. We are simply attempting, as the Commission has encouraged us to do on many occasions, to project future needs and, using sound reasoning, act in advance so that we can save our customers' money. We feel the purchase of additional land for this site as it becomes available is a prudent action.

Q. On page 28, Mr. Larkin recommends excluding the Caryville subsurface study from working capital. Do you agree?

A. No. The subsurface investigation of the Caryville site is still valid relative to the geological conditions. This information will be utilized in the design of foundations and placement of structures for future generating capacity.

Q. Do you agree with Mr. Schultz's recommendation beginning on page 28 of an adjustment of $617,595 for SCS expenses?

A. No. Mr. Schultz references OPC Interrogatory No. 53 and places undue emphasis on isolated items without including the entire text of Gulf's response. For example, Gulf does state that Southern Company Services (SCS) "prepares estimates of its billings to Gulf"; however, that same paragraph goes on to detail how this

interaction takes place. As shown in this interrogatory, this is a very detailed process in which Gulf interacts with SCS personnel on a continuous basis in the development and monitoring of the SCS budget and actual expenses.

Q. On page 29, Mr. Schultz implies that indirect expenses which are allocated to the operating companies based on a set percentage "are not subjected to the same scrutiny by the Company as that of the costs of a specifically requested item." Do you agree with this statement?

A. No. There is no statement in OPC Interrogatory No. 53 which indicates that only direct charges are handled in the manner described. On the contrary, work orders exist for the allocation of these indirect charges and are monitored in the same method as direct charges. The generic allocated work orders remain a standing authorization of work to be performed, unless termination of these work orders is recommended by the various committees and/or operating companies.

Q. On page 2 of 3, line numbers 1 - 9 of Mr. Schultz's Schedule HWS - 7, he recommends that the Commission disallow SCS expenses related to a variety of research

projects and studies undertaken on behalf of Gulf Power Company. Is this a duplication of work between Gulf, SCS, and EPRI?

A. No. The recommended disallowance is based on the incorrect presumption that these services are duplicative of research managed by the Electric Power Research Institute (EPRI). These services are, in fact, complimentary and not duplicative. Some 600 member utilities fund EPRI's large-scale, cooperative research and development programs. As a result, EPRI undertakes research programs that are responsive to the needs of the electric utility industry as a whole. EPRI does not undertake individual utility specific research nor does it apply its research only to individual utility specific problems.

SCS assists Gulf Power Company in attaining maximum benefit from EPRI's research. These research and research management activities include:

a) participating in the EPRI advisory system to ensure that EPRI's research meets the needs of Gulf Power Company;

b) reviewing, summarizing, evaluating, and communicating the results of EPRI research to Gulf Power in order to ensure maximum benefit

from its investment in EPRI research (Technology Transfer); and

c) conducting local, company-specific studies in order to apply the results of key EPRI research to specific Gulf Power Company issues. In some cases this can include co-funding EPRI projects conducted at Gulf facilities or within Gulf's service territory.

SCS also conducts site specific research at Gulf's facilities on areas of concern not addressed by EPRI. The majority of the research performed by SCS for Gulf is specific to the needs of Gulf and the system.

Q. **On page 34, Mr. Schultz recommends an adjustment removing "the cost of SCS services which have been budgeted at amounts substantially in excess of actual average costs for such services." Do you agree?**

A. No. We do not agree that excess costs have been budgeted for SCS. Any budget approved by Gulf for SCS work has been thoroughly reviewed by Gulf personnel responsible for that activity. When the budget is approved, it is our best estimate for required manpower. That is the case in 1990. The budget is

reflective of conditions and work loads faced by our Company under present circumstances.

Q. Why do SCS expenses for System Planning exceed the benchmark?

A. The 1984 benchmark of allowed charges from SCS of $57,000 was developed from seven months of actual charges (January through July of 1984) extrapolated to the end of the year.

Although the actual charges were below the budget for the first seven months, this relationship did not hold true for the remainder of 1984 due to workload and resource usage fluctuations. The actual charges for 1984 were $157,000. Therefore, considering the entire year of 1984, the base was lower than it should have been.

A compound inflation multiplier of 1.2468 was used to calculate a 1990 benchmark from the 1984 base. Applying this same multiplier to the 1984 SCS actual charges of $157,000 would result in a 1990 adjusted benchmark of $196,000. The 1990 SCS budget for this work order is $167,000, which is 14.8 percent below the adjusted benchmark.

These charges are for valuable services which SCS delivers to Gulf in providing expert engineering

assistance for the planning of reliable, economical, and flexible resources to meet the energy requirements of Gulf Power. If SCS were not providing these services, then, in order to perform these tasks, the Company would either retain outside consultants, who have less understanding of Gulf Power and the Southern system, or have to increase the number of employees in Gulf's System Planning Department.

Q. At page 37 of his testimony, Mr. Schultz argues that expenses related to Atmospheric Fluidized Bed Combustion and Living Lakes, Inc., are duplicative or unnecessary. Is there any validity to his contention?

A. No. Mr. Schultz makes this statement but provides no support for his recommendation. The research and development charges as noted on MFR Schedule C-57, page 3, are fully justified.

Future legislation requiring significant reductions of sulfur dioxide emissions from coal-fired utilities mandates the development of new, cleaner combustion techniques. Atmospheric fluidized bed combustion is such a technology and the TVA/Duke Power project is a full scale development project for this important new clean combustion system. The knowledge

gained in working with the TVA/Duke project will allow the SCS engineers to evaluate future designs of the system.

Living Lakes Inc. is a not-for-profit corporation whose primary purpose is to demonstrate effective technologies for the neutralization of acidified surface water. Living Lakes, Inc., has developed mitigation and investigative techniques for lowering the acidity of lakes that become acidified, either from natural or man induced causes. Living Lakes, Inc., has successfully treated numerous lakes in the country and restored them to a healthy condition at a fraction of the cost of emission control projects currently being debated in Congress.

Q. **Beginning on page 49, Mr. Schultz recommends an adjustment to disallow Gulf's nuclear power research expenses associated with EPRI. Do you agree with this adjustment?**

A. No. Much of the costs incurred by EPRI relative to nuclear power production research are also inherent to steam production (turbines, feedwater heaters, controls, condenser fouling, cooling towers, valves, fans, etc.) and, therefore, advantageous directly to Gulf. However, Gulf also benefits from the

remainder of the nuclear research because of its participation in the Southern system pool. Benefits received directly by other sister operating companies also indirectly benefit Gulf through increased efficiency of units and lower costs of purchased power. Future generation requirements by Gulf's customers dictate that new sources of power be evaluated to determine which are most economical and efficient. Nuclear projects should be a part of that evaluation. It is essential that nuclear power research be funded as we look forward to the future.

Q. Mr. Schultz questions the fact that some research expenses were zero during the benchmark period. Was this a correct entry on Gulf's part?

A. Yes. Gulf prepared its benchmark based on the Commission's instructions. Gulf summarized the total variance on page 3 of MFR C-57 showing a variance of $210,000 for specific research and development expenses in the Steam Production function. These expenses could have been listed individually on page 3 but, because they were related, they were grouped under this heading just as we grouped all of Plant Daniel's expenses. As shown on pages 4-9 of MFR C-57, there were no dollars budgeted in 1984 for any of these expenses and

therefore, the base for calculation of the benchmark is zero.

Q. Are any of Gulf's research and development costs a duplication of research undertaken by EPRI?

A. No. Approximately 1700 different projects are undertaken by EPRI annually. These projects are spread over 60 different strategic programs. There is no way Gulf or Southern could duplicate either the depth of EPRI's research or the number of EPRI projects. Gulf conducts research through SCS for site specific needs at Gulf's system or through the FCG for Florida specific issues. These projects are long term and designed for meeting our customers' needs for continued low cost power.

Q. On page 85 of his testimony, Mr. Schultz discusses research expenses. Mr. Schultz seems to be suggesting that the Company has merely shifted the focus of research since 1984, and then used the new focus as the justification for research variances over the benchmark. Is this a fair characterization of what Gulf has done?

A. Absolutely not. Again, the benchmark presented for this docket was developed according to Commission guidelines from prior rate cases and as instructed in

MFR C-57. What is reflected in our benchmark is not a shift in focus but rather an increased scope. For example, the electric magnetic fields (EMF) study is a new project added since 1984.

Q. Was the EMF project undertaken by Gulf through the Florida Electric Coordinating Group a duplication of research done through either Southern Company Services or the Electric Power Research Institute?

A. No. This was not a duplication of effort. EPRI's research encompasses human health effects of exposure to electric and magnetic fields. The goal of EPRI is to provide measurement methods and equipment to assess possible effects resulting from the exposure of workers and the public to EMF. SCS acts as a coordinator, interfacing with EPRI, to distribute information to the operating companies. There was no further research undertaken by SCS regarding the EMF issue.

At the state level, the Florida Department of Environmental Regulation (DER) was mandated by the legislature to investigate, develop, and adopt a standard for EMF from new transmission lines for the state of Florida. Since the standard for EMF was to be common to all utilities within the state, the FCG joined with the DER in providing expert testimony.

Gulf was actively involved in this process. In 1989, as directed by the legislature, DER adopted a rule and numerical standards and the utilities have begun to implement this rule.

Q. On page 86 of Mr. Schultz' testimony, he infers that $47,452 was approved in Gulf's 1984 rate case for acid rain monitoring. Is this a true assumption?

A. No. Gulf's 1984 rate case was based upon our 1984 budget. There were no dollars budgeted in 1984 for this project. The expenses shown on Gulf's response to Staff Interrogatory No. 101 from Docket No. 881167-EI are the actual dollars spent for the Acid Rain Study for the years 1981-1988. As Gulf specifically states in MFR C-57, the acid rain monitoring costs are a result of a request by the Florida Department of Environmental Regulation and an independent scientific review panel to continue this monitoring in order to complement a growing data base on the acidity of wet and dry deposition. This data base will provide information which could be very critical to measuring the success of new federal Clean Air Legislation.

Q. Mr. Parsons, an issue has also been raised regarding Gulf's heavy oil inventory level. Would you please

discuss the basis for the Company's request?

A. Yes, the Company's inventory request of $1,042,000 serves to protect Gulf's ratepayers from having three of Gulf's generating units unavailable for use due to an interruption in fuel supply. Without a supply of heavy oil in inventory on the plant site, these units could be considered non-firm generating capacity, thereby not receiving full credit in the Intercompany Interchange Contract (IIC). The primary fuel for these units is pipeline natural gas, which is subject to interruption or curtailment.

The plant receives oil only by truck. If an emergency fuel situation developed and Units 1, 2, and 3 were required to run at full capacity, procurement and delivery problems could prevent sustained operation. The present oil in storage provides adequate oil to allow the units to run for an emergency period and simultaneously procure replacement oil.

Q. **If Crist Units 1,2, and 3 are considered non-firm capacity due to not having a sufficient quantity of standby fuel available, does that affect Gulf Power's IIC capacity payments?**

A. Yes. The loss of 84.4 MW of fossil generating capacity in the Intercompany Interchange Contract would result

in a net loss of over $6 million in capacity payments for 1990.

Q. Mr. Parsons, an issue has been raised as to whether the Company's proposed inventory for No. 2 oil should be adjusted. Would you please discuss this proposal?

A. Yes. Gulf is requesting a total of $359,000 of No. 2 oil inventory to serve as fuel for the combustion turbine and as lighter fuel at all five plants. The inventory level advocated by Staff in their preliminary position equates to a 68 percent reduction from the Company's proposed level. No. 2 oil is not consumed at a constant rate, but varies on a relatively unpredictable basis from day to day. The usage depends on peaking requirements, unit start-ups, and load changes. This oil is delivered by trucks which restricts the amount a plant can receive at any one time. The requested oil inventory is necessary to allow for variations in plant consumption and procurement and to guard against market volatility and supply disruptions.

Gulf has recognized the decreased likelihood of supply disruptions and the minimal operation of the combustion turbine. The requested combustion turbine

oil inventory is only 50 percent of available tank capacity.

Q. **Mr. Parsons, will you please summarize your testimony?**

A. I have provided additional testimony supporting the inclusion of Plant Scherer Unit 3 capacity in Gulf's rate base. Again, this capacity was acquired for the long-term benefit of our territorial customers and has been deemed by the Commission in past dockets as a prudent acquisition. In addition, I have addressed the planning reserve margin guideline used by Gulf and adopted by the Commission in prior dockets versus that level proposed by Mr. Rosen. Also, I have supported the continued inclusion of the current Caryville site and future land purchases in plant held for future use based on its value to territorial customers for future generation needs at a reasonable cost. Next, I have attempted to address several O & M issues raised by Mr. Schultz. Testimony has been provided disputing the incorrect presumption on the part of Mr. Schultz in his prefiled testimony relative to a duplication of work between Gulf, SCS and EPRI for various O & M costs and research expenses. As I have stated earlier in my testimony, these services are not duplicative. Gulf, SCS and EPRI have taken great care to ensure all

programs compliment one another in order to attain the maximum benefit from these projects. Finally, I have addressed the issues relative to Gulf's oil inventory. Without the requested inventory for heavy oil, Crist Units 1, 2, and 3 could be considered non-firm generating capacity and would result in a net loss of over $6 million in capacity payments through the IIC for 1990. The No. 2 oil inventory is critical at all five of Gulf's plants as lighter fuel and serves as a primary fuel for the combustion turbine.

In conclusion, I would like to assure the Commission that Gulf's Power Generation and Transmission Department is manned with a highly qualified and competent staff who take great pride to ensure that every expenditure approved and every decision made are in the long-term best interest of Gulf's customers.

Q. Does this conclude your testimony?

A. Yes, it does.

Q (By Mr. Holland) Would you summarize your testimony, Mr. Parsons.

A Yes, sir.

In 1978, Gulf came before this Commission to present a cost effective alternative to continuing construction at the Caryville site. During this workshop, we presented our proposal for cancelling Caryville and acquiring capacity at Plant Scherer, resulting in a significant cost savings to our retail customers. In addition, I have presented extensive testimony in Gulf's last four rate cases and attended a number of planning workshops and planning hearings at which time our generation expansion plans were fully discussed with the Commission.

There has never be any concern expressed relative to the prudence of acquiring Scherer other than concern that we might not be able to consummate the purchase. In fact, this Commission felt so strongly that we should make this purchase that it held subject to refund our write-off of the Caryville cancellation cost approved in Order No. 9628 pending completion of the contract with Georgia to acquire Scherer.

Gulf is gravely concerned at Staff's position in Issue No. 26 regarding exclusion of Plant Scherer 3

capacity and rate base. We notified Georgia of our intent to purchases 25% of Scherer Units 3 and 4 in 1980. We signed an agreement with Georgia in 1981 for Units 3 and 4; that contract was revised in 1984 to include only 25% of Unit 3 and finally received SEC approval. During that entire period, Scherer 3 was scheduled for commercial operation in 1987. With the encouragement and support of this Commission, the Scherer capacity was acquired for the long-term benefit of Gulf's territorial customers, not for the purposes of unit power sales.

If the Commission follows the prehearing recommendation of its own Staff and disallows recovery for capacity which it has deemed prudent in prior dockets and hearings, it will break the regulatory compact which has been established with Gulf. Any such action by this Commission would be an extremely negative signal to the Company regarding what constitutes prudence in its decisions.

Gulf has continuously shown that the Scherer capacity would eventually come back to our territorial customers at a greatly reduced price when needed.

In Rate Case 810136-EU, Order No. 10557 stated, for system planning purposes, a margin of 25% is considered adequate. As late as 1986 in Docket No.

'860004-EU, the Commission's own consultant supported Gulf's 20 to 25% planning reserve margin guideline as being reasonable and consistent with utilities practices. Mr. Rosen stated that Southern's reserve level for planning purposes is based on a minimum of 20%. However, he went on to say that capital expenditures for capacity additions have been limited to a 16% planning reserve margin.

The preamble to expansion plan 9081, which is a part of this case, states as follows: Although the operating companies have determined to maintain a minimum 20% planning reserve margin guideline, capital expenditures for capacity additions have been limited in this resource expansion plan based on a 16% reserve margin until detailed studies are completed before the adoption of the fall 1990 plan. Capacity to meet the minimum 20% planning reserve margin guideline can be met through short lead time options, such as purchases, and are not shown. Active DSO additions are shown as combustion turbine equivalent megawatts. Passive DSO additions are not explicitly shown but are reflected in the load forecast. Detailed economic and reliability studies will be made as appropriate to determine resource additions on a timely basis.

This simply states that during a one-year period no commitments for new capacity will be made to raise system reserves above 16% until detailed economic and reliability studies are completed this year.

To day our reserves, including the Scherer

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capacity, is within the level previously supported by this Commission. The Scherer capacity is available for use by our territorial customers. It has been used by territorial customers and is presently used and useful in 1990.

Mr. Larkin recommends excluding the Carrabelle site from rate base because there is no plan to build a generating unit at this site during the period covered by our present generation expansion plan. I strongly feel this site should be retained as plant held for future use as approved by the Commission in previous rate case dockets. For example, in Order 9628, the Commission supports this decision by stating, "We agree with the Company that its plans for the site are sufficiently definite to warrant its inclusion, and that to deny that request would be to the disadvantage of ratepayers in the long run."

The inclusion of the Carrabelle site and plant held for future is still a prudent decision. The associated subsurface investigation which was performed prior to site certification should be included in working capital as a valid analysis of geological conditions at the site and will be used during the design phase of plant construction. There is no doubt that future generation will be required as our

territorial customers' needs grow.

Carrabelle is one of the few sites available in northwest Florida that would allow Gulf to provide the expansion required to handle this growth in an environmentally accepted manner. If Gulf is forced to sell this land, its ability to meet long range generating capacity needs at a reasonable cost would be jeopardized.

Mr. Schultz has joined with Staff in recommending an adjustment to disallow Gulf's EPRI expenses associated with nuclear power research. Since approximately 22% of Southern's kilowatt hour generation is provided by nuclear power, any improvements in efficiency and equipment performance will directly benefit Gulf Power Company. When nuclear energy is available for use by the owning company, more economical fossil-fired capacity is available through the system pool.

In addition, research in the area of a new generation of nuclear units to serve future load will benefit Gulf.

The EPRI dues structure is based on a formula using kilowatt hour sales and revenue. Nuclear research is not a line item of this formula. It simply receives a portion of EPRI's budget.

In conclusion, as I have stated many times before, our Company is staffed with dedicated, highly-trained employees. The decision we make and the expenditures we approve are made in the long-term best interest of our customers. This concludes my summary.

MR. HOLLAND: Tender Mr. Parsons.

MR. BURGESS: No questions.

MR. PALECKI: No cross.

CHAIRMAN WILSON: Questions, Commissioners?

COMMISSIONER BEARD: I got one. Nuclear megawatts are excluded from the interexchange?

WITNESS PARSONS: Yes, sir, nuclear capacity and hydro capacity is retained by the owning company for serving their own customers and is not included in intercompany interchange contracts.

COMMISSIONER BEARD: Then expand for me just briefly the impact to Gulf Power of increased or decreased efficiency or operation of the nuclear plants, for example, in Georgia, has to be an indirect one, is that not correct?

WITNESS PARSONS: Let's say, for instance, we have a 1000 megawatt unit on Georgia Power Company's property. It's operating at full load, as all nuclear units do. If that unit comes off line, that 1000 megawatts to carry Georgia's load is lost. Fossil

capacity will be utilized to carry that load in place of the nuclear unit. If that nuclear unit is available to carry that 1000 megawatts, then it frees up a 1000 megawatts of fossil-fired capacity, which could be, and probably is, less expensive to Gulf Power Company as far as the energy out of that unit, then may be producing energy out of our own Southern System. So it makes additional capacity available on the system for purchase by Gulf Power.

COMMISSIONER BEARD: It makes additional capacity available that may or may not be of use at that time to Gulf, and may or may not be more or less expensive? There's a probability if they don't have to go to peakers, that it is, obviously?

WITNESS PARSONS: No, sir, that's not always the case, Mr. Beard. Our units are not considered strictly baseload units. We have -- even though we have fossil-fired, coal-fired and generating plants, they will cycle, usually during the day. We have very few units that we will put on line and run at 100% load. Georgia has some of those units, the newer, more efficient units, which, in the sense of the word, are really baseload units, and those will run. But then there will be other units that both the nuclear and those units, fossil-fired units, will replace the need

for capacity that would make it available for sale to the pool which Gulf in turn purchases.

I agree with you to the point that the capacity has to be needed for it to be an advantage to Gulf. But under the assumption that the nuclear unit is running full out and there would be capacity available, in my opinion, more economical for Gulf to purchase energy.

CHAIRMAN WILSON: Is that all that's excluded from the IIC?

WITNESS PARSONS: Yes, sir, the hydro and nuclear energy, or capacity, hydro and nuclear capacity.

CHAIRMAN WILSON: Redirect?

COMMISSIONER GUNTER: Let me ask one question. Who is the Southern Electric Generating Company? Who do they serve?

WITNESS PARSONS: That is a jointly-owned Company that is owned by Alabama Power Company and Georgia Power Company.

COMMISSIONER GUNTER: Who do they serve?

WITNESS PARSONS: Well, they have units at Wilsonville, Alabama. They are -- it's just a jointly-owned company by Alabama Power and Georgia Power. They have units there.

COMMISSIONER GUNTER: Who do they serve?

WITNESS PARSONS: Well, the capacity is shared between Alabama and Georgia.

COMMISSIONER GUNTER: In other words it's some sort of hybrid off where Georgia owns some pieces of plant and Florida owns some pieces of plant?

WITNESS PARSONS: Well, it's a jointly owned plant, just as we own a part of Scherer, that is a unit or plant that is jointly owned by Alabama and Georgia and the --

COMMISSIONER GUNTER: You got any idea why they did it that way rather than doing it the way you all have done it with Mississippi and with Georgia, created a separate company?

WITNESS PARSONS: No, sir, I do not.

COMMISSIONER GUNTER: When was that built? Do you know? I'll look at your book. I'll find it. 1970?

COMMISSIONER BEARD: You did a dangerous thing, Mr. Parsons, you gave him a new toy.

COMMISSIONER GUNTER: 1970.

COMMISSIONER BEARD: Worse than the state statutes.

CHAIRMAN WILSON: What is the legal form of that? Is that a joint venture or is that a separate

corporation or what?

WITNESS PARSONS: It's just a separate company that is jointly owned by Alabama and Georgia. I believe the commercial operation on Unit 1, Mr. Gunter, was May, 1960 on Unit 1, and July of 1960 on Unit 2.

COMMISSIONER GUNTER: Excuse me, I was looking at the combustion turbine.

WITNESS PARSONS: Unit 3 was 61, unit 4 was 62.

COMMISSIONER GUNTER: These look like forerunners to IPPs, doesn't it?

COMMISSIONER BEARD: Maybe even the five runners.

CHAIRMAN WILSON: Anything on redirect?

MR. HOLLAND: No redirect.

CHAIRMAN WILSON: Thank you very much. Call your next witness.

(Witness Parsons excused.)

- - - - -

MR. HOLLAND: Call Mr. Howell. (Pause)

(Discussion off the record.)

M. W. HOWELL

having been previously duly sworn as a witness on behalf of Gulf Power Company, was called as a rebuttal

witness and testified as follows:

DIRECT EXAMINATION

BY MR. HOLLAND:

Q Mr. Howell, you're the same M. W. Howell that testified previously in this docket?

A Yes.

Q And have you prefiled in this docket testimony entitled "Rebuttal Testimony of M. W. Howell"?

A Yes.

Q Do you have any additions or corrections to that testimony?

A Yes. On Page 18 of the rebuttal testimony, Line 10, it says "Schedule 3." That's a typo. It should be "Schedule 7." That's the only change.

Q Is that all your corrections?

A I'm sorry, what?

Q Does that complete your corrections?

A Yes, that's the only change.

Q With that change, Mr. Howell, if I were to ask you the questions today contained in your testimony, would your answers be the same?

A Yes.

MR. HOLLAND: Mr. Chairman, we'd ask Mr. Howell's testimony be inserted into the record as

though read.

CHAIRMAN WILSON: Without objection, it will be so inserted into the record.

MR. HOLLAND: I believe his exhibits have likewise been premarked and stipulated to.

(Exhibits previously stipulated into the record.)

Record Copy

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
M. W. Howell
Docket No. 891345-EI
Date of Filing May 21, 1990

Q. Please state your name, business address and occupation.

A. My name is M. W. Howell, and my business address is 500 Bayfront Parkway, Pensacola, Florida 32501. I am Manager of Transmission and System Control for Gulf Power Company.

Q. Are you the same M. W. Howell who has previously testified in this docket?

A. Yes.

Q. Have you prepared an exhibit that contains information to which you will refer in your testimony?

A. Yes. My exhibit consists of nine schedules to which I will refer. This exhibit was prepared under my supervision and direction.

Counsel: We ask that Mr. Howell's exhibit, comprised of nine schedules, be marked for identification as Exhibits 99-107 (MWH-2).

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to rebut portions of the testimony of Witnesses Johnson, Rosen, Schultz, and Wright. These issues relate to inclusion of Scherer in the rate base, bulk power sales efforts, Scherer transmission line "rental" expenses, and the system planning aspects of cost of service methodology.

I will demonstrate that the Scherer capacity was prudently acquired and results in long-term lower costs to our customers, that Gulf has marketed off-system power to the maximum extent possible, that the Scherer transmission "rental" amount submitted by Gulf is correct, and that the equivalent peaker method of cost allocation and dedicated facility philosophy proposed by Mr. Wright are based on flawed assumptions and reasoning.

Office of Public Counsel's witness, Mr. Rosen, has recommended that Gulf's 63 mw of Scherer Unit No. 3 should not be included in the rate base. Mr. Rosen used incorrect numbers and flawed reasoning in his calculations which led him to this conclusion. I will show how the numbers he used are wrong, leading him to wrong conclusions, and resulting in his unsupported recommendation. I will also demonstrate that

Mr. Rosen is recommending that the Florida Public Service Commission (Commission) completely reverse previous decisions it has made related to the prudence of Gulf's participation in Plant Scherer and the unit power sales, and that Mr. Rosen has violated virtually every basic principle of prudence determination.

Mr. Rosen also raised a number of side issues in unsuccessfully trying to show a lack of need for Scherer. But he carefully avoided the only question that is pertinent:

Was Gulf prudent in having entered into the agreement in 1984 to purchase Scherer? The answer is either yes, or no.

Gulf could have acquired Scherer, or not acquired Scherer. There is no middle ground. If we had not acquired it, it would not be an issue here. When we did acquire it, the purchase was completed in 1984, and the capacity will be there for 40 years as a resource that must be paid for by someone. I will show that the decisions related to the Scherer purchase were prudent and that Scherer is a long-term benefit to our customers.

Q. Should the Commission allow Scherer capacity to be included in retail rates?

A. Yes. The Commission has not only previously recognized the long-term value of this resource to our customers, but has also encouraged us to participate in Scherer to be able to make off system sales to Florida such that it will reduce Florida's dependence on oil while the sales are in effect. If the Commission reverses its stand on Scherer, this will represent not only a decided blow to our territorial customers in the long term, but will also represent a serious breakdown in the regulatory compact.

Q. You stated that the Commission has previously recognized the long-term value of Scherer to your customers. When did that take place?

A. We initially reviewed our plans regarding Scherer with the Commission in October, 1978, when we held a workshop to review with them the customer savings which we could secure by purchasing Scherer capacity in lieu of the Caryville generation, which was in the early planning and construction stages. At that workshop, the Commission indicated that they agreed with Gulf that it was the proper course of action to secure the Scherer capacity.

During Gulf's next rate case in 1980, in Docket No. 800001-EU, the Commission expressed definite concern that, since Gulf did not have a guarantee from Georgia that Georgia would sell the capacity to Gulf, Gulf might not be able to secure the Scherer capacity and bring about these savings to its customers. The Commission acknowledged that Scherer was a good deal for Gulf's customers, and felt so strongly about the need to acquire the capacity that it made the Caryville cancellation cost recovery subject to completion of a contract for the Scherer capacity.

In Gulf's next rate case, Docket No. 810136-EU, Order No. 10557 stated that Gulf's decisions regarding Scherer were based on the long-term best interests of our customers and would result in cost savings because of our participation in Scherer. In our next rate case, Docket No. 820150-EU, Order No. 11498 stated that the Unit Power Sales contracts, of which Scherer was a significant part, would cause our customers to "benefit handsomely" from the sales.

In addition to these direct statements by the Commission in the orders, Gulf has also presented its plans regarding Scherer acquisition in the third 500KV line hearing in 1982, in which the Commission clearly encouraged Gulf and Southern to make additional unit

power sales from Scherer and other units. Also, Gulf has presented its plans regarding Scherer at the 1982 Annual Planning Workshop, the 1983 Annual Planning Workshop, the 1984 Annual Planning Workshop, our 1984 rate case, Docket No. 840086-EU, the 1985 Annual Planning Workshop, the 1986 Annual Planning Hearing, and the 1989 Annual Planning Hearing. Also, since the late 1970's, Gulf has annually filed its Ten Year Site Plan with the Commission detailing our future expansion plans including Scherer, our expected generation percent reserves, and our associated off-system sales.

We have openly communicated with both the Commission and the Staff over the last 12 years regarding our plans. In not one single instance has the Commission ever expressed any reservation or concern over Gulf sharing in the Scherer capacity. We have also heeded the Commission's urging to maximize unit power sales out of the Scherer capacity, since it was recognized from the beginning of the unit power sales concept that this would help to minimize customer revenue requirements in the early years of the capacity.

Q. Why did Gulf purchase capacity in Plant Scherer?

A. The plan to participate in Plant Scherer began in 1978 as an opportunity to cancel proposed construction plans for a coal-fired plant at Caryville, Florida. It was determined that the participation in ownership of Plant Scherer would, at that time, save Gulf's customers over $350 million in capital costs. At that time, commitments had already been made for the installation of Caryville No. 1 as a 500 mw unit in 1985. Because of commitments previously made with the suppliers for Caryville Unit 1, cancellation and deferral charges were originally estimated to be approximately $20 million. As a result of intensive negotiations with vendors, we were able to reduce these charges by several million dollars by June, 1979, and we then began writing off the cost over a five year period.

This Commission approved the cancellation and amortization in a prior rate case, Docket No. 800001-EU, and reaffirmed this position in Docket No. 810136-EU and Docket No. 820150-EU on the basis of the savings to be realized for the purchase of Scherer. In all three rate cases, the Commission fully reviewed the economics of the Scherer purchase. The plans to participate in Plant Scherer have thus been reviewed by, concurred in, and even praised by the Florida

Public Service Commission many times in past dockets.

Since Gulf acquired this capacity for the long-term lowest cost for the territorial customer, but it was not immediatley needed by the Company's territorial customer, the Commission encouraged the Company to sell as much of this capacity as possible. The Company made every effort to do so. The customers will receive substantial long-term benefits from this capacity. Thus, the customers should properly pay for Plant Scherer capacity costs that have been incurred to serve their load.

Q. On page 25 of his testimony, Mr. Rosen concludes that because Scherer capacity is more costly than other capacity in the Southern pool in 1990, there is no justification for having this capacity. Is he correct?

A. No. Mr. Rosen is making a hypothetical assumption, which doesn't exist in the real world, that Gulf can pick and choose the times when it needs to buy from the pool. Acquiring capacity is a "package deal." You might have some parts of the package that are, by themselves and separate from the others, uneconomical. But taking the whole package, it's clearly economical. Scherer is just such a "package deal." The capacity was acquired for the long-term benefit of Gulf's

customers, as a whole package. Once acquired, the entire package is there for the duration of the contract. Gulf can not choose to simply do away with the capacity in one year and buy from the pool. All of this capacity exists and it must be paid for every year.

The territorial customers, for whom Scherer was purchased, receive the long-term benefit of Gulf's ability to serve both present and future needs for electricity at low cost, and it is proper that these customers be asked to pay for the Scherer capacity which gives Gulf that ability.

The pooling arrangement under the Intercompany Interchange Contract (IIC) states that all parties will add capacity to meet their customers' demand for electricity. In some years, companies will obviously have to acquire capacity which is higher cost than the average of all the units in the pool. To follow Mr. Rosen's philosophy of disallowing any new capacity which is more expensive than the pool average would eventually disallow <u>any</u> new capacity in rate base! His proposal is so seriously flawed, it is preposterous.

Q. **Mr. Rosen's recommendations seem to be based on a short run analysis of the need for Plant Scherer. Should this Commission make decisions strictly on short-term considerations?**

A. Clearly, no. Mr. Rosen's testimony is based on a short run analysis, but this is not proper. This is one of the biggest concerns I have with Mr. Rosen's testimony. He has clearly held himself out as an expert at assessing the prudency of utility generation expansion plans. Gulf is frankly disturbed that none of his testimony reviewed the prudence of Gulf's plans in the time frame when it committed to the purchase of Scherer capacity, nor did any of his testimony look at the long term benefits or costs.

Instead, Mr. Rosen has focused solely on the test year, clearly revealing the narrow, short term nature of his review. On p. 25 of his testimony, he admits that the only basis for his recommendation to disallow Scherer is that pool capacity is cheaper in 1990. If we followed Mr. Rosen's logic and only planned one year at a time, it would spell certain disaster for the customer.

Mr. Rosen's testimony would have the Commission believe that a utility is able to exactly match its generating capacity need with its load each and every

year. That would be true if generating capacity could be purchased and installed, and refunded occasionally, in very small increments as needed. The cost of a guaranteed availability of buying capacity in this manner, however, would be so prohibitive that no one could afford to use electricity for very long.

The realities of operating a modern power system are that utilities must build generation in economical sizes, not in 1 mw blocks. The Scherer capacity isn't available in 1 mw blocks, and even if it were, we couldn't go to the supplier and get a full refund on megawatts we decided we didn't want for 1990 or any other year.

Q. Mr. Rosen alleges that the 63 mw of Gulf's Scherer capacity is excess. What is Gulf's response?

A. I have previously discussed that it is not practical to isolate pieces of generating units. Both Gulf and this Commission determined that our participation in Scherer, as well as the unit power sale concept, was in the long-term best interests of our customers, and that they would save hundreds of millions of dollars. We could either participate in Scherer or not. The fact that there was a long-term benefit to our customers led us to do it. The capacity is serving the customer and

the customer is the rightful party to support the investment. Never in any of Gulf's deliberations did the Company ever intend to go out and secure Scherer capacity with the thought of selling it as a generation resource for the benefit of stockholders.

Gulf's use of the stockholders' investment to purchase the Scherer capacity was solely for the purpose of enabling the Company to meet its statutory obligation of service to and for the long-term benefit of our territorial customers. The sale of UPS capacity to Gulf States Utilities likewise was made with the best interests of our territorial customers in mind. The GSU sale enabled Gulf Power to preserve and enhance the long-term benefits of the Scherer purchase for its territorial customers while at the same time meet its obligation to the stockholders whose funds were invested.

The fact that Gulf States defaulted is in no way related to Mr. Rosen's concept of a business risk incurred by the stockholders. We were simply selling as much capacity as we could to maximize the long-term benefits to our customers. Just because Gulf States has defaulted does not in any way change the fact that now, as well as the time frame in which we made the decision, Scherer provides long-term benefits to our

customers. I will later discuss the technical errors in Mr. Rosen's testimony which apparently caused him to believe the 63 mw was surplus to Gulf's needs.

Q. Mr. Rosen is clearly attempting to show excess reserves in 1990 and thereby imply imprudence. Is there any validity to his claim?

A. None at all. I have previously discussed Mr. Rosen's exclusive preoccupation with the short-term, and how this is totally incorrect and will ultimately spell disaster for the customer both in reliability and cost. He has also erred regarding the prudence issue by failing to look at how Gulf got to where it is. The test of prudence regarding reserves is never what a utility's reserves are in any particular year, but how prudent the decisions were in the time frame they were made which brought the utility to that point.

It is interesting to note that in Gulf's particular case, 1990 conditions are significantly different than earlier expected. For example, during our 1984 rate case before the Commission, Gulf's reserves for 1990 were expected to be 18.4%, including a 42 mw sale to Gulf States. But Gulf's load at that time was only estimated to be 1600 mw. We now project our load for 1990 to be 1750 mw, to which Mr. Rosen

basically agrees. If we were to calculate our reserves for 1990 with the 1750 mw load instead of the 1600 mw estimated, but add to our capacity we anticipated in 1984 the 42 mw on which Gulf States has defaulted, our reserves in 1990 would be only 10.7%, which even Mr. Rosen would agree is not excess.

Q. **Why then, are Gulf's reserves estimated to be 25.5% for 1990?**

A. This is due to two reasons. One, we have 55 mw of additional capacity which we have been able to squeeze out of our existing units. We have been encouraged by our Commission to do that, so we should certainly presume that that was a prudent action. The other component is 175 mw of additional capacity which we now will have as a result of extending the retirement dates of our five oldest generating units, three of which burn expensive oil.

Because this extension of the retirement dates of these units also results in significant savings to our customers, it certainly is a prudent action. Mr. Rosen neglected to review these factors in hastily attempting to show excess reserves which he could attribute to Scherer for 1990.

In order to more easily understand the difference between what we expected in 1984 and what we now see, I have attached as Schedule 1 a comparison of the capacity forecast and the load forecast plus 20% reserves which we estimated in 1984. As I stated before, our reserves were then estimated to be 18.4% in 1990. But, conditions are different now as compared to what we estimated in 1984.

I have also attached Schedule 2, which compares our 1984 capacity forecast with the actual loads we have experienced from 1984 through 1989 and our current forecast. As in Schedule 1, the load has been increased by 20% to reflect reserve requirements. Schedule 2 indicates how much higher actual loads have been than what we anticipated in 1984, and demonstrates that the capacity forecast which we had in 1984 would have been quite inadequate for the loads we actually experienced.

My Schedule 3 compares the 1984 load projection with actual loads and the current forecast. This shows just how much additional capacity is needed compared to what we estimated in 1984.

Fortunately for Gulf, we have been able to gain additional capacity significantly above that estimated in 1984 without the construction of any new generating

units. By 1990, this has totalled approximately 230 mw, 55 mw from squeezing more capacity out of existing units, and 175 mw from extending the retirement dates of five older units, including three that burn expensive oil.

This significant capacity addition to our system is demonstrated on Schedule 4. This schedule is important for two reasons. First, it shows why our reserves for 1990 are higher than we anticipated in 1984, even with a substantial load above what we expected. Second, it allowed us to enter the 1990's with significantly more capacity than we expected, and be in a better position to make the new unit power sales which I will discuss later in my testimony.

Incorporating this increased capacity which we have been able to secure without any new generating units, in conjunction with the much higher loads which we have experienced, Schedule 5 demonstrates our current capacity and load condition.

I have also included Schedule 6, which shows all four of the curves I have previously discussed on Schedules 1 through 5 for overall reference. If Mr. Rosen had attempted to understand this and had focused his attention on these relevant facts rather than his diversionary smokescreen issues, he would not be making

any such allegation that Gulf has excess reserves for 1990, and he would certainly not be suggesting that the Scherer capacity be disallowed in rate base.

Q. **How have these conditions which have changed significantly from what you estimated in 1984 affected Gulf's decision to enter into the new Unit Power Sales?**

A. They have had a major effect on that decision. Had we not taken the steps to increase our capacity by this 230 mw, then Gulf would be short of capacity entering the 1990's and in an extremely deficit position. The decision to make the additional sale of the Scherer capacity between 1993 and 2010 would have been much more difficult, and it is doubtful that Gulf would have entered in the sale. The fact that we had this additional capacity, however, allowed us to make the sale and realize the tremendous monetary benefits to our territorial customers which I will cover later. Thus, it is extremely inappropriate for Mr. Rosen to allege that these capacity changes, which have resulted in millions of dollars of savings for our customers in the long-term, constitute a capacity excess in 1990 for which Gulf should be penalized.

Q. **Mr. Rosen even suggests that the new UPS contracts which Gulf Power signed were imprudent. Also, Staff has suggested as the basis for its recommendation to disallow Scherer in the rate base the fact that the capacity is all sold starting in 1995. Are these valid positions?**

A. No. I have already demonstrated that the Scherer capacity is clearly a long-term benefit to our customers. I have also included with my testimony Schedule 7, which shows a comparison of Scherer participation with and without the new unit power sales. Because the off-system customer is bearing the costs of the capacity during the early years when carrying costs are higher than in the later years, the capacity is a significant bargain to Gulf's customers when it returns.

Mr. Rosen has made a number of misleading comments about the new unit power sales and their relationship to Scherer prudence, but this schedule clearly shows that Gulf acted prudently in making the additional sales, and thereby ensuring additional future benefits to its customers.

Q. What are the reasons for the savings associated with the new unit power sales?

A. The primary savings result from the fact that off-system customers are supporting the investment in the Scherer capacity, which is a significantly higher cost in the early years of its useful life compared to the cost of combustion turbines, which, as we all know, cost significantly less than base load coal capacity. There are other reasons for the savings, but that is the primary difference.

Q. How would you characterize this analysis indicated on this schedule?

A. This is certainly not intended to be an exact, exhaustive analysis. It is intended to be a simplistic analysis which still does, however, accurately capture the difference in the two scenarios. The difference in the two scenarios is what is important, since this represents the incremental effect on Gulf's customers.

Q. What assumptions were made in performing this analysis?

A. Because Gulf already owns the Scherer capacity, it is a part of our resources. Absent the new unit power sales, this resource would be fully available for territorial customers starting June 1, 1995. With or

without the new unit power sales, this capacity will be a territorial resource from June 1, 2010 forward. Thus, regardless of what happens to other existing generating units on Gulf's system, Gulf will have this capacity beyond 2010.

In our current plan, we are fully selling the capacity starting in 1995, and our present budget calls for the addition of a 126 mw CT in 1995 and another similar unit in 1998. If we did not make the new unit power sales, the 212 mw of Scherer capacity would be available for territorial load, and no additional capacity would be needed through year 2000. From 2000 to 2010, capacity additions would be common to both plans, and are omitted for simplicity. Since we are only interested in the difference in the two scenarios, and these costs are the same in both scenarios, their omission will have no effect on the difference in cost of the two scenarios.

In the year 2010, the Scherer capacity returns to territorial service in the scenario with the new unit power sales, and this capacity addition will be utilized by territorial customers. In the scenario in which no unit power sales were made, the capacity was available to territorial customers during the previous fifteen years, and two 126 mw CT's are required in

2010. At this point in time, both plans have 212 mw of Scherer capacity and two 126 mw CT's which have been added. Since both plans now have exactly the same capacity, future capacity additions will be the same and there will be no further differences in the plans.

Q. Would either plan be affected by changing retirement dates, particularly Daniel 1, which is currently projected to retire in 2012?

A. No. In 2010, both plans have exactly the same amount of base load capacity. Thus, any change in the extension in retirement dates of base load capacity would have the same effect on both plans, would be common to both of them, and would thus introduce no difference between the plans. Since we are only looking at differences between the plans to establish the benefit of the new unit power sales, integrity in the difference is maintained regardless of what happens to changes in retirement dates of base load units.

Q. What amount of generating capacity from Plant Scherer was committed to Gulf States Utilities (GSU) for UPS in 1990?

A. A total of 44 mw. Mr. Johnson is incorrect in his assumption that if Gulf States had not defaulted on its

UPS contract, 63 mw would not have become the responsibility of Gulf's retail customers. The remaining 19 mw, as Mr. Scarbrough discussed with the Commission in his 1984 rate case testimony, was planned to be in territorial service and be the responsibility of the Company's retail customers through base rates.

Q. One issue raised in this proceeding is whether an adequate attempt has been made to market the unit power sales capacity available because of the default of Gulf States Utilities (GSU). Does Gulf have additional UPS capacity which it would be willing to sell should a buyer be found?

A. Yes. Gulf has 63 mw of Scherer capacity which it would be willing to sell as UPS during 1990 in order to further enhance the long-term benefits of this Scherer capacity to Gulf's territorial customers. If Scherer were sold, Gulf could purchase pool capacity at a lower price than Scherer.

Q. Is this capacity considered excess capacity on the Gulf system?

A. This capacity is not "excess". The word excess implies capacity that is greater than a utility's needs. Since the Scherer capacity is required to meet our

customers' long range needs, and has been found by this Commission to be beneficial to the customers in the long run, it certainly cannot be considered excess. In the short run, if an alternative means of supporting this investment could be found, Gulf would obtain for its territorial customers the additional advantages related to such an alternative. Nevertheless, this capacity is being used by our retail customers today.

Q. **What short term alternative are you speaking of?**

A. Selling the 63 mw off-system through a UPS type arrangement. Unfortunately, there simply is no market for additional unit power sales in 1990 at this time due to the current economic situation. While we have been able to sell additional unit power during the mid 1990's and beyond, there simply is no market for 1990. It appears that this is the case through 1992. However, we continue to pursue every such possibility.

Q. **What efforts has Gulf made recently to attempt to market this capacity in the 1990 - 1992 timeframe?**

A. Through Southern Company Services (SCS), Gulf and the Southern system have contacted every utility that is either interconnected with or within a reasonable transmission distance of Southern regarding the

possibility of their purchasing this unit power capacity. No one has expressed any interest.

Q. **Does the Florida Public Service Commission Staff (Staff) agree that Gulf has diligently attempted to market the Scherer capacity?**

A. It is my understanding that they do. In 1989, Staff extensively reviewed the market situation with bulk power marketing personnel at SCS, who related that there currently is not a market for additional UPS capacity. Staff has indicated they have seen no evidence to the contrary, and further that an adequate attempt has been made to market the UPS capacity which became available because of Gulf States Utilities' default.

Q. **Has Gulf "pulled out all the stops" to sell all the power it could off-system for 1990?**

A. Yes. Gulf has "pulled out all the stops." It has made every reasonable effort to sell additional power, but the market simply does not exist.

Q. **Mr. Rosen's argument is that Gulf should utilize reserve margins which would have occurred had Gulf States not defaulted on its contract. Are his calculations correct?**

A. No, his calculations are wrong. This is one of the major errors in Mr. Rosen's testimony. He has misled himself, and is attempting to mislead the Commission. For some reason, he has assumed that our contract with Gulf States called for 150 mw of sales in 1990. In fact, the contract only called for 42 mw of sales during the test year. I have attached as Schedule 8 of my exhibit, a copy of the Gulf States allocations as of December, 1983. These allocations were utilized in the expansion plan provided as part of our last rate case, Docket No. 840086-FI. It quite clearly shows that Gulf was only planning to sell Gulf States 42 mw during the peak of 1990. The entire basis for Mr. Rosen's allegation that Gulf should utilize a 15 percent planning reserve margin is based on his statement that we felt this level, with the Gulf States sales, would be adequate in 1990. Mr. Rosen's misunderstanding of the facts caused him to reach an erroneous conclusion.

Q. It is well known that Gulf will sell all of its Scherer capacity from 1995 through 2010. Is Scherer 3 still in the long-term best interests of the rate payers?

A. Definitely. There will still be twenty years of life left in Scherer when it again will be committed for our customers' use in 2010. At that time, its cost will be

a small fraction of what equivalent new coal capacity will cost. During that time frame, Gulf and the Southern system will need to add new coal resources as part of our generation mix; not only will the Scherer capacity be a tremendous benefit during that period, but it also allows Gulf to avoid the need to add capacity between now and the mid 1990's.

Q. You have covered the significant errors Mr. Rosen made which led to false conclusions. Are there conceptual problems in his testimony as well?

A. Yes. It is troubling enough that his analysis was mathematically flawed, but even more troubling is his conceptual philosophy. He candidly admits on p. 25 of his testimony that the only basis for his proposed disallowance of Scherer was that Scherer was more expensive than pool capacity during a single year, 1990. To make such a drastic recommendation based on one year, and ignore the long-term benefits which this Commission has recognized are associated with the Scherer capacity, is a dangerous philosphy to adopt, as such action will drastically increase customer costs in the long term.

Perhaps the biggest conceptual flaw is Mr. Rosen's proposal that investments which were prudently incurred

at the time the decision was made should be disallowed simply because conditions change in the future. I have discussed in my testimony the conditions which led Gulf Power to participate in the Scherer capacity. These matters were fully reviewed with the Commission on several occasions, and the Commission has consistently agreed with us that participation in Scherer was appropriate and prudent because of the long-term savings to our customers.

The Commission has aggressively encouraged us to make off-system sales of this capacity, until needed by territorial customers, to the maximum extent possible. We have certainly done that. We have exhausted the marketplace. We have "pulled out all the stops." We have made all of these efforts in order to minimize the cost of electricity to our territorial customers over the long term. It would be patently unfair for Gulf to now be penalized by excluding from rate base some capacity that was a part of a sale due to the unforeseeable default on the purchasing party. This is especially true since the Scherer capacity, even without GSU, is still a clear long-term benefit to the customer. As stated previously, this capacity is being used by our customers at this time.

The standard of utility prudence has consistently been that if the decisions made were prudent, based on the information available at the time, then investments resulting from these decisions are properly the responsibility of the customer. The fact that Scherer remains a long-term benefit to our territorial customers exacerbates the implications of Mr. Rosen's proposals.

It is important to stop at this point and understand Gulf's situation in early 1984: (1) It had already purchased the Daniel capacity for the long-term best interests of its customers. (2) It had already purchased the Scherer capacity, again to secure long term-benefits for its customers. (3) It had already executed contracts for the unit power sales.

Since that time, Gulf has made no additional commitments to secure new generating capacity. Those decisions that were cemented in 1984 were considered prudent by Gulf, were considered prudent by the Commission, and ensured long-term benefits to Gulf's territorial customers as a result of the Daniel capacity, the Scherer capacity, and Gulf's participation in the unit power sales with this capacity.

Where was Mr. Rosen in the early 1980's when these decisions were being made? What is it he is suggesting that we do differently now than that which we have proposed? Other than the punitive action of disallowing stockholders a return on their investment which was risked so that the customer could get lower costs, Mr. Rosen has no recommendations for changes that Gulf should have implemented now or in the past. Gulf has demonstrated that Mr. Rosen's recommendations due to his erroneous calculations are ill-founded and without merit. We ask that the Commission honor the regulatory compact which has been built with Gulf and allow the Scherer capacity in the rate base.

Q. Was Plant Scherer Unit 3 capacity, as Witnesses Johnson and Schultz state, obtained by Gulf for the purpose of making unit power sales (UPS)?

A. No. Mr. Johnson and Mr. Schultz are mistaken when they say that Scherer was planned for UPS. Gulf's purchase of Plant Scherer capacity was initiated and completed for the specific purpose of meeting the long-term electrical needs of the Company's territorial customers. During the mid-1980's time frame in which Gulf was able to acquire this capacity, it was not immediately needed to meet existing territorial

customer load and we made off-system sales, but off-system sales never dictated the need or goal of the acquisition.

Q. How did unit power sales enter the picture?

A. Oil price increases initiated by the Arab oil embargo of 1973 had caused significant decreases in the load forecast, higher prices for oil as a boiler fuel, and a significant advantage for coal fired power as compared to that generated by oil. In 1979, the Organization of Petroleum Exporting Countries (OPEC) initiated a second sharp rise in the price of oil, triggering a number of changes worldwide, particularly in the United States. The economy slowed down, load forecasts again dropped significantly, and the price of oil-generated electricity shot upward. Because of this tremendous drop in the load forecast, Southern determined that it had more base load capacity under construction than it would need, and it faced a decision regarding this capacity.

Q. What decision did Southern face?

A. With these large amounts of capacity committed and under construction, Southern had two choices. The first choice would be to simply defer and/or cancel the

generating units at significant cost to Southern's customers and stockholders. The second choice, which appeared feasible, was to go ahead and complete the generating units before they would be needed for territorial load, sell the capacity to oil burning utilities off the Southern system for a finite period of time, and then recall the capacity as it was projected to be needed for territorial customer load.

We began in 1980 to determine the market condition to see if such a plan could be implemented. Because of the extremely high price of oil and the forecast of even sharper rises in the future, we found willing listeners in Florida and Texas where utilities were major consumers of oil. We were able to negotiate arrangements with these utilities whereby they purchased the capacity from the generating units over a scheduled period, and the capacity was then scheduled to be returned to the Southern system operating companies when it was needed for use by our territorial customers.

This gave our territorial customers the best of all possible worlds. Not only did they not have to bear any cancellation or deferral costs associated with these units, but they were also assured of additional base load coal generating capacity, which was being

encouraged by this Commission, which they were able to secure at low committed prices of the 1970's, and the capacity would come back to the companies even further depreciated when it returned to territorial use in the 1980's and early 1990's.

Thus, the Unit Power Sales (UPS) concept was born. The UPS concept has been successfully implemented by the Southern system, saving our customers many hundreds of millions of dollars.

Q. Were the Unit Power Sales reviewed by this Commission?

A. Yes. The Commission has reviewed the unit power sale concept in depth. In fact, the Commission stated in Gulf's 1982 rate case, Docket No. 820150-EU, Order No. 11498, that it had reviewed these sales from all angles and concluded that Gulf's participation in such unit power sales caused our customers to "benefit handsomely".

Q. On pages 17 through 21 of his testimony, Mr. Rosen discusses the unit power sales and states that these were attempts to alleviate excess capacity on Gulf's system. Is he correct?

A. No. We find it noteworthy that our own Commission, over many years of review and oversight, has found

these sales in the long-term best interests of our customers, who "benefit handsomely", and yet Mr. Rosen, who has reviewed the situation for only a short period of time, comes to a completely different conclusion.

Mr. Rosen's repeated references to the stockholder's business risk is nothing more than a smokescreen. The Scherer capacity was clearly acquired for our territorial customers' long-term needs. Gulf is not in the business of acquiring capacity to permanently sell off-system. We are a public utility in Florida, statutorially obligated to meet the needs of our territorial customers. We have used our stockholders' funds to meet this obligation. The costs for the prudently acquired Scherer capacity are clearly the territorial customers' responsibility. Mr. Rosen's characterization of UPS contracts as attempts to "get rid of" this "excess" coal capacity is mere sensationalism.

Q. **If the Commission does not authorize this Scherer capacity in rate base, what will Gulf do?**

A. I cannot answer that exactly at this point. We certainly will have to review what our options are. If the Commission reverses its earlier decisions and disallows the inclusion of 63 mw in the rate base,

thereby determining that the Company's participation in Scherer is not in the long-term best interest of our territorial customers, even though these same customers are using and benefiting from this capacity, one of our obvious options must be to secure a permanent buyer for the Scherer capacity, bricks and mortar, lock, stock, and barrel.

Q. I thought you said earlier that there is no market for additional unit power sales in this time frame.

A. I certainly did, and it is true that there is currently no buyer for unit power capacity in 1990, 1991, or 1992. But if Gulf were to make a permanent sale of the Scherer capacity, that is, for the life of the plant, I believe that the economic benefits to be gained at the end of the new unit power sales contract will cause many utilities to be very interested in purchasing the capacity from us. If we can find a suitable buyer, that will have to be our first option in order to relieve our stockholders from the significant burden that results from having to carry this capacity with no return on their investment.

As a long time participant in the planning and operation of our system, I would really hate to see that happen. Gulf and the Southern system have worked

long and tirelessly in responding in a commendable way to the tremendous upheaval that has burdened the industry in the last fifteen years. We have worked well with this Commission, demonstrating to it the benefit of the Scherer capacity for our territorial customers. It is not in the best interests of our territorial customers to lose the obvious benefits of Gulf's participation in the Scherer capacity. We ask the Staff to reconsider its position taken on this issue. We ask the Commission to reaffirm earlier decisions recognizing the prudency of Gulf's decision and allow Scherer in the rate base in this case.

Q. Mr. Rosen discusses on pages 21 and 22 of his testimony the concept of Gulf's business risk in making UPS sales. Is he correct?

A. No. Mr. Rosen has completely misapplied the concept of business risk. The concept of business risk is that the party who stands to benefit from an investment should bear the risk of the investment. Gulf's stockholders have never taken a risk of building capacity in order to be able to make sales with the thought of earning a higher than reasonable return on their investment. Mr. Rosen's allegations about excess stockholder profits from UPS are a farce. The Federal

Energy Regulatory Commission (FERC) regulates the allowed rate of return from these, as well as all other, bulk power transactions. All the capacity which Gulf has secured at Scherer has been for the benefit of the customer. Since the customer is the beneficiary, it is only reasonable that the customer should bear these prudently incurred costs associated with the investments that bring about that benefit.

Q. Mr. Rosen discusses, on page 23, how Southern's stockholders have greatly benefited from UPS since 1983, by having made greater profits than if new baseload coal units sold in UPS had never been built. Is this true?

A. This is absolutely incorrect. Gulf and the Southern system do not construct capacity for stockholders. Stockholders do not use electricity; they do not influence the amount of load the company is obligated to serve. Customers use electricity; they create the demand for electricity, and the company must plan to serve that load. Because the company must construct or otherwise obtain generating capacity for the customer, it is the customer's proper responsibility to pay for that capacity.

The UPS since 1983 have not increased Gulf's stockholder profits. As a matter of fact, the stockholder has fared terribly. This is true simply because the Gulf States UPS default has forced stockholders to absorb the expenses associated with capacity planned and purchased for the long-term benefits of Gulf's territorial customers.

Q. Mr. Rosen draws the same conclusion regarding stockholders about the new UPS which run from 1993 through 2010. Would you like to comment on this?

A. The system made these sales for the territorial customers' benefit. No stockholder-related analyses were conducted in preparing to make these sales. Instead, we looked at the revenue requirements associated with the investment in the capacity for which the territorial customer was responsible, and saw that the territorial customers would benefit from these sales. That was the sole criterion on which the Company based its decision to make the new UPS. This was carefully reviewed with Mr. Rosen during my deposition, but he chose to ignore it.

Q. Has this Commission ever in the past expressed any concern regarding the prudence of Daniel, Scherer, or the unit power sales?

A. The Commission has never expressed any concern about the prudence of our generation expansion plans related to purchasing Daniel or Scherer. The Commission's only concern was during the early 1980's as to whether or not Gulf started quickly enough making off-system sales. Although Gulf's witnesses testified that there has to be a willing buyer to consummate a UPS sale, the Commission's position was that Gulf's efforts at making off-system sales were not agressive and timely enough. The Commission has never expressed any concern with our management of this area. During the early 1980's, it even penalized Gulf for not starting off-system sales efforts early enough!

Q. How long has Gulf been trying to market the capacity in Scherer?

A. Since 1980, Gulf and Southern have attempted to market unit power sales off-system to the maximum extent possible. During the last ten years, we have had a non-stop aggressive program of maximizing these sales.

Q. Then could there be any validity to any claim that Gulf and Southern have not started early enough in attempting to market the 63 MW of Scherer?

A. Absolutely not. Even though only 19 MW was available for sale during part of this period, efforts at selling other capacity during this time frame clearly prove that no additional sales of Scherer could have been made, even if it had been available.

Q. When it was obvious that Gulf States was defaulting on the contract, did Gulf attempt to market the Scherer capacity which would be freed up?

A. We were already making a maximum effort to make additional unit power sales that would increase long-term benefits to our customers. Gulf specifically instructed Southern Company Services to make every effort to sell the capacity on which Gulf States defaulted.

Q. Were any of these efforts successful?

A. No. There simply has not been any market for additional unit power sales during the 1985-1990 time frame since we made the sales to Gulf States.

Q. Then Gulf really has "pulled out all the stops" to minimize territorial customer revenue requirements by maximizing off-system sales?

A. Yes. We have truly "pulled out all the stops". No effort earlier in time or more aggressive would have made any difference in securing additional unit power sales during the 1985-1990 time frame.

Q. Has this Commission previously reviewed the prudence of Gulf's participation in Daniel and the relationship to unit power sales?

A. Yes. In Order No. 10557 of Docket No. 810136-EU, issued February 1, 1982, the Commission stated that Gulf's expansion decisions, including our decision to participate in Plant Daniel, were in the long-term best interests of our customers. The Commission later specified in Order No. 11498 of Docket No. 820150-EU, issued January 11, 1983, that it had reviewed the unit power sales contracts from all angles and concluded that our retail customers benefited handsomely from the contracts. In 1983, the Commission, as well as Gulf, had had adequate time to assess the then-expected impact of the 1973 Arab oil embargo and the 1979 rise in oil prices. Based on Gulf's and the Commission's best knowledge at the time, our participation in both

Daniel and Scherer was deemed prudent. It was recognized that our customers would receive significant benefits over the long term as a result of the unit power sales contracts.

Q. Do generation expansion studies which were conducted in the 1980's for the Gulf system indicate a level of baseload capacity which is greater than an optimal amount?

A. No. All decisions have been driven by minimizing the cost to Gulf's customers. In the 1970's, when load forecasts were dramatically impacted by the energy crisis, Southern had a number of baseload generating units committed for construction and a choice had to be made. The system could cancel construction of these units, thereby moving the generation mix away from base load, but at a cost to the system of hundreds of millions of dollars. Alternatively, the system could finish the units and sell the related capacity to utilities off system that were dependent on oil for a finite period of time. This would result in neither cancellation costs nor associated capital costs related to these units which would have to be borne by the territorial customer. When the units would be needed by the system, they would be highly depreciated and be

available at a much lower cost than would other baseload capacity.

The system chose to complete the units and sell the capacity to other oil burning utilities in Florida and other areas as unit power sales (UPS). As I stated earlier, the Commission reviewed Gulf's plans to participate in the ownership of Plant Daniel and Plant Scherer and encouraged Gulf to participate in Unit Power Sales to Florida utilities. Through the Southern system, Gulf sold Daniel and Scherer capacity off-system to the maximum extent possible.

Q. Is is proper for Mr. Rosen to state that Gulf and Southern did not review their expansion plans, and that a less than optimal mix of baseload capacity existed on the system during the 1980's?

A. No. The successful completion of those units of Southern's under construction which had been committed to in the 1970's and 1980's, accompanied by the UPS undertaking, required constant review. All planning studies conducted during the 1980's operated under the inherent assumption that these units would be finished. Quite naturally, the studies would show, as Mr. Rosen points out in his testimony, that peaking capacity should be added after this baseload capacity was

completed. It is unknown what the studies would have shown if the units which were under construction had been assumed to be cancelled.

Baseload unit construction could possibly have been indicated as the proper course of action. The key point to be made here is that the system had adequate capacity for the 1980's, and the purpose of the generation mix studies which were conducted in the 1980's was to determine what capacity to add after the completion of previously committed capacity. The driving criterion during expansion plan review in the 1980's was "What course of action will result in the lowest long-term cost to the territorial customer?" This was far more important to us than an artifical concern with mix proportions.

Q. **Mr. Rosen alleges that during the 1980's, Southern embarked on an expansion plan of base load units, whereas the mix study showed that new generating capacity in the 1990's should be new peaking capacity. He then implies that some of the capacity planned during the 1980's should have been peaking. Is he correct?**

A. No. The Southern system did not plan any new additional generating capacity during the 1980's. We

already had adequate capacity under construction coming on line which would be sold in unit power sales and then returned to our customers' use as our load grew. The fact that we were able to complete this capacity and sell it for a short period of time, rather than incurring the wasteful cost of cancellation, certainly meant that the next units beyond this capacity should be peaking units. Based on current planning studies, that is exactly what Southern intends to do.

Q. Mr. Rosen states in his testimony that the 1986 Planning Hearing document filed in Docket No. 860004-EU-A showed that the long-term optimum mix of capacity for the Southern system should be approximately 57 percent base load, whereas capacity in 1995 was expected to be 83 percent base load. He then states that these results imply that the current mix of capacity is far from the long-term optimum. Is he correct?

A. Absolutely not. The study shows that in the year 2015, quite a long time from now, our long-term optimum mix is expected to be 57 percent base. But the optimum mix for 2015 bears no relationship to the optimum mix for 1995. The year 2015 is twenty years beyond 1995. This study was based, among other things, on cost estimates

for future units which would have cost thousands of dollars per kilowatt by year 2015, whereas existing coal units on Southern by 1995 will be depreciated to a cost far below that. Southern's mix for 1995 will certainly be reasonable based on the cost of embedded capacity on the system. Mr. Rosen, by not having participated in earlier proceedings, is perhaps unfamiliar with the Commission's recognition of our plans as appropriate for the territorial customer. We have, in addition to the many rate cases cited, continually brought our expansion plans to the Commission's attention through annual Ten Year Site Plans, Annual Planning Workshop proceedings, and Planning Hearings. The Commission has been regularly advised of our plans.

Q. Did the Commission hire its own consultant to review the filings of Gulf for the 1986 Planning Hearings?

A. Yes. The consultant had high marks for our study with respect to our methodology, data sources, computer tools, and results.

Q. On pages 28 through 30, Mr. Rosen discusses Gulf's reserves in 1990 and beyond. Are his observations correct?

A. No. He assumed that Gulf would have deemed it prudent to maintain the relatively low reserve margins which he calculated. In doing so, he has ignored the information which we discussed with him during my deposition in this docket as well as the information provided in response to various discovery and information requests from the Office of Public Counsel. We have explained that Gulf does not do its planning totally independent of the Southern system. Gulf plans its expansion both to meet its territorial needs and as part of the Southern system. As long as adequate capacity is available on the Southern system for Gulf's purchase through the IIC in any particular year, Gulf certainly does deem it prudent to maintain a relatively low reserve margin on its own system, consistent with an overall optimized expansion plan to minimize the long-term cost to its customers.

Q. On pages 30 and 31 of his testimony, Mr. Rosen attempts to make a mathematical tie between the percent reserve and EUE criteria. Is such a tie reasonable?

A. Not in the method utilized by Mr. Rosen. Our forced outage rates on our generating units are well below industry averages at this time. Whether we can keep them there in the future is a question that only time

will tell. The EUE level calculated is low compared to our criterion, and it is probably not within the accuracy of the computer program. There has been no need to calculate it more precisely because future generation additions have been triggered by the 20 percent reserve margin criterion.

An EUE or LOLP criterion is admittedly difficult to understand. The calculation of an appropriate level for utility systems is also admittedly quite difficult. That is why Southern has adopted a policy of dual criteria, in that a reserve margin is much easier to understand and, more importantly, more appropriate to determine capacity adequacy on the system. The simplistic ratio comparison of EUE and reserve margin levels perfunctorily performed by Mr. Rosen is totally meaningless, and simply another attempt at promoting his empty argument that Gulf has excess reserves.

Q. Mr. Rosen has me confused. One place he says Gulf has excess reserves and other place he says Gulf is planning too low a reserve margin. Can you help me out?

A. I will certainly try. As I have previously discussed, Mr. Rosen erroneously manipulated the numbers for the future in his attempt to show a very low reserve margin

for Gulf. He has failed to even mention the fact that Gulf, on a stand-alone basis separate from Southern, had negative reserves in 1988, and he has attempted to show that Gulf has excess reserves in 1990. If he were correct, that would violate every principle for examining long-term reserves, which is the only reasonable way to assess generation adequacy. Fortunately for our customers, we have shown this Commission that Mr. Rosen's calculations are not correct; thus, there is no validity at all to his conclusion. It is interesting to note that, on page 32 of his testimony, Mr. Rosen concluded that 131 mw of supposed excess capacity was extremely close to the 150 mw of capacity which he falsely assumed Gulf would have supplied GSU during 1990 had GSU not defaulted. We have already shown how that assumption is completely invalid.

Q. Is there such a thing as an absolutely correct level of reliability or absolutely correct reserve margin?

A. There really is not. What is appropriate is to establish reasonable levels for targets of reliability or percent reserve. Gulf has consistently maintained that a 20 to 25 percent reserve margin is appropriate for long range generation planning requirements. While

our reliability criterion, EUE, is not expected to initially trigger any additions of generation capacity, it certainly could if the reliability of our units were to decrease. Of course, providing for adequate levels of funding in base rates works to keep our reliability suitably high. We have utilized these dual criteria in reviewing with the Commission a number of rate cases, Ten Year Site Plan filings, Annual Planning Workshops, and Planning Hearings, and the Commission has agreed that these are reasonable levels.

Q. You said earlier that the Commission's own consultant reviewed the planning studies filed by Southern in the 1986 Planning hearing. Did he also review the planning criteria utilized of 20 percent reserves and 0.02 percent EUE?

A. Yes. He found both of them reasonable and consistent with normal utility practice. It is interesting to note how much his impartial assessment differs from that of Mr. Rosen.

Q. Turning to Scherer transmission line "rentals," Mr. Shultz questions whether the amount budgeted for Scherer transmission line rents is appropriate. What

are the various methods that Gulf considered for getting Scherer power to Gulf?

A. Gulf and Georgia Power began discussions regarding reasonable transmission service arrangements between the two companies well before 1987. We initially investigated the feasibility of a proxy path similar to that used for Daniel. Because of the physical arrangement of the transmission system, this proved to be impractical and illogical. Because of the high cost of the significant amount of 500 kv line involved, it would also have potentially resulted in a prohibitively high price for Gulf to pay. Another option considered was to simply build a transmission line from Scherer to Gulf. This also would have resulted in a prohibitively high price. Since no new line was needed from a transmission capacity standpoint, it just didn't make sense to build an unneeded line just in order to establish a metallic path.

Another method considered was for us to simply pay a standard fully embedded transmission service charge rate on the capacity. This method is universally utilized in transmission service contracts which are in place throughout the United States and has received consistent approval by the FERC. Through negotiation, Gulf has convinced Georgia to accept a modified

transmission service charge method that resulted in a lower price for Gulf.

Q. **Did Gulf choose the lowest cost option?**

A. Yes. Schedule 9 of my exhibit shows that Gulf's choice overwhelmingly proved to be the lowest cost option.

Q. **Mr. Shultz, on page 28 of his testimony, recommends that the full amount of Scherer transmission facility expenses be disallowed because Plant Scherer capacity is "for unit power sales." Is this reasonable?**

A. No. As I have stated earlier in this testimony, 63 mw of Plant Scherer capacity is available to serve Gulf's territorial customers in 1990. A total of 19 mw of this capacity was not even sold under UPS contracts. All the capacity has been acquired and managed for the benefit of our territorial customer. Mr. Schultz is absolutely incorrect in saying that "all" Scherer capacity is "for unit power sales."

Q. **Another issue in this case addresses the appropriate cost of service methodology. Witness Scheffel Wright on pages 11 through 13 of his testimony proposes the equivalent peaker methodology, stating that this most closely fits system planning considerations. What are**

the primary considerations a system planner evaluates in determining whether to add any generation?

A. Clearly, relevant considerations change over time. In Southern's early years, for example, we matched new generation capacity very closely to expected peak load. Essentially, all new capacity was hydro and it simply became a matter of how much hydro capacity to develop. Later, oil, gas, and coal steam units were added as growth in loads began to outstrip the ability of hydro resources to keep up. During the 1950's and 1960's, coal was the predominant fuel of choice for generation additions on the Southern system. The relative domestic abundance and low cost of coal, coupled with the relatively small cost of environmental compliance, made coal an extremely attractive fuel.

In the 1970's, when oil imports were a major national concern, any utility technology which utilized oil was basically prohibited. Now that the Fuel Use Act has been repealed, it appears that natural gas is reasonably abundant, and the system planner has a wider choice of options for adding new capacity. Widespread use of the philosophy of an optimum generation mix, which Mr. Wright uses as a basis for his method, did not really take hold until some time in the 1970's. By

that time, the bulk of Gulf's current generating resources had either been constructed or committed.

Also, Mr. Wright's theory only holds true for a single system, and is totally inapplicable for a pool-type operation such as that in which Gulf operates. It also ignores economies of scale, in that a small peaking unit could cost almost as much in $/kw as a very large base load unit. It also fails to recognize that in a pool operation, a utility might actually purchase most of its energy from other pool members during many hours. His proposal also cannot account for hydro, a peaking capacity that frequently is base-loaded in valley hours.

Thus, the methodology which Mr. Wright proposes does not apply at all to the system planning considerations which were in effect at the time Gulf's existing generating units were constructed. His method should be recognized for what it is -- an overly simplistic generalization which might be intellectually interesting, but which is not at all appliable on a system such as Southern.

Q. From a system planning standpoint, are there problems with the equivalent peaker method?

A. Yes. The equivalent peaker method shifts a considerable burden of funding production capacity on the high load factor user. Basically, such a customer is paying for the relatively expensive coal plants, whereas the low load factor customer is only paying for relatively inexpensive peaking capacity. Under Mr. Wright's proposed allocation, all customers would continue to pay average fuel costs for all energy utilized. Thus, the high load factor customer would pay for high cost generating capacity and high cost fuel.

This method would thus cause a significant shift in cost from the low load factor customer to the high load factor customer. This would discourage the high load factor customer from utilizing utility power. The result would be an increasing shift to a sharp peak and a shallow valley. Over time, this would cause a utility to add additional oil fired peaking units, underutilize the coal units, and increase oil usage. This runs exactly counter to this Commission's goals of reducing our dependence on oil and would actually violate the state's goals towards reduction of our dependence on petroleum fuel.

Q. What about rate stability?

A. I find it very interesting that Mr. Wright states on page 10 of his testimony that one goal of proper rate setting is to establish rate continuity and stability and to avoid rate shock. Utilization of the equivalent peaker method, however, would have exactly the opposite effect, in that it would cause rate shock. As high load factor customers realize a higher cost, they will subsequently decrease their consumption of electricity in the off-peak as in all hours, especially as they convert to their own generation. This results in an increase in price for all remaining customers.

Q. Is the basic theory of the equivalent peaker method correct?

A. No. Mr. Wright states on page 13 of his testimony that if a utility were building a generating plant only to serve a brief peak demand, it would build the least expensive peaking units available. This theory is extremely flawed and presents one of the biggest concerns I have with his proposed method. The equivalent peaker method is only a theory. It does not recognize real life conditions.

Taken to its extreme, it actually suggests that a utility's generation would consist of all combustion

turbines if it had a sharp peak and no load in the valley. In fact, there is no utility system with such a load. Although utility load factors vary anywhere from approximately 40 percent to perhaps up to 70 percent, they all typically consist of a mix of industrial, commercial, and residential load. If there were such a thing as a peak in the absence of other off-peak load, a utility simply could not afford to serve its customers with the expensive cost even of peaking generation. There must be considerable off-peak load, as well as the peak load, to justify the installation of generating equipment. In the absence of off-peak load, the utility would have no choice but to attempt to buy power for the short duration of the peak or attempt through load management to simply cut the load.

Especially in today's market, in which many utilities are opting for bidding as a means to meet new generation, the cost to meet a sharp brief peak would be extremely unstable, vacillating wildly from year to year depending on market conditions and availability of non-utility suppliers. Such wild swings in cost would do nothing to further Mr. Wright's professed goals of stabilizing rates or providing customers with

confidence that they will be insulated from wild rate shock.

Q. On pages 22 and 23 of his testimony, Mr. Wright asserts that no change in fuel cost recovery would be necessary under his method? Is he correct?

A. Absolutely not. Basically what he is proposing is that customers with sharp peaks pay the construction costs of a peaking unit and customers with flat load pay the construction cost of a coal unit. It hardly seems fair for a customer who pays only the low capacity cost of a combustion turbine (CT) to enjoy the benefits of low cost coal energy that flow from the higher priced base load capacity for which another customer has paid. There is no way to avoid this "fuel symmetry" problem that critics of the equivalent peaker method have discovered.

Q. On pages 32 and 33 of Mr. Wright's testimony, he states "the company should estimate the rate base value of primary and higher voltage-level conductor that functions as dedicated distribution facilities, or as a higher voltage service drop, and directly assign these estimated amounts to the classes that include the customers who are served by these facilities." From a

system planning standpoint, are there conceptual flaws to this suggestion?

A. Yes, there are. As we expand the system to serve new load, it may happen on many occasions that a new distribution line, or even a new transmission line, may be necessary to provide the needs of a new customer. But Gulf is not dedicating these facilities solely to that customer. As new load in the vicinity develops, and it is economical to serve additional customers off this line extension that formerly served only one customer, such additional load will be added. The logical first option in serving a new customer where no facilities exist is to examine those facilities which are geographically most convenient, whether or not they serve other customers in the vicinity. We certainly do not go all the way back to the substation to serve a new customer just because existing facilities may serve only one customer. It simply isn't practical or cost effective, in general, to reserve facilities for a single customer.

This is especially true in the case of high voltage lines. A good recent example is our new 115 KV transmission line that serves Pensacola Naval Air Station (NAS). NAS was adding new load that could not reasonably be served over the existing 12 KV system

providing their service. To provide adequate service, a new 115 KV line was constructed to NAS from our Bayou Chico Substation. The only load on this existing 115 KV line is the NAS load, but it is not reserved for them. We have current plans to build a new 115 KV line out of the NAS Substation on to Beach Haven Substation to provide necessary reliability to loads in this area. Thus, this 115 KV tap line will become part of the network. There are any number of situations that might arise on other 115 KV taps or 12 KV taps which serve one customer, whereby we would tap such a line to provide new customer load.

Thus, from a real-world perspective, Mr. Wright's suggestions simply do not match realistic system planning considerations.

Q. On page 33 of his testimony, Mr. Wright further asserts that fuel inventory should be reclassified as energy-related. Is this correct?

A. No. The amount of fuel inventory required for a generating plant is a function to a large degree of its capacity. There are factors which affect the required inventory of a generating plant which are far more important than the expected annual kilowatt hour generation. Since most of these relate to the megawatt

size of the unit, his proposal is seriously flawed.

Q. Would you please summarize your testimony?

A. Office of Public Counsel's witness, Mr. Rosen, has recommended that Gulf's 63 mw of Scherer Unit No. 3 should not be included in the rate base. Mr. Rosen used incorrect numbers in his calculations which led him to this conclusion. I have shown how the numbers he used are wrong, leading him to wrong conclusions, and how this resulted in his unsupported recommendation. I have also demonstrated that Mr. Rosen is recommending that this Commission completely reverse its previous decisions regarding the prudence of Gulf's participation in Plant Scherer and the unit power sales, and that Mr. Rosen has violated every basic principle of determining prudence in attempting to fabricate an incorrect basis for a penalty to Gulf Power Company.

I have shown that the Scherer capacity was prudently acquired, that Gulf has marketed off-system power to the maximum extent possible, that the Scherer transmission "rental" amount proposed by Gulf is correct, and finally, that the equivalent peaker method of cost allocation and dedicated facility philosophy proposed by Mr. Wright are based on flawed assumptions.

Q. Does this conclude your testimony?

A. Yes.

Q (By Mr. Holland) Mr. Howell, do you have a summary?

A Yes.

Q Would you please proceed?

A Commissioners, you heard from Mr. Rosen earlier this week, and he held himself out as a person who is qualified to advise the Commission regarding Gulf's rate case, but he did acknowledge and even volunteered his unfamiliarity with the past prudence determinations regarding Scherer. He volunteered that he was confused over Gold Rock. He acknowledged he made a major error in calculating our reserve margin, which mislead him to false conclusions. I think these demonstrate that he is not quite yet prepared to advise this Commission on rate base matters which greatly affect Gulf Power's financial health.

He did make a major error in calculating Gulf's reserve margin because he didn't realize our contracted Gulf state sales for 1990 were only 44 megawatts, not the 150 megawatt level that existed when the Gulf State sales were suspended in 1988.

This error he made misled him regarding Gulf's required reserve level.

In attempting to correct that error during cross examination, he did introduce changes to his

prefiled. As a result of that, he now has his prefiled testimony contradicting itself.

He failed to consider any long-term impacts in his recommendations. He would have you to abandon all the long-term considerations for short-term considerations. The record is clear that you have encouraged us to acquire Scherer; that you found Scherer to be prudent in the long-term best interest of our customers.

His prefiled testimony clearly states that the reason for proposing the disallowance of Scherer is that it costs more than pool capacity in the test year. He repeatedly made this clear in his prefiled testimony.

He admitted he is unfamiliar with the reserve margin range which this Commission has approved for prior rate cases; that he's not familiar with the Commission's planning hearings; that he's not familiar with the Commission's own consultant's review of the 1986 planning hearing, and yet he went ahead and calculated an excess reserve margin for Gulf that he proposed.

In doing so, he failed to account for all the capacity which we sell through interchange, and he did not make any adjustment for the additional capacity

which we have gotten out of our existing units since 1984 as a result of the Commission's own GPIF program.

He was careful never to challenge the prudency of acquiring Scherer, but he would not acknowledge that once it's acquired, it's a resource that must be paid for by those who gain the benefit in the long term, and that's the territorial customer.

Commissioners, we are sensitive to the Staff's concern over the Scherer capacity being completely sold in 1995. But these new sales will result in lower long-term cost to our customers by allowing less expensive CT capacity to be added in 1995, and then allowing Scherer capacity to return to territorial use at the end of the new sales.

Witness Schef Wright proposes a peaker method for allocating demand and energy cost based on his understanding of system planning considerations.

His approach is based on theory. It does not match the actual system planning reality which has existed on the Gulf Power system. His method would cause all customers to eventually have higher cost; would cause an artificial shift in fuel use from coal to oil; would be counter to this Commission's goals regarding fuel use; would be counter to the Legislature's intent regarding getting Florida off of

oil.

In summary, we're asking you to do two things: One, to allow proper full recovery for the Scherer capacity, and to reject the equivalent peaker capacity proposed by Mr. Wright.

This completes my summary.

MR. HOLLAND: Tender Mr. Howell.

CROSS EXAMINATION

BY MR. BURGESS:

Q Mr. Howell, as I understand it, one of the criticisms you have with the equivalent peaker method is that in today's market utilities might opt for bidding as a means to meet new generation, particularly with regard to meeting a drastic peak, is that correct?

A Yes.

Q And I think you indicate that the costs would then be extremely unstable and they would vacillate wildly from year to year.

A That very likely could happen, and would send the wrong signals to the customers in that they would never know what to expect for that cost. It would depend on what the market was, and we have seen in the past, and I think should be prepared to expect in the future, drastic swings in the markets.

Q Within the context of this description, what

do you consider to be drastic swings or fluctuation?

A Well, I would say that there may be some years you could get this. As Witness Dawson earlier talked about, you may not have to pay a capacity charge, depending on the market. You might be able to just buy it as energy, and, therefore, your capacity cost would be zero. If capacity were short, as we have experienced in the past, you may not be able to buy it at any price. That happened as recently as December of 1989 when you could not buy capacity at any price in Florida.

Q So what costs would you call that then?

A I'm sorry, what's the question?

Q What cost would you call that, then, if you're talking about the costs vacillating wildly from year to year?

A If, for example, in December, if you couldn't get it, we would say the price would be infinite. So going from zero to infinity, I would call that vacillating quite a bit.

Q Okay. So you're talking about infinite costs as being a problem with dealing with it along these lines.

A Certainly if it's not available at all, and that's what we saw in December.

Q Now, wouldn't Gulf or Southern Company build its own peaker to meet an anticipated peak if that would be less expensive than what it anticipated that it would have to pay in a bidding system?

A Are we talking now about the concern of the vacillation in the price?

Q Yes.

A Yes. What we would do is try to estimate what we thought the price might be, if we could do that; and we might, and I would think we would, go ahead and make arrangements to the capacity rather than just waiting to see what the price might be, but you may not be able to do that.

Somebody might not be willing to sell you capacity on just a very sharp peak basis. They might only be willing to sell you capacity if you buy it for, say, several years. So you're at the mercy of the market then if you don't buy what I think he might characterize as baseload capacity, you might be at the mercy of the market in trying to buy capacity just for the sharp peak, one-hour type capacity.

Q But if the price is too much, or if the price reaches a certain point, Gulf or Southern Company would simply build its own peaking unit, is that correct, to meet that peak?

A Well, I can't say for sure, because one of the problems we run into is where does real life operation stop and where does the theory start?

And I think if we look at what happened at the Christmas freeze in 1989, it's my understanding, and you can correct me if I'm wrong, that the utilities in Florida recognize that once every five or so years they do get a severe front coming through, and right now I don't believe they anticipate adding capacity for a reoccurrence, say, of the December 1989 freeze. If that happens again, their plan is to try to offer the customer as much advance notice that they are going to drop the load, and their plan is to not serve the load for that we might call a brief peak.

Q Then in that case they wouldn't incur the infinite costs that you were talking about?

A That's right. They would not build the capacity. And my point is that Mr. Wright's theory presumes that for a brief peak you would always build a peaker. In fact, you may decide it's better, considering all the variables, to just not serve that peak. And, in fact, if Gulf --

COMMISSIONER GUNTER: Mr. Howell --

WITNESS HOWELL: Yes, sir.

COMMISSIONER GUNTER: Are you aware that we

have one utility in the state that is contemplating at this time either somewhere between 6 and 900 megawatts of peaking capacity?

WITNESS HOWELL: Yes, sir.

COMMISSIONER GUNTER: Okay.

WITNESS HOWELL: And I appreciate that, and as well as Gulf and Southern are planning to add peaking capacity as the next capacity.

My only point was that I don't think they are planning to add enough capacity for reoccurrence of the Christmas freeze.

The cost effective thing to do, I think, has been determined to be don't try to serve that peak. And that's the only point I was trying to make, is that Mr. Wright assumed in his methodology that you would always serve the peak and, in fact, it may not be cost effective to do so.

Q (By Mr. Burgess) Well, to the extent there would be wildly fluctuating costs, they would be capped by the cost it would take to build its own peaking unit, wouldn't it?

A Only if you built it.

Q And if you chose not to serve the load, then you wouldn't be incurring those costs anyway, would you?

A You would only choose not to serve the load if you could not secure capacity. Obviously if you didn't construct the generation, and you were depending on the market, you would make every attempt to try to secure capacity to serve that load. And if you were unable to, then you'd just have to not serve it. So it really all depends on how you went into the situation. And my only point is that you would not necessarily always build a peaker to serve peak load. (Pause)

Q Do you know what the planning criterion is to the state as far as loss of load probability?

A There are two criteria, two separate sets of criteria. The peninsular has one set and Southern has another set.

Q Do you know what it is for Peninsular Florida?

A Yes.

Q Can you tell me what that is?

A As of a year ago, unless they've changed it, it's .1 LOLP is their criteria.

Q And what does that equate to as far as the --

A Reserve margin.

Q No, as far as the number of days in a given period of time that would be acceptable for not being able to serve load.

A It really doesn't -- it doesn't equate; you cannot equate it to that.

In reliability criteria, as we have struggled with this with the Commission for a number of years, and you all know this, the .1 LOLP is very difficult to comprehend compared to a reserve margin which is somewhat easy for see. Some have tried to explain LOLP as a .1 LOLP means a tenth of a day per year, or one day in ten years.

Q That's my question, is one day in ten years.

A That's what I was getting to. That's what has been explained by some, but that is not what the calculation means. The calculation is a rather comprehensive, and I will acknowledge, complicated calculation that looks at the probability in all of the periods that you break it down into. If you try to equate it to something, the one day in ten years is a little misleading as far as I'm concerned. That's not not what the .1 LOLP means.

Q Is one day in five years what it means?

A No, that's what I'm saying, it does not mean that. The .1 LOLP means literally if you look at all the cumulative probabilities of not being able to serve the load in all the periods where you disaggregate the load period, they sum up to 0.1 for the year.

COMMISSIONER GUNTER: So what you're really talking about is sort of a statistical probability.

WITNESS HOWELL: Yes, sir, that's a good characterization.

COMMISSIONER GUNTER: As versus an actual one day in ten years.

WITNESS HOWELL: Yes, sir, that's right.

COMMISSIONER GUNTER: The statistical probability over that time period, if you set a number of factors together, it could perhaps be equated to one day in ten years?

WITNESS HOWELL: That's right.

COMMISSIONER GUNTER: But you have to have all the blocks together for it to work out that way.

WITNESS HOWELL: Yes, you do.

COMMISSIONER GUNTER: Isn't that right?

WITNESS HOWELL: That's right.

COMMISSIONER GUNTER: Okay.

WITNESS HOWELL: That answer your question?

Q (By Mr. Burgess) Yes. And my question with regard to that is: Then isn't that inconsistent with your comment that peninsular utilities are simply anticipating at this point not being able to meet load, to serve their load, once every five years?

A No. Not at all. The utilities don't know

how often they're not going to be able to serve the load. They do recognize that severe cold fronts come through and recently it has been on the order of once every five years. We had one in 1983, I believe, where there were problems. I don't think they were anything like what they were in 1989.

We don't normally get that cold a weather in the peninsula every year, but about every five years, you have one come through. Sometimes it's two years in between, sometimes maybe 10 or 15 years in between. They just don't know.

But my point was that, as a result of the analysis of what happened in Christmas of 1989, the utilities have determined that it's not practical to try to construct generation to serve that kind of load because it occurs so infrequently. And they have decided for now, at least, that they just won't construct capacity to serve that load, they will let it go unserved.

That is not in any way connected with the criterion of .1 LOLP. Because if you recall what I said earlier, part of what you do in the LOLP analysis is you divide your load into various periods and you use what we call a weather-adjusted load forecast which does not take into account these unusual aberrations in

weather. So the two are really not related.

Q So what you are saying, you would expect a peninsular utility that built based on a .1 LOLP to experience outage or inability to serve load about once every five years?

A No. I didn't say that.

Q I thought you indicated that that's what the peninsular utilities are anticipating is simply not being able to serve load about once every five years.

A No. I said in this particular instance, they have deemed it not practical to try to serve that load. They do know they have cold fronts come through, every so, every four, every five years on average. Some of the cold fronts, they're able to serve the load; some they're not able to. It really depends on the conditions that exist at the time.

If you look at all the conditions that existed in December of 1989, if things that weren't right or ideal would have been different, they would have been able to serve the load. But you look at all the things that happened to them and they were just unable to serve the load.

If we got weather just like that again next year and conditions on the system were different, they might be able to serve the load. You again have to

look at the probability of being able to do it.

Q Within that probability of .1 LOLP, would you expect the inability to be able to meet the load requirements to take place at least once every five years?

A I really don't have a feel for that because I have not looked at how often and how much load they've had to drop. I think all of us recognize that, with all the press this one got last December, we looked at it a little bit closer. I'm not familiar with some of the others in as much detail as I am that one. (Pause)

Q Mr. Howell, is it correct that Gulf Power intends to add peaking generation to its system in 1995?

A It was either '94 or '95. If you will give me just a second, I'll look it up.

That's right.

Q And the purpose of this is to satisfy the reliability criteria requirements for its system load?

A No.

Q Will you tell me what the purpose is.

A It's to satisfy the percent reserve criterion.

Q Is it correct that the peak demands anticipated are driving Gulf's or Southern's need to

add this peaking capacity?

A Right.

Q Is it correct that the combustion turbines are being constructed or anticipated to be constructed, rather than some other unit, because of the economic considerations?

A Yes.

Q And when you agree with me that these economic considerations are what drive the decisions as to this type of plant, do you agree that what we're talking about is that is the lowest projected present worth revenue requirements of any other option that would meet the same requirement -- meet the same criteria?

A I think you asked two parts to the question. What was the first part, did I agree with what?

Q That the economic consideration is one in which this particular type of capacity you anticipate to prove the lowest present worth revenue requirement of the various alternatives?

A You're speaking of the 1995 addition?

Q Yes.

A The answer is yes.

Q As far as you know, has Gulf ever built a baseload unit when peaking capacity would have provided

a lower projected present worth revenue requirement?

A Well, if you review that part of my rebuttal testimony where I talk about that, planning is very sophisticated now. We have very sophisticated computer models, we have very sophisticated analysis tools which we now use in looking at future generation. In the past, we weren't nearly as sophisticated as we are now and we didn't use these type of tools. And we didn't use what you might call the present worth of revenue requirements back then, it was more on judgment and other factors.

And we can go all the way back, if you would like, to when we first started adding capacity.

Q Would you say in hindsight that you have added baseload capacity when peaking capacity would have provided a lower total present worth revenue requirement?

A Well, I really can't, I can't answer that yes or no. Because in the past, when we had the freedom to add CTs for many periods of time, there were problems with CTs regarding reliability. And they might have been available to add and on paper they might have shown to be lower in cost, but the experience of other utilities was such that perhaps it wasn't too wise an option.

So we -- and I'm speaking now of perhaps 20 or more years ago. We have looked at other factors, including our judgment and what our capacity options are, and economics was not the only criterion on which it was based.

I've said all that to say -- excuse me, go ahead.

Q No, go ahead, I'm sorry.

A I said all that to say what I said in my rebuttal, and that is that the considerations you use change over time. And that's the main point.

Q Does that mean you've not gone back -- does that mean you don't know whether any of the baseload units that have been added were added when, even with the advantage of hindsight, that those baseload units were not the lowest present worth revenue requirement alternative available to the system at the time?

A I think the answer is yes. And I'll elaborate. I came into System Planning in 1976. And no, I did not go back and look at what type of economic evaluations were done for all the baseload type capacity which Gulf added prior to that time.

Q What about since the time that you've been involved in the planning situation?

A Since the time that I have been involved, the

answer is yes, that has been done. There are only two instances where we've added capacity since then, and actually only two instances since 73, when it was our last baseload unit territorial. And that was in the Daniel and the Scherer case. And the answer is yes, that type of analysis was done, the economic analysis.

Q In generation expansion planning, is it correct that one of the steps is to select a list of the generating technologies that are candidates for future additions?

A Are we speaking of what has happened in the past or what our present practice is?

Q What your present practice is.

A Yes. That's true in our present practice. You note that our present practice started, that I'm familiar with, in mid 1976. We have not had to commit to any new capacity since then.

Q Are you saying -- well, let me ask. Were Plant Daniel, the construction of Plant Daniel and Plant Scherer, the subject of this type of economic analysis that's included in the Southern System generation expansion planning document?

A I rather doubt it. Because Plant Daniel, the planning for that started in the early '70s or maybe before, long before I came into System Planning. I do

know some economic analysis was done, but I feel sure it was not anywhere near the rather sophisticated approach we now have.

Plant Scherer, also, the plans for that were laid long before I came into System Planning as far as adding that capacity on the system. I'm not that familiar with what economic options might have been done that initially resulted in that being included in the system expansion plan.

Q When you say it was less sophisticated, does that mean that they would not have begun with first developing the various alternative plans that might meet the requirements for the system?

A Well, it means that it's so far back and before my time that I really don't know in detail what they did. I know what resulted, but I don't know what type of, I don't know what kind of capacity options they might have looked at. You'll find that, as I said earlier, we're far more sopnisticated, far more paranoid about keeping records now; and you just don't find those kind of records any more. These decisions occurred over 20 years ago and that's a long time for us to go back.

Q I understand. So you don't know, really, what all did go in, what the various steps in the

planning processes were for the units that were on line or the planning stages had reached a fairly extensive point by the time you started working for Gulf?

A I'm sorry?

Q By the time you became involved in the System Planning in 1976, --

A Okay.

Q -- you are not aware of the various steps in the planning stages or in the planning phase of determining which plants to bring on to the system?

A Certainly not in detail in all cases. I will tell you that initially on the Southern System the only capacity we had, basically, was hydro. And we tried to match load to capacity. And we did that because it was a very good, cheap energy resource.

When we exhausted the economic hydro, we started adding small oil, gas and coal steam units. The first CT that Gulf added had to do with meeting the peak in the construction time frame. It was not associated with any economics, it was just trying, saying, "What capacity is available to meet the peak that we see coming?"

CHAIRMAN WILSON: Mr. Burgess, could you make a brief proffer of evidence as to where you're going here?

MR. BURGESS: Basically, I'm dealing with the rebuttal testimony in the question of his criticisms of the equivalent peaker method. And the equivalent peaker method is based on the planning process in the determination of which plants to bring on line or which plant to construct, what type of generating unit to construct.

And so, as I understand it, that's the basic premises of the criticism, that the equivalent peaker method does not follow that particular planning. So it seems to me it's relevant to or directly responsive to his rebuttal testimony.

COMMISSIONER BEARD: A lot of discussion of the equivalent peaker method back in the '60s? Did you use that methodology to develop the earlier hydro plants, did we?

MR. BURGESS: It's my understanding that Gulf is saying that the plants that are embedded at this point were not, that the choice of the plant was determined under a process that would not lend itself to the economic considerations that we're dealing with today. And I'm simply trying to find out precisely what economics processs or economic considerations were being brought into the determination of which plants to, what type of generating plant to build.

CHAIRMAN WILSON: Well, let's move on along here. (Pause)

Q (By Mr. Burgess) Mr. Howell, are all demand loads projected to be served by the Southern System included in the generation expansion analyses conducted by Gulf? Are all of the demand loads that are projected to be served by the system, included in the expansion analyses?

A You mean the territorial load of our customers; is that included?

Q Yes.

A The territorial load is included. I'm not sure I understand if I'm answering your question or not.

Q You are. Are you including the interruptible demand?

A Well, as far as the generation expansion plan, we include all the demand, but the interruptible, we recognize that that's a nonfirm load, so we can interrupt that. So from that standpoint, it is not a load that we would commit generation to serve. Does that answer your question?

A Yes, it does. Thank you.

In determining the most economic plant to build, do you include the interruptible load as one of

the anticipated loads that will be served under the various alternatives?

A As far as the demand, we are talking about?

Q No, as far as what the total overall cost of the various alternatives would be.

A I'm sorry, I don't understand then.

COMMISSIONER GUNTER: I think he's trying to say when you're doing your planning, you've got a bucket over here with demand in it.

WITNESS HOWELL: Firm demand?

COMMISSIONER GUNTER: Firm demand.

WITNESS HOWELL: Okay.

COMMISSIONER GUNTER: Now, do you include any interruptible demand when you're deciding what kind of plant to build? Do you plan capacity for interruptible load?

WITNESS HOWELL: We don't plan to meet the interruptible load, no.

COMMISSIONER GUNTER: Do you plan capacity to meet interruptible load?

WITNESS HOWELL: We would not add capacity to meet the interruptible load.

COMMISSIONER GUNTER: Do you plan capacity -- do you plan interruptible demand in your capacity expansion plan?

WITNESS HOWELL: Well, all of the energy associated with that, we do. I don't understand the question.

COMMISSIONER GUNTER: I'm trying to ask it every way. Do you -- when you have a generation expansion plan, do you look at interruptible, that interruptible --

WITNESS HOWELL: Yes, sir, we take it into account. We take everything into account.

COMMISSIONER GUNTER: So you build capacity for interruptible load? If you're considering it and it's all in the demand component.

WITNESS HOWELL: We would not -- for example, if we were adding capacity to meet 20% reserve margin, we would not put in capacity to serve the interruptible load because it is not going to be there.

COMMISSIONER GUNTER: Great. Okay. Great. I apologize. I just had to keep --

WITNESS HOWELL: Yes, sir, I think everytime I testify, I have trouble with at least one question.

MR. BURGESS: I have trouble with at least one witness.

WITNESS HOWELL: I'm glad it's not me this time.

COMMISSIONER EASLEY: We're setting records.

CHAIRMAN WILSON: We always have trouble with at least one lawyer.

COMMISSIONER GUNTER: Yeah, but he gives me a ride on his --

MR. BURGESS: Take that to heart.

COMMISSIONER GUNTER: Yeah, but he gives me a ride on his truck.

Q (By Mr. Burgess) Is it correct that the generation expansion analyses are not run for any particular subset of hours each year?

A I'm sorry, what now?

Q When you are determining the economic considerations of the various generation expansion possibilities, in that analysis, do you run the analysis for any particular subset of hours for each year?

CHAIRMAN WILSON: Of "yours"?

MR. BURGESS: Pardon?

CHAIRMAN WILSON: Of "yours"? Of "ours"? Oh, you mean "hours."

COMMISSIONER GUNTER: Wait until 10:30.

WITNESS HOWELL: I need a clarification there. I don't know if you're talking about the capacity determination based on the demand, or if you're talking about the production cost associated

economical analysis. Which one are we talking about?

Q (By Mr. Burgess) The latter.

A The latter?

Q Yes.

A When we do the analysis, depending -- in the mix program, yes, it does separate the year into typical periods so that the method of doing production cost analysis, which is a probablistic type technique, will more accurately capture the expected production cost. So from that standpoint, it divides the year into proper periods to get a little bit better picture of the production costs. If we only looked at one period in a year, it would not give a very accurate picture of the production costs.

Q So it does include all the energy anticipated to be sold in a given -- in all the years for which the particular alternatives would be in effect?

A Yes, it looks at all the territorial load that we anticipate having an obligation to serve.

Q Now, you're familiar with the equivalent peaker and the refined equivalent peaker methods of classifying the costs of baseload generating units, aren't you?

A No, sir.

Q You're not?

A That's correct. My testimony was addressing the system planning considerations, and I'm familiar with that. All the other stuff they do, you need to talk to maybe some other witness that we've sponsored.

Q Would you explain what you mean on Page 57 of your testimony, beginning on Line 9 where you indicate that it hardly seems fair for a customer who pays only the load capacity cost of a CT to enjoy the benefits of low cost coal energy that flow from the higher priced baseload unit?

A Well, in the method proposed by Mr. Wright, he's proposing, based on his testimony, that all demand-related costs be associated with whatever the demand is, and then if you have a unit that's not a baseload unit, that you take the sum equivalent cost, which I'm not sure exactly how they get, and include that as a demand-related cost. And then, whatever investment is left over, after you've taken out whatever part would apply to a peaking equivalent, you put that investment and recover that through the energy cost.

Basically what that's doing is asking a customer who is -- uses off-peak energy, is going to pay more of the capacity charge, it's asking him to pay higher capacity charge and still pay for the high cost

energy associated with the CT.

To my way of thinking, if a fellow is going to be charged for the full cost of a baseload unit, and another customer is not, I would want to take all the coal-generated energy for myself, since I paid for the baseload unit, and then let the fellow that paid for the CT pay for the cost of the energy associated with the CT. And that was what I was saying; it just hardly seems fair.

Q Is this residential class a low load factor class?

A I don't know what the load factor is. I'm not the witness for that.

Q Do you know what the various classes' allocated responsibility of the production costs are under the equivalent peaker or the refined equivalent peaker methods?

A I don't even understand the terms you are using. I'm sorry. (Pause)

Q Well, if -- if a particular customer class is receiving the benefits of the -- of the low -- excuse me, strike that.

With regard to your particular criticism that you have a problem with a customer who pays only the load capacity costs of a combustion turbine, then

enjoying the benefits associated with fuel from a higher capital cost baseload unit, do you know whether that's happening, if you don't know what the particular portions of those costs that each customer class is bearing?

A Well, I think it goes back to what I said earlier in that testimony, if you'll look at Page 6 -- I'm sorry, on Line 6 there, and my testimony there was my understanding, and you can correct me if I'm wrong, it says basically what he, Mr. Wright, is proposing, is that customers with sharp peaks pay the construction costs of the peaking unit, and customers with flat load pay the construction costs of a coal unit.

Now, that's the impression I got from reading his testimony. And based on that, you're asking customers that have a sharp peak to only pay the cost of a CT. You're asking customers with a flat load shape to pay the cost of a coal unit. And to me, if you're going to segregate what kind of plant they buy, they ought to get the energy out of it. And that's what I was saying is a little unfair to me.

COMMISSIONER BEARD: That's a new concept, we have load-bearing customers?

WITNESS HOWELL: I'm sorry, what? Load-bearing members maybe?

CHAIRMAN WILSON: Sharp peaks.

MR. BURGESS: Thank you, Mr. Howell. That's all we have.

CHAIRMAN WILSON: Mr. Palecki?

CROSS EXAMINATION

BY MR. PALECKI:

Q When Gulf was evaluating the purchase of Scherer, did Gulf consider peaking capacity as an alternative in its analysis?

A Going back to that time frame, the answer is yes, we did consider it and we rejected it.

Q And when was peaking capacity considered as an alternative?

A I can't really give you an exact time frame. We were aware that the fuel -- basically in 1973, if we'll go back to that time frame -- when the Arab oil embargo sharply increased the price of oil, and then in 1979 when you saw oil prices again double and almost triple, our estimates at that time said that combustion turbines would not be cost effective compared to baseload units because of the expected prices.

I think in about 1985 we saw a significant decrease in the price of oil and, therefore, the expected future price of oil. Sometime in that time frame in '85 is when, based on the estimates for

future, that we felt CTs were an economically viable option.

I do recall that in 1984 we discussed CTs, we evaluated them. There was a lot of concern on our part about what's going to happen to the price of oil.

I think this Commission shared our concern. They were pushing sales into Florida. Nobody knew what was going to happen to the price of oil except we were concerned it was going to rise. And I guess I can't give you an exact date as to, you know, at this point we didn't consider it; at this point we did. I've tried to give you a feel for what our thinking was in that time frame.

MR. PALECKI: We would ask for a late-filed, Documentation of Analysis of Peaking Capacity as an Alternative to Purchase of Scherer. And any documentation of that analysis you may have in your files would satisfy that request.

CHAIRMAN WILSON: That would be Late-filed Exhibit 617.

(Late-filed Exhibit 617 identified.)

Q (By Mr. Palecki) Are nuclear plants and hydro plants included in Exhibit J of the IIC as "owned fuel plants," by each company?

A Let me turn to that, okay?

MR. HOLLAND: Did you say hydro and nuclear, is that -- I didn't catch that.

MR. PALECKI: In the question, yes, nuclear plants and hydro plants.

A Exhibit J, you said, to the interchange contract?

Q Yes.

A That's right.

Q Exhibit J of the IIC.

A Do you have a line number there you're reading from?

Q No, I don't.

A I'm sorry, what was the question again?

Q Are nuclear plants and hydro plants included in Exhibit J of the IIC as "owned fuel plants" by each company?

A Okay. That's Line 3-B. No, that is not true.

Q Is that the same answer for both nuclear plants and hydro plants?

A Well, the hydro is included in Section Two.

The nuclear is included as a capacity there. It is a fuel plant so it's part of the owned fuel plants. Mr. Parsons testified earlier that it's not included and he was referring to the capacity pricing.

We need to be sure we keep all this straight in that the price of the nuclear units does not appear -- is not a part of the calculation to determine the price. It has to be a part of the calculation to determine what your load responsibility is because it obviously serves some load, so it is part of that.

Q Let me make sure I have the answer correct. Nuclear plants are owned fuel plants; hydro plants are not.

A As far as the capacity that is true. Not the pricing.

Q On Page 26 of your rebuttal testimony you said that Scherer allows Gulf to avoid the need to add capacity between now and the mid-1990s.

If Gulf did not own 212 MW of Scherer, what capacity would have to be added before 1995?

A Well, the Scherer capacity, along with all the other capacity on the system, is what I'm referring to. Obviously, if we did not have enough capacity on Southern between now and 1995, we would have to add some kind of capacity to satisfy our requirements. Scherer is one, is part of the capacity which we have, which allows us to not have to add other capacity.

COMMISSIONER BEARD: Let me ask that differently if I can, maybe we can get there faster.

My understanding is with Daniel included, and with Scherer excluded, you have 20% reserve margin?

WITNESS HOWELL: Commissioner, I'm not sure what the number is. I will agree with Mr. Parsons that if we did not have the 63 megawatts, if we sold it, there is adequate capacity that we could buy from the pool to where reliability would not be endangered. I do not know what the number is. We could calculate it, if you'd like.

COMMISSIONER BEARD: I've seen it on a document, and I think it was without UPS sales 25 or 28, and with UPS sales it was around 20%. At any rate my point would be this: Given that that were true, just as a hypothetical or subject to further re-examination or whatever, subject to verb, you're within the range of 20 to 25%, right?

WITNESS HOWELL: Yes, sir.

COMMISSIONER BEARD: If Scherer didn't exist on the face of the earth, never even been dreamed about, what would you add between now and 1995?

WITNESS HOWELL: If the entire unit were not there?

COMMISSIONER BEARD: Never even heard of Scherer, doesn't exist, never heard of it, never thought about it, but you have to decide today what

you're going to add between now and 1995 to meet your overall system needs, which is not only reserve but it's also demands of varying kinds.

WITNESS HOWELL: Just Scherer 3.

COMMISSIONER BEARD: Just Scherer 3. Everything else is equal.

WITNESS HOWELL: That's 800 megawatts. Well, as I recall, the system reserves are about 20%. If it weren't there at all, it might have made a difference in what we committed to sell. I doubt that we would add anything if Scherer 3 weren't there because we're within a reasonable range.

COMMISSIONER BEARD: Okay. I tried and failed. It's your turn.

WITNESS HOWELL: I thought I answered that. I'm sorry.

Q (By Mr. Palecki) I would like to ask the same question that Commissioner Beard just asked, but only in terms of Gulf's portion, and not in terms of the entire Southern System.

A We would not add anything if we just didn't have that. If we didn't have that in all of our other resources, if you kept chipping away at what we now have, we might have to add something. But it's part of the resources that we have that allow us not to have to

add anything, and that's the point.

COMMISSIONER BEARD: Okay. Let's assume that we put the 63 megawatts in rate base, okay, as you've requested. My understanding is that between now and 1995 you plan on adding some peaking capacity?

WITNESS HOWELL: In 1995.

COMMISSIONER BEARD: But now you're telling me if we -- if the Gulf portion of Scherer didn't exist, you wouldn't add anything.

WITNESS HOWELL: We wouldn't add anything now, if, in fact, we didn't have any of the 800 megawatts on the Southern System, and we were 800 megawatts short, and there were -- and the unit power sales is not a consideration, by '94 we probably would add something. I'd have to look at it.

COMMISSIONER EASLEY: What would you add by '94. Guess.

WITNESS HOWELL: If we didn't have Scherer 3. We'd add a combustion turbine.

Q (By Mr. Palecki) How much of Scherer 3 is dedicated to territorial service in late 1994? (Pause) Would you accept, subject to check, 177 megawatts?

MR. PALECKI: We have 17 megawatts.

COMMISSIONER BEARD: Scherer 3.

MR. PALECKI: Scherer 3. Exhibit No. EBP-1,

Schedule 10.

WITNESS HOWELL: Commissioner, 177, that's the right number but that's what's sold, so the part that's committed to territorial would be the difference in 212 and 177. For the record, that's 35, unless I made a mistake. You said in late 1994. I assumed up meant like the last half of the year.

MR. PALECKI: Correct.

WITNESS HOWELL: 35.

Q (By Mr. Palecki) Would having an additional 35 MW on the system allow you to avoid building a plant?

A Avoid building which plant now? In 1994 we're not going to add anything.

Q A peaking plant in 1994.

A I'm sorry, I don't understand the question.

Q Well, you just said without Scherer you would add a peaker in '94. Now we find out that the only amount of Scherer that's included in the territorial service is 35 MW.

A I think we're confusing what we do on Gulf, with what we do on Southern, and if we did not on Southern have Scherer 3, then my best guess is yes, we'd add a combustion turbine in 1994 because we would be short of capacity below what we expect our range to

be.

Q Would you add a combustion turbine for 35 MW?

A On Southern, no. I doubt that. We might. You know, well, Gulf is part of Southern, if we're right on the edge of needing to add capacity, at some point you've got to add capacity. And I think all of us realize that you probably wouldn't add capacity if you're one megawatt short but at some point you're going to be over a hump you say you need to add capacity. So for 35 megawatts, that's a small amount on Southern. We always look at what might be available on Southern before we make any decisions to add capacity.

Q I'd like to ask for another late-filed. Could you please provide an exhibit which shows the effect of a 10 W cogenerator, the effect a 10 W cogenerator would have on Gulf's capacity receipts through the IIC --

COMMISSIONER EASLEY: Didn't you ask for this earlier?

COMMISSIONER GUNTER: 10 megawatt.

MR. PALECKI: 10 megawatt cogenerator, the effect the 10 megawatt cogenerator would have on Gulf's capacity receipts through the IIC if that 10 megawatts were included as a capacity resource to Gulf.

MR. HOLLAND: Isn't that what you asked for?
COMMISSIONER EASLEY: I don't remember.
CHAIRMAN WILSON: The reason I had this sounds really familiar.
MR. PALECKI: This has already been included.
MR. HOLLAND: There were late-fileds that were right together, and I think the second one Commissioner Easley asked for is identical to what you just asked for.
MR. PALECKI: This is on an iter that we have been requested by --
CHAIRMAN WILSON: Well, go ahead, we'll give it an exhibit number. If it's a duplicate, then you only have to give one or make two copies. I don't care.
MR. PALECKI: We'd like like you to provide this in the same form as Exhibit J of the IIC.
(Late-Filed Exhibit No. 618 identified.)
WITNESS HOWELL: That's a 10 megawatt cogenerator added to Gulf's system for which year?
MR. PALECKI: Included as a capacity resource to Gulf in 1990.
CHAIRMAN WILSON: I have that as Late-filed 586 already.
MR. PALECKI: This is an item that Bob Trapp

wants.

CHAIRMAN WILSON: We can go ahead and leave it with both numbers. Only supply it once.

WITNESS HOWELL: This is with the assumption that it is a capacity resource. I think we've testified earlier that if somebody came to us in 1990 we would say we don't need capacity right now, we wouldn't put it in. But if you want to make the assumption, am I understanding the hypothesis right?

MR. PALECKI: That is correct.

CHAIRMAN WILSON: You had previously asked for that exhibit from Mr. Parsons?

CHAIRMAN WILSON: And you had previously asked for that exhibit from Mr. Parsons?

COMMISSIONER EASLEY: In a different --

COMMISSIONER GUNTER: It was in a different context, though, because in that time period we were talking about the capacity equalization and what it would do if you added additional capacity? And I think the increments were the same, 10 and 20 megawatts, and what it would do to that equalization process that would take place throughout the -- we wasn't counting Savannah. We thought there weren't but five companies; but we found out, after reviewing you all's pretty little thing, six companies in the Southern Company.

MR. HOLLAND: Five operating companies.

(Discussion off the record)

MR. PALECKI: So this is a separate late-filed, since it is the effect of the plant on IIC?

CHAIRMAN WILSON: Yes.

WITNESS HOWELL: Is that 618?

MR. PALECKI: Yes.

(Late-Filed Exhibit No. 618 identified.)

Q (By Mr. Palecki) Is it correct that under the IIC the energy charges Gulf pays to Southern when Gulf buys power from the pool are based on the Southern system's hourly economic dispatch sequence?

A Well, we don't use those terms, but it's certainly based on, all the dispatch is based on the economic, the system economic dispatch; and the price that we pay is governed by what units are dispatching.

Q Is it correct that under the Company's IIC, the capacity charges Gulf pays to Southern when Gulf buys from the pool are based on monthly equalized reserves?

A Yes.

Q Is it correct that, for a significant portion of the costs incurred by Gulf when the Company is buying power, that seasonal rates charged to the ultimate customer are not tracking costs in the way

they are incurred?

A I don't know anything about seasonal rates. Mr. Haskins could probably address that. I can talk about the payments we make in the interchange.

Q Well, the reason I'm asking you is that, when we asked Mr. Haskins these questions, he referred us to you. And I could specifically refer to Mr. Haskins' testimony, he said that Mr. Howell would be able to answer these.

COMMISSIONER BEARD: Then he lert.

(Laughter)

COMMISSIONER GUNTER: Are you saying he lied?

(Laughter)

WITNESS HOWELL: I'll be glad to explore this with you and tell you what I know, but there's a lot I don't know about ratemaking and rate setting.

MR. HOLLAND: I know there was an interrogatory response that asked the same question that we responded to, and for the life of me, I don't know --

WITNESS HOWELL: We did have an interrogatory response and I don't know exactly what it said. But it said something to the effect of, "Why do you not have seasonal rates in the interchange?" And we did respond in there, as I will say now, that we base it on

the cost that's incurred. And this question came up again, I recall, in my direct. We charge capacity prices based on the cost that's incurred. And if the plant is there year-round, then we charge it year-round.

You might think of capacity as something that maybe you borrow money to go build and the banker comes around every month and says, "Pay me the interest on the money you borrowed." And from that standpoint, the capacity costs you on a monthly basis, so we charge on a monthly basis. And all this, of course, is in strict accordance with what FERC allows and approves.

Now, as to why that's different from the seasonal rates from the standpoint of energy costs, energy costs are very much, if you will, seasonally adjusted in the interchange. Our costs are higher in the summer, so we charge accordingly whatever the prices are. They're lower in the off peak typically because you have fewer of your higher-cost units dispatching.

Other than that, I really don't know that much about seasonal rates. I know we have a winter/summer differential -- or I know we used to. I have no idea how they calculated it.

MR. PALECKI: We have no further questions.

CHAIRMAN WILSON: Questions, Commissioners?

COMMISSIONER BEARD: Real quick.

CHAIRMAN WILSON: Five minutes?

COMMISSIONER BEARD: Yeah. Scherer 3, you got 149 megawatts right now that are UPS sales, okay?

WITNESS HOWELL: Right.

COMMISSIONER BEARD: Tell me how the dollars flow.

WITNESS HOWELL: Basically, we charge the customer in accordance with how Mr. Dawson told you we make up the capacity charge. That is paid -- that is charged to the off-system purchaser, FP&L and JEA.

COMMISSIONER BEARD: And it's charged at the Scherer 3 rate?

WITNESS HOWELL: Well, yes. All those components he talked about, which include allocation of general plant and all the things that are applicable to that.

COMMISSIONER BEARD: And then Southern System pays Gulf?

WITNESS HOWELL: Yes, sir. I think -- the contract specifies, and I don't recall, that FP&L has to wire the money to SCS to an account they have set up; and I don't know how SCS gets the money to us, but Arlan could probably tell you that.

But SCS just serves as a collection agent for the companies. Because, particularly like in FP&L and JEA, three different companies are making sales of capacities that they have; so SCS charges, they get one check, if you will, over the wire from the customer and then SCS allocates the money out based on who is providing what. But it is very much based on the incremental cost of the unit.

COMMISSIONER BEARD: When it gets to Gulf Power, where does it go?

WITNESS HOWELL: Mr. Scarbrough is coming up after me and I don't know what he does with the money.

COMMISSIONER BEARD: Above the line? Below the line?

WITNESS HOWELL: Okay.

COMMISSIONER BEARD: Wait on Mr. Scarbrough, right?

WITNESS HOWELL: I think it will be best. Because I do know that the capacity associated with that is not in the territorial rate base. He is very familiar with the accounting of that.

COMMISSIONER BEARD: That's fine, I don't have anything further.

CHAIRMAN WILSON: Redirect?

REDIRECT EXAMINATION

BY MR. HOLLAND:

Q Mr. Howell, in response to Commissioner Beard's question, though, you are aware that the unit power sales is a separate jurisdiction from the retail?

A Yes.

Q In that the revenues derived from the UPS sales would not be allocated to or put into the retail revenue side?

A That's my understanding, as the cost of the capacity is not in the rate base, also. So it's consistent.

Q Okay. With respect to some questions you were asked by Mr. Burgess, how many of Gulf's generating units resulted from the planning method described by Mr. Wright in his testimony?

A None.

Q Would the equivalent peaker method that he is advocating cause more or less of the CTs or the peakers to be built on Gulf's system long-term?

A Well, if we go to what he is saying, it will cause more CTs to be built because it will send the signals to the customer that there's no problem with using energy or capacity over the peak. And you'll find that you'll have a peakier type of load shape. You'll get off of coal, you'll get on to oil. In the

future, you'll wind up building more CTs, you'll have a higher demand, and that would be the result of that.

MR. HOLLAND: That's all I have.

CHAIRMAN WILSON: Anything further? All right, thank you very much. You may step down.

How much cross examination do you have for Mr. Lee?

MR. BURGESS: None.

MR. PALECKI: None.

COMMISSIONER EASLEY: He said none.

CHAIRMAN WILSON: All right, call Mr. Lee.

MR. HOLLAND: If no one has any questions, do the Commissioners -- he's got a summary of his testimony, we need to give him that opportunity.

MR. PALECKI: We have no objections to his prefiled testimony being inserted into the record.

MR. HOLLAND: Let me confer with him for just a minute. (Pause)

MR. HOLLAND: We can just stipulate his rebuttal in, we'll send him home.

CHAIRMAN WILSON: All right, we'll do that. Thank you. Without objection, the rebuttal testimony -- wait a minute, I want to see your chart (Laughter).

COMMISSIONER BEARD: That's enough, back away. That's really good.

COMMISSIONER EASLEY: I can understand that one.

CHAIRMAN WILSON: Without objection, his rebuttal testimony is inserted into the record and the exhibits have already been stipulated?

MR. HOLLAND: Yes.

(Exhibits Nos. 126 through 128, inclusive, stipulated into evidence.)

GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
Colen R. Lee
In Support of Rate Relief
Docket No. 891345-EI
Date of Filing May 21, 1990

Q. Please state your name, business address and occupation.

A. My name is Colen R. Lee and my business address is 500 Bayfront Parkway, Pensacola, Florida 32501. I am General Manager of Power Generation for Gulf Power Company.

Q. Are you the same Colen R. Lee who testified previously in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. My purpose is to rebut the testimony of Mr. Helmuth W. Schultz, and Ms. Roberta S. Bass and the positions taken by them with respect to issues raised in this case within the production function.

Q. Have you prepared an exhibit that contains information to which you will refer in you testimony?

A. Yes.

Counsel: We ask that Mr. Lee's Exhibit, comprised of 3 schedules, be marked for identification as Exhibits 126-128 (CRL-2).

Q. Beginning on Page 18 of his testimony, Mr. Schultz talks about turbine and boiler inspections. Mr. Lee, do you agree with Mr. Schultz's testimony?

A. No. Mr. Schultz makes a conclusory statement that the $5.34 million budgeted in 1990 for turbine and boiler inspections is not reasonable. His analysis does not even attempt to review the work that has been budgeted. Mr. Schultz has no experience in the construction, operation or maintenance of power generation facilities. I have been employed in some area of generating plant engineering, maintenance and supervision for twenty five years. My Department Management Staff collectively, has 1,793 years of generating plant experience which averages approximately 20 years per person.

Q. Mr. Lee, what should the Commission allow for turbine and boiler inspections?

A. As I stated in my direct testimony, since 1984 Gulf has performed our turbine and boiler inspections essentially as scheduled and all necessary work was

performed. Gulf budgeted $5.34 million for turbine and boiler inspections for 1990. The 1990 budgeted amount is reasonable and should be the amount allowed by the Commission. We estimate that Gulf's actual territorial turbine and boiler inspection expense for 1990 will be over the 1990 budget of $5.34 million. These expenses are for turbine and boiler work that is necessary in 1990. Therefore, I can assure the Commission that the $5.34 million that was budgeted for turbine and boiler inspections is not unreasonably or unrealistically high.

Q. Beginning on Page 19, of his testimony, Mr. Schultz addresses Plant Daniel. Mr. Schultz testifies that Gulf does not have any control over the Plant Daniel expenses. Mr. Lee, do you agree?

A. Absolutely not. Mr. Schultz has taken the discussion of Plant Daniel contained in Mr. Gilbert's deposition, taken in Docket 881167-EI, out of context. Mr. Gilbert was explaining the difference in documentation produced in the 1989 budget process for "Corporate Controlled" items; that is, expenses controlled external to Gulf's normal budget process. Mr. Schultz's misapplication of this discussion to the reasonableness of the Plant Daniel expenses results in a distorted and misleading

picture of the interaction between Gulf and Mississippi Power concerning the operation and maintenance of this jointly owned facility.

As an active participant on the Supervisory Committee that reviews all of the operating aspects of Plant Daniel, I can unequivocally tell the Commission that we review the budgets submitted to Gulf from Mississippi Power for reasonableness. Throughout the year, we review the budget comparison report regarding Plant Daniel expenditures versus budget.

I assure this Commission that through my participation in the oversight of Plant Daniel, Gulf does have input and control over the expenses budgeted by Mississippi Power for Plant Daniel. Our control is not exclusive, nor should it be, since Mississippi's ownership in the Plant is equal to ours. I would also point out that Mississippi answers to both Gulf and to their own commission with regard to the reasonableness and appropriateness of the expenses related to Plant Daniel. Mississippi Power has every incentive to control these expenses. It is unreasonable to assume or imply that the operation and maintenance activities at Plant Daniel have been conducted on anything but the most professional and prudent basis. Based on my experience in this area of electric operations, and my

participation in the oversight process for Plant Daniel, I can assure this Commission that this is the case.

Mr. Schultz's proposed adjustment for these expenses is nothing more than treating the benchmark as an absolute limit on spending. He makes no attempt to analyze the justifications provided for the benchmark variance of $646,000 which he seeks to exclude. Thus Mr. Schultz ignores the Commission's characterization of the benchmark as an analytical tool.

As shown in MFR C-57, on page 44 of 94, Plant Daniel has three benchmark variances listed that total $877,000. These variances are $231,000 more than the overall Plant Daniel total benchmark variance of $646,000. Two of the three benchmark variances for Plant Daniel are items which are necessary due to regulatory requirements. The ash landfill is necessary due to new environmental regulations that make adding ash pond capacity virtually impossible. The sodium fuel additive is utilized to meet environmental regulations concerning particulate emissions.

The third item discussed in the Company's justification for the Plant Daniel variance, turbine and boiler, is over the benchmark because the amount of work planned on Unit 1 at Plant Daniel is much more

extensive than the work budgeted in 1984. The 1984 amount formed the base for the benchmark calculation. As stated in MFR C-57, the 1984 allowed figure included only a turbine valve inspection for Daniel Unit 1. As also stated in MFR C-57, the 1990 budget for Daniel turbine and boiler work includes work on the Unit 1 low pressure turbine, boiler feedpump turbine and generator, all in addition to the turbine valve inspection. From a review of the material, it is apparent that the overall benchmark variance for Plant Daniel is more than justified.

Q. Mr. Schultz implies that Gulf does not have the right to audit Plant Daniel expenses or billings. Is this implication correct?

A. Again, absolutely not. We certainly have the right to conduct an audit, or to have one conducted. For manpower efficiency purposes, we have relied on the audits performed on our behalf by Southern Company Services. The results of these audits and our own direct involvement in the oversight process have not given us any reason to question the appropriateness of Plant Daniel expenses from any standpoint. Certainly, with this background, it would be unwarranted on our part to duplicate the audit performed by SCS.

Mr. Schultz does not challenge any of the expenses at Plant Daniel. He criticizes the process as he understands it; an understanding which is clearly wrong. The expenses at Plant Daniel are reasonable, justified, and should be allowed in this rate case.

Q. At page 26 of his testimony, Mr. Schultz questions whether the Company has taken the appropriate steps to determine the propriety of the budget for Plant Scherer steam production expenses. Has the Company taken the "appropriate steps"?

A. Yes. Each year Gulf reviews the budget for Plant Scherer, that was prepared by Georgia Power, for reasonableness. Not only was the first year's budget reasonable, but as shown in my attached Schedule 3 (CRL-2), the budgeted expenditures for Plant Scherer have decreased each year since the unit started up in 1987.

Q. Beginning on Page 35 of his testimony, Mr. Schultz proposes an adjustment related to the Southern Company Services benchmark variance for Generating Plant Electrical System Application. Mr. Schultz suggests disallowance of the $44,000 related to this work. Mr. Lee, do you agree?

A. No. As stated in MFR C-57 and the Company's response to Public Counsel Interrogatory 231, attached as Schedule 2 (CRL-2), this type of work is specialized and Gulf cannot justify directly employing personnel for this type of specialized work. Our engineering staff is well educated, well trained, experienced and dedicated to their profession. They are knowledgeable in most areas of power plant work. This is a unique area in which our otherwise qualified engineers are not well trained and, therefore, specialists are needed. Gulf, due to our size, cannot cost justify employing personnel to perform this specialized work. Through the economies of scale available to SCS by virtue of its work throughout the Southern Electric System, the expertise of these specialists is made available at a much lower cost than would otherwise be possible, to the ultimate benefit of our customers.

Q. Beginning on Page 52 of his testimony, Mr. Schultz begins addressing ash hauling and storage at Plant Smith. Mr. Schultz states that the ash hauling at Plant Smith is excessive. Mr. Lee, do you agree?

A. No. We budgeted in 1990 for the amount of ash that we expect to dig from the ash pond and haul to the ash landfill. In the past we had a contract to dig, haul,

spread and compact ash at a cost of approximately $2.48 per cubic yard of ash. We utilized this amount with an inflation factor times the amount of ash to be hauled. For 1990 budgeting purposes, Gulf estimated roughly $2.65 per cubic yard since the previous hauling contract was ending and a new contract would be bid. Therefore, in reviewing our past expenses and present budget I strongly believe that these expenses are justified, not excessive and should be allowed by the Commission.

Q. On page 59 of his testimony, Mr. Schultz lists an amount of disallowance for fan and duct repair. Mr. Lee, do you agree?

A. No. The amount budgeted of $1,109,000 is the amount Gulf needs to properly maintain our equipment. The full justification for the increased spending in this area is set forth in MFR C-57, pages 54 through 56 of 94. I do not believe that the Commission should make any disallowances to the expenses budgeted for fan and duct repair. Mr. Schultz's practice of using a historical average analysis ignores the fact that, as our plants age, the need for this type of work increases. This practice should be rejected by the Commission. These expenses are reasonable, justified,

not excessive and should be allowed by the Commission.

Q. Beginning on page 78 of his testimony, Mr. Schultz addresses condenser and cooling tower corrosion at Plant Crist. Mr. Lee, should any disallowances be made to this item?

A. No. Mr. Schultz in his testimony could not reconcile the difference between the 1989 and 1990 budget for this work. The method used to calculate the reduction between 1989 and 1990 is shown in Schedule 1 of my exhibit (CRL-2). Also shown in this schedule are the actual expenditures for this work by year for the period 1984 through 1989. As can be seen in this schedule, since 1984, we have consistently made these necessary expenditures. Our budget for 1990 is justified, not excessive and should be allowed by the Commission.

Q. Ms. Bass questions Gulf's doing business with Stock Equipment Company while its President is a member of Gulf's Board of Directors. Ms. Bass acknowledges that such business should not be prohibited, but suggests that any transactions be at arms length. Does Gulf Power maintain an arms length position in its transactions with Stock Equipment?

A. Yes. For various reasons, many items of major equipment are best maintained with parts and service supplied by the original equipment manufacturer (OEM). Stock Equipment is the OEM for several pieces of major equipment installed at Gulf's plants.

Q. Has Gulf purchased any new major equipment from Stock Equipment since Mr. Tannehill became a member of Gulf's board?

A. No.

Q. Can you give me the names of a few of the other OEM from which Gulf Power purchases material and/or labor?

A. Gulf purchases material and/or labor from Westinghouse, General Electric, Allis Chalmers, Alien Sherman Hoff, Foster Wheeler, Combustion Engineering, and Babcock and Wilcox.

Q. Do you obtain competitive bids on all purchases from these vendors?

A. No. In many cases the parts or services are only available from the OEM.

Q. Does this mean you do not obtain bids from these vendors?

A. No. Competitive bids are obtained when other vendors can supply the parts and/or services.

Q. How long has Gulf Power been purchasing material from Stock Equipment?

A. Stock Equipment has been supplying material, equipment and services to Gulf Power for more than 30 years.

Q. When Mr. J. H. Tannehill became a Director with Gulf Power in 1985, did Gulf Power make any changes in any way it transacts business with Stock Equipment?

A. No.

Q. Is there any difference in the way you transact business with Stock Equipment as compared with other OEM vendors such as Westinghouse?

A. No. We purchase material, equipment and service available only from Westinghouse without competitive bids. We also competitively bid material, equipment and service that is available from other vendors. Transactions with Stock Equipment are coordinated in exactly the same manner.

Q. What about the three invoices reviewed by the FPSC auditors in their review of Gulf's transactions with

Stock Equipment?

A. Two invoices were for material supplied only by Stock Equipment for OEM equipment purchased before Mr. Tannehill became a member of Gulf's Board. The third invoice was for material and fabrication of a coal hopper. Two local vendors were contacted by the Smith Plant for bids on this item. The two bids were for $29,875.00 and $45,070.20, respectively. In order to save the difference of $15,195.20. Gulf accepted Stock Equipment's low bid.

Q. Mr. Lee, how do Gulf's annual expenditures with Stock Equipment compare before and after Mr. Tannehill became a member of Gulf's board?

A. Mr. Tannehill became a member of Gulf's Board of Directors in 1985. Gulf's annual expenditures to Stock Equipment for the three years before Mr. Tannehill became a member of the Board of Directors were $267,000. Gulf's annual expenditures to Stock Equipment for the four years since Mr. Tannehill became a member of the Board of Directors have been $226,000.

Q. Mr. Lee, please summarize your testimony.

A. My testimony continues to demonstrate that the Power Generation Department efficiently and effectively

manages its O&M expenditures. I have defended the O&M test year budget for areas within my responsibility. I have also demonstrated that Gulf's management carefully considers and evaluates all O&M expense related decisions. The decisions ultimately made by the Company are prudent, justified and necessary for optimal efficiency and production in utility operations.

Q. Mr. Lee, does this conclude your testimony?

A. Yes.

COMMISSIONER GUNTER: Mr. Chairman, I move we rise for the evening.

CHAIRMAN WILSON: We're going to adjourn and make it at 8:30 to come back.

COMMISSIONER BEARD: How much do you have for Jordan? We're on a roll.

MR. PALECKI: We have none for Jordan.

CHAIRMAN WILSON: Where is Public Counsel? Steve?

CHAIRMAN WILSON: That's all right. If you have questions, we'll do it in the morning. We're not going to rush you. (Pause)

MR. BURGESS: None. None for Jordan.

CHAIRMAN WILSON: Have you got some for Jordan (Pause)?

MR. PALECKI: No.

CHAIRMAN WILSON: You don't?

MR. HOLLAND: We have some corrections but we could give an errata sheet to the reporter, they're not substantive.

MR. BURGES: Stipulate.

CHAIRMAN WILSON: Without objection, then, the corrected rebuttal testimony of Mr. Jordan will be inserted into the record as though read.

CHAIRMAN WILSON: I believe his exhibits have

been stipulated into the record.

(Exhibits Nos. 139 and 140 stipulated into evidence.)

Record Copy

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GULF POWER COMPANY

Before the Florida Public Service Commission
Rebuttal Testimony of
Charles E. Jordan
In Support of Rate Relief
Docket No. 891345-EI
Date of Filing May 21, 1990

Q. **Please state your name, address and occupation.**

A. My name is Charles E. Jordan, and my business address is 500 Bayfront Parkway, Pensacola, Florida 32501. I am General Manager of Power Delivery of Gulf Power Company.

Q. **Are you the same Charles E. Jordan that has filed direct testimony in this docket?**

A. Yes.

Q. **Mr. Jordan, what is the purpose of your rebuttal testimony?**

A. The purpose of my rebuttal testimony is to address the testimony of Public Counsel's witnesses, Mr. Schultz and Mr. Larkin, with regard to their recommendation of certain disallowances of distribution Operation and Maintenance (O & M) expense and recommended disallowance of the investment in Greenhead substation (Leisure Lakes).

Q. **Have you prepared an exhibit that contains information to which you will refer in your testimony?**

A. Yes.

Counsel: We ask that Mr. Jordan's Exhibit comprised of 2 Schedules, be marked for identification as Exhibits 139-140 (CEJ-2).

Q. **Would you please address Mr. Schultz's contention with regard to the expense associated with underground line extensions?**

A. Yes. On page 83, lines 5 through 16, Mr. Schultz reveals his misunderstanding of the relationship between underground and overhead O & M expense. Schedule 1 of my Exhibit (CEJ-2), which summarizes the overhead and underground expenses as filed in conjunction with Gulf's Underground Differential Tariff, shows Gulf's historical experience with distribution line O & M expense. As shown on this exhibit, Gulf's six year average underground O & M expense is $2,122.63 ~~$2,100.27~~ per mile, which compares to the six year average overhead O & M expense of $1,197.84 ~~$1,227.22~~ per mile. This comparison demonstrates that the maintenance costs associated with underground lines are, in fact, considerably higher than that associated with overhead lines. Gulf's experience over the past six years has

not provided any basis to suggest that this relationship between overhead and underground maintenance will change in favor of underground in the foreseeable future.

Mr. Schultz makes a mistaken assumption regarding the reason Gulf is experiencing greater growth in the amount of new underground facilities relative to new overhead facilities. This greater growth is not because of any cost savings benefit, but rather is the result of our customers' demand for these facilities. This customer demand is met by the Company consistent with the Commission's policy of allowing the customer or developer to select underground facilities, so long as any differential cost of installation is paid up front by the customer or developer. Once the developer or customer chooses to pay this differential, Gulf is not only obligated to install the underground service but also to maintain it through its service life.

Underground distribution system failures have some significant characteristic differences when compared to overhead distribution failures. An underground distribution failure is more difficult to locate than an overhead failure, involves removing earth or other coverages in order to gain access to

the fault or failure, and introduces a source for future failures from moisture leakage at the splice. The increased labor expense associated with repairing an underground distribution failure coupled with the higher cost splice material associated with an underground repair, once again, are some of the reasons why underground maintenance is higher than overhead maintenance.

As a result, the requested level of expenses relative to this issue should be allowed.

Q. Would you please address Mr. Schultz's contention regarding the benchmark variance for distribution system work order (DSO) clearance?

A. Yes. First, Gulf would like to apologize for a typographical error in the MFR which indicated that the percentage of CWIP allocated to expense was 8.0 percent in 1984 and 12.9 percent in 1987. The actual percentage of DSO clearance from CWIP to expense in 1984 was 7.02 percent and in 1987 it was 11.66 percent. These figures and the actual amounts on which they were based are shown on Schedule 2 of my Exhibit (CEJ-2). These errors would not have affected Mr. Schultz's analysis.

Although Mr. Schultz accepts the Company's

justification for the variance, he questions our math and wrongfully concludes that our explanation leaves a portion of the variance unjustified. Additionally, Mr. Schultz has misinterpreted the statement of Gulf to which he referred in his testimony on page 81, lines 23 - 25. This misinterpretation has led Mr. Schultz to omit customer growth and inflation from 1984 to 1987 when calculating his figure. When we stated that the relative level of dollars to do the work did not increase, we included allowance for increases in cost due to the growth in customers and an increase in expense due to inflation. Therefore, Mr. Schultz is incorrect when he states that our justification does not address the full amount of the variance.

For the period 1985 through 1989, as can be derived from the data on Schedule 2 of my Exhibit (CEJ-2), 10.89 percent was charged to maintenance versus the 7.02 percent which was charged in 1984. This means the base should be increased by an additional 55.1 percent (10.89% over 7.02%) as a result of the revision in the method of allocating expense from CWIP that has occurred since 1984. The revised base should then be escalated for customer growth and inflation. The appropriate new base should be

$1,846,000. This amount, when multiplied by the customer growth and inflation factor of 1.5073, is $2,782,000. Gulf's 1990 Budget for expenses transferred from Construction Work in Progress to maintenance of $2,745,000 is, therefore, $37,000 below the appropriate benchmark. As can now be seen, our explanation does address all of the variance identified for this area of expense.

Q. **Mr. Jordan, would you please address Mr. Schultz's discussion of the O & M variance of $83,000 associated with obsolete distribution material?**

A. I would first like to point out that our $109,000 obsolete material write-off figure for 1990 is approximately ~~0.99%~~ 1.1% of our average inventory. This compares closely with the write-off figures for Florida Power & Light (1.2%) and Florida Power Cooperation (1.0%) and is reasonable.

Gulf's variance over the benchmark in 1990 is reasonable because the 1984 benchmark was non-representative of what should have been occurring with regard to obsolete material write-offs. Gulf has instituted a program to better control our inventory and save our customers from the burden of higher costs on a long term basis.

As Mr. Schultz correctly points out, Gulf Power Company did implement the Communication Oriented Production Information System (COPICS) in 1984. Throughout 1984 the COPICS system was enhanced, and the new functions were tested and modified as needed for implementation on a systemwide basis.

In early 1985 the COPICS system was installed in all of the Division warehouses as Gulf's first on-line material and inventory control system. At the conclusion of 1986, Gulf Power Company had two full years of experience with the system's material and inventory usage patterns. These two years worth of information identified some inventory items which had little or no use and allowed the Division and Corporate engineers to analyze these materials to determine whether they were truly needed in inventory as one-of-a-kind special items or whether these items were no longer usable materials for Gulf Power Company. At the end of 1987, a comprehensive analysis of these materials was completed and a decision was made to attain the best recovery possible from the sale of this material and to write-off those items which could not be sold.

Gulf Power Company acknowledges that the system in place prior to implementing the COPICS system resulted in the Company carrying obsolete and unusable

materials in inventory longer and in greater quantities than was reasonable. However, it is important to note that Gulf itself recognized and took steps to correct the situation in order to make sure that both the inventory book amount and the physical inventory in Gulf's warehouse is appropriate. This entailed a program which would require Gulf to catch up with its write-offs of obsolete and unusable materials. This catch up with write-offs occurred in 1988.

Mr. Schultz's figure of $16,485 as shown on page 58, line 7, excludes the 1988 write-off and misrepresents the situation which has occurred. He offers no evidence to support his implication that we are not purchasing appropriate quantities of materials. It should also be pointed out that, as a result of the obsolete materials identification program, Gulf has also gained the ability to immediately and more appropriately assign the proper account when charging off these materials. As a result, a shift occurred from the former practice of writing-off obsolete materials initially to the FERC 163 Clearing Account, to the current practice of writing these materials off directly to the proper O & M Accounts. The following tabulation indicates that, when combined, these

accounts average $165,555 per year in obsolete material write-offs over the past six years.

GULF'S OBSOLETE MATERIALS WRITE-OFFS

	1984	1985	1986	1987	1988	1989
O & M ACCOUNTS	$ 8,855	$ 11,167	$ 7,509	$ 5,895	$480,000	$49,000
CLEARING ACCOUNT	$17,049	$129,989	$56,399	$207,345	$ 20,157	($33)
TOTAL	$25,904	$141,156	$63,908	$213,240	$500,157	$48,967

SIX YEAR AVERAGE ---------- $ 165,555 ----------

In fact, if the entire 1988 write-off of $500,157 were excluded from the calculation, the remaining five year average would be $98,635. This figure also confirms the reasonableness of Gulf's $109,000 - 1990 Budget amount.

Q. Mr. Jordan, do you have any comments as to witness Hugh Larkin, Jr. and his statements in his prefiled direct testimony starting on page 13 with regard to the facilities initially intended to serve Leisure

Lakes subdivision, which is properly known as Greenhead substation?

A. Yes. I would like to further amplify that Leisure Lakes is a subdivision and Greenhead is a substation. Mr. Larkin apparently feels that since this particular investment was disallowed in the 1984 rate case, it should continue to be disallowed without regard to the critical fact that the Greenhead substation facilities are currently in use providing service to Gulf's existing customers and, as such are used and useful. In my prefiled direct testimony I have justified the inclusion of the Greenhead substation equipment (what he calls Leisure Lakes) and have clearly described how it does and will serve Gulf's customers in their best interest. Mr. Larkin does not contest my direct testimony, just simply ignores it.

Gulf's study of the Vernon area has clearly indicated that conversion to 25 kv distribution is in the best interest of its customers. It just so happens that the Greenhead transformer and its buswork in the substation provides the most cost effective utilization of equipment for the Vernon area distribution. Although it will take two to three years for the complete conversion of the Vernon area distribution system to 25 kv, in the interim, as the

conversion takes place, the Greenhead substation will be picking up greater portions of the Vernon distribution customers, even as it sits at Greenhead. In addition, the Greenhead substation transformer and facilities at this time not only back-up the Sunny Hills 25 kv subdivision, but also pick-up, on a daily basis, some of the Vernon area distribution load through the Moss Hill autobank transformer.

The alternatives to utilizing the Greenhead transformer facilities in Vernon are far more expensive but would, in future rate proceedings, be included in rate base since this improvement is legitimately justified for the service conditions in the Vernon area distribution system. If the Commission should accept Mr. Larkin's recommendation on this issue, Gulf will certainly be back to the Commission with an alternative solution requested for rate base inclusion which will, in fact, cost Gulf's general body of customers more than if Gulf were to utilize the Greenhead substation equipment in the Vernon area as I have discussed both here and in my direct testimony.

Gulf Power Company does not contest Mr. Larkin's statement that in Docket No. 830484-EU, the Commission did rule in favor of the rural electric cooperative with regard to Leisure Lakes subdivision. What Gulf

would like to point out is that we have used and continue to use the Greenhead substation (which Mr. Larkin continues to refer to as Leisure Lakes) for the useful function of back-up to the Sunny Hills subdivision and also to add reliability support to the Vernon area distribution system. What Gulf would like to point out is that we have subsequently found an additional very valuable and useful function for those facilities directly in the Vernon distribution area where the equipment will continue to provide back-up to Sunny Hills while further improving the service to the Vernon area distribution customers.

The conversion to 25 kv in the Vernon area would commence whether or not the Greenhead substation facilities were available for utilization in the conversion. The point is that if the Greenhead substation facilities were not available, it would increase the cost to our general body of customers to provide the upgraded capacity and to back-up Sunny Hills. Gulf's customers are fortunate that the Greenhead facilities are available to make this service improvement at a lower cost then would otherwise be possible.

Q. Mr. Jordan, does this conclude your testimony?

A. Yes.

COMMISSIONER GUNTER: Are we going to have the late-filed exhibits I requested of Mr. Conner, are we going to have those in time for his testimony tomorrow?

MR. HOLLAND: He's not doing that exhibit, Mr. Scarbrough is. You've complicated it a great deal but we will make every effort to try to get it here.

CHAIRMAN WILSON: Way to go, Commissioner.

COMMISSIONER EASLEY: If Conner doesn't have the late-fileds, you still have questions?

COMMISSIONER GUNTER: Yeah.

CHAIRMAN WILSON: We will reconvene in the morning at 8:30.

(Thereupon, hearing recessed at 7:30 p.m., to reconvene Thursday, June 21, 1990, at 8:30 a.m., at the same location.)