BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 010283-EI

In the Matter of

CALCULATION OF GAINS AND APPROPRIATE TREATMENT FOR NON-SEPARATED WHOLESALE ENERGY SALES BY INVESTOR-OWNED ELECTRIC UTILITIES.
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VOLUME 2

PAGES 94 THROUGH 246

PROCEEDINGS:	HEARING
BEFORE:	CHAIRMAN E. LEON JACOBS COMMISSIONER LILA A. JABER COMMISSIONER BRAULIO L. BAEZ
DATE:	Friday, August 31, 2001
TIME:	Commenced at 9:30 a.m. Concluded at 2:29 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	JANE FAUROT, RPR Chief, Office of Hearing Reporter Services FPSC Division of Commission Clerk and Administrative Services (850) 413-6732
APPEARANCES:	(As heretofore noted.)

I N D E X

WITNESSES

EXHIBITS

NUMBER:		ID.	ADMTD.
6	Composite	143	161
7	Exhibit Attached to Witness Kordecki's Prefiled Testimony	184	221
8	Rule 25-6.035, Adequacy of	213	221
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PROCEEDINGS

(Transcript follows in sequence from Volume 1.)

CHAIRMAN JACOBS: All right, Mr. Beasley.

MR. BEASLEY: I call Mr. Brown.

CHAIRMAN JACOBS: I assume there are no objections to that order change.

MR. BEASLEY: We have discussed that with the other parties.

W. LYNN BROWN

was called as a witness on behalf of Tampa Electric Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Sir, would you please state your name, your business address, and your position with Tampa Electric Company?

A William L. Brown, Director of Wholesale Marketing. My business address is 702 North Franklin Street, Tampa, Florida 33602.

Q Mr. Brown, did you prepare and cause to be filed in this proceeding an 11-page document entitled Prepared Direct Testimony of W. Lynn Brown?

A Yes, I did.

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

A Yes, they would.

MR. BEASLEY: I would ask that Mr. Brown's prepared direct testimony be inserted into the record as though read.

CHAIRMAN JACOBS: Without objection, show Mr. Brown's testimony is entered into the record as though read.

TAMPA ELECTRIC COMPANY
DOCKET NO. 010283-EI
FILED: 04/23/01

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

W. LYNN BROWN

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

A. My name is Lynn Brown. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") as Director, Wholesale Marketing and Sales.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelors degree in Electrical Engineering from Louisiana State University in 1972 and subsequently joined Tampa Electric. I held various engineering, operations and managerial positions in Energy Delivery from 1973 through 1997. I became Manager of Short Term Wholesale Trading in April 1997 and was promoted to Director, Wholesale Marketing and Sales in August of 1998 where I am responsible for short and long-term wholesale power purchases and sales.

Q. Have you previously testified before the Florida Public Service Commission ("Commission")?

A. Yes. I testified before this Commission in Docket No. 990001-EI regarding the appropriateness and prudency of various purchased power agreements. I also testified in Docket No. 991779-EI regarding the appropriate application of incentives to wholesale power sales by investor-owned electric utilities.

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

A. The purpose of my testimony in this proceeding is to describe Tampa Electric's practices in making wholesale sales and purchases of electricity. I also describe the prudence of making concurrent wholesale sales and purchases. Finally, I discuss the appropriateness of the company's wholesale sales and purchased power practices from the standpoint of retail customers in general and interruptible customers in particular.

Q. Are there any general observations you wish to make regarding the usefulness of selling and buying power at wholesale?

A. Yes. Electricity is a unique commodity in that it is produced and then immediately consumed. Electric utilities are challenged to continuously match their power production and purchases with sales. This challenge is elevated by the fact that power production facilities are added in large blocks which, from time to time, result in a surplus or deficit of power. It is more economical to add power plants of a size that temporarily exceeds the marginal increase in system demand. Because of this, utilities enter into wholesale sales to make full use of their generating plants and, from time to time, purchase from other utilities when necessary or economical to do so. The overall goal in making wholesale sales and purchases is to keep the overall cost of electricity to retail customers as low as practicable.

<u>Tampa Electric's Wholesale Sales and Purchases</u>

Q. What circumstances are considered when determining whether to commit to a wholesale sale?

A. Tampa Electric evaluates its forecasted available generating capacity in excess of installed reserve requirements that could be offered in the marketplace.

Potential firm sales that appear beneficial are identified and pursued.

Q. Please describe the types of wholesale sales Tampa Electric makes.

A. Tampa Electric makes separated firm sales and non-separated firm and non-firm sales. Currently Tampa Electric has 320 megawatts of separated firm wholesale sales. Of this amount, 145 megawatts are unit power sales and 175 megawatts are requirements sales. These sales comprise less than 10 percent of Tampa Electric's firm load. These sales are longer than a year in duration and, thus, under the Commission's established policy, are separated from Tampa Electric's retail jurisdiction. In essence, a sale is separated to remove all generating plant and operating expenses associated with the sale from the retail jurisdiction. Since the proposed agency action portion of the Commission order that gave rise to the present proceeding only addressed the appropriate regulatory treatment for the revenues and expenses associated with non-separated wholesale power sales, separated firm sales are not being addressed in this proceeding.

Q. Please describe Tampa Electric's non-separated wholesale sales.

A. In accordance with the Commission's requirements, non-separated sales are normally less than a year in duration and may be firm or non-firm.

Q. What types of wholesale power purchases does Tampa Electric make?

A. From time to time Tampa Electric purchases wholesale firm and non-firm power to augment its existing generating assets to economically and reliably meet the needs of its customers. The company purchases power on a firm and non-firm basis, as necessary, to meet reliability requirements or to cover scheduled and unscheduled generation outages. The company also purchases power on a non-firm basis when it is less expensive than the cost of operating its own generating units. In so doing, Tampa Electric takes advantage of market opportunities that lower the cost of power delivered to Tampa Electric's customers.

Q. Does Tampa Electric make any other types of wholesale power purchases?

A. Yes. In addition to the purchases I have described, the company may, from time to time, make purchases that are classified as optional provision or "buy-through" purchases for non-firm retail customers taking service under interruptible rates.

Q. Are there times when Tampa Electric is unable to purchase "buy-through" power on behalf interruptible customers?

A. Yes. Occasionally Tampa Electric is unable to purchase sufficient energy to maintain service to non-firm customers and must interrupt their service. Non-firm customers may also be interrupted to provide state operating reserves as a result of the sudden loss of a large generating unit located within the Florida Reliability Coordinating Council ("FRCC") region. Further, these customers may be interrupted to provide emergency interchange service to FRCC member utilities that are unable to serve firm native load requirements due to insufficient generating capacity. These service requirements are described in Tampa Electric's Commission approved tariffs governing interruptible service.

<u>The Prudence of Simultaneous Sales and Purchases of Wholesale Power</u>

Q. Are there times when Tampa Electric simultaneously purchases capacity and energy for retail customers' needs while it is making firm wholesale sales?

A. Yes. Tampa Electric currently is serving long-term wholesale sales that are separated from the retail jurisdiction which yield cost savings to retail customers. There are occasions during the course of serving these long-term sales when Tampa Electric purchases power to meet reliability requirements and lower the company's system operating costs. The fact that Tampa Electric purchases power from time to time does not detract from the overall beneficial nature of its firm wholesale sales.

Q. Is it prudent for the company to make wholesale sales at the same time that it is purchasing capacity and energy?

A. Yes. Tampa Electric's capacity and energy purchases have augmented its system's generating resources to provide reliable service to customers. Capacity and energy is sometimes purchased for short periods of time to bridge the gap between generating resource additions. Additionally, Tampa Electric evaluates long-term purchase opportunities against constructing generation to serve native load. If an opportunity is advantageous, then the company may elect to purchase, rather than build generation.

Q. Is it prudent to make short-term, non-firm sales concurrently with longer-term power purchases?

A. Yes. Many power purchases require a minimum energy take or "energy put" which may, at times, cause a back down of Tampa Electric's generation. At these times, short-term wholesale sales are made to maintain native generation output at optimum levels. The resultant sales price may be more or less than the price for the purchased energy. Revenues from short-term sales help defray the cost of purchased power.

<u>Fair Treatment of Interruptible Customers</u>

Q. How are Tampa Electric's interruptible customers impacted by wholesale sales and purchases?

A. All of the company's retail customers, including interruptible customers, benefit from the company making wholesale sales and purchases. Short and long-term sales increase utilization of generating capacity. Retail customers benefit from the existence of separated sales since these sales relieve retail customers of the carrying costs of generating plant committed to these sales as well as the related operating expenses. Revenues from short-term sales are flowed back to retail ratepayers.

Q. Has Tampa Electric interrupted its interruptible customers to make any new firm separated or non-separated wholesale sales?

A. No. The only firm wholesale sales that the company is currently making have been in place for a number of years. In fact, these same sales were in place last year when the Commission concluded, in response to FIPUG's "motion for mid-course protection," that FIPUG had provided no factual support for a finding that Tampa Electric has made wholesale energy sales in violation of its interruptible service tariff or applicable law.[1] No new firm separated or non-separated sales have been entered into by Tampa Electric and, thus, the company has not interrupted interruptible customers to make any new sales.

[1] Order No. PSC-00-1266-PAA-EI issued in Docket No. 000001-EI on July 11, 2000.

Q. Does Tampa Electric have a policy of interrupting its interruptible customers in order to make non-firm wholesale sales?

A. No. Tampa Electric has a company policy of not making non-firm wholesale power sales at the same time it is interrupting its non-firm retail customers or making "buy through" purchases for them. Whenever interruptions appear imminent or "buy through" purchases are necessary, existing non-firm sales are ramped out as quickly as reasonably possible or power is bought for the purpose of continuing the sale. If power is bought for the purpose of continuing the sale, the cost is netted against the sale's revenues and retail ratepayers are not impacted.

Q. Please summarize your testimony.

A. My testimony described Tampa Electric's policies and practices as they relate to the company's sale and purchase of wholesale electric power. I described the purposes served by our sales and purchases and the appropriateness of making wholesale purchases contemporaneous with wholesale sales. Finally, I described how the company makes these sales and purchases to benefit Tampa Electric's general body of ratepayers including customers taking interruptible service.

Q. Does this conclude your testimony?

A. Yes, it does.

BY MR. BEASLEY:

Q Mr. Brown, would you please summarize your direct testimony?

A My testimony describes Tampa Electric's policies and practices as they relate to the company's sale and purchase of wholesale electric power. I describe the purposes served by our sales and purchases and the appropriateness of making wholesale purchases contemporaneous with wholesale sales. Finally, I describe how the company makes these sales and purchases to benefit Tampa Electric's general body of ratepayers, including customers taking interruptible service.

In particular, my testimony points out that Tampa Electric has not interrupted its interruptible customers to make any new firm separated or nonseparated wholesale sales. No new firm separated or nonseparated sales have been entered into by Tampa Electric. Moreover, Tampa Electric does not make nonfirm wholesale power sales at the same time it is interrupting its nonfirm retail customers or when it is making buy-though purchases for them.

Whenever interruptions appear imminent or buy-through purchases are necessary, any existing nonfirm sales are ramped out as quickly as reasonably possible or power is bought for the purpose of continuing the sale. If power is bought for the purpose of continuing the sale, the cost is netted against the sales revenues and thus retail customers are not impacted.

In short, Tampa Electric utilizes nonseparated wholesale sale and power purchases to help utilize its system and meet its customer needs in the most cost-effective way possible. Thank you.

MR. BEASLEY: We tender the witness.

CHAIRMAN JACOBS: Mr. Badders.

MR. BADDERS: No questions.

CHAIRMAN JACOBS: Mr. McGee.

MR. McGEE: No questions.

CHAIRMAN JACOBS: Mr. McWhirter.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Mr. Brown, on Page 3 of your testimony at Line 6 you talk about how a utility system works and you buy large blocks of power in excess of your current needs and then you grow into that, is that essentially what you are saying?

A I think my testimony refers to the fact that utilities often add generating capacity in blocks and they grow into that generating capacity, yes.

Q At the present time does Tampa Electric have substantial excess capacity?

A Not at the present time.

Q Does Tampa Electric have substantial excess capacity at any time in the foreseeable future?

A When our Bayside project hits the line in 2003 we will have excess capacity at that point.

Q Can you give us a brief estimate of what the situation will be at that point in time with respect to your generating capacity as opposed to the total demand of all of your customers, including demand-side management and other nonfirm customers?

A I don't have the exact numbers. I do know that in addition to our reserves that we are required to maintain we will have probably a couple of hundred megawatts extra above that level.

Q At the present time your company is authorized by the Federal Energy Regulatory Commission to sell power within the State of Florida and without the State of Florida at market prices?

A That is correct.

Q Have there been times in the last few years that Tampa Electric would receive more from a wholesale sale than it would receive from its IS customers?

A I don't know.

Q Can you give us an indication of what the typical market price for wholesale power is at this -- during the summer months?

A Are you referring to a nonseparated wholesale sale?

Q A nonseparated wholesale sale, correct.

A Any given hour during the summer if the market spikes, and it has over the past several years, any given hour or perhaps a given day you could -- if you are selling in that market you could reap a significant profit, and that could exceed the rate at which the interruptible customers are paying at that time.

Q Can you give us an example of what the interruptible customer would be paying for a megawatt hour compared to what you could get in the market under those spot market conditions?

A Well, I work in wholesale marketing, I'm not in the rates area. My understanding is the interruptible customers pay 30 to $40 a megawatt hour, something in that neighborhood, and that is total. And, of course, the utility has to pay for its costs to serve them. So what the net difference is, I don't know what the profit is, or the return is on that. But at any given hour, any given day during the summer if the market spikes it could spike up to several hundred dollars a megawatt hour. And depending on what your cost is, of course, your profit could be several hundred dollars a megawatt hour, perhaps.

Q And that is the amount of money you are looking at, you deduct your incremental fuel costs, which might be $20, and the remainder less whatever you have as an incremental O&M cost would be considered the gain, and Tampa Electric in this proceeding seeks 20 percent of that gain to go above-the-line?

A I think our position is that we seek 20 percent of the gain. In other words, we are in agreement with the Commission's decision last year.

Q Now, if you can purchase power to -- in the event there is some kind of outage and you aren't able to serve your IS customer, if you can purchase power you can still receive revenue from that customer and the customer pays the full cost of your base charges plus the cost of power you purchase to serve the load?

A Are you referring to buy-though power?

Q Yes.

A Yes. All of our interruptible customers have asked us to buy-though power for them whenever there is a generation shortage. And whatever the cost of that purchased power is, it is normally done on short-term, of course, whatever that purchased power is is passed on to them, exclusively to them.

Q Is that the total price that the customer pays for the electricity, just the cost of replacement power, or do they pay you something for your transmission system and your general --

A I don't know exactly what the rate details are.

Q Do you know how much prime time residential customers your company has?

A Not exactly, no.

Q Can you give us a general broad indication?

A I think it is somewhere in excess of 50,000.

Q And what is a prime time customer?

MR. BEASLEY: Commissioners, I would object. This is getting beyond the scope of Mr. Brown's testimony. And I would like to know which issue of the two or perhaps three issues on the table it pertains to.

CHAIRMAN JACOBS: Mr. McWhirter.

MR. McWHIRTER: Mr. Brown has segregated, he has focused on nonfirm customers, specifically interruptible customers, but Tampa Electric has many other nonfirm customers. They have customers that are on the GSLD rate and then they have prime time customers, all of whom are subject -- they are nonfirm and can be interrupted, and I wanted to ask him what the impact has been upon the other customers, the impact of buy-throughs have been on other customers in the past few years. It seems to me that it is well within the scope of his direct testimony.

MR. BEASLEY: Commissioner, buy-though power is not really within the scope of the issues that are before you. The issues are what is the appropriate regulatory treatment for the fuel and purchased power associated with nonseparated wholesale sales, and in the same issue with respect to O&M. And buy-though may be something that FIPUG wanted to tag onto this docket, but it is not a subject for this docket. Certainly prime time customers are not a subject of this docket.

MR. McWHIRTER: Buy-through as I used it was not the technical phrase, the buy-though tariff. I'm talking about power that is purchased in order to serve the retail load during times when TECO is short on capacity. And they have indicated that the interruptible customers are the only ones that are really affected, but you have a very substantial number of other customers that are affected by capacity shortages. They are also affected by the fuel costs and they also pay for TECO's total fuel cost. So I think this is all win the scope of Mr. Brown's testimony and certainly worthy of at least brief exploration.

CHAIRMAN JACOBS: I will allow you a narrow bit of latitude in identifying because we are specifically looking at the treatment of costs, having to do with the incremental fuel costs and the O&M costs. So please restrict your questioning to get at those particular issues. And I think there may be some associated --

MR. McWHIRTER: I intend to do just that, Mr. Chairman.

CHAIRMAN JACOBS: Thank you.

BY MR. McWHIRTER:

Q Do you buy power -- do you know whether you buy power in order to serve prime time customers, or do you always interrupt prime time customers when there is a shortage of capacity?

A Sometimes we will buy power to serve them and sometimes we'll interrupt them.

Q When you buy that power, is the full cost of the power that is purchased included in the fuel cost that the company charges to customers?

A My understanding is that -- and, again, I'm not in the rates group, the witness after me is Denise Jordan, who is in our rates group. Perhaps she could answer these questions better than I could. But my understanding is that that purchased power cost is just put in our fuel clause, it is part of the fuel clause.

Q How large is your department, Mr. Brown?

A Thirteen people.

Q And are you paid from wholesale sales revenue or are you paid from the corporation's general revenues?

A Our salaries are based on -- or actually come from Tampa Electric Company. We are not paid an incentive based on wholesale sales or anything like that.

Q Part of this case deals with incremental O&M cost. Is any portion of your department considered as part of the incremental O&M cost attributable to wholesale sales?

A I don't know. The O&M issue before us today can best be addressed by Ms. Jordan.

Q Do you have any knowledge -- well, you don't know anything about O&M cost, what is incremental and so forth?

A No, sir.

Q Your company presently has 320 megawatts of wholesale sales which you classify as separated sales?

A That is correct.

Q And how much -- how many megawatts of long-term capacity purchases do you have? This would be capacity purchases that are in excess of one year.

A I don't know offhand.

Q Is there anybody appearing in this case that would know? Would Ms. Jordan know that?

A No. No, I have the information, but I don't have it with me.

Q You indicated in your testimony that Tampa Electric is currently engaging in firm and nonfirm nonseparated short-term sales. I am going to -- instead of always using the phrase nonseparated sales, I am going to talk about just short-term and that would be synonomous in my questioning for nonseparated. Is that okay with you?

A Well, let me address something you said. I think you said we are engaged in firm and nonfirm nonseparated sales, is that what you said?

Q Yes.

A We are not currently engaged in firm nonseparated sales. We have none going on at this time. We do have firm separated sales going on at this time, but we do nonfirm nonseparated sales.

Q Okay. So on Page 5 at Line 11, you say from time to time Tampa Electric purchases wholesale firm and nonfirm power, but you don't sell firm power at this time other than your separated sales?

A That is correct.

Q And in the part of this case that went toward the final order that is in evidence as Exhibit 5, one of the Florida Power witnesses testified that in today's market most sales have differing degrees of firmness. Do you know what he meant by that?

A Yes.

Q What?

A That is exactly right. The sales do have different degrees of firmness. The firmness of the sale could be based on a generating unit, the availability of a particular generating unit, or they could be based on a priority of interruption, such as interrupting the sale before interrupting your firm customers, for example, or interrupting the sale in proportion to interrupting your firm customers. There are various levels of firmness.

Q I see. But you don't have any firm short-term sales?

A That is correct, not at this time.

Q And all of your short-term sales are recallable, just like Florida Power and Light?

A That is correct.

Q An you indicate there is a procedure you go through --

A Well, I'm not speaking on behalf of Florida Power and Light. I can only speak on our behalf.

Q She testified to that.

A Okay.

Q You said that they are recallable. What procedure do you go through to recall these sales?

A If we lose a generating unit, for example, and we are engaged in a nonfirm nonseparated sale that, you know, it's a short-term sale, then we may attempt to buy power for that sale if we wish to continue the sale. And if we buy power for that sale, then the cost of that power gets charged to the sale. Or if we choose not to buy power for the sale, we will notify the other party, the buyer of our sale that we need to cut the sale. And we will cut it generally at the top of the next hour. Ramp the sale out, in other words.

Q Do you know the process for interrupting your interruptible, your DSM, and your prime time customers?

A I am not responsible for that, no, I do not.

Q If I told you subject to check that it was done by --

MR. BEASLEY: The witness said he is not familiar with that. I would object to any questions in that area since he has no knowledge of it.

MR. McWHIRTER: That is a rational objection and I will accept it and will not pursue that question.

BY MR. McWHIRTER:

Q I would presume that as your -- you have two kinds of capacity problems, one is slow and evolving based on current temperature and other weather conditions, and one is a forced outage. In the event of a forced outage, what procedure do you go through with respect to notifying your nonfirm short-term sales that they have got to get off the line?

A We immediately contact them, and this is assuming that we have not chosen to buy power to continue the sale. We immediately contact them and let them know that we are ramping the sale out as soon as reasonably practical. And some of them can find replacement power quickly, that is immediately, and some we may have to hold the sale for ten minutes, 15 minutes, perhaps to the top of the hour in order for them to ramp in replacement power.

Q Are they always off the line by the top of the hour?

A Sales are ramped out either at the top of the hour or across the top of the hour. There are a couple of different types of ramps that are used.

Q What happens if they don't terminate their demand?

A We cut the sale. We notify them we are not going to continue the sale beyond generally the top of the next hour.

Q How do you cut it?

A Well, in wholesale, we just -- we just send a message to our reliability side, the reliability side of the house. We are functionally unbundled from reliability as per FERC order. And the reliability side of the house ramps out the sale as far as the grid is concerned. They handle the actual ramping out of the sale.

Q And you don't know how that is done?

A No. No, I don't.

Q Do you know whether or not the reliability side of your house can just pull a switch and get rid of them?

A No, they don't actually pull a switch. What they are doing is they are redirecting that generation that was directed across a tie line, for example, to another -- to a buyer. In other words, you were selling that power to that buyer through a nonfirm nonseparated wholesale sale. They don't cut the switch. The generation is simply now used to serve retail load.

Q Well, if you have got a tie line that has a firm separated customer and a nonfirm short-term customer, how do you deal with that?

A They coordinate that with the reliability function of the buyer.

Q Of the buyer?

A Yes.

Q And that to your knowledge always occurs within an hour?

A To my knowledge, yes.
Q On Page 9 of your testimony you refer to FIPUG's motion last year for a midcourse protection and you point out that the Public Service Commission found at that time that Tampa Electric has -- that FIPUG presented no factual support for a finding that Tampa Electric has made wholesale sales in violation of its interruptible service tariff or applicable law. If you interrupted an interruptible customer in order to make a wholesale sale, would that violate your tariff?
A Not to my knowledge. It depends on the type of sale, but as far as I know, no.
Q Is there any law that would be violated if you interrupted one of your retail customers in order to sell at market to a wholesale customer?
A Not to my knowledge.
Q Your company policy, however, is that you wouldn't do that even though law doesn't require it?
A We are talking about nonfirm sales here, nonfirm nonseparated sales. It is our policy to interrupt the sale before we interrupt the interruptible customers.
Q But there is no law, or tariff, or other regulatory requirement that is in place at this time that requires you to make only nonfirm short-term sales. You can make firm short-term sales if you want to?
A Yes.

CHAIRMAN JACOBS: Mr. McWhirter, you are going to a point with this line of questioning, I assume.

MR. McWHIRTER: I am about to wind up, Mr. Chairman.

CHAIRMAN JACOBS: All right.

BY MR. McWHIRTER:

Q If someone wanted to examine your records to determine exactly what was happening with respect to those transactions, is that public information that is readily available or is it confidential?

MR. BEASLEY: Commissioners, I would object to that question. It is well beyond the scope of the two issues involved here and it goes into legal matters pertaining to confidentiality, which is a subject unto itself, as this Commission is fully aware. And I would urge that the --

MR. McWHIRTER: I'm not asking him what the law is, I'm asking him how his department treats it.

MR. BEASLEY: Well, I didn't hear that in the question.

CHAIRMAN JACOBS: You can go ahead and restate your question, Mr. McWhirter.

BY MR. McWHIRTER:

Q Is the information concerning your daily transactions on nonfirm sales and the interruptions of them, is that public knowledge available for examination?

A No. It would be available for examination provided the examiner signed a confidentiality agreement and they were an approved examiner, yes.

Q Let me give you a hypothetical example. Say you have 50 megawatts that you are on a Tuesday and it looks like rain is forecasted for Wednesday and Thursday, and you make a sale of that 50 megawatts at $30, and $17.48 of that is incremental fuel cost, and $2.52 cents is O&M costs, and you have $10 dollars left over. Is it TECO's position in this case that of that $10 left over, TECO would get $2, or 20 percent, and the other $8 would be flowed through the environmental and fuel clauses?

A We would get the $10 assuming we had achieved the three-year benchmark, yes. The $10 profit would be split 80/20 assuming that we had achieved the hurdle rate, the benchmark.

Q Yes. You had already met your threshold.

A Yes, that is my assumption.

Q And then the next day the rain doesn't come and you have got a capacity problem, and you go out and buy $125 power in order to meet the demand, not of your nonfirm, but of your firm customers.

A Well, if this $30 sale that we are making is nonfirm --

Q Yes. Well --

A -- then we would generally cut the sale.

Q You would cut the sale rather than purchasing?

A That is correct. Unless we chose to purchase for the sale.

Q Tell us the criteria that you have established relating those two sales and the point at which you would -- if there is power available on the wholesale market, the point at which you would ask the nonfirm customer to curtail rather than buying the more expensive power to serve your retail load?

A I'm not sure I understand your question, but --

Q Well, you said that you can buy power for 125 and serve your load and you can at the same time serve that 50-megawatt sale --

A Yes.

Q -- but you said you wouldn't buy that power, you would ramp down the customer. There must be some level at which you would buy it and some level beyond which you would not buy it.

A Well, if we are making a 50-megawatt sale for $30 on a next-day basis, and I think that is your scenario, we are making it on a next-day basis, and we get into that day and we have to buy power at $125 because we lost a generating unit or whatever, then we will ramp that nonfirm sale out rather than buy the $125 power.

Q Would you do it if it cost $35?

A Probably.

Q You would ask him to ramp down?

A Yes.

Q Well, then in that circumstance there would -- in your system there would never be a situation in which you would purchase power simultaneously with a nonfirm sale of wholesale power in order to meet your retail demand?

A We purchase power and we make nonfirm sales all the time contemporaneously. We purchase -- generally, we purchase longer term power, must take power, options, things like that that the option is struck or called on for a period of time, so it becomes a must take. And then if we have surplus in an hour or two of that period of time, we may make a contemporaneous nonfirm sale. That's common.

Q But in any event, the cost of purchased power to meet your retail load is more expensive than the revenue that you are receiving from a nonfirm short-term sale, you would always cut out that sale?

A Not necessarily. It depends on the power that you are purchasing and it depends on what you purchased it for. And maybe we are talking past each other, but to give an example, if you purchased power for tomorrow on a 16-hour schedule, and the power of schedule starts at 7:00 a.m. in the morning and runs until 11:00 p.m. that night at a fixed price, and at 7:00 a.m. if you happen to have surplus generation, of course it's a must take purchase, it ramped in at 7:00 a.m., but you have extra generation.

The reason you purchased that 16-hour schedule was for your retail customers to get over the peak, but you had to purchase it for 16 hours. So in those early morning hours you had extra generation on your system. And so it behooves you to make nonfirm hourly sales until you need that power that you purchased to serve all of your retail load.

Q That is what you would call a must buy sale?

A Must take, yes.

Q Must take sale?

A Excuse me, must take purchase, not sale.

Q Thank you very much. Okay. Now, under that must take purchase that you have -- is it possible that would cost you $125?

A It could.

Q Now, of that $125, the full cost of that would be recovered through your fuel or purchased capacity clause, would it not?

A Yes. Yes, it would.

Q And the full cost of that would be paid by the retail customer?

A Yes.

Q And so the retail customer would be charged $125, and for the simultaneous 50-megawatt sale he would receive an $8 profit?

A If you were making this sale that you described at

$30, is that what you are saying?

Q Yes.

A That is correct.

Q Okay. Since the customers pay the full cost of the must take power, and the $30 is used really to reduce some of the hurt on the customer for having to buy that expensive power, don't you think it would be reasonable to let the customer get the whole 10 rather than just 8 of the 10?

MR. BEASLEY: Mr. Chairman, this is again going far afield. It is readdressing the formula for the incentive which you have adopted as a matter of final agency action. It's done, it's over, and this is a reevaluation or a reattack on that final decision, and it doesn't relate to the issues that are before you.

MR. McWHIRTER: I most strongly disagree with that interpretation. This is exactly what FIPUG is talking about. If you have a sale in which we call -- I would call a bail-out sale and the utility had purchased power at a high price and sold for a low price its own power at the same time, we don't think an incentive ought to be paid on that kind of transaction. And I'm asking him if he wouldn't think that was fair.

CHAIRMAN JACOBS: Well, I can agree that is the context of your question. But I also agree that the only aspect of that is how they allocate the costs, not whether or not it is equitable or not. And on his testimony I think those are the only two issues that he is dealing with.

MR. McWHIRTER: Well, he answered how they allocate the costs, so I won't ask him any more questions, Mr. Chairman, and I thank you very much.

CHAIRMAN JACOBS: Very well. Thank you. Mr. Burgess.

MR. BURGESS: No questions.

CHAIRMAN JACOBS: Staff.

MR. KEATING: No questions.

CHAIRMAN JACOBS: Commissioners? Redirect.

MR. BEASLEY: Yes.

REDIRECT EXAMINATION

BY MR. BEASLEY:

Q You were asked a series of questions about bail-out power and other priorities when you have sales and purchases, can you assume that a utility system has the following power supply resources in its portfolio: It has a firm purchased power contract for 100 megawatts at $80 a megawatt hour, and that is must take; it has a $75 per megawatt hour CT, combustion turbine; and it has a $25 per megawatt hour base load intermediate unit. And that is all it has on its system.

How would you call upon these resources in the order of dispatch sequence, Mr. Brown?

A You would put the must take at the bottom of the dispatch stack, because you have no choice as to whether or not you can dispatch that, you must take it. And so even though it is the most expensive cost, it would go at -- it would be dispatched first, essentially. And then on top of that you would put your $25 base load, and then on top of that you would put your $75 CT.

Q In which order would you call upon those resources?

A The must take would be first, then the base load, then the CT.

Q Okay. Assume you have got that system, that purchased power and those two other power resources, and on any given day you are being able to serve all of your load with the purchased power and part of your base load unit. And you can use another part of that base load unit to make a sale. Let's say you sell it at 5 megawatts of power for $50 a megawatt hour. What would be the incremental cost of that sale, Mr. Brown?

A Well, if you are selling it off your base unit which is -- based on your example it is described as your incremental unit on the stack, then the incremental cost would be $25 a megawatt hour.

Q What would be the difficulty of using, let's say, the more expensive $80 per megawatt firm purchased power must take contract as your incremental cost?

A Well, the $80 is a must take. It's incremental cost

I really zero. And, frankly, if you use that as your incremental cost, you wouldn't make the sale because the sale price is $50. It's less than the cost of the must take, so you wouldn't make the sale at all. What you would essentially do is ramp down your base load unit and not make the sale at all.

Q What impact would that have on your general body of ratepayers?

A It would hurt them.

Q How would it hurt them?

A Well, by not making the sale, that is, not being incented to make that sale you would be ramping down the generation and not receiving a $25 profit because your base load incremental cost is 25, the sale price is 50, therefore it would be a $25 profit. You would not be reaping that $25 profit is what would happen.

Q Is the availability of wholesale purchases and sales beneficial to your general body of ratepayers?

A Yes.

Q How is it beneficial?

A Well, it utilizes generation. It utilizes all of your resources to the best of their ability at the time.

Q In managing all of your purchases and sales, do you strive to do that as efficiently and as economical and as optimally as you can?

A Yes.

Q You were asked a question about the confidential nature and public access to documents and other information concerning your purchases and sales?

A Yes.

Q That information is always available to the Commission for audit and review, is it not?

A Yes, to my understanding. And the reason I said that it is not available just to the public is that it contains sensitive market information.

MR. BEASLEY: Thank you very much.

CHAIRMAN JACOBS: There were no exhibits. Thank you.

MR. McWHIRTER: I would like to ask just one question on recross. Just one question, Mr. Chairman.

CHAIRMAN JACOBS: I am very leery, Mr. McWhirter, because of your esteemed knowledge and skill. I'm afraid we are going to open the door back to another round of questioning. If it is absolutely necessary and something that you need to bring out, but I hope it is not going back to the line of questioning --

MR. McWHIRTER: No, sir, it is imperative.

CHAIRMAN JACOBS: Okay.

RECROSS EXAMINATION

BY MR. McWHIRTER:

Q You said that you would not make the $25 incremental sale to reduce the impact on your customers unless you were incented to do it?

A No. I said that if the $25 generation, which is your base load generation, was indeed your incremental cost, then, yes, you would be incented to make the sale because the sale price is $50.

However, if you were forced to use $80 as your incremental cost by some order, then you would not make the sale because you would lose $30 on the sale.

MR. McWHIRTER: I'm not going to ask another one, although --

CHAIRMAN JACOBS: Thank you. You are excused, Mr. Brown.

Call your next witness.

MR. BEASLEY: I call Denise Jordan.

J. DENISE JORDAN

was called as a witness on behalf of Tampa Electric Company and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Would you please state your name, your business address, and your position with Tampa Electric, please?

A J. Denise Jordan, 702 North Franklin Street, Tampa, Florida 33602. I am the Director of Rates and Planning.

Q Ms. Jordon, did you prepare and submit in this proceeding a 12-page document entitled prepared rebuttal --

excuse me, I'm jumping ahead -- prepared direct testimony consisting of six pages?

A Yes, I did.

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

A Yes, they would.

MR. BEASLEY: I would ask that Ms. Jordan's direct testimony be inserted into the record as though read.

CHAIRMAN JACOBS: Without objection, show Ms. Jordan's direct testimony is entered into the record as though read.

TAMPA ELECTRIC COMPANY
DOCKET NO. 010283-EI
FILED: 4/23/01

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED DIRECT TESTIMONY

OF

J. DENISE JORDAN

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

A. My name is J. Denise Jordan. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director, Rates and Planning in the Regulatory Affairs Department.

Q. Please provide a brief outline of your educational background and business experience.

A. I received a Bachelor of Mechanical Engineering degree in 1987 from Georgia Institute of Technology in Atlanta, Georgia. Prior to joining Tampa Electric, I accumulated 13 years of electric utility experience working for Florida Power Corporation in the areas of rate design and administration, demand-side management implementation, commercial and industrial account management, customer service and marketing. In April 2000, I joined Tampa Electric as Manager, Electric Regulatory Affairs. In

February 2001, I was promoted to Director, Rates and Planning. My present responsibilities include the areas of fuel and purchased power, capacity, environmental and energy conservation cost recovery clauses, and rate design and analyses.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address the calculation of gains for non-separated wholesale sales. In addition, I will address the regulatory treatment of revenues, expenses and gains associated with these sales. These are the outstanding issues that remain after the Florida Public Service Commission's ("Commission") proposed agency action in Part III of Order No. PSC-00-1744-PAA ("Order No. 00-1744") issued on September 26, 2000 in Docket No. 991779-EI.

Q. Have you reviewed the regulatory treatment of revenues and expenses of non-separated wholesale sales recommended by Commission Staff and approved by the Commission in the proposed agency action portion of Order No. 00-1744 that gave rise to this proceeding?

A. Yes, I have.

Q. What is Tampa Electric's position regarding that proposed regulatory treatment?

A. Tampa Electric agrees with the regulatory treatment recommended by the Commission Staff and proposed in Order No. 00-1744. It is consistent with the approach proposed by Tampa Electric in Docket No. 991779-EI, and we believe it to be reasonable.

Q. Is it appropriate for Tampa Electric to credit any incremental operating and maintenance ("O&M") costs to the fuel and purchased power cost recovery clause ("Fuel Clause")?

A. No. An amount equal to all incremental O&M costs attributed to the sale should be credited to operating revenues because Tampa Electric does not have any associated fuel-related O&M expenses charged to the Fuel Clause.

Q. Does the company make non-firm wholesale power sales while simultaneously making optional provision or "buy-through" purchases to serve its non-firm retail customers?

A. Tampa Electric has a company policy of not making non-firm wholesale power sales at the same time it is making optional provision or "buy-through" purchases for its non-firm retail customers. As explained fully in the direct testimony of Tampa Electric's witness W. Lynn Brown, there may be occasions of overlap due to operational issues that must be considered.

Q. Are Tampa Electric's non-firm retail customers required to purchase "buy-through" power to avoid interruptions?

A. No. Tampa Electric's interruptible retail tariffs include an **optional** provision for "buy-through" power purchases that is entirely **voluntary** on the part of the customer. This provision is exercised entirely at the customer's discretion and direction. All of Tampa customers taking service under the interruptible service rates have requested this option.

Q. Are there times when it is appropriate for Tampa Electric to make non-separated wholesale sales while purchasing power to serve firm and non-firm retail customers even though the price of the purchased power is greater than the price of the power being sold?

A. Yes. The company purchases power based upon its forecasted needs to serve retail customers. The company also purchases power at the request of interruptible customers in lieu their being interrupted. The company makes non-separated wholesale sales based upon generation and purchased power in excess of retail customers' needs. Gains from these sales benefit all retail ratepayers. According to witness Brown, there are instances when the company makes wholesale sales when proceeds from these sales are less than the cost of purchased power for various reasons. Had the company not made the sales, the entire cost of purchased power would have been borne by retail ratepayers. By making non-separated sales even when the wholesale sales proceeds are less than the purchased power costs, the total costs are minimized. These actions are appropriate, prudent and in the best interest of ratepayers.

Q. When calculating the incremental fuel costs to be credited to the Fuel Clause, should the cost of purchased power be considered in the event the company is purchasing power for retail customers at the same time it is making a non-separated wholesale sale?

A. No. For reasons stated above, the appropriate fuel costs to consider are simply the incremental fuel costs of generating the energy for the sale.

Q. Does that conclude your testimony?

A. Yes, it does.

BY MR. BEASLEY:

Q Would you please summarize your direct testimony, Ms. Jordan?

A As my testimony explains, Tampa Electric agrees with the regulatory treatment recommended by the Commission staff and proposed by the Commission in Order Number 001744. It is consistent with the approach Tampa Electric proposed in Docket Number 991779, and we believe it to be reasonable.

Tampa Electric believes that each IOU should credit its fuel and purchased power cost recovery clause for an amount equal to the incremental fuel cost of generating the energy for such sales. With respect to O&M, Tampa Electric believes each IOU should credit its operating revenues for an amount equal to the incremental O&M cost of the generating energy for each such sale. With respect to implementation of the incentive mechanism approved by the Commission in Order Number PSC-1744, Tampa Electric agrees with the implementation methodology set forth in the Commission staff's September 22nd, 2000 memorandum issued in the fuel adjustment docket.

That concludes my testimony.

MR. BEASLEY: Thank you. We tender the witness for cross.

CHAIRMAN JACOBS: Very well. Mr. Badders.

MR. BADDERS: No questions.

CHAIRMAN JACOBS: Mr. McGee.

MR. McGEE: No questions.

CHAIRMAN JACOBS: Mr. McWhirter.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Ms. Jordan, I have handed you two documents; one is the testimony that you filed last week with respect to your actual capacity cost recovery and your estimated true-up for the rest of the year. Do you recognize that?

A Yes.

Q And the second document is a FIPUG exhibit --

MR. CHILDS: Which, Mr. Chairman, if you will give me a number, I will mark it for identification.

COMMISSIONER JABER: Is that 6?

CHAIRMAN JACOBS: Yes. Show this marked as Exhibit 6.

MR. BEASLEY: Mr. McWhirter, could you differentiate between which of these two is being marked Exhibit 6.

MR. McWHIRTER: You have to open the first page and you will see where down at the lower right-hand corner it says received August the 21st, that is Exhibit 6.

(Exhibit 6 marked for identification.)

BY MR. McWHIRTER:

Q Ms. Jordan, if you look at Exhibit 6 and would you confirm that the pages I have extracted are true and accurate extracts from the exhibit that you filed with the Commission?

A Yes, they are.

Q Ms. Jordan, Schedule E6 indicates the amount of power that Tampa Electric Company anticipates that it will sell this year on the wholesale market. And if you look at the very bottom of the page it has a Bates mark 15 on it. You will see the different types of sales and the amount of money received on each one, and it has a fuel cost and a total cost. Do you see that?

A Yes.

Q Okay. Now, which of those sales would be classified as nonseparated sales that are the subject matter of inquiry in this case?

A The various, jurisdictional, market-based.

Q Would you say that again, please, I didn't hear you?

A It is Column 2, what is identified as various.

Q Uh-huh.

A Going across sold to, jurisdictional, type and schedule, market-based.

Q Okay. Would Schedule J be a nonseparated sale?

A The Schedule J that is shown there is really as a result of the open access transmission tariff, it is ancillary service that is being provided to independent power producers that are wheeling through our service area.

Q Okay. And Schedule D would be included?

A Yes, it is nonseparated.

Q Now, those are FMPA sales and you are not making those anymore, is that correct?

A We are not making those anymore.

Q Now, there is a difference in the market-based sales, you get instead of 3.548, I'm going to say $35.48 a megawatt hour is the fuel cost you get on these sales and $38 is the total cost. What is the cost that you are identifying there that is more than the fuel cost?

A The total cost includes the O&M.

Q All right. So in this case when we are talking about O&M, the difference between those two columns is the amount of money --

A Is the variable O&M associated with making the sale.

Q So that money would flow back to Tampa Electric's general operating revenues and customers wouldn't see any part of the difference between $35 and $38, is that correct?

A Well, first of all, it would flow back, but it would be matching the costs. The costs are a rate base component, I think, as Witness Portuondo said earlier, and you are being consistent. You are matching your costs with your revenues. And if you were in a situation where you were overearning, then at that point, yes, the ratepayers would see that.

Q Mr. Brown said that he couldn't tell us what those costs -- what your O&M costs are. Can you tell us how you derived that?

A We have a methodology that we have had in place -- EPRI developed it back, I think, like in 1982/'83 time frame. It was researched, developed, and published by EPRI. And basically it takes into account the previous year's O&M expenses utilizing the capacity factor for the coal-fired generation and picking up the variable O&M piece that way.

Q And it generally winds up to be $2.52?

A It has varied over time. But right now based on the 2000, it is $2.55 per megawatt hour.

Q 55 cents?

A Yes.

Q And that money you will keep, but it will be reflected in your surveillance report?

A That would be my assumption, yes.

Q Do you prepare the surveillance report?

A No, I do not.

Q Now, is there anything in your report filed on August 21st that -- or at least that I received on August 21st -- that describes what price was paid for these different sales by the buyer?

A Individually, no.

Q Is it anywhere in total shown?

A Well, the fuel cost, this is just the fuel docket, if that is -- fuel adjustment clause, so I'm not sure what you are asking.

Q Well, the staff's memorandum that has been discussed here today that you are well familiar with, in its reporting requirements it asks you to set out the gains. Does this report set out the gains in accordance with that memorandum?

A Not on this particular schedule the gains are not shown, but they are shown.

Q Where are they shown?

A In total, not in individual, if that is what you are asking me.

Q I just want to know what the gains are.

A I don't have an A Schedule in front of me, but --

Q Well, look at Page 8 of your exhibit. Go back to the second page in. I think that is your E1-B?

A Okay.

Q Do you find the gains on that page?

A No. At that point it is -- it is included in the total cost of power sold, A2, Line Item A2. That includes the gains, so it's a gross number there.

Q Line A2, which has 22 million?

A Right. The 22.1 million includes the gains from the sales.

Q But there is something you filed somewhere that breaks out the specific gains, is that right?

A In total, correct.

Q Was that in the big document that I gave you that I didn't extract for the exhibit?

A When you look at the A Schedule --

Q Yes, ma'am.

A -- on A6 there is a line that shows the 80 percent gain. There is a column. I don't know if you have an A Schedule in front of you.

Q No, I don't. Is it in that other document that I handed you?

A No, it's in what we file every month with the Commission.

Q It's a monthly report?

A Yes.

Q All right. Now, look at the page that is marked as 17, and this is the power you purchased for the year. And you have gotten it in various aspects, but the only one we are dealing with is market-based, I guess. Look at the very bottom of Page 17.

A Yes.

Q Which of those are nonseparated? Is it just the market or is it some of the others?

A This is purchased power. This is purchased power.

Q Yes, that's what I'm asking you.

A Separating purchased power, I'm not sure what you are asking me.

Q Well, what is nonseparated purchased power, where is that shown on this exhibit?

A Can you --

Q Schedule E7 is purchased power?

A Right.

Q And that is power you buy in order to serve your customers?

A Right.

Q And you charge them for it?

A This is the purchased power that was required to meet retail needs.

Q That is correct.

A So what do you mean by nonseparated purchased power?

Q I guess I'm a dumb questioner. What does market-based mean down there?

A Marked-based is the type of schedule that it was bought, or the agreement.

Q So the average price for the year for the power you buy to serve your retail load will be $66.06?

A Correct.

COMMISSIONER JABER: Mr. McWhirter, may I interrupt you for just a minute?

MR. McWHIRTER: Yes, ma'am.

COMMISSIONER JABER: Ms. Kaufman, the exhibit that you handed me is numbered a little bit differently, so I'm having some trouble following the questioning. Can I have another copy, please?

MS. KAUFMAN: Absolutely.

COMMISSIONER JABER: I only have one exhibit, but there are two.

CHAIRMAN JACOBS: While we are at a break, Mr. McWhirter, that number you just quoted, that's on Schedule E7, which is Page 17?

MR. McWHIRTER: Yes, sir.

CHAIRMAN JACOBS: Whereabouts on that page?

MR. McWHIRTER: You may have the wrong one, too. At the very bottom it shows the power that -- Schedule E7, Page 2 of 2.

CHAIRMAN JACOBS: Yes, I have that.

MR. McWHIRTER: You've got it now?

CHAIRMAN JACOBS: It shows total numbers, it didn't break it out to the dollar figure, so I was just wondering. You just did a calculation on that, then?

MR. McWHIRTER: Yes. I was looking at the cents per kilowatt hour, and that is in Column 3.

BY MR. McWHIRTER:

Q Is that the total price that you pay for the power you purchased from the market?

A That is the fuel cost.

Q Now, is all of this -- all of this power that you purchased, that is power that you are obligated to purchase?

A Not in the sense if you mean from a QF, but in order to serve our retail load, any utility does not have just their own generation. Your generation is usually -- your resource mix is consistent of your own generation, purchases from qualifying facilities and purchases from other utilities. And to maintain the reserve margin, let's say in the shoulder months when you know you are going to be doing maintenance, you may go out into the market and purchase for a three-month purchase or a six-month purchase to maintain your reserve margin. So, in essence, yes, it's obligation because it is obligation to serve, but it may not be contractual, if that is what you are asking.

Q Can you give me the relative lengths of the period that you are obligated to purchase this power under Schedule J, IPP, other and market-based?

A They vary. The IPP is a contract, long-term contract, the Schedule JAs are short-term. The other are usually block purchases that are shown in our ten-year site plan, and the market-based is usually spot.

Q I didn't understand. You said purchases that are in your ten-year site plan?

A Correct.

Q That means from companies that you list as purchased capacity to give the overall capacity of your company and those --

A Yes.

Q -- you pay $72.23 a megawatt for that capacity?

A Correct.

Q And HPP/IPP, that is your affiliated TECO Power Partners company?

A Correct.

Q And you pay them $53.82?

A Yes.

Q All right.

MR. BEASLEY: Commissioners, may I inquire? This is starting to sound like an omnibus deposition for the fuel docket and the ten-year site plan proceeding, and I would like to inquire how it is related to the issues that are before you?

MR. McWHIRTER: I will tie it in shortly, Mr. Chairman.

CHAIRMAN JACOBS: I will allow you that latitude.

MR. McWHIRTER: I can do that quicker than explaining to him what I'm trying to do.

BY MR. McWHIRTER:

Q Back on Page 15. And you sell power to Hardee Power Partners under a separated contract for $32.76?

A That is correct.

Q Can you give me some quick insight into why you pay so much more for the power that you buy from your affiliated company than the price you sell to the affiliated company?

A Well, I wasn't involved with the original contract, but I can tell you -- and I guess I see where you are going in terms of looking at the price of the power sold versus what we are purchasing. As I mentioned earlier, we are purchasing several different types of power here to serve over peak load that we will need. And as Witness Brown pointed out earlier, what is happening is that when we are going to the market it may be during the shoulders hours. And obviously your price that you -- that you sold it for is not going to match apples-to-apples to what you purchased the original purchased power agreement for. So I don't think that you can say it's a one-for-one situation. We are utilizing the purchased power when we need it to get us through the peak, and we are selling it in order to help mitigate that cost or impact to the ratepayers.

Q So the $48 million you paid to Hardee Power Partners last year is not related to a fixed price that you agreed to, but it's what you pay from time-to-time when you buy from Hardee, is that it?

A That's not what I said. I said that the prices that we enter into for the purchased power are done in order to meet anticipated load, forecasted load, to meet the system reserve margin requirements. To cover our obligation to serve.

Q How are those -- how is that power priced to you, who prices it and what rationale do you use?

A At that point I cannot tell you exactly how everything is priced.

Q That would have been Mr. Brown?

A That would have been Mr. Brown.

Q All right. When you calculate your gain, is that done one time a year or is it done every time you make a sale? Just how does that come about?

A The gain is calculated on every sale.

Q Okay. And then when do you -- when do you send the money around? Do you wait until the end of the year to determine whether you get your incentive, or do you take an incentive out of every sale?

A Well, first of all, we have to reach the benchmark before we can even start sharing in the incentive, and that's probably not going to happen until later in the year, if it happens then. So it wouldn't make sense to take it out of every sale because you have to wait until you get there.

Q If you get there in August, do you then take it out of every sale as the sale occurs, or do you wait until sometime later?

A You would take it out at that point.

MR. McWHIRTER: That's all the questions I have, Mr. Chairman.

CHAIRMAN JACOBS: Mr. Burgess.

CROSS EXAMINATION

BY MR. BURGESS:

Q Ms. Jordan, you made passing reference to the FMPA sales. And as I recall, that contract specified the units out of which the sale was being made, did it not?

A Correct.

Q When that -- and you make those -- those are nonseparated sales, were they not?

A Correct.

Q When you do that, does that enter into the issue of incremental cost in any way, either from the standpoint of the fuel that is removed from the retail portion of the fuel adjustment clause or in the calculation of gain?

A The incremental fuel cost for that sale is based upon those units, and so that is what is removed or matched up.

Q And what you are saying is in those cases, then, the incremental cost would have nothing to do with the dispatch sequence, it would be that specified in the contract?

A For that sale.

Q For that sale. But you would -- and you would use that, but you would use that as the amount to be removed from the balance that is apportioned to the retail load, fuel load?

A Correct.

Q And you would use that same amount to be subtracted from the price in calculating the gain --

A Right.

Q -- to be credited against the fuel?

A Yes.

MR. BURGESS: Thank you.

CHAIRMAN JACOBS: Staff.

CROSS EXAMINATION

BY MR. KEATING:

Q Ms. Jordan, I have the same questions for you that I had for the previous two utility witnesses. When TECO economically dispatches its resources to serve its load, does it distinguish between resources from its own generation and resources purchased from other generation sources?

A No.

Q And I will provide the same hypothetical example, as well, and I hope that you were listening when I clarified it for the previous witness. I will try to phrase it that way this time around, as well.

Assuming that TECO has made a 50-megawatt wholesale energy sale for one hour. If TECO must concurrently purchase power from another generation source to serve the last 50 megawatts of its total load, is the energy cost of the purchased power the incremental energy cost of TECO's 50-megawatt wholesale sale?

A Yes, if the purchase was made to serve specifically that 50-megawatt sale.

Q And, again, assuming that TECO is making a

50-megawatt wholesale energy sale for one hour, and if TECO currently purchases power from another generation source to serve part of its load, but still is required to dispatch its own generation -- this is where I had to clarify last time, let me make sure I state it clearly.

If TECO is concurrently purchasing power from another generation source while it is making that 50-megawatt sale for one hour to serve part of its total load and that purchase would be dispatched ahead of generation that must be used to serve TECO's total load, is the energy cost of the purchased power the incremental energy cost of the 50-megawatt wholesale energy sale?

A No, it would not be. I am assuming that is a must take situation and, therefore, it would be zero incremental cost, so it would not be on the increment.

Q And that assumption was correct in my question.

A Thank you.

Q If the Commission orders each utility to credit operating revenues with an amount equal to the O&M expenses of a nonseparated wholesale energy sale, would that order create a double recovery of those expenses, those O&M expenses for TECO?

A No, it would not.

Q Okay. For a nonseparated sale -- and this would be a nonseparated sale that is firm and for less than one year, does incremental cost for the purpose of calculating net gain and the incentive on that sale include costs for firm or nonfirm purchased power made in anticipation of facilitating the nonseparated sale?

A Could you repeat that, please.

Q Sure. For a nonseparated sale that is firm and less than one year in duration, does the incremental costs of that sale for the purpose of calculating the net gain and any incentive include costs for firm or nonfirm purchased power made in anticipation of facilitating the nonseparated sale?

A It would depend on the intent of why you entered into the original sale to begin with.

COMMISSIONER JABER: Ms. Jordan -- excuse me, Cochran. While staff thinks about that a little bit more, let me just ask you a question with respect to if the Commission were to find that O&M expenses, the incremental O&M expenses were not appropriate for recovery through the clause, but rather could be included in base rate, what effect do you expect that would have on your incentive sales?

THE WITNESS: I don't think it would have an effect.

COMMISSIONER JABER: Is that because the O&M expenses are minimal?

THE WITNESS: No, I think that that would be appropriate so it would not impact our decision to go and enter into sales. It would just be lining up the revenues with the expenses, which would be appropriate.

COMMISSIONER JABER: So if the recovery was through base rates, as long as obviously the revenues and expenses were included in base rates there wouldn't be any problem with not allowing that sort of pass-through in the fuel clause?

THE WITNESS: Correct.

BY MR. KEATING:

Q Ms. Jordan, in response to my last question -- if you would like for me to repeat it, I will?

A Would you, please.

Q Certainly. For a nonseparated sale that is firm and less than one year in duration, does incremental cost for the purpose of calculating net gain and any incentive that would apply include costs for firm or nonfirm purchased power made in anticipation of facilitating the nonseparated sale?

A If the purchased power was on the increment from making the sale, then it would be included. But if you were not purchasing, or if you were purchasing it with must take and there was zero incremental, then it would be the incremental cost of whatever it took to make that sale, whether it be base or CT units.

Q For a nonseparated sale that is -- again, that is firm and less than one year in duration, would the incremental costs for purpose of calculating net gain and any incentive include costs for firm or nonfirm purchased power not anticipated as being needed to facilitate the sale, but made because of some unforeseen event?

A Give me the scenario one more time, please.

Q It's for a nonseparated sale that is firm and less than one year in duration, would the incremental costs for that sale for the purpose of calculating the net gain and any incentive include costs for firm or nonfirm purchased power that was not anticipated as being needed to facilitate that nonseparated sale firm less than one year, but made because of some unforeseen event?

A No.

MR. KEATING: Okay. That's all the questions I have. Thank you.

CHAIRMAN JACOBS: Commissioners.

MR. BEASLEY: One redirect.

REDIRECT EXAMINATION

BY MR. BEASLEY:

Q Is that because the power purchased to meet some unforeseen event like a unit outage or something was must take and, therefore, zero cost?

A Correct.

MR. BEASLEY: That's all I have.

CHAIRMAN JACOBS: Very well. Exhibits.

MR. BEASLEY: I don't believe we --

CHAIRMAN JACOBS: Mr. McWhirter, I believe you had Exhibit 6. Do you want to move that?

MR. McWHIRTER: Yes.

CHAIRMAN JACOBS: Without objection, show Exhibit 6 admitted.

(Exhibit 6 admitted into the record.)

CHAIRMAN JACOBS: Thank you. I guess you will be back, Ms. Jordan. We are going to finish up, but we are going to take a 15-minute break for the court reporter, and then we will come back and finish up.

I have a document that I think had all of the schedules that you referred to on it, but let's be real clear about that. The docket that I have has Schedule E1B, Schedule E2, Schedule E6, which is two pages, and Schedule E7, which is two pages.

MR. McWHIRTER: That's it.

CHAIRMAN JACOBS: That's the complete --

MR. McWHIRTER: Yes, sir.

COMMISSIONER JABER: But I had a different document. I had a second document that had Schedules A1, and I think through A7, so should we just identify those as separate --

CHAIRMAN JACOBS: Did you intend to mark that or was that just accidentally distributed?

MR. McWHIRTER: That was accidentally distributed. I did not ask her questions about it.

COMMISSIONER JABER: Yes. Because I didn't recall you asking any question on any of those schedules.

MR. McWHIRTER: I didn't.

COMMISSIONER JABER: Questions with respect to FMPA, showed up on the page that I have here, Schedule A5, Page 1 of 3. During the break would someone please look at this and make clear for me. And if this is not an exhibit I am supposed to have, I would rather that you take it back.

MS. KAUFMAN: We'll do that.

CHAIRMAN JACOBS: Very well. We will return at 1:10.

(Recess.)

MS. KAUFMAN: Mr. Chairman, I think we have straightened out Exhibit Number 6 now, and each of the Commissioners should have the correct one. And I gave one to the court reporter, as well.

CHAIRMAN JACOBS: Great. Thank you. And so we are now with Mr. Kordecki. You may proceed.

GERARD J. KORDECKI

was called as a witness on behalf of Florida Industrial Power Users Group, and, having been duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. McWHIRTER:

Q Mr. Kordecki, you have been sworn?

A Yes, I have.

Q Would you state your full name and your address, please?

A Gerard J. Kordecki, 10301 Orange Grove Drive, Tampa, Florida 33618.

Q And you are the same Gerard Kordecki that filed testimony in this case?

A Yes, I am.

Q And if I asked you the same questions that were posed in that testimony, would your responses be the same?

A Yes, they would.

Q Would you summarize for us what you said in the testimony?

A My testimony addresses how each jurisdictional utility should calculate the incremental cost of making nonseparated wholesale sales. I discuss the incremental fuel costs of generating the energy for these sales and the calculations of incremental operation and maintenance costs caused by these sales.

Utilities should only receive incentives when customers are realizing benefits from the utility's management of the generation resources. In rewarding utilities for their wholesale sales, only net benefits or net gains should be calculated in determining the incentive benchmark.

The calculation of these gains must take into account costs which may be shifted to retail customers or costs which retail customers are already paying in their base rates. In its order the Commission stated each IOU shall credit its fuel and purchased power cost recovery clause for an amount equal to the incremental fuel cost of generating the energy for each such sale.

I would add to this statement that the incremental costs should be the higher of purchased power or generation in each hour. This would mean that during simultaneous purchase and sales that if purchase costs were higher than generated costs, that purchased power costs would be used to calculate the profits. Adoption of this highest cost allocation protects retail customers against shifting higher costs caused by the transactions.

Another element of cost described in the order was operation and maintenance costs. The order states, "Each IOU shall credit its operating revenues for an amount equal to the incremental operating and maintenance costs of generating the energy for each such sale." The standard for O&M expenses for these sales should be a credit to the clauses. Crediting operating revenues from sales is a direct reduction from the gain from the sale. A utility should not be allowed to credit the operating revenues for O&M unless the utility can prove that these costs are, in fact, incremental, that is, would not occur without the transaction. This would also include how these O&M costs were exactly calculated.

Secondly, the utility must be required to show that these O&M costs are not already being received in base rates. This would require that a utility show that the O&M costs allowed in their last rate case when expanded for increased kilowatt hour usage since that case, would be excluded if the O&M expenses -- I'm sorry, if without the collection of these expenses the O&M budget would be -- I have lost my place, I'm sorry. It would go over the O&M budget as expanded and be a reduction in operating revenues, from their operating revenues.

That is my summary.

Q Does that conclude your summary?

A Yes, it does.

MR. McWHIRTER: Mr. Chairman, I would request that Mr. Kordecki's testimony be entered into the record and I will submit him for cross examination.

CHAIRMAN JACOBS: Without objection, show Mr. Kordecki's prefiled testimony is entered into the record as though read.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DIRECT TESTIMONY

OF

GERARD J. KORDECKI

ON BEHALF OF

THE FLORIDA INDUSTRIAL POWER USERS GROUP

DOCKET NO. 010283-EI

I. Introduction

Q. Please state your name and address and occupation.

A. My name is Gerard J. Kordecki. My business address is 10301 Orange Grove Drive, Tampa, Florida 33618. I am self employed as an energy and regulatory consultant.

Q. Please summarize your educational background and work experience.

A. I received a Bachelor of Science degree in Advertising in 1963 and a Master of Arts in Marketing in 1965. Both degrees are from the University of Florida. I also pursued graduate study in Economics at the University of Florida. I worked for Tampa Electric Company for 33 years in various capacities involving marketing, conservation, resource planning and rates and regulation. I have participated in the development of and supervised the preparation of numerous studies and plans involving conservation goals and programs, cost allocations, rates, load research and resource plans. Since January 1999, I have consulted with power plant developers, merchant plant applicants and industrial and institutional utility customers on rates, regulatory policy and transmission access issues.

Q. Mr. Kordecki, have you previously testified before the Florida Public Service

Commission ("FPSC" or "Commission")?

A. Yes, I have testified regarding the subjects identified in my preceding answer on more than 36 occasions which included rate cases, determination of need hearings and various conservation dockets. I have also participated in a number of rule hearings, agenda conferences and Commission workshops.

II. Background

Q. Describe some of the major changes you have observed during your 33 years experience in the electric industry in Florida.

A. Before the 1980s, most wholesale sales were made to serve the native load requirements of the purchasing utility. In the late 1970s and early 1980s, the effect of OPEC on oil prices changed the power market. Those utilities with coal capacity sold to oil-burning utilities to displace high-priced oil units. Of course, this was only done when selling utilities did not need the lower cost capacity for their retail customers. Most of these transactions were done on the Florida Broker System. The savings were split between the seller and the buyer. There were little or no significant sales outside of Florida. A number of utilities built or purchased coal capacity in anticipation of even higher oil costs. In the 1980s, this was termed "oil-back out." The wholesale market continued to revolve around requirements sales and the as-available sales on the Florida broker to displace oil.

The 1990s brought about changes in capacity availability. Utilities built very few new generating units and cogeneration potential declined. This situation wasn't limited to Florida. It was widespread through the U.S. as supply tightened. The present shortages of capacity (California and the far West), which are familiar to everyone, are a result of this lack of construction. Even the three Peninsular Florida IOUs are increasing their capacity levels by adopting a 20% reserve margin (up from 15%) for 2004.

FERC Order 888 brought about a second change in the market. This order required transmission-owing utilities to allow power suppliers (including IPPs, marketers, merchant plants, etc.) to use their transmission systems to make wholesale sales. Many of these FERC-defined utilities can sell energy at market-based rates--whatever the market will bear. In fact, all utilities in Florida have this market-based rate authority. Two, I believe, can only make market-based sales outside of Florida; however, this changes the "opportunity cost" for in-state wholesale sales when the purchases are to supply retail customers, specifically DSM and other non-firm customers.

In the late 1990s, and especially in the last two years, we find ourselves with dwindling capacity, broader markets due to expanded transmission access, and market pricing, which can take advantage of the lower reserves.

Q. Mr. Kordecki, what effect do you believe these conditions have on Florida utilities today?

A. When utilities were buying power, they were paying more. When they were selling, they could take advantage of higher pricing over a larger geographical area. Except for cost-based emergency sales, wholesale sales probably were made out of state, even if the energy could have been sold in state but at lower prices. So power that might have been sold on the Florida Broker in the 1980s may have been sold elsewhere. In state, there were probably situations where buying utilities were willing to make longer term purchase commitments to ensure themselves of power availability; that is, to be first in line.

Q. Is your answer a condemnation of the buying and selling practices of Florida utilities?

A. No, it is not a condemnation. The utility reactions to shortages in supply are very rational. On the selling side, it is good business, encouraged by FPSC incentives, to maximize profits for the good of retail customers. On the buying side, utilities try to obtain a reliable energy supply at the lowest cost. These should be the objectives of every utility trading floor. However, the concern in this volatile trading market is that retail customers not assume risks or higher costs because wholesale sales are not adequately or properly priced at the true costs of these discretionary sales.

Q. What is your understanding of the events that have led up to this hearing?

A. The Florida Commission Staff concluded that utilities no longer needed an incentive to make wholesale sales. It asked the Commission to consider doing away with the incentive. Utilities responded by suggesting that the incentive should be broadened. There have been a series of hearings focusing on the question of whether it continues to be necessary to offer incentives to investor-owned utilities to encourage them to maximize their wholesale sales.

On May 10, 2000, a hearing was held on this issue in Docket 991799-EI. As a result of that hearing, the Commission issued Order No. PSC-00-1744-PAA-EI on September 26, 2000. This Order allowed incentives to be applied to all non-separated wholesale power sales that exceed a benchmark. The incentive applies to both firm and non-firm sales, except for emergency sales. The Commission also dealt with the calculation of gains and the appropriate regulatory treatment for revenues and expenses associated with non-separated wholesale power sales. This aspect of the Order was Proposed Agency Action

(PAA) because there was no issue or evidence presented in the May 10th hearing on this subject. On October 11, 2000, FIPUG filed a motion for clarification of parts I and II of the Order, protested part III of the Order, and requested a hearing on the PAA section.

FIPUG pointed out that the Order, as written, could ignore higher cost replacement purchased power when determining the cost of an incremental sale even if the cost of replacement power far exceeds any benefits retail customers would derive from the wholesale sale. FIPUG asserted that the Commission did not intend to design an incentive that might promote such a bizarre result.

The formula for calculating the gains on wholesale sales should consider all of the costs of the sale. When a utility lacks capacity to meet the demand of its retail customers because it has entered into a non-separated wholesale transaction, the cost of replacement power is not to serve retail customers, but should be considered a cost of the wholesale transaction, exclusive of other appropriate costs involved in the transaction. The assumption is that the Commission wants wholesale sales to be made when, and only when, captive customers, who bear the cost of the plant in rate base, benefit from the wholesale sale. The Commission should require that the marginal cost on the utility system, whether generated or purchased, should be used in the calculation of the cost of a non-separated sale.

FIPUG's second contention is that proper regulatory policy should prevent a utility from double collection of costs. No O&M costs collected from wholesale customers should be retained by the utility when these costs are already paid by retail customers in their base rates. When calculating gains from non-separated wholesale sales, no revenue recovered as O&M costs should be considered part of the gain to be divided between the utility and customers because it is a cost reimbursement, not profit on the sale.

III. Summary

Q. Please summarize the elements of your testimony.

A. My testimony will address the issues raised by FIPUG in its protest and recommend "costs" which should be included in the calculation of the gains on making a wholesale sale. Such "costs" determine the margin or profit of an energy/capacity sale between utilities as defined by the Federal Energy Regulatory Commission (FERC). I will recommend a proper basis for determining the profit from applicable sales and a profit pooling mechanism that should be adopted to ensure that retail customers are protected against unwise wholesale sales.

Q. What is the guiding principle for calculating the profit on these sales for the protection of retail customers?

A. The revenues from non-separated sales must be reduced by removing the full costs attributable to the transaction. This procedure will protect retail customers from being required to subsidize the sale.

IV. Types of Sales

Q. Are all wholesale sales the same?

A. Not at all. There are numerous variations on the theme ranging from short-term emergency sales to long-term firm full requirements sales. In this case, we are dealing only with two broad categories of sales. These are firm and non-firm non-separated wholesale sales.

Q. What do you mean by separated and non-separated sales?

A. Separated sales are wholesale sales in which the generating plant, ancillary assets and all allocated expenses are removed from the rate base for ratemaking purposes. The utility keeps all the revenue from the sales and bears all of the expense related to the sale. Non-separated sales are wholesale sales in which the assets remain in the retail rate base. All revenue is allocated to retail customers and all fixed costs are borne by retail customers.

Q. Define a non-separated sale.

A. As stated above, a non-separated sale involves a sale where the utility has not broken out the cost components of the wholesale transaction and reduced its retail rate base for those components. The revenues from non-separated sales must be reduced by their "costs" so retail ratepayers do not subsidize wholesale transactions. The remainder or profit is distributed to retail customers or shared by retail customers and the utility, depending on whether the utility has met a sales or incentive benchmark.

Q. What types of wholesale sales are classified as non-separated?

A. Most non-separated sales are non-firm transactions, no longer than a year. Also included are firm sales of less than one year, and there may be some seasonal non-firm sales and sales which have some level of firmness depending on certain circumstances or events. Examples of sales with some degree of firmness might be a sale from a single generating unit (unit power sale), which is a firm sale only while the unit is on line. If the unit has a forced or planned outage, the sale is discontinued. Another example might be a reservation sale in which Utility A contracts with Utility B to make a purchase (normally over an extended period of time). The purchasing Utility A pays a fee to have the right of purchase, but it must notify the selling Utility B a set number of hours in advance on the day before

Utility A takes the capacity. At the point of notification, if Utility B has the power, the purchase for the next day becomes firm. There are an infinite number of ways to structure transactions which may have some level of firmness.

Q. When does the distinction between separated and non-separated sales become important to customers?

A. Generally only when there is a rate case or when rates are under a return on equity ceiling that requires a refund to customers when the ceiling is breached. Classification of a sale is important to utilities because it affects their stated regulatory earnings. Utilities file monthly earnings surveillance reports. If a sale is separated between rate cases, it doesn't affect base rates of retail customers, but it may trigger an over earnings situation. In the case of both separated and non-separated sales, the allocation of fuel costs is most important in protecting retail customers.

Q. Why do customers benefit from non-separated wholesale sales?

A. Retail customers pay base rates that cover the capital carrying costs and the fixed O&M expenses attributable to facilities in the retail rate base. However, retail customers do not require use of the generation capacity 100% of the time. When capacity is not being used to serve the retail load, retail customers can benefit from off-system wholesale sales if the revenue from these sales is used to reduce the utility's fuel cost recovery factor or other costs recovered through the cost recovery clauses.

Customers will always appear to "benefit" from a wholesale sale any time the sales revenue exceeds incremental sale costs. Sales of unneeded capacity should be encouraged, but care needs to be taken in today's active wholesale market that the incentive to make wholesale sales does not backfire and encourage off-system sales when capacity is needed to serve retail customers. If the utility can keep any portion of the revenue from off-system sales, but not face any risk when the rate-based capacity is diverted to wholesale transactions, then there is no corresponding disincentive to avoid risky wholesale sales.

Q. What differentiates firm sales from non-firm sales?

A. Utilities may enter into binding contracts with wholesale customers to maintain a firm supply of power to a wholesale customer, regardless of if the sale eventually proves to be profitable or unprofitable. For example, if Utility A has a sale to City C which will supply City C's full electrical requirements for more than one year, this would be a firm sale that should be separated from Utility A's rate base to accurately reflect its earnings. If the sale were less than one year, it would be a non-separated sale.

Non-firm sales may be recallable by the utility if capacity is needed to serve retail and wholesale requirements or to supply capacity to another utility which is in an emergency capacity situation. Let's say Utility A is making a non-firm sale to Utility B. Utility A's retail load rises to a level which requires Utility A to discontinue or recall the sale to Utility B. The key element of this non-firm sale is that there should be a superior obligation (meeting retail demand) which the selling Utility A should meet before it can make or continue a sale to Utility B.

Q. Are utilities required to recall a non-firm sale in order to serve retail customers?

A. By stated custom, yes, but not by FPSC mandate. It is my opinion that the FPSC should assert its authority to ensure that there is no doubt as to the regulatory policy of the state on this subject. The practice has been to recall the non-firm sales in capacity shortfall situations. It is my opinion that FIPUG is correct that a utility should be required to recall a non-firm sale in order to meet retail load demand. Now that the expanded shareholder incentive covers all wholesale sales, excluding firm long-term transactions, FIPUG has expressed legitimate concern that a utility may be tempted to maintain or enter into a non-firm sale to the detriment of its retail customers, and specifically, its non-firm retail customers.

Q. How can non-firm wholesale sales that are not recalled affect non-firm retail customers?

A. Non-firm retail customers may be forced to purchase optional power or even be interrupted while the utility is making a wholesale sale. Non-firm customers pay for the capacity in their overall retail rates, though these rates may be less than firm customers' rates. Non-firm customers pay less for this capacity because they have volunteered to be interrupted or purchase third-party option power when capacity is needed by a utility to protect its firm retail load. Non-firm customers were not informed and they did not bargain for the utility to use their loads as a vehicle to make wholesale sales.

Q. Is there a difference between a non-separated firm sale and a non-firm sale during a capacity shortage?

A. Yes, a non-separated firm sale normally has no recall rights unless conditions or events for recall are explicitly stated in the contract. Typically, there are no recall rights in firm sales contracts. If Utility A is in a capacity shortage, it must attempt to purchase power on the wholesale market to meet its obligations to serve retail and wholesale customers. If the capacity shortage occurs at a time when the utility is making wholesale sales, logic would dictate that the replacement power is being purchased to serve the wholesale sale, not the retail customers, who should have a higher priority of service from the utility's capacity. Utility A should not be allowed to purchase power and pass those costs directly through to retail customers via a recovery clause, but this can happen if care is not taken to prevent it. If Utility A cannot find enough power to cover its firm wholesale and retail demand, it can interrupt non-firm retail customers (interruptible, load management and curtailable). In this example, the costs incurred during the capacity shortfall are borne by the utility's non-firm customers who essentially "pay" so Utility A can make a wholesale sale to another utility. The potential adverse effects of a firm wholesale sale or a non-firm sale that is not recalled during a capacity shortage are, for all practical purposes, the same. There is the real potential for the costs of these sales to be inappropriately shifted to retail customers.

V. FIPUG's Protest

Q. Mr. Kordecki, with the above background in mind, describe FIPUG's protest.

A. Order No. PSC-00-1744-PAA-EI, Section III-Calculation of Gains and Appropriate Regulatory Treatment, contains four findings by the Commission which are the subject of this hearing. FIPUG has no disagreement with the general principles of the Commission decision but believes more specificity in the application of those principles is needed to equitably deal with the costs of wholesale transactions so that retail ratepayers are held harmless.

Q. Describe the first aspect of the PAA Order which requires more specificity.

A. Item #1 of the PAA states:

Each IOU shall credit its fuel and purchased power costs recovery clause for an amount equal to the incremental cost of generating the energy for each sale.

Q. What is FIPUG's concern with this statement?

A. The proper costing of incremental wholesale sales helps the Commission determine how well the utility is managing its assets in meeting its obligation of supplying reliable power at reasonable rates. If marginal or incremental costs are properly estimated, then cross-subsidy issues between retail customers and wholesale customers are minimized when making wholesale transactions. If there are any purchased power costs which are higher than the utility's marginal generating costs of its units, such cost must be included as the cost of the non-separated sale. When purchased power is the highest cost power on the utility system, <u>it is</u> the incremental cost.

Q. Can you give us some examples?

A. Yes. Let's say a utility is making a short-term firm sale of 100 megawatts at \$55/MWH of which \$45/MWH is considered the incremental cost (fuel \$40 and \$5 for everything else). A capacity shortfall occurs and the utility cannot meet its retail and wholesale requirements (in this example, the utility has no non-firm load). The utility then purchases 100 megawatts at \$70/MWH for five hours in the afternoon. In the calculation of the incremental costs of the 100 megawatt sale, the incremental costs in those five hours becomes \$70 plus any incremental "other" costs. In the calculation of the costs of the non-separated transaction, the \$70/MWH should be averaged into the calculation of the incremental costs of the sale.

Now we change the utility load from all firm to include 100 megawatts of non-firm load. The utility has a third-party option purchase provision in its tariff. The same anticipated capacity shortfall occurs and a purchase will be made by the utility. The incremental cost to make the 100 megawatt sale and maintain the retail and wholesale requirements is the same as the earlier example, where the utility had all firm retail load. The question posed in this example is: should the utility treat the purchase as part of the incremental cost to make the sale or should the utility be allowed to pass through the purchase costs of the 100 megawatt purchase to those customers whose non-firm tariffs have a third-party purchase option. The proper costing procedure is to count the 100 megawatt purchase as a part of the incremental cost of the sale. The existence of non-firm load is to help protect firm load from interruptions during capacity shortfalls. Non-firm load was never intended to help the utility make or protect off-system wholesale sales.

Q. Your example describes the utility making a 100 megawatt firm non-separated sale. What are the consequences if the sale is non-firm?

A. If the utility does not recall the non-firm sale, the results are identical to a firm sale. The Commission should require non-firm wholesale sales to be recalled during a capacity shortfall. Without a recall requirement, the Commission should use the incremental cost treatment previously described so that retail customers are protected from unreasonable costs.

Q. You have discussed situations where a utility finds itself both selling and buying in order to maintain a non-separated wholesale sale. If we change the example so that there is no purchased power available to cover the incremental sale during the capacity shortfall, what should the Commission require?

A. I would hope that the utility would recall the sale voluntarily. If the sale is firm or not recalled, customers will be cycled or interrupted. Some type of credit amount taken from the proceeds of the sales should be credited to the affected customers. A credit would reflect that retail customers were adversely affected by a sale that was not in their best interest. A credit for megawatts interrupted would also be appropriate. The marginal costs of third-party purchases or marginal power purchases for firm power should be applied to the estimated hourly megawatts and refunded to affected customers.

Q. What incentive is there for a utility to make sales that would adversely affect retail customers?

A. My comments are not meant to assert that utilities would intentionally make imprudent wholesale sales from their perspective. I am sure that their various planning groups and trading floors look at incremental sales with great diligence. But there can always be unforeseen events, such as unit forced outages, higher loads than forecasted etc., which may cause "unintended consequences" which result in higher costs which may be borne inequitably among the classes of customers. All incremental sales are made from reserves or excess capacity. When a utility uses non-firm load as part of its reserves and has a significant amount of its reserves supplied by non-firm load, aggressive wholesale sales activity can lead to higher incidences of "unintended consequences." The risks of interruptions or high cost third-party purchases for customers with this purchase provision increase when utilities have incentives to make more wholesale sales and are able to lay off the risks to retail customers.

Q. What can be done to limit the risks of higher costs to retail ratepayers from

wholesale transactions?

A. The following measures would help mitigate the risk:

1. Each non-separated sale should be priced at the marginal cost of the sale, as discussed earlier; and

2. A cumulative profit pool should be adopted for all non-separated sales.

Q. Explain how the cumulative profit pool would work.

A. When sales are properly costed, there may be instances when a non-separated sale is not profitable and incurs a loss. Hopefully, most sales will result in gains. The fuel factor is only adjusted annually; therefore, instead of dealing with each sale individually, the net revenues or profits should be accumulated for all non-separated sales, whether firm or non-firm. To the extent there are losses from some sales and credits from others, these losses and credits would be netted against the profit pool. This would ensure that there are truly benefits to customers before an incentive is paid to the utility. Total incremental costs of sales should be accounted for before any incentive mechanism is applied.

Q. What is the second aspect of the PAA that concerns FIPUG?

A. Item 3 of the PAA provides:

> Each IOU shall credit its operating revenues for an amount equal to the incremental operating and maintenance (O&M) costs of generating the energy for each such sale.

O&M costs are hard to quantify; it is even more difficult to identify O&M expenses that are not already being collected in the utility's base rates. All O&M expenses charged to a wholesale transaction should be credited back 100% to the appropriate clause(s) unless a utility supports the charge as a cost which is incremental to any present costs being collected by the utility in its base rates. If a cost is truly incremental, it may be appropriate to charge the sales with the cost and credit the utility's operating revenues. The utility carries a heavy burden of proof that a cost is incremental before any credit to operating revenues should occur. Remember that between rate cases and earnings restrictions, the utilities keep all revenue. It is appropriate for the utility to keep all revenue if it is an incremental cost recovery, but not appropriate for the utility to keep 100% of the money without sharing, if retail customers have already paid the cost through retail base rates.

Q. What are the other items covered by the PAA?

A. The second item in the PAA is:

> Except for FPC, each IOU shall credit its environmental cost recovery clause for an amount equal to the incremental SO2 emission allowance cost of generating the energy for each such sale. FPC, because it does not have an environmental cost recovery clause, shall credit this cost to its fuel and cost recovery clause.

It is my opinion that this is any appropriate cost that should be credited to the environmental cost recovery clause.

The last PAA item concerns transmission and capacity revenues and says:

> In accordance with Order No. FPSC-99-2512-FOF-EI, issued December 22, 1999, in Docket No. 990001-EI, each IOU shall credit its capacity cost recovery clause for an amount equal to any transmission revenues or separately identifiable capacity revenues.

Transmission and capacity costs paid to third parties in order to make a non-separated sale are part of the incremental cost of the sale. It should be clarified that these costs should be removed from the revenues before profit on the sale is calculated and will be removed from the margin. Crediting is appropriate for transmission revenues and separately identifiable capacity revenues but a more accurate method would be to credit the fuel clause for non-firm transmission transactions and credit the capacity clause for firm transmission transactions. In this manner, revenue would track the firmness of assets and not credit capacity when there is no firm transmission capacity obligation.

Q. Mr. Kordecki, please summarize your testimony.

A. My testimony describes protections against some potential "unintended consequences" which may occur with aggressive wholesale sales activities among Commission jurisdictional utilities. If we think of these sales as new incremental sales to a utility system, then their costs should be treated as incremental. I recommend the following procedures be applied to non-separated wholesale sales:

- Each utility shall credit its fuel and purchase power recovery clause for an amount equal to the incremental fuel cost of generating the energy for each such sale. In the event wholesale power is purchased to serve retail load while non-separated sales are being made, the highest cost fuel shall be allocated to the wholesale sale not to the purchase used to meet retail load.

If incremental crediting of the higher of either generated or purchased power costs is used for incremental non-separated sales, risks of higher cost to retail customers or non-firm retail customers due to these sales should be negated. The proper costs will be assigned to the cost causer-- the non-separated sales.

- All O&M costs assigned to non-separated sales should be treated as a cost and credited back to the fuel and/or capacity clause.

If a utility can prove by clear and convincing evidence that the O&M cost is incremental, that is, does not already exist in the retail customers' base rates and that no costs would exist without the sale, then and only then, can the O&M cost be taken from the margin or profit of the sale and credited back to the utility's operating revenues.

Q. Does this conclude your direct testimony?

A. Yes.

CHAIRMAN JACOBS: Do we have an order or -- would you like to go first, Mr. Beasley?

MR. BEASLEY: Yes. Thank you, sir. I think at the outset it might be good to address the two exhibits attached to Mr. Kordecki's deposition. I think that the second exhibit has been now marked as Exhibit 3, the memorandum of the staff dated September 20, 2000. And I believe that has been admitted into the record. The other exhibit I will hand out to you is a document that I want to ask Mr. Kordecki a couple of questions about.

CHAIRMAN JACOBS: Oh, they weren't attached to the transcript, they are separate?

MR. BEASLEY: They were attached to the transcript, so I don't know that they need to be marked as an exhibit here if they are a part of transcript if you allow it in.

CHAIRMAN JACOBS: I don't show any attachments to the transcript. Maybe I missed them.

MR. BEASLEY: It's attached to the original the court reporter has. I'm sorry, it wasn't attached to your transcript.

CHAIRMAN JACOBS: Okay. So you will mark this as Exhibit 7.

MR. BEASLEY: That sounds good.

(Exhibit 7 marked for identification.)

CROSS EXAMINATION

BY MR. BEASLEY:

Q Mr. Kordecki, do you recognize the document that has been identified as Exhibit 7?

A Which one, I was handed two?

Q All three of them. They are marked Roman numeral I, II, and III?

A Yes.

Q During the course of your deposition, did I give you certain assumptions regarding three different portfolios of power resource items?

A Yes.

Q And, for example, the first one included a combustion turbine peaking generation at $75 a megawatt hour, the one that says generation should say base load generation, but that is $25 a megawatt hour, and then the firm purchased power at $100 a megawatt hour, and then the must take purchased power agreement at $125 a megawatt hour?

A Yes.

Q And I asked you to arrange those. Those were on post-it notes, and I asked you to arrange those in ascending order of how you would dispatch those units, is that correct?

A For economic dispatch, that is correct.

Q That's right. And these are the results of your having put these in the order of how you would dispatch them for economic dispatch, is that correct?

A That is correct, for economic dispatch.

MR. BEASLEY: I would offer this as an exhibit, which is Mr. Kordecki's acceptance of a hypothetical, and his arrangement of the order of these in which he would dispatch it as being an indication of what he believes should be the dispatch order, and ask that it be included as part of the deposition transcript.

CHAIRMAN JACOBS: I tell you, since we had already marked and we didn't -- I guess had I known it we could have included it as part of the deposition transcript. But since I already marked that and I didn't have a copy of it, why don't we just make that a separate exhibit. So the transcript is marked as Exhibit 1?

MR. BEASLEY: Yes, sir.

CHAIRMAN JACOBS: And I think we marked this as Exhibit 7 just now.

MR. BEASLEY: Okay.

MR. BURGESS: May I ask on clarification now, the transcript is Exhibit 1, has there been a distribution of that transcript?

CHAIRMAN JACOBS: Yes. I thought it was distributed. I have a copy.

MR. BURGESS: If you have got an extra copy, I would appreciate it.

MR. BEASLEY: You don't have a copy, Steve?

MR. BURGESS: I don't think so. Thank you, Mr. Chairman.

BY MR. BEASLEY:

Q Mr. Kordecki, is it true that you prepared and submitted your testimony in this proceeding solely to address the size of the incentive pot and nothing else?

A To specifically address how incremental cost and incremental O&M should be treated for purposes of arriving at the gains or the profits from nonseparated wholesale sales.

Q Would you turn to your deposition at Page 47, please, and read me the statement at Lines 19 through 21?

A "My testimony specifically is only to address the size of the incentive pot, so to speak, or what is eligible for incentive, nothing else. It wouldn't matter if the Commission went to a 50/50 sharing or an 80/20, if the utilities gets," et cetera, et cetera.

Q Is it true that the only difference between the Commission's proposed method and your proposed method of calculating the incremental cost of a nonseparated wholesale sale is that your method shrinks the incentive pot?

A No. My first comment would be that as stated in the order, I don't believe incremental costs, they seem to be specifically related only to generation and not to purchases in terms of how you would effect the incremental cost, being whichever was higher at the time of a separated sale. So that is specifically what I was addressing in terms of the fuel cost used for determining separated costs.

Q Would you turn to Page 39 of your deposition, please. There were you describing your methodology for calculating the gain?

A Starting at Line 4, or I'm sorry, starting at Line 9? Where am I starting? "Well, then, would the shrinking of that incentive pot tend to discourage as opposed to encourage or be neutral to the utilities to make these off-system sales," is that what you are saying?

Q If you would just read for us, please, the paragraph that begins on Line 4 and ends on Line 8?

A "What I'm saying is that the customer should not bear it. The utility doesn't bear any losses. All right? The only thing that it accomplishes is to shrink the incentive pot. They'll see that, and that is the only thing it does. The customers still bear the cost."

Q What is the only thing that accomplishes, what is the thing you are referring to there in that sentence where the only thing that that accomplishes is it shrinks the incentive pot?

A By using the incremental cost and applying it probably in this case specifically to firm or short-term firm sales is that you would be applying to the separated sale in all probability higher incremental costs than would be applied or were being applied by the utilities. Because they are using basically that sale -- once the sale is made, or the purchase is made, I'm sorry, it becomes a zero cost sale. And to that extent, by moving that higher cost sale and applying it to the separated sale cost, you by definition will lower the amount of gain and therefore you will shrink the pot.

Q Is that the proposal that you are sponsoring in this proceeding?

A Is to use incremental cost of purchases as the surrogate for the cost of fuel as applied to nonseparated sales, that is correct.

Q And is it correct that the only thing that accomplishes is that it shrinks the incentive pot?

A No, I think it accomplishes some other things. I think it --

Q Well, what were you referring to on Page 39, Line 6 and 7 when you said the only thing that accomplishes is it shrinks the incentive pot?

A Effectively that's what it does. I think later you will find that I made some other comments.

Q Does shrinking the pot mean it reduces the total gains that may qualify for the utility to receive an incentive on?

A What it does is put into perspective the way the utility is operating the whole system between serving its retail customers and serving wholesale customers. And to the extent the retail customers may be absorbing costs because of sales, it shifts those costs over to the sales. Ultimately they will pay the same cost.

Q Could you answer the question whether shrinking the pot means it reduces the total gain that may qualify the utility to receive an incentive?

A Well, that line does, yes.

Q Okay. Mr. Kordecki, is what shrinks the pot the fact that your method on occasion will substitute a higher purchased power cost in place of the true incremental cost of a nonseparated sale at times when a utility happens to be buying higher priced firm power at the time of the sale?

A If the example is only firm power, yes.

Q Okay. So you really use a surrogate for incremental cost, don't you?

A That's correct, that's what I said.

Q A higher priced purchased power?

A Using the higher purchased cost that is supporting the overall sale, the overall load and sale.

Q But that is really a proxy for the incremental cost of the sale, right?

A Yes, it's not the dispatched cost?

CHAIRMAN JACOBS: How you do the matching of that?

THE WITNESS: I'm sorry?

CHAIRMAN JACOBS: I'm a bit naive on this, but I want to make sure I understand what you're saying. As I take it you would have identified that there was -- that for a wholesale sale there would have been a purchase power transaction to cover that?

THE WITNESS: No, not necessarily. It would be a situation where a utility was making a nonseparated sale and it was also purchasing power at the same time.

CHAIRMAN JACOBS: But not necessarily to cover that wholesale sale? In other words --

THE WITNESS: It basically is the purchase is being used to cover the whole load and that sale as far as I'm concerned.

CHAIRMAN JACOBS: Okay. And then you would then take the cost of that purchased transaction as a surrogate for what should have been a gain on the sale?

THE WITNESS: It would be a surrogate for whatever the utility was using as its incremental fuel cost.

CHAIRMAN JACOBS: Okay.

THE WITNESS: If it's higher.

CHAIRMAN JACOBS: And so my question then, you wouldn't need to match it to any particular sale, then?

THE WITNESS: No, it doesn't match the sales. Everything goes to the increment.

CHAIRMAN JACOBS: Okay.

BY MR. BEASLEY:

Q Mr. Kordecki, you would use the higher priced purchased power cost even when it is a zero incremental cost must take purchase, would you not?

A Yes, because of the timing issues, yes.

Q It's your view, is it not, that any higher priced purchased power should be, quote, used as the incremental cost of making a sale, even in circumstances where it doesn't reflect the true incremental cost of the sale?

A No.

Q What would you use?

A I would exclude all long-term firm purchases that were being used as reserves like on the ten-year site plans. In other words, if a utility was making a firm purchase and using it as reserves, I would not -- I would exclude those. Only short-term.

Q But you wouldn't look at the true dispatch incremental cost of that sale, would you? You would use whatever higher priced cost is being made during that time frame whether it was made for that sale or not?

A Yes. And I will explain to you why. What is bothersome is the ability for the utilities to make very conservative must buy or firm purchases and then turn around and treat those as zero cost. And at that point sell on their increment which is lower than that the cost of that purchase.

At that point it gives a much larger gain.

Q You think they would do that to get a gain for purposes of incentives?

A I just don't think it should be there.

Q Well, do you think the utilities would do that in order to gain incentives?

A I have assumed for my testimony that they are all making prudent decisions. Now, some of those prudent decisions cost be very conservative.

Q Mr. Kordecki, in your view of calculating gains there might be no relationship whatsoever between the costs that you are using for incremental costs and the actual incremental cost of a sale, isn't that correct?

A Not totally in my testimony, no. You have assumed that all the purchases -- if you are assuming that all the purchases are firm and that at that point they take a zero incremental cost, yes, but some of the purchases may not be firm.

Q Would you look at Page 38 of your transcript. I asked you the question so there might be no relationship between that cost that you are using as the incremental cost and the actual incremental cost of the sale?

A Yes, there might not be.

Q What was your answer to that? Line 24.

A "There are instances where that is true, that is correct."

Q Okay. Your substitution of higher cost purchased power isn't affected by when the purchase commitment was made or whether the decision to purchase was prudently made, is it?

A It may not have, yes. I mean --

Q But your substitution of the higher purchased power cost doesn't depend on those parameters, does it?

A Well, it depends on what time that -- I'm sorry, when the purchase was made.

Q How about when the decision to make the purchase was made?

A Well, the same thing. In other words, if the utility already had the nonseparated sale, they might make the firm purchase after they have contracted for the sale.

Q The use of the higher priced purchased power cost in lieu of the true incremental cost of the sale is what would have the effect of shrinking the incentive pot, is it not?

A As a surrogate, it will -- as long as there are higher costs in that increment, yes.

Q Well, shrinking the pot would reduce the potential for a utility to receive an incentive, would it not?

A It will reduce -- two things. It will reduce the incentive, the potential for incentive, but it also potentially may reduce risky purchases and sales. I'm sorry, sales. And to the extent that those sales will be borne -- or purchases will be borne by retail customers.

Q Mr. Kordecki, have you looked at the item, the item that has been marked in this hearing as Exhibit 3, which was Exhibit 2 to your deposition transcript, that being the September 20, 2000, staff recommendation from Mr. Keating and Mr. Bohrmann to the parties in the fuel docket?

A Yes.

Q Do you accept this as a reasonable method of implementing what the Commission has decided in the way of an incentive mechanism?

A I think it implements what the Commission decided, not necessarily the specifics of the definition of gains and -- which is the subject of this hearing, it is a method to roll it into the fuel clause, that I would agree with.

Q Did you say during your deposition that it is fine as far as a way of implementing what the Commission adopted as an incentive mechanism?

A Yes. But my intention was in terms of how it was going to be adopting the incentive mechanism in terms of how it was going to be used in the fuel adjustment. Not the elements necessarily of each one of the items. I believe those are the subjects of the hearing today.

Q But this road map for implementation doesn't really deal in those, does it, the details of gains and whatnot?

A No, that's what I'm saying.

Q So for purposes of what it is written for, you have no difficulty with it, do you?

A The form, no.

Q Substance?

A Yes.

Q What difficulty do you have?

A I'm not sure that it is appropriate to estimate gains.

Q I'm sorry?

A I'm not sure it is appropriate to estimate gains.

MR. BEASLEY: Thank you. That's all we have.

CHAIRMAN JACOBS: Mr. Badders.

MR. BADDERS: We don't have any questions for this witness.

MR. McGEE: Just a few, Mr. Chairman.

CROSS EXAMINATION

BY MR. McGEE:

Q Mr. Kordecki, do you by any chance have a copy with you of the protest that FIPUG filed that was the reason we are here for this hearing today?

A No.

Q If I may, I would like to show you the one I have. I have shown you a copy of the protest, and on Page 10 there is a recommended revision to Item Number 1 in the PAA portion of the order that we are considering today. And FIPUG there has in the underlying portion indicated the revision that it thinks needs to be made. On Page 17 of your testimony you indicate a recommended revision to this same Item Number 1 from Part 3 of the PAA order. Yours is different than the one in the protest. If you need a minute to compare those two, I would be happy to give you that.

A Yes, I see that.

Q Florida Power at the time it filed its testimony did not have your testimony before it, of course, and was commenting in disputing the revision that was recommended or suggested in that protest. Would it be fair to say that you also disagree with that in that you have changed in a fairly significant way the portion of the modification in that suggestion?

A Yes. I believe, as stated in the protest, the applicable fuel cost factor probably was inappropriate in terms of the calculation. You arrive at that calculation by doing -- by assigning the incremental cost and then whatever falls out becomes the applicable fuel factor.

Q And the other element that at least I had identified as being different between the one in the protest and in your testimony, the recommendation in the protest provided for a particular treatment that would be given to buy-through customers, meaning interruptible customers. You also agree that that is not appropriate to be included in the Item Number

1?

A I think the buy-through power when nonseparated sales are taking place is appropriate. I'm not sure it is appropriate in terms of defining what the incremental cost is, no.

Q That is the issue that we are dealing with today, right, the identification of the proper amount of incremental cost?

A Right.

Q Just one other clarification point. On Page 16 you have a question and answer that goes to the top of 17 that deals with the second and fourth item in the PAA portion of the order we have been discussing.

A Right.

Q The protest that you have in front of you identifies Items 1 and 3 as the elements of that PAA portion of the order that are being protested.

A That is correct.

Q Would you agree that this question and answer that begins on Line 9 of Page 16 has nothing to do with any of the issues that are before the Commission today?

A Yes. That was my error when I wrote my testimony. I addressed all the issues and probably should have removed it before it was filed.

Q Okay. Do you recognize the possibility that a nonseparated wholesale sale by a utility could be advantageous to the general body of ratepayers and be disadvantageous to interruptible customers?

A A nonseparated sale may be disadvantageous to interruptible customers. You have to explain to me in what way.

Q Well, maybe we can look at that by using your example. On Page 12 of your testimony you have a two-part hypothetical. And in the second part you are dealing with a firm sale that a utility has made for 100 megawatts. The utility also has 100 megawatts of nonfirm load.

A Right.

Q By the price figures that you have given, the general body of ratepayers will benefit from that sale by the difference between its costs and the revenues that it receives, or $10, and I guess in this case if the utility is over the threshold it might be 80 percent of that. The incremental customers suffer an increased risk of being interrupted by that 100-megawatt firm sale, don't they?

A Yes. I would like to comment to what you are asking me. This is not a subject of this hearing. I think there is a significant policy question about utilities making sales that are nonseparated. In other words, the existing retail customers are paying the fare, the total fare, and interrupting either load management customers, or interruptible customers, or other nonfirm customers in order to continue to make that sale. I don't believe the tariffs state the ability of the utility to do that. I believe there is a rock and a hard place problem once a firm contract is signed. I agree that that is a problem, but I think that is probably a problem the Commission might want to address in another hearing, or under another venue.

Q If the utility were to enter into a sale of the type you have described in your hypothetical on Page 12, it would be clear that that would produce a benefit that would be received by the general body of ratepayers, is that correct?

A Yes, to the deference of those people who were interrupted or had to buy third party.

Q Which actually that brings up another point I wanted to ask you about. You were describing a situation on Page 14 of your testimony in the answer that begins on Line 10, and you talk about even if the utility and its planners and traders are making incremental sales using great diligence, you still have the possibility of unforeseen events that could result in unintended consequences, but you conclude by saying that these unintended consequences may be borne inequitably among the classes of customers. I take it from that you mean borne inequitably by nonfirm customers?

A Yes. All the nonfirm customers, that is correct.

Q I'm curious as to the inequity that is involved in the consequences, those unintended consequences of unforeseen events being borne by the nonfirm customers when those customers are being compensated to incur that risk.

A Well, I don't believe they were. I believe that they signed up for the various nonfirm rates in order to be part of the -- I will call it reserves for the individual utility to serve its firm load. The Commission changed that slightly, or actually slightly more than slightly, I believe in 1993 when it ordered that utilities would use their -- interrupt their nonfirm load to sell to firm load of other utilities under emergency conditions. I have never read anything that said the Commission has stated that the utility should be interrupting or buying third party so that utilities could make nonseparated wholesale sales. So I think you and I are reading possibly the tariff of the utility differently.

Q Well, if we set aside the situation where it is possible that a utility may need to interrupt nonfirm load to make sales to maintain the firm load of other utilities --

A The emergency condition, that is correct.

Q We have a situation in the example that you have used where a sale is being made that -- if I understand what you have just indicated -- clearly is to the benefit of the general body of ratepayers, it allows the assets that they are supporting to more efficiently and they are credited with the profit from that. Why is it that you think it is inappropriate that customers who are being compensated to incur a higher risk of interruption should allow that beneficial sale to continue?

A Because I don't think when they signed up for the various tariffs were aware that their service would be possibly interrupted, or in the case of buy-through increased prices in order for the utility to go out and make incremental sales out of, in a sense, incremental available capacity. I think they signed up to be part of the reserves to protect firm load.

Q All right. And if that were the case and the utilities were required to engage in wholesale market transactions with that view that you just expressed in mind, you would agree that there would be less of these nonseparated sales made by the utility?

A Well, from what I heard this morning, apparently no one is making firm sales. Everyone stated that they are making nonfirm sales. And when they become short of capacity they recall them. So if that is the condition today, I don't see that in one sense this is going to be affected at all.

Q So you don't see that there is a problem?

A I don't see there is a problem as long as that is what utilities are doing, but they are not required to do that.

Q Well --

A They do that as part of their policy or procedure.

Q Would you expect that a utility making a sale at any given time that that sale may take place would receive more if they -- if that sale was made under firm conditions than under nonfirm conditions?

A I would think so, yes.

Q And that would increase the benefit of that sale to the general body of ratepayers?

A That would also increase the likelihood that these nonfirm customers would be either interrupted or inconvenienced.

Q So it would be your testimony that the utility should avoid the situation where it can maximize the profit from its sale in order to take greater care that interruptible customers aren't interrupted?

A Nonfirm customers, not interruptible customers. In other words, you have a lot of other types of nonfirm customers. Yes, I believe that is -- I don't believe that that is what those people signed up for. I don't believe that you necessarily should use one class of customers to subsidize, in a sense, the other balance of classes. I think that is like the cost of service parity rule. And I think what you are stating, I think, is what you are advocating.

Q Just one more question. You have an indication on Page 11 of your testimony, Line 18 and 19, that retail ratepayers should be held harmless from the effects of the utility's nonseparated sales. Do you see that?

A Yes.

Q I'm curious as to how you mean that. Going back to your example where a utility is making a sale for 24 hours, and during five hours of that 24-hour sale the sale is unprofitable. Should the ratepayers be held harmless from the effects of the five hours even though the overall sale is profitable?

A Yes. In the sense that if there are higher incremental costs during those five hours, then they should be -- they should be used as the incremental cost of the sale. The hold harmless part is to the extent that the utility may be above the benchmark that, in fact, the utility customers are sharing a greater amount of the, quote, profit that was slightly inflated by the way the sales may have been managed and the purchases were managed.

Q All right. I may not have made that clear. Under your example, the utility would be receiving a gain of $10 each hour -- well, actually $10 times 100-megawatt hours during each hour except for the five hours that you have identified in which there would be a loss of $15?

A Right.

Q So with the five-hour loss of $15 you are looking at 75, a 19-hour period with be a gain of 10, you would be looking at $190.

A Right.

Q The net effect would be $115 for the overall transaction to the good. Should the fuel clause process the $115 net gain, or should the loss of $75 be excluded in the utility required to pass-through a gain of $190?

A I may have misunderstood the way you dealt with it. I didn't see that being a loss, I just saw a smaller gain relative to what was going to be established for the benchmark.

Q Well, you talk about making a purchase during the five hours at $70.

A Right. The inclusion of those costs will lower the level of, quote, gain. The dollars are still going to be paid in the fuel clause. They are still going to be paid.

Q After the netting takes place?

A Right.

MR. McGEE: Thank you. That's all I have.

CHAIRMAN JACOBS: Mr. Childs.

CROSS EXAMINATION

BY MR. CHILDS:

Q Mr. Kordecki, what methodologies to determine variable O&M for the investor-owned utilities in Florida have you evaluated?

A The only thing I have looked at -- and it was post my testimony was what was filed in the interrogatories.

Q So when you critiqued the variable O&M methodology language in the Commission's order, you were not aware of what the utilities did to quantify their variable O&M?

A The way I looked at that language was that it didn't define the boundaries or what should be in the calculation of that. I thought that's -- what my testimony addresses is there ought to be a standard calculation assigned methodology for at least assigning the calculation of that, yes.

Q Do you know how the methodologies that have been discussed, even those as to which you have become aware after your testimony was filed, for the investor-owned utilities differ from the methodologies that they have filed with this Commission in connection with purchases of power from qualifying facilities?

A I know that in qualifying facilities there is an O&M adder given to the QFs. To the extent they may be different from utility to utility, I really don't know.

Q But there was a concept there that utilities when they purchase are avoiding O&M when they purchase from qualifying facilities, isn't that correct?

A There is a concept, yes, theoretically.

Q Well, it's not -- I mean, is it theoretical because you take exception with what the Commission requires?

A No. I think it basically becomes a mathematical calculation based on theory, yes.

Q All right. Then I want to go back to --

CHAIRMAN JACOBS: Could I ask a quick question on that? Is the upshot of your position that wholesale customers are paying O&M costs in nonseparated sales?

THE WITNESS: Well, I believe the utilities are collecting O&M costs when they make a nonseparated sale. To the extent of the level of that cost and how it is calculated, there are two aspects. One is that they should come before the Commission and support the calculation. I don't find that to be anything problematic. Two is that they need to come in and support the idea that those dollars aren't already being collected.

CHAIRMAN JACOBS: Okay. Is it --

THE WITNESS: To the extent that both of those are met, fine, I have no problem with them collecting incremental O&M.

CHAIRMAN JACOBS: It is a fair assumption to assume all O&M costs would be in retail?

THE WITNESS: No. I think it really depends on the level of O&M that has been granted to the utility previously, expanded for whatever sales or however it was expanded, and I think sales is probably the best surrogate for a variable in terms of what was separated into retail rate base. In other words, if there was $100 million of O&M and sales are now -- for retail purposes are 50 percent higher, then they are collecting approximately -- all things being equal, 150 percent more of that O&M than they were granted. To the extent that their O&M level now is less than that expansion factor, I don't think they should get any, should get the O&M. If it is greater than, then that's fine.

CHAIRMAN JACOBS: Now, at a practical level -- let's say we accept your position. I'm trying to think how we would implement it. It sounds like you would have to figure out a way to take out O&M from the proceeds of the --

THE WITNESS: I think you could go back to the last rate case, and in some cases you may have to go through the archives for a couple of these companies and take whatever O&M budget they are allotted and expand it for whatever sales increases have taken place since then. I think it's a reasonable surrogate.

CHAIRMAN JACOBS: No, I understand that part. I'm going forward to implementing how we would address your concern with regard to the wholesale -- dealing with the gains, I'm sorry.

THE WITNESS: Well, to the extent that their O&M expenditures today are less than what would be found in the applicable rate schedules totalized, I think it should all be credited back to the clause. To the extent it may be higher than, then they should keep -- in other words, then they have a problem and they should keep --

CHAIRMAN JACOBS: Okay. I was going -- you would do some kind of formula where you try to take it out of the gains before you do the 80/20 or something?

THE WITNESS: No, I just want to know -- it's where you put it. In other words, as soon as you all have decided what it should be, or how it should be calculated uniformly, or reasonably uniformly, then the second step would be to calculate, in fact, if it is already being collected or not being collected in base rates.

CHAIRMAN JACOBS: Thank you.

BY MR. CHILDS:

Q Isn't the essence of calling it variable to indicate that the cost level varies with the level of kilowatt hour output?

A No argument that it is not an additional cost.

Q Okay. And isn't the concept that this Commission has used as to variable O&M in connection with purchases from qualifying facilities based on that premise, that is, that by avoiding the necessity to generate itself the utility is avoiding an O&M cost?

A Yes, I don't have a problem with that.

Q And the flip side of that is that if it does generate to make an off-system sale it is incurring a cost, it's variable?

A Yes.

Q I want to turn you to your testimony on Page 14. Mr. McGee asked you about it. It's a question and answer on -- it's a question starting on Line 8 of Page 14. You're talking about your testimony here that addresses, I believe, Issue 2, which has to do to the calculation of gains, is that correct?

A Yes.

Q And so as I read this testimony what you are saying is that it doesn't make any difference whether the utility's actions were prudent, you still propose this is a proper adjustment?

A No, I think what I'm saying is I am assuming that their actions were prudent, but I'm not sure that they ought to be rewarded --

Q For being prudent?

A -- for actions that are outside of their control that may, in a sense, turn out to be mistakes.

Q They are really not outside of their control, are they?

A Well, I think they are in the sense that they have like a forced outage that requires something to take place or something like that.

Q That is outside of their control. But they are not being rewarded for that. They are being rewarded for achieving a gain on a sale, aren't they?

A Well, to the extent that the ratepayers are subject to higher costs, let's say, because they had this forced outage, then they are being rewarded for a sale based on a cost, and that that cost is not tracking what happened in the unintended event. In other words, they actually might be able to make a sale because of a problem.

Q I want to understand, and I want to backtrack for a minute on variable O&M. To what extent do utilities include variable O&M in their dispatch costs?

A I believe they do.

Q They do. Why do they do that?

A Because they can bring in the revenues and they believe -- I hope they believe they have a cost and they also get the revenues for it.

Q Well, dispatch cost is used for more than making purchases off-system, isn't it?

A For making sales?

Q It's used for dispatching your system, isn't it?

A Right.

Q Isn't that correct?

A Yes.

Q So you have a different variable O&M associated with one unit than you do for another, isn't that correct?

A That is correct.

Q And so the utility in attempting to achieve lowest overall cost factors that in to its evaluation process?

A It should, yes.

Q And, therefore, when it makes an off system sale it should attempt to recover the incremental O&M in the purchase price that it receives for the sale, should it not?

A I have no disagreement with that.

Q Okay. Now, let's go back to this discussion. You said also, I think, in discussing this, and I may not have your comment word-for-word correct, but correct me to the extent it is wrong. I thought that you said in your approach about using the purchased price, the fuel cost of purchases if higher, the reason that was proposed was to reduce risky sales situations to the extent the risk is borne by the customer. Is that in close proximity?

A Generally that is good enough.

Q I want to explore with you the extent to which that is a realistic estimate of what goes on today in terms of utilities' decisions. You don't have the view that utilities are selling -- would be selling capacity on a firm basis even if that is what they did, and reduce -- and create a risky situation, would you?

A I'm not sure I necessarily agree with that, but generally I would agree with that.

Q Okay. Well, let me show you a document. Mr. Kordecki, what I have given you is a page from the rules of the Commission. And what I'm going to reference is the Rule 25-6.035, adequacy of resources.

MR. CHILDS: And, Mr. Chairman, I would like to have that marked for identification.

CHAIRMAN JACOBS: Show that marked as Exhibit 8.

(Exhibit 8 marked for identification.)

BY MR. CHILDS:

Q Now, as to the utility's obligation, the first sentence under Subsection 1 of that rule requires the utility to maintain reserves, as I read it, sufficient to meet all reasonable demands for service and provide a reasonable reserve for emergencies, isn't that correct?

A That's what it says, yes.

Q So when a utility made an off-system sale on a firm basis it would still -- or it is supposed to meet the requirements of this rule, isn't that right?

A It should, yes.

Q It should. And so if we had a situation where the utility ended up incurring a purchase price such as you pose, it would have had to have inadequate generation to meet load, wouldn't you agree?

A You're talking about operating reserves, correct?

Q I'm talking about whatever reserves are available. In reserves it would not have capacity available to it on its system to meet its demand and, therefore, would have to make an off-system purchase?

A That is correct.

Q And it would do that, it would make that purchase only because the emergency was so significant that it was beyond the requirement of this rule, wouldn't you agree?

A Generally, yes.

Q Generally, yes. Okay. Now, the next question I want to ask about relates to Subparagraph 2, which addresses purchased power. And there it says only firm purchased power agreements may be included as a resource for purposes of calculating a planned or operating reserve margin.

So, if we had the situation that you postulate where a utility is making a purchase, then I would assume it would be a purchase that was not firm and not included in this part of the rule.

A Well, I think where it becomes a little cloudy to me is the term describing the varying levels of firmness.

Q The rule doesn't describe that?

A The rule doesn't, but I think the market has evolved that way. And I'm not sure that the rule necessarily conforms to what people call firm and nonfirm.

Q Would you read the next sentence of that section of the rule, however. Doesn't it say the utility may ask for a waiver based on the very high availability of specific nonfirm purchases?

A Yes.

Q Isn't that exactly what the Commission was talking about as it wasn't really firm, but it had -- in the sense of being absolute, but it had some firmness attached to it?

A Yes.

Q So here we have a requirement, and I'm trying to understand the riskiness. It would seem to me that the utility making these sales would -- if it violated this rule, it would probably be imprudent, wouldn't you say?

A Well, it may be unintended. In other words, it may end up violating the rule in the sense that it is after the fact, and that's where I have got the -- where there is a problem.

Q Well, if it didn't maintain adequate plan reserves and it made off-system sales on an opportunity basis, wouldn't it be considered imprudent to make the off-system sale?

A Apparently there must be some disagreement about the adequacy issue, because I think we sat through about three days of hearings where no one really particularly agreed about what adequacy was, particularly in operating serves reserves. So to that extent I'm not sure because it is written here necessarily means that everybody agrees that everyone is performing to the same level.

(Simultaneous conversation.)

Q Well, this tells you what you do, doesn't it? Doesn't this rule tell you what is supposed to be done?

A What you are supposed to do, that is correct.

Q And are you familiar that utilities report every day to everybody else what their planned units to operate for the next day are?

A Yes.

Q They tell everybody what units they are going to operate, don't they?

A Well, yes, functionally the same.

Q And they tell what you units are down, not going to operate?

A For the most part, yes.

Q And what units are constrained, right?

A Right.

Q And what their expected load is, right?

A Right.

Q And so the whole purpose is so there can be all the utilities together to plan to meet the load for the next day?

A Right.

Q And the next week and the next month, isn't that right?

A That is correct.

Q Okay. So, in order to make an off-system sale -- excuse me, in order to make an off-system purchase to fit your criteria it would have to be a nonfirm purchase, wouldn't it? A purchase that you didn't anticipate making?

A No.

Q Isn't that what you are talking about here in your testimony on Page 14, unforeseen events?

A Right.

Q So you wouldn't plan to make a purchase if you didn't -- if you weren't aware that the unforeseen event would occur, would you?

A I think we are starting to talk past each other.

Q Maybe.

A My feeling is that you may have made what apparently could be a prudent purchase, because let's say you have a couple of units that are limping and you're not sure they are going to make it.

Q So you make a purchase?

A And you make a purchase.

Q You make a firm purchase?

A Yes, make a firm purchase.

Q Okay. And then your position is that ought to be used as the dispatch, or as the incremental cost if a utility then makes an off-system sale?

A That's correct.

Q Okay. And I'm not talking about that circumstance. I'm talking about the circumstance where the purchase comes around because of an unforeseen event and the utility makes the purchase.

A Yes.

Q Wouldn't that be either a nonfirm purchase or one that was entered into after the utility had committed to the sale?

A In other words, in the event -- yes. As you have described it, yes.

Q And if the utility knew that it was going to incur that cost, it would have used that in its dispatch price, wouldn't it?

A It should, yes.

Q It should. Okay.

MR. CHILDS: That's all I have.

CHAIRMAN JACOBS: You didn't have any? Good, because I took you out of order.

Staff.

CROSS EXAMINATION

BY MR. KEATING:

Q Just a couple of questions. This may cover some of what you just discussed with Mr. Childs, and if I am duplicating, I apologize. But in the event -- I want to make sure I have your position clear.

In the event the utility makes an unanticipated purchase due to an unforeseen circumstance such as an unplanned outage at the same time that it is making a nonseparated firm wholesale sale, what should be or how should the incremental cost of the sale be determined for purposes of calculating the gain on the sale?

A If the purchase is higher than the incremental generating cost, then it should be used, for purposes of the incentive used as the incremental cost.

Q And that would be your position even in the event that the purchase is made because of an unplanned outage?

A Yes. For purposes of deriving the incentive, yes.

Q And if the purchase was made in consideration of making a nonseparated wholesale sale, would your position be the incremental cost is still the purchase price or the purchased cost?

A Say that again, please.

Q Yes. In the event that the utility planned a power purchase in consideration of making a nonseparated wholesale sale, under that circumstance what is the incremental cost?

A If that is the higher cost, then that should be the incremental cost.

MR. KEATING: Okay. That's all that I had. Thanks.

CHAIRMAN JACOBS: Redirect. I'm sorry, Commissioners, any questions? I have one very quick question. You advocate looking at the whole idea of incentives on a system-wide basis more so than a transaction basis, is that a fair statement?

THE WITNESS: Yes, because I believe that the utility should and does attempt to manage the system both for retail and for wholesale purposes, so to that extent you should look at the whole system.

CHAIRMAN JACOBS: And the underlying premise of that is that -- well, you just said it, is that there has to be some level, some view of how the system is being managed relative to the interest of wholesale and retail?

THE WITNESS: That is correct.

CHAIRMAN JACOBS: The challenge, of course, being how do we balance that with regard to the incentive mechanism and this is your answer to how to do that?

THE WITNESS: Yes. My testimony does not reflect that people are necessarily imprudent in what they are doing, just that the incentive gained should not be enlargened or be greater than the net effects of what is happening on the system.

CHAIRMAN JACOBS: Okay. Redirect.

MR. McWHIRTER: No redirect.

CHAIRMAN JACOBS: And there was one exhibit. I'm sorry, two exhibits.

MR. McWHIRTER: Those were not proffered by me.

CHAIRMAN JACOBS: One by TECO.

MR. BEASLEY: We would move Exhibit 1 and 7.

CHAIRMAN JACOBS: I'm sorry, there were three exhibits, you're right.

MR. CHILDS: I move Exhibit 8.

CHAIRMAN JACOBS: Without objection, show Exhibits 1, 7, and 8 are entered into the record.

Thank you. You are excused, Mr. Kordecki.

(Exhibits 1, 7, and 8 admitted into the record.)

MR. BEASLEY: Recall Witness Jordan.

CHAIRMAN JACOBS: Mr. Jordan. I have to attend to a matter upstairs. Absolutely no disrespect to you, Ms. Jordan, but since we are at a closing out, I will listen to the remainder of the testimony -- or, I'm sorry, I will be reading the transcript of the remainder of the testimony before our decision. Thank you.

Commissioner Jaber.

Thereupon,

J. DENISE JORDAN

was recalled as a rebuttal witness on behalf of Tampa Electric Company, and having been previously sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. BEASLEY:

Q Ms. Jordan, did you prepare and submit in this proceeding a 12-page document entitled Prepared Rebuttal Testimony of J. Denise Jordan?

A Yes, I did.

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

A Yes, they would be.

MR. BEASLEY: I ask that her testimony be inserted into the record as though read.

COMMISSIONER JABER: Ms. Jordan's rebuttal testimony shall be inserted into the record as though read.

TAMPA ELECTRIC COMPANY
DOCKET NO. 010283-EI
FILED: June 11, 2001

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

PREPARED REBUTTAL TESTIMONY

OF

J. DENISE JORDAN

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

A. My name is J. Denise Jordan. My business address is 702 North Franklin Street, Tampa, Florida 33602. I am employed by Tampa Electric Company ("Tampa Electric" or "company") in the position of Director, Rates and Planning in the Regulatory Affairs Department.

Q. Are you the same J. Denise Jordan who filed direct testimony in this docket?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my testimony is to address various aspects of the direct testimony of Florida Industrial Power Users Group's (FIPUG) witness Gerard J. Kordecki.

Q. Do you believe Mr. Kordecki's testimony addresses the calculation of gains and appropriate regulatory treatment of the revenues and expenses associated with non-separated wholesale sales prescribed by the Commission's proposed agency action ("PAA") in Part III of Order No. PSC-00-1744-PAA ("Order No. 00-1744") issued on September 26, 2000 in Docket No. 991779-EI?

A. No, I do not. Mr. Kordecki's testimony and FIPUG's proposed changes to the PAA portion of Order No. 00-1744 claim to address the calculation of gains and the regulatory treatment of the revenues and expenses associated with non-separated wholesale sales. However, in reality what they present is a thinly disguised effort to readdress the already decided issue of whether these types of sales should have incentives. FIPUG attempts to substitute an economic disincentive for making these sales in place of what the Commission decided in the final agency action portions of Order No. 00-1744 and confirmed in the Commission's Order No. PSC-01-0084-FOF-EI denying FIPUG's Motion for Clarification of Final Order. This is an inappropriate attempt to once again argue the Commission's final decision to provide incentives for non-separated wholesale sales and should be recognized as such.

Q. What economic disincentives were included in Mr. Kordecki's testimony?

A. Under Mr. Kordecki's approach and FIPUG's proposed change to Item 1 of the PAA portion of Order No. 00-1744, retail customers would continue to receive gains from non-separated wholesale sales, while utility shareholders would be saddled with one hundred percent of the risk of any capacity shortfall that might coincide with the making of such sales.

Q. Were there other economic disincentives included in Mr. Kordecki's testimony?

A. Yes. In addition to the above, Mr. Kordecki and FIPUG have erroneously assumed that for any given time that Tampa Electric is purchasing power and making a wholesale sale, the purchase is being made specifically to "replace" power for the wholesale sale. There is no such direct linkage between a decision to purchase power and the fact that the company may be making a wholesale sale at the same time. The company purchases power to meet its forecasted needs to serve retail customers or because there may be purchased power available that is priced lower than the company's system incremental cost of generation. The goal of the purchase is to meet the company's system requirements in the most economical way possible. The decision to purchase is for the system - not to replace power for a wholesale sale. The creation of any artificial link between a particular power purchase and a short-term wholesale sale would establish an economic disincentive to entering into potentially beneficial short-term sales.

Q. Does the proposal of Mr. Kordecki and FIPUG regarding economic disincentives constitute inappropriate re-argument of issues in direct opposition of decisions previously decided by the Commission?

A. Absolutely. The intent of the Commission was made perfectly clear as evidenced by their statements in Order No. PSC-00-1744-PAA-EI:

> In summary, we find that to encourage [emphasis added] the types of wholesale sales that are currently providing the greatest cost reduction benefit to Florida's retail ratepayers, a properly structured shareholder incentive should apply to all non-separated wholesale sales, firm and non-firm, excluding emergency sales, made under current and future FERC-approved schedules.

and

> We reject FIPUG and OPC's contention that any shareholder incentive structure should include a penalty for substandard performance, because imposing such a penalty would potentially counteract the incentive.

Q. What would be the effect of adopting Mr. Kordecki's approach and the modification to PAA Item 1 that FIPUG has proposed?

A. If FIPUG's approach were adopted, no utility would make short-term firm wholesale sales unless they could guarantee against unit outages or abnormal weather conditions or other uncontrollable factors for the duration of the sale, which they cannot. FIPUG's approach, therefore, would discourage utilities from making any short-term firm wholesale sales, even in circumstances when beneficial to the general body of retail customers, by making the utility shareholders guarantors of firm and non-firm sales. By discouraging the utilities from making wholesale sales, FIPUG would conveniently enhance its prospects of receiving firm service at deeply discounted interruptible prices.

Q. Does Mr. Kordecki's assessment of the benefits of non-separated wholesale sales to a utility's retail customers have any merit?

A. Yes. Mr. Kordecki's statement that retail customers can and do benefit from off-system wholesale sales is correct. Customers do indeed benefit from off-system wholesale sales any time the sales revenues exceed incremental sales costs. I also agree with Mr. Kordecki's view that sales of unneeded capacity should be encouraged.

However, I disagree with the implication in his direct testimony (page 9, lines 1-3) that a utility somehow benefits from making "risky" and "aggressive" wholesale sales, especially in the case of non-separated wholesale sales. One hundred percent of the benefits from these sales are flowed through to retail customers until such time that the utility exceeds the wholesale incentive benchmark. For most utilities, this benchmark will not be exceeded until late in any year, if at all.

Q. Does Mr. Kordecki's testimony make any direct or indirect reference to a determination of the prudence of short-term or non-separated sales?

A. Yes. While Mr. Kordecki and FIPUG concede that off-system sales are beneficial to all retail customers, these sales suddenly become retroactively imprudent if, for any reason, a capacity shortfall occurs that would require an interruptible customer to be interrupted or to pay the incremental cost of optional provision buy-through power. If a utility prudently enters into a beneficial non-separated wholesale sale while abiding by its planning reserve criteria, any interruptions or optional buy-throughs that may later be required due to a capacity shortfall are not the "fault" of or attributable to the non-separated sale, any more than a capacity shortfall would necessarily be anyone's "fault" when it occurs at a time when no wholesale sales are being made. A capacity shortfall can occur for any number of uncontrollable reasons, whether or not a wholesale sale is being made at the time of the shortfall.

Q. Are any procedures currently in place for the Commission to determine prudence of short-term wholesale sales?

A. Yes. The Commission always has the ability to review a company's approach and prudence in making wholesale sales. A wholesale sales disincentive as proposed by Mr. Kordecki is neither appropriate nor necessary. The more appropriate way to assess the prudence of a sale is not with hindsight but through a consideration of the facts and circumstances that existed when the commitment to make the sale was made.

Q. Has Mr. Kordecki demonstrated any need for the modification FIPUG proposes to Item 1 of the PAA portion of Order No. 00-1744?

A. No, he has not. Indeed, interruptible customers have faired quite well without FIPUG's proposed unfair retroactive prudence determination and economic disincentive. As Tampa Electric's witness Lynn Brown has testified, Tampa Electric <u>is not</u> interrupting any of its interruptible customers to make new firm separated or non-separated wholesale sales. Moreover, witness Brown testified that the company terminates non-firm wholesale power sales before it interrupts its non-firm retail customers or makes optional buy-through purchases for them.

The company's interruptible customers are receiving approximately a 22 percent discount below the otherwise applicable firm service rate even taking into account the additional cost of buy-through purchases. At the same time, they are receiving a minimum of 99.5 percent electric service availability. They are also receiving the same benefits from non-separated wholesale sales as firm retail customers even though their contribution to plant carrying costs is significantly less. Neither FIPUG nor Mr. Kordecki has submitted any facts demonstrating the need for FIPUG's modification to Item 1 of the regulatory treatment proposed in the PAA portion of Commission Order No. 00-1744.

Q. On page 9 of his testimony beginning at line 20, Mr. Kordecki urges the Commission to require utilities to recall non-firm sales in order to meet retail load demand. Please respond to this.

A. Mr. Kordecki is suggesting that investor-owned utilities be prohibited from making non-separated wholesale sales in certain circumstances. As the Commission noted in Order No. PSC-01-0084-FOF-EI denying FIPUG's Motion for Clarification in Docket No. 991779-EI, the proceeding did not concern, nor was it intended to concern, a prohibition on making certain non-separated wholesale sales. That order stated:

> None of the issues identified for hearing by any party addressed the question of whether any types

> of non-separated wholesale sales should be prohibited; rather, the issues simply addressed the question of what type of shareholder incentive program, if any, was appropriate for non-separated wholesale sales. Thus FIPUG's requested prohibitions go beyond the scope of this docket...

Mr. Kordecki's approach in this regard is likewise beyond the scope of the PAA portion of Order No. 00-1744 and should not be considered in this proceeding. As I mentioned above, the Commission always has the ability to review a company's approach and prudence in making wholesale sales. A wholesale sales disincentive as proposed by Mr. Kordecki is neither appropriate nor necessary.

Mr. Kordecki reiterates his request that the Commission disallow non-firm wholesale sales during certain circumstances (page 13, lines 14-18). Again, this prohibition was rejected in the order denying FIPUG's Motion for Clarification and is beyond the scope of the issues to be considered in this proceeding. FIPUG's multiple attempts to readdress the appropriateness of incentives, including these portions of Mr. Kordecki's direct testimony, should be rejected.

Q. Please address Mr. Kordecki's testimony as it relates to the treatment of incremental O&M expense associated with a non-separated wholesale sale?

A. First, Mr. Kordecki states that incremental O&M costs are hard to identify. He then states, however, all O&M expenses attributable to a sale should be flowed back through the "appropriate clause(s)." Finally, he acknowledges if O&M costs are truly incremental <u>it may be appropriate</u> to credit the utility's operating revenues with these costs, which is exactly what Tampa Electric supported in direct testimony and which the Commission proposed in Order No. 00-1744. Incremental O&M costs associated with a sale should be credited to the utility's operating revenues since Tampa Electric does not charge associated fuel-related O&M expenses to the fuel clause.

Q. In conclusion, do you believe the comments contained in Mr. Kordecki's direct testimony warrant any deviation or modification of the regulatory treatment of revenues and expenses associated with non-separated wholesale power sales addressed in Part III of Order No. 00-1744?

A. No, I do not. Tampa Electric continues to support the regulatory treatment set forth in Part III of Order No. 00-1744. Mr. Kordecki's comments evidence the desire of interruptible customers to continue receiving deeply discounted electric service without interruptions and without ever having to pay the cost of optional provision buy-through power. His testimony fails to state any justification for departing from the regulatory treatment set forth in Part III of Order No. 00-1744. Instead, as I have described, the main focus of Mr. Kordecki's testimony simply reargues the merits of incenting utilities to pursue non-separated wholesale transactions - something the Commission has clearly decided and reaffirmed in denying FIPUG's Motion for Clarification. FIPUG's efforts in this direction should once again be denied.

Q. Does that conclude your testimony?

A. Yes, it does.

BY MR. BEASLEY:

Q Would you please summarize your rebuttal testimony?

A My rebuttal testimony addresses various aspects of the prepared testimony sponsored by FIPUG's witness, Mr. Kordecki. FIPUG opposed the Commission's approval for an incentive mechanism in the incentives docket and even petitioned for reconsideration seeking to preclude application of an incentive in certain situations. Having lost in those efforts, FIPUG through Witness Kordecki's testimony now appears to be suggesting changes to the Commission's proposed regulatory treatment of the incremental cost of nonseparated wholesale sales to create a disincentive for utilities to make those sales.

FIPUG's proposed modification to the regulatory treatment of incremental costs associated with nonseparated sales is somewhat confusing. Mr. Kordecki and FIPUG have erroneously assumed that for any given time that a utility is purchasing power and making a wholesale sale the purchase is being made specifically to replace power for the wholesale sale.

Utilities purchase power to meet needs to serve retail customers or because at given times there may be purchase price available that is priced lower than the utility's system incremental cost of generation. A decision to purchase power is for the system, not to replace power for a wholesale sale.

We find it odd that Mr. Kordecki would go on record in favor of utilities making nonseparated sales for the benefit of their retail customers and then suggest changes to the PAA portion of the Commission order regarding the incremental cost calculation in a way that discourages utilities from making those sales.

It is apparent that FIPUG's real goal here is to discourage nonseparated sales and thereby free up generation that would enhance the prospect of interruptible customers receiving essentially firm service at deeply discounted interruptible rates. While that may be to FIPUG's liking, it certainly would be contrary to the best interests of the general body of ratepayers.

In summary, we believe that the Commission's regulatory treatment proposed in the PAA portion of its final order in the incentives docket is appropriate and that the suggested changes proposed by FIPUG and Mr. Kordecki are inappropriate and should be rejected.

That concludes my testimony.

MR. BEASLEY: Thank you. We tender the witness.

COMMISSIONER JABER: Mr. Badders.

MR. BADDERS: No questions.

COMMISSIONER JABER: Mr. McGee.

MR. McGEE: No questions.

COMMISSIONER JABER: Mr. Childs.

Mr. McWhirter. I was going get to you.

CROSS EXAMINATION

BY MR. McWHIRTER:

Q Ms. Jordan, on Page 3 at Line 4 through 8, you talk about shareholders being saddled with additional risk if the Kordecki proposal is developed. What is the risk that you talk about? Is it the risk of losing an incentive?

A No, sir. Since the time that I read Mr. Kordecki's direct testimony, he has cleared up the fact that he is not actually utilizing the incremental sale, that he wants to use a proxy which is the highest. So at that point, based upon his deposition he is saying that the shareholders would not be at risk because the ratepayers would make the clause whole.

Q All right. So even though you repeated that comment in your summary, you conclude that --

A Right, that was my understanding at the time.

Q You should have stricken that from your summary, is that the deal?

A No. My understanding at the time that I read his direct testimony, that was correct. Since his deposition I now understand that he is utilizing a proxy.

Q And so there is no additional risk on the shareholders?

A Correct.

Q And then you talk about replacement power. As I understand what you and Mr. Brown have said, it's really not replacement power so much as that it is asking the customers to pay for power that you bought that you didn't need, would that be a more apt description?

A I don't think that would be an apt description. I would respectfully disagree with you on that. We forecast what the needs are. You would have to be clairvoyant to buy the exact amount that you need to cover your load. So at the time the decision that we make, that is the best known information that we have. And we make a purchase in order to serve, to meet our obligation to serve.

Q Well, you have the --

A If the rains come in, I'm not in control of that. Or no one is in control of that. And that may create excess capacity.

Q And so what has happened is you have made a high priced must take purchase because of an anticipated weather condition that didn't transpire, and now you have got excess power that you can sell, but the customers are going to take a hit because they are paying the higher cost. And the money that comes in from the sale that you make doesn't cover that cost.

MR. BEASLEY: Commissioners, Mr. McWhirter has gone to testifying again. I would object to the question and the form of the question and the various facts that are woven into it.

COMMISSIONER JABER: Mr. McWhirter, why don't you just restate your question. There has been an objection as to the form.

MR. McWHIRTER: I can easily do that, Ms. Chairman.

BY MR. McWHIRTER:

Q There are circumstances, are there not, in which you are buying must take power and selling incremental power on the wholesale market, is that correct?

A That is correct.

Q And some of the time that you are making those simultaneous transactions the cost of the purchased power substantially exceeds the price that you receive from selling your surplus power, is that correct?

A That is correct. But you should also keep in mind that if we don't make that sale, the ratepayer will still see the entire amount of that higher cost purchased power. So, therefore, by making the sale you are actually mitigating some of the impact of that purchased power cost to the ratepayer. And also keep in mind that it is flowing back 100 percent until you get to the benchmark.

Q Now, my question is does Tampa Electric require being paid a reward for trying to protect its customers from having to face such a situation as that where they are paying more for purchased power than you are getting for the power you sell?

A The issue of incentives I think has already been addressed by the Commission and has been ruled upon as being appropriate, so it's not a question of Tampa Electric requiring an incentive.

Q Well, Ms. Jordan, the Commission is studying the way you calculate the gain against which the incentive -- and you understand we are here talking about those transactions that are simultaneous and how you calculate the gain in that circumstance, is that not correct?

A I think it is not correct. I disagree with that.

Q Well, what do you think we are doing here today?

A In terms of there is -- when you say simultaneous, there is not always a one-for-one situation. You may have entered into the purchased power agreement a month ago, six months ago, a week ago. And as mentioned earlier, there may have been unforeseen circumstances. And at that point in time you had to go out into the market. So, I don't see it as one-for-one.

Q It may not be one-for-one, the timing of the things, you don't make the transaction for the sale and the purchase simultaneously, the transactions are made but the customers pay the full price of the purchased power. And a lot of times if you hadn't made that purchase that power would be available for the customers at a much lower price, is that not correct?

A But that may not be the case. If we didn't make the purchase then we may not have been able to serve our native load, which is obviously not something we would want to do, number one. Number two, had we not made the purchase and we came -- depending on if it was during the peak hours and we had something happen and we had to go to the market, it could be more expensive. So to look at it as isolated as that, I couldn't agree with your statement.

Q I'm not -- you don't think that I'm questioning the prudency of your purchase, do you?

A No.

Q All right. What I'm questioning is with hindsight we see a circumstance in which you have got power that you are purchasing at a high price and you have power that could have been used to serve the customers if you weren't purchasing that power?

A I understand --

Q So you want to do something with it, isn't that what the situation is that we are talking about?

A Correct. I understand what you're saying, but when you made the decision to make the purchase, you had the information at hand. So, hindsight really doesn't apply. If this is Monday and you are looking at what your forecasted load is and what your need requirements are, you are covering yourself on Monday for Tuesday. If it storms on Tuesday, or if people don't run their A/C because they don't need to, and your demand isn't where you thought it would be, then it would behoove you to go ahead and make a sale so that you can mitigate some of the impact to the ratepayers.

Q Now, that is my question. It's Tuesday, the sale has already been made. The purchase has already -- I mean, the purchase has already been made, and you find that you have got some power, and you find you have got somebody that will buy it. Would you refuse to sell that unless you got an incentive to sell it, even though it would help your customers reduce their loss?

A No. But the way I understood Mr. Kordecki's testimony, what he was saying was that the incremental cost would be the highest price in that dispatch stack. Therefore, you probably wouldn't even be able to make the sale because you are using an artificial high number as opposed to what may have been on the increment at the actual time of the sale.

Q You could still make the sale and bring the revenue in to offset the loss?

A Now you are starting to disconnect and put in proxies and artificial as opposed to doing a simple calculation of looking at what is actually on the increment.

Q Well, all I'm trying to ask you is that if you can reduce the loss to the customers would you reduce it if you didn't get paid to do it?

A We are doing that every day, sir. Every day that we have the opportunity that we have excess capacity we are entering into sales in an effort to reduce that impact.

Q And you would continue to do that even if you weren't paid a reward to do it, wouldn't you?

A Right.

Q And so if the customers were able to get the reward, that would reduce their loss, wouldn't it?

A Mr. McWhirter, they are getting the reward up until the point that we reach the benchmark. We are flowing back 100 percent of all of those gains up until the time we reach the benchmark.

Q And we are not talking about what happens for the whole year, we are talking about on this particular transaction you would make the transaction anyway. The customers would be better off if they didn't have to pay you to do it, wouldn't they?

A Yes.

MR. McWHIRTER: All right. That's all the questions I have.

COMMISSIONER JABER: Mr. Burgess.

MR. BURGESS: No questions.

COMMISSIONER JABER: Staff.

MR. KEATING: No questions.

COMMISSIONER JABER: Commissioner Baez? Redirect.

MR. BEASLEY: One redirect.

REDIRECT EXAMINATION

BY MR. BEASLEY:

Q Ms. Jordan, when the Commission adopted an incentive mechanism to encourage all nonseparated sales, did it say that some of those sales should be encouraged and others shouldn't?

A No.

MR. BEASLEY: Thank you. That's all I have.

COMMISSIONER JABER: Thank you, Ms. Jordan. Those are all the witnesses listed in the prehearing order.

Staff, are there matters that we need to take up before we adjourn?

MR. KEATING: The only other thing that I would like to make sure I have done is to have the staff composite exhibit, which is marked as Exhibit 2, moved into the record.

COMMISSIONER JABER: It was. But just to be clear, Exhibits 1 through 8 have been admitted into the record.

MR. KEATING: Other than that, I'm not aware of any other matters. Pursuant to the procedural order, briefs, post-hearing briefs would be due September 24th.

COMMISSIONER JABER: When?

MR. KEATING: September 24th. And the proposed dates for staff recommendation would be October 25th for the November 6th agenda.

COMMISSIONER JABER: Okay. Parties, are there items which you would like to discuss before we adjourn?

MR. BEASLEY: No, thank you.

COMMISSIONER JABER: This hearing is adjourned. Thank you.

(The hearing concluded at 2:29 p.m.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, JANE FAUROT, RPR, Chief, Office of Hearing Reporter Services, FPSC Division of Commission Clerk and Administrative Services, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed under my direct supervision; and that this transcript constitutes a true transcription of my notes of said proceedings.

I FURTHER CERTIFY that I am not a relative, employee, attorney or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

DATED THIS 10th day of September, 2001.

Jane Faurot

JANE FAUROT, RPR
Chief, Office of Hearing Reporter Services
PSC Division of Commission Clerk and
Administrative Services
(850) 413-6732

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

- - - - - - - - - - - - - -X
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In Re: Calculation of gains and :
appropriate regulatory treatment for :
non-separated wholesale energy sales :
by investor-owned electric utilities :
:
- - - - - - - - - - - - - -X

DEPOSITION OF: GERARD KORDECKI

DATE: August 21, 2001

TIME: 12:30 p.m. to 1:52 p.m.

PLACE: TECO PLAZA
702 North Franklin Street
Tampa, Florida

PURSUANT TO: Notice by counsel for Tampa Electric Company, for purposes of discovery, use at trial or such other purposes as are permitted under the Florida Rules of Civil Procedure

BEFORE: DAWN M. DANTSCHISCH, RMR, CRR
Notary Public, State of Florida at Large

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010283-EI EXHIBIT NO. 1
COMPANY/
WITNESS. Tampa Electric
DATE:

ORIGINAL

1

APPEARANCES:

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ALSO PRESENT:

Denise Jordan, TECO Director of Rates and Planning
W. Lynn Brown, P.E., TECO Director of Wholesale Marketing and Sales

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EXHIBITS

GERARD KORDECKI,

the witness herein, being first duly sworn on oath, was examined and deposed as follows:

DIRECT EXAMINATION

BY MR. BEASLEY:

Q. Mr. Kordecki, would you please state your name and your address?

A. Gerard J. Kordecki. The address is 10301 Orange Grove Drive, Tampa, Florida 33618.

Q. Your testimony indicates that you have testified in a number of proceedings. Have you had your deposition taken before?

A. Yes.

Q. Approximately how many times?

A. Probably between 15 and 20 times.

Q. So you're familiar --

A. Yes, sir.

Q. -- with how the procedures operate in a deposition?

What materials did you review, Mr. Kordecki, in preparing your direct testimony in this docket?

A. The past two orders that emanated -- began this docket, and I believe I had a rough copy of FIPUG's protest of Section 3 of the previous PAA.

Q. Okay. That would be the order protesting the

proposal agency action --
A. Yes, sir.
Q. -- in the incentives docket?
A. Yes.
Q. Docket Number 991779?
A. I believe that's right.
Q. Have you reviewed the pre-hearing order in this docket?
A. Yes, sir.
Q. Is it your understanding that the issues in this docket are limited to those set forth in that pre-hearing order?
A. Yes.
Q. Mr. Kordecki, will you agree with the general proposition that the prudence of a particular decision should be judged based on the facts and circumstances that the decision-maker knew or should have known at the time he made his decision?
A. I'm not sure I agree with that.
Q. What else would you rely upon in judging the prudence of that decision?
A. All right. I'm sorry, I'll take that back. The prudence of it, yes. Not necessarily the circumstances or what might be the final actions because of it.
Q. We're just talking about the prudence of the

decision.

A. The prudence, yes.

Q. Do you agree me with that the prudence of a particular decision should not be viewed and judged with the 20/20 perspective of hindsight?

MR. McWHIRTER: Are you asking for a legal opinion as to --

MR. BEASLEY: I'm just asking for his view as to what he thinks is fair to look at in judging the prudence of a decision.

THE WITNESS: Well, I think you have to look back to judge whether it's prudent or not.

BY MR. BEASLEY:

Q. Have to go back and look at what?

A. At the decision-making process.

MR. McWHIRTER: Can you folks in Tallahassee hear Mr. Kordecki?

MR. KEATING: This is Cochran Keating. I can hear him most of the time, but it's a little faint.

MR. McWHIRTER: Mr. Kordecki, you need to speak louder. I can't hear you, and I'm sitting next to you.

BY MR. BEASLEY:

Q. Well, I guess what I'm getting at is do you believe that someone, in an effort to decide whether someone acted prudently, should engage in Monday-morning quarterbacking?

A. You're going to have to give me an example. I'm not sure that -- in other words, you know, whether Bobby Bowden starts Joe Blow at quarterback or not, the prudence of that decision -- I don't know -- you always will do on Monday morning.

Q. My example is -- and let me just coin one -- a utility company makes a decision to build a particular unit because all of the facts and circumstances and knowledge they have available at their disposal when they decide to build that unit suggest that is the kind of unit to build. And then some unforeseen thing later takes place and that unit is not as efficient, for example, as some different type of unit.

Do you think that they were imprudent in building that unit?

A. Not if whatever the regulatory and legal authorities are approved the unit, no.

Q. Mr. Kordecki, have you reviewed the overall position of Tampa Electric on the matters that are at issue in this proceeding?

In other words, have you reviewed Tampa Electric's testimony, for example?

A. Yes, but I only sketched it. I just ran through it in April. I guess it was filed in April. I couldn't tell you the specifics in any of the testimony.

Q. Well, can you tell me or describe for me your take of how Tampa Electric's position on the issues in this case differs from your own?

A. As I remember reading, I think Witness Brown's testimony, I thought he and I were almost -- had identical testimony. I think the other witness' testimony was different, but I wasn't totally sure what the -- why it was different. In fact, I thought it was in conflict with their other witness, their own testimony.

Q. How is your testimony similar to that of Mr. Brown's testimony?

A. In the use of incremental costs to cost the transactions.

Q. We may come back to that.

A. Like I said, I just read it one time going through, I didn't -- haven't studied it.

Q. On your testimony, on page 3 at lines 5 through 10, you mention that many of the FERC-defined utilities can sell at market-based rates, in other words, whatever the market will bear.

To your knowledge do any of FIPUG's members sell energy in the wholesale market at market-based rates?

A. In Florida?

Q. Yes.

A. I don't know.
Q. How about outside of that Florida?
A. The numbers, I don't know.
Q. So, you don't know if there are any FIPUG members supporting your testimony in this proceeding who sell at market-based rates?
A. No, I don't.
Q. Okay.
A. I don't know who their regulatory authority would be, either.
Q. Okay. In your testimony on page 4, lines 7 through 9, you state, "However, the concern in this volatile trading market is that retail customers not assume risks or higher costs because wholesale sales are not adequately or properly priced at the true price of these discretionary sales."
And my question is: What do you mean by the statement "...wholesale sales are not adequately or properly placed at the true cost of these discretionary sales"?
A. Though the response there looks somewhat global, it's actual meant to be to be very specific to instances where there are transactions, probably simultaneous transactions, and sales are being made and purchases are being made. The purchase may be at prices higher than sales, so it's really more specific to that issue.

Q. Do you believe that retail customers who receive service under an interruptible rate tariff should be served prior to a firm non-separated wholesale sale?

A. As opposed to interrupted?

Q. Yes.

A. Yes, I think they should be served. I'm sorry, say it again, please.

Q. Do you believe that retail customers who receive service under an interruptible rate tariff should be served prior to a firm non-separated wholesale sale?

A. All right. Does that -- you need to elaborate a little bit. In other words, the situation is only whether the utility will serve the non-firm customers or the interruptibles or make the wholesale sale, which is firm? Is that either/or?

In other words, there's no other part there could be to that transaction? In other words, they could make a purchase, too, while they were making the sale, as opposed to interrupting them.

Q. Well, should the interruptible customers be served prior to the making of any firm non-separated wholesale sale?

A. Well, I would think the utility -- it would be incumbent on the utility in its planning process that that ought to be the order of interest. In other words, serving your customers first and then making sales in addition out of reserves or excess capacity.

Q. Okay. How about this, do you believe that retail customers who receive service under an interruptible rate tariff should be served prior to a non-firm non-separated wholesale sale?

A. Non-firm, non-separated?

Q. Right. That would just be an opportunity --

A. Long-term separated non-firm sale?

Q. No, it's a non-firm, in other words, it's not long-term -- excuse me. It's not firm and it's not separated, which means it's not long-term.

A. Yes, I do believe they should be served first.

Q. Okay. To your knowledge, are there any utilities in Florida who have any restrictions in their interruptible rate tariffs precluding them from making firm or non-firm opportunity sales while they're interrupting their interruptible customers?

A. Seems to me the language of the tariffs I was familiar with talked about emergency conditions for purposes of interruptions to those customers, including low management rates. Whether it is precluded, I don't think so, but I don't believe there's any addition that says that it is there. In other words, I don't see how the tariffs, as I remember them, meet that purpose, to make wholesale sales.

Q. But you're not aware of any specific restrictions in any utility's tariff saying that they can't make these opportunity sales while they're interrupting their interruptible customers?

A. No, I don't think there's an exclusion, but I don't think -- this has got to be memory serving me -- that that was the purpose stated in the tariff.

Q. Do you, Mr. Kordecki, believe that a Florida utility should be allowed to make firm separated wholesale sales as long as they maintain their 15 percent reserve margin?

A. Do that again. Firm separated sales?

Q. Right. Firm separated wholesale sales. As long as -- and they should be allowed to do that as long as they maintain their 15 percent reserve margin?

A. Well, I thought they were supposed to be reaching 20 percent, but whatever their reserve margin is that's been allotted to them.

Q. That should be allowed to?

A. Anything in excess --

Q. Anything in excess of that they should be allowed to make as a firm separated wholesale sale?

A. In the general frame, yes, not necessarily -- doesn't mean necessarily -- if their whole reserve margin, let's say, was made up of non-firm load, then I might not have the same answer.

In other words, if their reserve margin level was 15 percent or 20 percent and they want to sell five percent, but all 20 percent of it is non-firm load, no, I'm not sure that's necessarily appropriate.

Q. On page 5 of your testimony at lines 13 through 16, it's stated "The assumption is the Commission wants wholesale sales to be made when and only when captive customers who bear the cost of the plant in rate base benefit from the wholesale sale."

Do interruptible service customers bear the cost of generating plant in their rates?

A. Yes.

Q. Do you know to what extent the various interruptible customers around the state bear the cost of generating plant in their rates?

A. Depending on the system. I think in TECO's case, TECO uses a 12CP and one-thirteenth, so whatever one-thirteenth works out to be as a proportion.

As I remember, the other two that have interruptible rates, Florida Power Corp. and Florida Power and Light, actually have customers on firm rates with discounts. The discount is to interrupt. So, as far as what do they pay, I guess if you net the discount, in a sense they get a discounted rate; they pay less. What that proportion is, I don't know.

Q. Okay.

A. I have no idea.

Q. Well, the portion they bear is not equal to the same share as other classes of retail customers, is it?

A. No. No, it's not.

Q. Is it less?

A. Oh, yes.

Q. Okay. On page 8 of your testimony, lines 2 and 3, the statement is "There are an infinite number of ways to structure transactions which may have some level of firmness." Could you tell us what your definition of a firm wholesale sale is?

A. From which side of the sale? A sale could be firm on one side and non-firm on another.

Q. Well, why don't you explain both of them those, then, from both vantage points.

A. Well, a firm sale would be that I have -- that the sale -- let's say I'm making a purchase, and I've notified the seller that I'm going to -- let's say it's a day-ahead sale, and I've notified that I'm going to take it. And it's a take-or-pay at that point, so at that point if they don't take it, they still pay for it.

The other side of that may be that I'm the selling utility and I've been notified, but my contract says if I can't serve my native load, I don't serve. I don't have to serve. In that sense, that's non-firm. So the same sale is non-firm and firm depending on which side of the coin you're on.

Q. Okay. If you're making a firm sale, should you serve your interruptible customers first, or is there any priority there that you would assign?

A. Well, if you have a contractual firm sale, you're probably going to make the sale. But my testimony, to my knowledge, doesn't say you ought not make the sale.

Q. Okay. On the bottom of that page, page 8, line 21, continuing over to page 9, line 2, it says, "Sales of unneeded capacity should be encouraged, but care needs to be taken in today's active wholesale market that the incentive to make wholesale sales does not backfire and encourage off-system sales when capacity is needed to serve retail customers."

Is this true for firm -- is this true for firm non-separated wholesale sales?

A. That is for both firm non-separated and for non-firm sales that are not recalled -- that might not be recalled.

Q. Okay. Are you familiar with the concept of economic dispatch as it relates to the operation of an electric utility?

A. Yes.

Q. What is your understanding of that concept?

A. Within reason, the most economical units are dispatched in order of their dispatch cost.

Q. Okay. What is a dispatch stack?

A. That would be the economical stack of units relative to their dispatch cost.

Q. Okay. Are the power resources in a dispatch stack generally called upon in an ascending order starting at the bottom of the stack and going up the stack as needed until you have enough power resources to meet the load that you've experienced?

A. Generally.

Q. And as load subsides, do you shut down or curtail your power resources in a descending order, working your way down the stack as far as needed to match the load?

A. Yes.

Q. As you go up the dispatch stack to call on a higher power resource block to serve a higher load level, is it fair to say that the cost of the higher load block is the incremental cost of serving the higher increment of load that caused you to turn to that load block?

A. Yeah.

Q. All right. How do you define "incremental energy cost" for an electric utility?

A. For purposes of a non-separated wholesale sale?

Q. Well, let's say for purposes of any non-separated sale, whether it be firm or non-firm.

A. It would be -- in my mind, the causation cost would be whatever is in that increment to make that sale at that hour, within each one of those hours, whether it's purchased power or on the generator -- with the generator. Because if the sale wasn't to be made, it would be back down, according to what you asked me in a previous in response.

Q. Is that different than the incremental cost of serving retail load?

A. Yes.

Q. How? Could you describe how it differs?

A. There is no incremental cost to serve retail load. Everything is done on average cost.

Q. Okay. Would you consider it fair to say that the incremental cost of any particular action is the cost of whatever it takes you to do to get that action to occur?

A. I think a better definition is what cost would not be incurred if the transaction did not take place.

Q. Okay.

A. Or the action, whatever it be.

Q. Okay. You familiar with what -- are you familiar

with what a "must take" power purchase agreement is?
A. Yes.
Q. What would you define that to be?
A. Well, without knowing the structure of whatever the contract is, in terms of fuel costs, variable costs, and fixed costs, my initial reaction would be that the take-or-pay is you pay whatever the fixed amount is that's been agreed to. You'll pay it whether you take it or not.
Q. So if you have like a must-take contract for a certain number of megawatts of power at X dollars per megawatt hour, you've got to pay that amount whether you use that electricity or not?
A. That's correct.
Q. Okay. Can you give me an example of what you would consider to be a must-take power purchase agreement?
A. I think the one I mentioned earlier where you have an agreement on a day-ahead basis and you've called at whatever hour is stated that you have to notify the seller and you say, "I'm going to take it." And at that point, you've got the commitment.
Q. Okay. What about a multi-year co-generation or small power purchase agreement that's priced under FERC-prescribed avoided costs for the utility that's required to make that purchase, is that a must-take power purchase agreement? Would that fit within that category?

A. Well, I didn't think they were FERC costs, I believe there are Florida Public Service Commission costs.

Q. Okay.

A. But beyond that --

Q. Implemented by the Florida Public Service?

A. Right. Yes, you pay -- in other words, it's the same as owning the generator unit.

Q. Okay. If a utility must take power under a purchased power agreement over a period of time without regard to what the utility's load requirements are for the duration of that obligation, would this influence where you placed the must-take power supply on your dispatch stack?

A. I can't answer that question, because you haven't given me enough information. It depends. In other words, if I have a variable cost involved and the variable cost is higher than the incremental cost on my system, no, I wouldn't -- it would rise up on the system. It really depends contractually how it's been put together. I really can't answer that question based on that information.

Q. Well, just generally, wouldn't you dispatch a must-take obligation first, since you're going to have to pay for it whether you use it or not?

A. If you're paying the full cost for the must-take, yes.

Q. So you would dispatch it first, in other words, at the bottom of the stack, if you're going to have to pay for it come what may; is that correct?

A. Yeah.

Q. If you place any other power supply resource below the must-take supply and dispatch the other power supply resource ahead of the must-take, wouldn't this possibly create a risk that the utility might have to pay more for its total power requirements than it would have if the must-take had been put on the bottom of the stack?

A. The way you phrased it, yes. But, again, without contractually describing what the must-take is, I don't know what the cost is.

Q. Well, just assuming that there's some cost for the must-take that's fixed and ignoring any kind of variable costs or other costs that might influence it, let's just assume there are none, just looking at the block cost of the must-take, would you put that on the bottom of the stack and then go up from there with your other obligations that aren't take-or-pay?

A. Yes, that's correct.

Q. Okay. We've found another ingenious use for Post-It Notes. And I know the folks on the phone can't see this, but I'll try to get you a copy later.

But let me show you this scenario of -- these are Post-It Notes with different things written on them, and there are three different scenarios. This is the first one. In this scenario, the utility has committed ahead of time on a must-take basis the purchase of firm power at $100 per megawatt hour to serve its retail load.

A. That's its whole retail load?

Q. No, just a portion of its retail load. And it has other power supply resources that are shown on those various Post-It Notes. And I wonder if you could, Mr. Kordecki, align those notes in a vertical fashion in the order in which you would dispatch them as you go up the dispatch stack.

A. Now, none of these -- all of these are considered variable costs? Which ones are variable and which ones are fixed?

Q. These are all just resources, power resources that the utility has available. It has base load generating capacity, it has combustion turbines. That incremental purchased power -- excuse me. That purchased power that I mentioned is $100 per megawatt hour. The CTs are priced at $75 per megawatt hour, the base load intermediate generation is priced at $25 a megawatt hour, and then the utility has a purchased power agreement must-take at $125 per megawatt hour.

So those are the generating resource options that the utility can draw on as it needs to as it goes up its generating stack. And I'm just asking you if you could arrange those in an ascending way on that sheet of paper in the way that you would call upon them to meet load as your load increases.

A. What is "firm purchased power"? Is that already contractually obligated?

Q. The which? I'm sorry.

A. Is that already contractual? In other words, that's just another must-take?

Q. Which one?

A. "Firm purchased power."

Q. Yes.

A. So you have two must-takes?

Q. Right.

A. Or two that you pay for whether you use them or not?

Q. Right. And for purposes of this analysis, if you would assume that all firm purchases are fixed, there's no variable costs involved, then you can ramp up or down your generation as the case -- as your needs require.

A. Wait a minute. Two of these are basically firm.

Q. That's right, must take.

A. And there's no variable cost, they're just fixed? They're a fixed purchase cost?

Q. Right.

A. And the other two have variable costs, correct? Two are variable costs?

Q. That's right. We're only talking about these two firm. And you've aligned this where -- okay. You've got the must-take on the bottom, the firm purchased --

A. The two, both must-takes.

Q. Both must-takes, and then the base load generation, and then at the top you've got your combustion turbine peaking generation.

Okay. Let's assume that that stays the way it is, and on the next morning or the next day, it gets cloudy and the utility has some extra generation from its total resources that it can sell, and it sells 10 megawatts of power on the wholesale market on a non-separated basis.

What would be, in your view, the incremental cost of that sale coming out of those resources?

A. Specific to no other circumstances?

Q. Right.

A. If you still had combustion turbines running, then that would be the incremental cost. If you dropped down to intermediate or base, whatever the pricing is on the other, that would be the cost.

Q. Okay. And that would be the incremental cost of that 10 megawatt sale?

A. Right.

Q. Okay. The second scenario I'm going to show you has -- let's say the purchased power agreement, the must-take, is only $20 a megawatt hour, the firm purchased power is -- you buy 70 megawatts of firm purchased power to avoid what would be your combustion turbine peaking generation, and then you've got your base load intermediate the same at $25 a megawatt hour as we discussed in the first example.

A. Wait a minute now. All right. Now, the must-take -- well, the firm is -- I'm just doing an incremental stack, and this is not what -- this is different than what you just asked me.

Q. Right. Exactly. That's not in any order, though. Those haven't been put down in that paper in any order. I'm just asking if you could stack them the way you would call upon them if you were dispatching to meet your load.

Okay. And under that one, Mr. Kordecki, if we did the same cloudy-day scenario where you could sell 10 megawatts at wholesale on a non-separated basis, which of those blocks --

A. I'm sorry. I got this one backwards.

Q. Okay.

A. Your statement about displacing it, I was trying to -- I was going to put it under it.

Q. Okay.

MR. McWHIRTER: Let me see that.
BY MR. BEASLEY:
Q. Okay. The next day, it's cloudy, and you can sell 10 megawatts off-system. Which of those blocks would your incremental cost come out of?
A. The top block, $75 combustion turbine, if it's running.
Q. And if it's not running?
A. Then you drop down to the intermediate generation at $25.
Q. Okay. The third scenario is very much like the first, only it's eleven o'clock at night.
A. I would put one caveat. The firm purchase that you've made to replace the peaking or intermediate really depends somewhat on the timing on how you did that also.
Q. Okay. But the incremental cost of the wholesale sale would come in -- would that influence that? Which one did you say?
A. Yes, the incremental cost should always be the influence on the sale, the influence of the sale.
Q. And which would the incremental cost come out of for that 10 megawatt sale?
A. Well, since your load was dropping down, if you were still running combustion turbines, then it'd be out of the combustion turbines. If you drop down below the

intermediate, it would be the cost of the intermediate.

Q. This third one is really the same as the first, only it's eleven o'clock at night and all you've got is base load running. And the must-take, this time it's $125 per megawatt hour and the base load is $25 per megawatt hour. You don't have any combustion turbine peaking generation in operation, nor do you have any firm purchased power.

So you've really got only two blocks to stack there, don't you?

A. Repeat it, would you, please?

Q. Okay. This one, you don't have any of those two that have the hatch mark on them.

A. Okay.

Q. So you've only the must-take and the base load intermediate at $25 a megawatt hour. So how would you stack those two?

A. I don't have a firm purchase?

Q. No.

A. And all I have is the base load and the intermediate?

Q. Right.

A. Okay.

Q. Okay. And if by some stroke of luck you're able to sell 10 megawatts, which would that come out of as far as incremental cost of the 10 megawatt sale?

A. It would be at the base load, $25.
Q. Okay. What I would like to do --
A. The question I would phrase -- I haven't given you a response whether the sale you were making is firm or non-firm, either.
Q. Okay.
A. I'm guessing that it's a non-firm sale since you were out buying power to cover yourself.
Q. Right. So it's a non-firm, that's your assumption?
A. Yes.
Q. How would it differ in your answer if it were a firm sale?
A. Then you would be buying firm to sell firm, and I have a little problem with that.
Q. Okay.
A. Depending on when things were contracted for. But the way you laid it out to me, they would be -- I suspect you'd be paying more than what you were selling for, all things being equal.
Q. What I would like to do, Mr. Kordecki, is get copies made of these three items. I want to make sure that they're in the same order that you did them. I'm just going to put Roman Numeral 2 here since that's covered up, Roman Numeral 1 on that one, and you can see the "III" on that

one. I don't know if you want to make any notes to make sure that those are the same order when we get them back after being copied as they are there.

A. Yeah, I believe they're correct.

Q. Okay. On page 12 of your testimony, lines 11 and 12, you state that "When purchased power is the highest cost power on the utility system, it is the incremental cost."

What if --

MR. McWHIRTER: What page are you on?

MR. BEASLEY: This is on page 12, Mr. McWhirter, lines 11 and 12, middle of the page.

BY MR. BEASLEY:

Q. What if at any given point in time there are purchased power costs that are higher than the utility's marginal generating cost of its units, but there are no non-separated sales at that point in time? What would the higher purchase power cost be the cost of? I mean, what would it be associated with if there are no non-separated sales?

A. It would be the highest cost.

Q. Okay. Would it just --

A. Whatever's the highest cost is the highest cost.

Q. It would just figure in as part of the average cost of system sales to retail customers?

A. Probably, yes.

Q. Okay. Is it your position -- hold on a second.

A. I probably would better phrase that in terms of whether it was firm or non-firm and short-term or long-term, but my testimony is directed primarily at purchases, short-term purchases.

Q. Okay. What do you mean by "short-term purchases," Mr. Kordecki?

A. Something less than a year, as defined by the separation factors.

Q. Okay.

A. Firm or non-firm.

Q. In your statement there on page 12, line 11 and 12, the one I just read you, "When purchased power is the highest priced power on the utility system, it is the incremental cost," what if that highest cost power that's purchased happens to be a must-take power purchase agreement?

A. Then it's firm, and it's not what I was driving at as far as purchased power --

Q. So --

A. -- as far as cost on the system.

Q. So then the must-take would not be the incremental cost of --

A. A must-take is the same as the firm power purchase, so it makes no difference.

Q. So it would be at the bottom of the stack?
A. Its incremental cost is -- incremental cost, remember, drives -- that's the cost for one more input. It does not cover fixed cost.
Q. Okay.
A. Incremental cost is only variable cost. In other words, it's the cost to make the next sale or whatever it would be. So all those things are basic things that will be -- even though you had them in dispatch order, they're basically in the base fuel adjustment and everybody pays them, because they're not incremental. They're the highest cost, but not incremental. It may be the highest cost.
Q. Thank you. Okay. Just for the record, going back to these dispatch stack charts, Mr. Kordecki, on the Roman Numeral 1, could you mark the block that the incremental would come from, as you testified earlier?
A. Incremental will come out of the $25 and $75 units.
Q. Okay. And then in Roman Numeral 2, that stack, which would your incremental cost come out of?
A. $25 and $75.
Q. I'm sorry?
A. $25 and $75.
Q. And how about Roman Numeral 3?
A. $25.

MR. BEASLEY: I'd like to have these charts marked as a deposition exhibit, Composite Exhibit 1.

(Deposition Exhibit No. 1 was marked for identification.)

BY MR. BEASLEY:

Q. Okay. Going over to page 15 of your testimony, line 13. Excuse me, lines 5 through 14.

A. Yes.

Q. Hold on one second. Let me get a confirmation here.

There you discussed the cumulative profit pool that your testimony addresses?

A. Right.

Q. Could you tell me how your proposal would differ from the Commission Order? And it's the final order in the incentives docket, it's Order No. 001744. It was issued in September of 2000 in Docket No. 991779.

A. I don't think, in essence, they're different. I think what I was portraying here was the instance that sales normally are accumulated, or the profit from sales, on a one-to-one basis, and then they're added up. You end up with a -- if all sales were profitable, you end up with the same answer.

Q. Okay.

A. What I'm saying here is there may be some sales that are not profitable, that may actually happen to lose money on the sale.

Q. Okay.

A. So that if there was a loss, the loss wouldn't be incumbent to the utility, the loss will be incumbent to the profits.

Q. So it would be a net effect, is that --

A. It would be a net effect.

Q. On page 17 of your testimony, you say "If a utility can prove by clear and convincing evidence that the O&M cost is incremental, that is, does not already exist in the retail customers' base rates and that no cost would exist without the sale, then and only then can the O&M cost be taken from the margin or profit of the sale and credited back to the utility's operating revenues."

What would you consider to be something that would meet the threshold of clear and convincing?

A. I'm not totally sure. There's two parts to what I've said here. The first part is that it's an incremental cost. The incremental cost would be that if the transaction didn't take place, the cost didn't take place. It's not a reallocated cost. In other words, there'd be no cost. That's number one.

Number two is what's in base rates. That's totally different than incremental costs in the sense that, if, for instance, there was a cost which the utility thought -- I'll use -- seems at least in the case of three utilities, and not one, that the O&M levels that were in their last rate cases were done on an overall basis, not on account basis. Florida Power and Light may have been an account basis, where they lump accounts, like 900 accounts, and used inflation or whatever they used.

So to the extent, let's say, there's one mill in a rate -- in the rate the customers pay, and let's say that one mill is for dispatch costs, just to use a number, and that since their last rate case, the amount of energy has gone up 200 percent, they also have to pay us that threshold.

In other words, there may be dollars, it may be an incremental cost, but it may already be, in a sense, recovered in base rates, because the O&M amount that's in base rates would more than overcome that. I think by giving you the example, I'm telling you what I think the threshold is. Not only is it a cost that would not have occurred, but also it has to be outside the O&M. In other words, that the utility, in fact, is spending all of the O&M, or as in this particular case, that it is embedded in the rate.

Q. Okay. Mr. Kordecki, I want to show you a document that says "Staff Memorandum" dated September 20, 2000, ask you if you have reviewed that.

A. No, I haven't.
Q. You haven't?
A. No.
Q. So you wouldn't be able to draw any conclusions from that as to whether you agree with it or not?
A. I just know there's a benchmark. That's all I know.
Q. Okay. Why don't we take just a few minutes and let you read this staff memorandum and go off the record.
(A brief recess was taken.)
BY MR. McWHIRTER:
Q. All right. Mr. Kordecki, I've asked you and you have reviewed what purports to be a September 20, 2000, memorandum from Cochran Keating and Todd Bohrmann of the Commission Staff to all parties of record in the fuel adjustment proceeding. Have you had a chance to look at this?
A. Yes, I have.
Q. Is it a proposed method of implementing what the Commission voted in the incentives docket?
A. Yes. That's my impression.
Q. Do you have any difficulty with what's set out in this document, or would you change anything in it from what the staff has proposed?
A. If I was instituting an incentive mechanism, or

just do I have a problem with what they've written there, specifically?

Q. Right.

A. No.

Q. You don't.

MR. BEASLEY: I'd like to ask that this be marked as a deposition exhibit.

(Deposition Exhibit No. 2 was marked for identification.)

THE WITNESS: That's not to be construed that I think it's right or wrong.

BY MR. BEASLEY:

Q. Okay. But you don't --

A. Or proper or improper.

Q. You think it's a reasonable way to implement what the Commission decided in the incentives docket?

A. No. No. I mean, based on the findings of the docket or instituting an incentive?

Q. No, based -- given what the Commission decided --

A. That's fine. Yeah.

Q. -- then it's appropriate to use this to implement what the Commission --

A. As best I can tell from what I heard, that's about what the Commission found, so --

Q. All right.

MR. BEASLEY: Okay. We're going to step out for a minute. Go off the record.

(A brief recess was taken.)

BY MR. BEASLEY:

Q. Just a few clarifying questions, Mr. Kordecki. What is the incremental cost of making a firm purchase for more than a year?

A. I don't know with that statement, but basically if it's just a set number of dollars per megawatt hour or something like that, then it's the total cost. If there's a fuel or an energy charge that's associated with how much you use, then that will become the incremental cost.

Q. Is there any difference in making the incremental cost determination if it's less than a year?

A. For purposes of what we've been discussing here, no.

Q. Okay.

A. With the exception of, I guess, the planning sequence in terms of why you made the purchase may be quite different if it's long-term versus something you had to do short-term.

Q. Would the cost of -- incremental cost of a sale be different for a non-firm versus a firm sale?

A. The cost?

Q. Incremental cost.

A. Yeah.
Q. How would it be different?
A. Well, if you're making the sale and it's firm, the cost is the cost. If it's incremental, then it's whenever they take it or whenever it is. It depends contractually. What you -- I think we're talking past each other right now.
Q. Okay.
A. I don't think you'd compare those.
Q. Well, with respect to a firm sale, is there any difference in what the incremental cost is depending on whether it's more than a year or less than a year in duration?
A. For purposes of the cost, no. For purposes of the planning and what you have to do, yes.
Q. When calculating the incremental cost of making a sale, when do you take into account the must-take, the cost of the must-take purchased power? Is that --
A. According to my testimony or according to the examples you gave? I think I might as well clarify it now. My stacking of units for incremental cost is based on the fact that there's no transaction problem. In short-term, non-separated sales, the utility is making decisions on purchases and sales that are somewhat volatile.
My testimony doesn't say that some of the purchased power that may be the highest that may be firm is

the incremental cost, it says it should be used as the incremental cost, because it is the utility's decision on how they manage the system.

For instance, I'll give you an extreme example. The utility might go out and make a couple of hundred megawatts of firm sales, firm non-separated sales, and be, you know, somewhat on the margin as far as the ability to serve it. If they can't serve it and they can't recall it, then they buy purchased power, or let's say purchased power is available, or they interrupt if they have interruptible customers.

And what my testimony is aimed at is that in the situations -- the short-term situations, less than a year, that those purchases should be substituted as the incremental cost because it's not the customer's fault that the sale was made.

Q. So you're saying, then -- and I think you just did -- that it might not be the incremental cost, it should just be used as the incremental cost?

A. I said "used." That's right.

Q. So there might be no relationship between that cost that you're using as the incremental cost and the actual incremental cost of the sale?

A. There are instances where that's true, that's correct, because they occurred at different times. In other

words, a utility may have made a large sale and it was a
mistake and they had to buy power, basically, in my
testimony, to cover the sale because they couldn't make it.
And what I'm saying is that the customer should
not bear it. The utility doesn't bear any losses. All
right? The only thing that accomplishes is it shrinks the
incentive pot. They'll see that, and that's the only thing
it does. The customers still bear the cost.
Q. You've testified, haven't you, that utility
customers benefit from utilities making off-system sales
when they have generation available; is that correct?
A. Yes.
Q. Well, then, would the shrinking of that incentive
pot tend to discourage, as opposed to encourage or be
neutral to, utilities to make those off-system sales?
A. I think it would encourage the utilities to be
sure when they make specifically firm sales. I think
non-firm sales, most of them are recalled anyway. To be
sure when they made firm sales that, in fact, they didn't
put themselves and, in essence, the customers at risk of
having to purchase. That's all.
Q. They should underwrite anything that occurs
between the commit time on the firm sale and the conclusion
of that sale?
A. No, they don't underwrite anything. Customers

underwrite the whole thing. The only thing that's underwritten or that's dealt with is the incentive, the affect on the incentive, the pot of incentive.

In other words, if they never get to the benchmark, it makes absolutely no difference whatsoever. None. Doesn't change anything. Unless the way money is dealt with in the fuel adjustment is different between these types of sales versus anything else that might go into the fuel adjustment. I don't think there are, but let's say that for our purposes.

So the only thing this is doing is saying if the utility makes a sale that's not in the best interest of the customer -- it may have been prudent when they made it -- that the utility doesn't bear any losses. The customers still see the same cost. The only thing the utility bears is that there might be some shrinkage in the incentive pot.

Q. And would that discourage them from pursuing the sales as much as they would if there were not a shrinkage?

A. I don't think so, unless they're badly managed or they're making a lot of high-risk sales. If they're making a lot of high-risk sales, I'd say, yeah, it's discouraging them from making high-risk sales.

Q. All of the benefits of these sales go to the retail rate payers until the benchmark is reached; is that your understanding?

A. That's my understanding, yes.

Q. Okay. Mr. Kordecki, one more example. You purchased -- on a next-day sale, you committed to buy, for 16 hours, power at $100 per megawatt hour. And then later on, during the shoulder hours, you realize that you didn't need all of that, you can sell some of it at, say, $50 a megawatt hours and mitigate your overall cost to your customers. Should you make that sale?

A. Yes.

Q. What would be your incremental cost for making that sale?

A. Actually or commitment cost? Commitment cost, I guess, is $50. Now, the reason you would make that sale is the utility is there to maximize the revenues from these sales. It's also there to minimize the cost of these sales. And to that extent, the utility has done what it should do and that was minimize the cost. But they don't make an incentive for it.

Q. No, I didn't ask you whether it should get an incentive, I just asked you what the --

A. Or to be eligible for an incentive for that. Now, I didn't say it was their fault, but it was their planning, it was their analysis that said "I need this 100 megawatts." It's not the customers' analysis, so the customers ought not, in the long run, potentially, in a sense, pay for the difference. They pay for the difference anyway, but the utility ought not build in a larger incentive potential because of it.

Q. And that aside, what is the incremental cost of that sale at $50 a megawatt hour during the shoulder period?

A. The incremental cost?

Q. The incremental cost of making that sale.

A. I think it's zero. If that's a fixed cost, then it's a fixed cost. There is no -- the incremental cost is the cost to make one more sale. So to that extent, it's zero.

Q. If you had a CT that you would ramp up and down at a cost of $30 per megawatt hour, would that be the incremental cost?

A. If you were using that CT it would be, yes.

MR. BEASLEY: Okay. That's all we have.

CROSS-EXAMINATION

BY MR. McWHIRTER:

Q. Mr. Kordecki, just because a utility takes an action does not necessarily make that action prudent; is that correct?

A. That's correct.

MR. BEASLEY: Wait. Form of the question.

MR. McWHIRTER: You object to the form?

MR. BEASLEY: Right.

BY MR. McWHIRTER:

Q. Is an action prudent because the utility takes it or can it become -- is it prudent after a determination is made on the prudency?

A. After the determination.

Q. When is the determination made?

A. Normally after the fact --

Q. And who --

A. -- if it's something like a purchase. If it's something like a unit being built, obviously, it's in advance.

Q. Well, in this situation, let's say the determination of prudency deals with a must-take acquisition of power. Who makes that determination of prudency?

A. I believe it would arise only at the fuel hearings if the Commission would make it an issue. I don't believe utilities are required to file any kind of rationalization or support for the purchases that they've made.

Q. All right.

A. Not to my knowledge, anyway.

Q. All right. If the issue is raised as to whether or not a transaction is prudent, who has the burden to determine the prudency, the Commission or the utility?

A. The utility.

Q. Do the utilities presently file concurrent fuel information with respect to specific purchases and sales, or does it file gross information dealing with all of the sales within a time period?

A. I think it's some of both. There are certain --

Q. Elaborate a little bit further on that.

A. I think there are certain contracts that are dealt with specifically, or have been historically, for purchases, firm purchases. But short-term transactions, I don't believe are forecasted, but I think they're dealt with after the fact.

Q. For instance, a 10-year contract with Hardy Power Partners that's submitted to the Commission, that would -- the information on that would be disclosed; is that correct?

A. In advance of approval?

Q. In advance of an approval, yes.

A. I can't -- I don't know that for a fact.

Q. All right. In the typical daily transactions in the wholesale market, what, if any, information is given to the Public Service Commission concerning the transactions in the last 24 hours?

A. None that I know of until after the fact.

Q. So if you had a situation as delineated in page 1 of Tampa Electric's Exhibit 1 in which you had a price of $75 for combustion turbine and $125 for purchased power agreement must-take, would the Commission have any way of knowing that those were, the prices involved, at the time period that the transaction was made?

A. No. On that page there, they may or may not know the must-take, depends on when it was done relative to the fuel adjustments.

The firm purchased power, probably if it was long-term, they would know, but it could be made during the year when they would not know. Their own generation would be -- they would know what ballpark they were in in terms of CTs, but they wouldn't necessarily know the cost in terms of generation or combustion turbine.

Q. Would it then be fair to say under the current circumstances the Commission might know about long-term transactions, but might not know about short-term transactions?

MR. McWHIRTER: If you want me to change the form of the question, I'll do it.

MR. BEASLEY: I started to say something, but --

MR. McWHIRTER: Huh?

MR. BEASLEY: That's all right. Go ahead.

THE WITNESS: Generally, yes. Yes, I would agree. They may not know.

BY MR. McWHIRTER:

Q. They may not know. What is the typical duration of a "must-take" contract?

A. That they can vary to -- the longest ones that I've ever had any familiarity with were five 16s over five months. In other words, somebody was contracting power to buy 16 hours a day during the peak hours, five weekdays across basically the summer months.

In a sense, they're all must-take. Any firm contract is a must-take in the sense you pay whether you take it or not. So in that sense, a must-take contract is no different from a regular firm contract. You pay it whether you take it or not.

Q. What is the typical duration of a must-take contract, would it be a matter of years, a matter of days, or a matter of months, or a matter of hours?

A. I don't think it would be hours. Mostly I would think you'd be looking at weeks and maybe months.

Q. Okay.

A. But I'm not totally familiar with all types of transactions that can be -- like I said, I think there's an infinite variety of ways you can structure contracts and the variables that go with them.

Q. Is there any minimum pre-notice period on a must-take contract?

A. Most of them have some type of notice the day before, whether they're going to take it, or the morning of, you know, in terms of the day before that the utility wants the power. But that's the same with a firm -- that can be the same with a firm contract. That's really no difference.

Q. Is there distinction in your testimony between separated and non-separated sales?

A. Yes.

Q. Which does your testimony address, separated or non-separated?

A. The specifics of my testimony are non-separated. There's some description of separated, but it's not germane to the points of my testimony.

Q. And your testimony deals with methodology for calculating the incentive, or does it deal with something else?

A. No, my testimony deals with what I consider the principles of determining what the net benefit of the sales -- of non-separated sales are, as long as there is an incentive base on net or profit from sales. If it was based on frequency, then it would be different.

But this is -- my testimony specifically is only to address the size of the incentive pot, so to speak, or what's eligible for the incentive. Nothing else. It wouldn't matter if the Commission went to a 50/50 sharing or 80/20. If the utility gets 80, the principles don't change in terms of how I think you should calculate the net profit.

Q. You were asked to do some ranking with respect to

Tampa Electric Exhibit 1.

A. Yes.

Q. Does that relate to separated or non-separated sales?

A. No, I think I was asked what was the incremental cost of the system. That's what they -- and the reason you would derive the incremental cost, I'm assuming, was that you were going to make a sale. That was my assumption when I said that was the incremental cost. Or there was going -- and I believe it was phrased that way, if I'm not mistaken.

MR. BEASLEY: If I may clarify, I recall asking what was the incremental cost of making a 10 megawatt sale --

THE WITNESS: Sale, yeah.

MR. BEASLEY: -- the day after the commitment was made.

BY MR. McWHIRTER:

Q. And did it relate to separated or non-separated? And your answer is what?

A. My answers were in terms of non-separated sales, yeah.

MR. BEASLEY: I think the record will reflect that the question coincides with the answer.

BY MR. McWHIRTER:

Q. On page 3 of this exhibit, you have a dispatch order. And I presume that in the dispatch order, the $125 sale --

A. Purchase.

Q. -- is dispatched first, and then the $25 sale would be dispatched later, is that correct, under that transaction?

A. Yes, because the incremental cost of the purchased power agreement for incremental purposes is zero.

Q. And on page 3, if you had simultaneous sales to the retail customers and then wholesale sales to the wholesale customers, under page 3, what would the wholesale customer be charged for this 10 megawatt sale?

A. I have no idea. But you would hope that they're being priced to make the sale off the $25 since the incremental is zero. But, again, my testimony is not how you establish the pricing, it's how you establish the net benefits.

Q. I see.

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

MR. BEASLEY: Read and sign?

MR. McWHIRTER: I'm done, yes.

MR. BEASLEY: Okay. Great. Anyone on the phone have any questions?

MR. BURGESS: I have no questions. This is Burgess.

MR. KEATING: This is Cochran Keating. I think you covered the one question I was going to ask, so I have no questions.

MR. BEASLEY: Okay. Very well.

(Deposition concluded at 1:52 p.m.)

CERTIFICATE OF OATH

STATE OF FLORIDA

COUNTY OF HILLSBOROUGH

I, the undersigned authority, certify that GERARD KORDECKI personally appeared before me and was duly sworn.

WITNESS my hand and official seal this 24th day of August, 2001.

Dawn M. Dantschisch

Dawn M. Dantschisch, RMR, CRR
Notary Public - State of Florida
My Commission Expires: 11/4/03
Commission No.: CC871116

DAWN M. DANTSCHISCH
MY COMMISSION # CC 871116
EXPIRES: November 4, 2003
Bonded Thru Notary Public Underwriters

REPORTER'S CERTIFICATE

STATE OF FLORIDA

COUNTY OF HILLSBOROUGH

I, Dawn M. Dantschisch, Registered Merit Reporter, Certified Realtime Reporter, certify that I was authorized to and did stenographically report the deposition of GERARD KORDECKI; that a review of the transcript was not requested; and that the transcript is a true and complete record of my stenographic notes.

I further certify that I am not a relative, employee, attorney, or counsel of any of the parties, nor am I a relative or employee of any of the parties' attorney or counsel connected with the action, nor am I financially interested in the action.

Dated this 24th day of August, 2001.

Dawn M. Dantschisch

Dawn M. Dantschisch, RMR, CRR

ERRATA SHEET

IN RE: DOCKET NO. 010823-EI
NAME: Gerard Kordecki
DATE: August 29, 2001

PAGE	LINE	CHANGE
12	21	"load" instead of low

Under penalties of perjury, I declare that I have read my deposition and that it is true and correct subject to any changes in form or substance entered here.

Aug 28, 2001 Gerard Kordecki

DATE Gerard Kordecki

FLORIDA PUBLIC SERVICE COMMISSION

I

Combustion Turbine
Peaking Generation

$75

Generation

$25

Firm Purchased
Power

$100

Purchased Power Agreement
(Must Take)

$125

II

Combustion Turbine
Peaking Generation

$75

Base Load/Intermediate
Generation

$25

Firm Purchased
Power

$70

Purchased Power Agreement
(Must Take)

$20

III

Base Load/Intermediate
Generation
$25

Purchased Power Agreement
(Must Take)

$125

State of Florida

Public Service Commission

-M-E-M-O-R-A-N-D-U-M-

DATE: September 20, 2000

TO: All Parties of Record

FROM: Cochran Keating, Senior Attorney WCK
Todd Bohrmann, Regulatory Analyst IV WBM

RE: 000001-EI - Fuel and purchased power cost recovery clause and generating performance incentive factor.

Via Facsimile

This memorandum is to confirm and delineate the Commission Staff's proposed methodology, as presented at our September 12, 2000, meeting with the parties, to implement the Commission's recent decision in Docket No. 991779-EI concerning the appropriate application of incentives to wholesale power sales. As stated at the meeting, although the Commission has not yet issued its final order in this docket, Staff believes that implementation of the Commission's decision remains an open issue which should be resolved at this November's fuel hearing.

To implement the Commission's decision in Docket No. 991779-EI, Staff believes that the following issues are appropriate for resolution at this November's fuel hearing:

1. How should the Commission's decision in Docket No. 991779-EI, concerning the application of incentives to wholesale power sales, be implemented?

2. What is the appropriate estimated benchmark level for calendar year 2001 for gains on non-separated wholesale energy sales eligible for a shareholder incentive pursuant to the Commission's decision in Docket No. 991779-EI?

As discussed at the meeting, Staff proposes the following methodology to address the first issue:

1. In its Actual/Estimated True-Up filing and testimony, each utility shall include an estimated value of gains on eligible non-separated wholesale energy sales for the current calendar year (2000) based on actual and estimated data;

DEPOSITION EXHIBIT #2 Kordecki 08-21-01
PENGAD-Bayonne, N.J.

2. In its Projection filing, each utility shall include a forecasted value of gains on eligible non-separated wholesale energy sales for the next calendar year (2001);

3. Each utility shall compare its forecasted value of gains from eligible sales for the next calendar year (2001) to an estimated three-year moving average of such gains. This estimated three-year moving average, or estimated benchmark, will be based on actual gains from eligible sales for each of the previous two calendar years (1998 and 1999) and the estimated gains from eligible sales for the current calendar year (2000). This comparison will be one of numerous inputs that each utility will use to calculate its levelized fuel cost recovery factor for the next calendar year (2001);

4. In its April True-Up filing in the next calendar year (2001), each utility shall indicate its actual gains on eligible non-separated wholesale energy sales for the previous calendar year (2000). Each utility will then re-calculate its three-year moving average based on the actual gains from eligible sales for each of the previous three years (1998, 1999, and 2000) to establish an actual benchmark.

5. Each utility shall record its actual gains from eligible non-separated wholesale energy sales on its Schedule A-6 filed monthly with the Commission. When these actual gains are equal to or less than the utility's actual benchmark, the utility shall credit 100 percent of these gains to its ratepayers through its fuel and purchased power cost recovery clause (fuel clause). When these actual gains are greater than the utility's actual benchmark, the utility shall credit 80 percent of the gains above the benchmark to its ratepayers through its fuel clause. The utility shall credit the remaining 20 percent to its shareholders;

6. Each utility shall reflect any differences between its actual and forecasted gains from eligible sales through its monthly true-up calculations in Schedule A-2;

7. The first estimated benchmark for gains on eligible non-separated wholesale energy sales shall be established at the November 2000 fuel hearing for purposes of calculating a levelized fuel cost recovery factor for 2001. The shareholder incentive shall apply to actual gains on eligible sales made over the actual benchmark for 2001. On a going-forward basis, the difference between actual and forecasted gains on eligible sales shall be "trued-up" at each fuel hearing.

For illustrative purposes, this methodology, using hypothetical data, is presented in table form in the attached document.

If have any questions or comments concerning Staff's proposal, please contact Todd Bohrmann at (850) 413-6445 or Cochran Keating at (850) 413-6193.

WCK
Attachment
cc: Division of Regulatory Oversight
Division of Economic Regulation
i: 000001m6.wck

Proposed Shareholder Incentive Implementation Methodology
Hypothetical Example

Part I Nov '00	A	1998 Actual Gains *	$100.00	
	B	1999 Actual Gains *	$110.00	
	C	2000 Actual/Estimated Gains	$120.00	
	D	2001 Forecasted Benchmark	$110.00	(A+B+C)/3
	E	2001 Forecasted Gains *	$130.00	
	F	2001 Forecasted Ratepayer Credit	$126.00	D+((E-D)*.8)
Part II Apr '01	G	2000 Actual Gains *	$75.00	
	H	2001 Actual Benchmark	$95.00	(A+B+G)/3
Part III Nov '01	I	2001 Actual/Estimated Gains *	$128.00	
	J	2001 Actual/Estimated True-Up	($4.60)	L-F
	K	2002 Forecasted Benchmark	$104.33	(B+G+I)/3
	L	2001 Estimated Ratepayer Credit	$121.40	H+((I-H)*.8)
Part IV Apr '02	M	2001 Actual Gains *	$140.00	
	N	2001 Final True-up	$9.60	O-L
	O	2001 Actual Ratepayer Credit	$131.00	H+((M-H)*.8)
	P	2002 Actual Benchmark	$108.33	(B+G+M)/3

Note: Items marked with an asterisk (*) are values that would be found in a utility filing, but are hypothetical for this example.

EXHIBIT NO. 2

DOCKET NO: 010283-EI

DESCRIPTION: COMPOSITE EXHIBIT:

1) FPL's Responses to Staff Interrogatories 4 & 5
2) FPL's Responses to OPC Interrogatories 1 & 3
3) FPC's Responses to Staff Interrogatories 4 & 5
4) FPC's Responses to OPC Interrogatories 1 & 3
5) TECO's Responses to Staff Interrogatories 4 & 5
6) TECO's Responses to OPC Interrogatories 1 & 3

PROFERRED BY: STAFF

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010283-EI EXHIBIT NO. 2
COMPANY/
WITNESS: FPSC Staff
DATE: 8-31-01

4. **For each year from 1998 to 2000, please provide the amount of operation and maintenance (O&M) expense that FPL incurred to sell its non-separated wholesale energy that was recorded as part of its operating expenses.**

1998	None
1999	None
2000	None

5. **For each year from 1998 to 2000, please provide the amount of O&M expense that FPL incurred to sell its non-separated wholesale energy that was charged to its fuel cost recovery clause.**

1998	None
1999	$2,220,056
2000	$951,765

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Calculation of gains and appropriate regulatory treatment for non-separated wholesale energy sales by investor-owned electric utilities	)	Docket No. 010283-EI Dated: August 13, 2001

FLORIDA POWER & LIGHT COMPANY'S ANSWERS TO PUBLIC COUNSEL'S FIRST SET OF INTERROGATORIES

Florida Power & Light Company ("FPL") hereby provides its Answers to Public Counsel's First Set of Interrogatories.

Q.1. Please give a clear definition of incremental fuel costs and detail how the utility determines incremental fuel cost. Provide a detailed example of such calculation. If there are numerous methodologies used by the utility, detail each methodology and explain the circumstance under which such methodology would be used.

A. Incremental fuel cost is the increase in dollars per hour associated with an increase in power output in megawatts. In other words, it is the cost to produce the next MWh. Incremental fuel cost is calculated by using the incremental heat rate curve for a given generating unit. The incremental heat rate curve shows the amount of additional fuel that must be added to a generating unit, at a given loading level, to produce an additional unit of output. The incremental heat rate curve is determined through periodic testing of each generating unit. These heat rate curves provide the basis of the data that is filed with the Commission and reviewed in conjunction with the Fuel and GPIF processes. The additional fuel required is multiplied by the fuel cost to give the incremental cost of raising the unit by 1 MW. The cost of the fuel is based on current market price.

Example

Assume that the incremental heat rate for a specific unit loaded at 100 MW is 8.25 mmBtu/MWh and the cost of the fuel for that unit is $3.20/mmBtu. The incremental cost to raise the unit 1 MW, from its current loading level, would equal:

8.25 mmBtu/MWh • $3.20/mmBtu = $24.75/MWh

This incremental cost will change at different loading levels because the incremental heat rate changes through the operating range of the unit.

Q.3. **Please give a clear definition of incremental O & M costs and detail the type of expenses included in incremental O & M costs. Detail how the utility determines and calculates incremental O & M for each type of incremental O & M expense. Provide a detailed example of such calculation. If there are numerous methodologies used by the utility, detail each methodology and explain the circumstance under which such methodology would be used. Identify each type of incremental O & M expense that is included for recovery in the fuel clause.**

A. When FPL makes off system sales from its gas turbine (GT's) peaking units, the incremental O & M cost incurred specifically due to operating these units for such off system sales is included as a component of the incremental generation cost. GT's are intended to operate for a limited period of time. However, when these facilities are used to make off system sales, the price of the sale reflects the added cost for the use of these GT's.

<u>Example</u>

- A log is kept for each transaction, noting when GT's are used to make a sale.
- A rate of approximately $15.00 per MWH is used to calculate the incremental costs.
- The $15.00 rate is based on historical costing data for variable operating costs primarily composed of component aging and increased maintenance cycles.
- The MWHs sold from the GT's are multiplied by the $15.00 rate to produce the total amount of incremental O & M.
- For 2000, this amount was approximately $950,000. The cost and revenue associated with this incremental O & M (GT maintenance) is included in the fuel clause.

4. For each year from 1998 to 2000, please provide the amount of operation and maintenance (O&M) expense that FPC incurred to sell its non-separated wholesale energy that was recorded as part of its operating expenses.

Response: FPC does not track operation and maintenance expenses incurred to sell its non-separated wholesale energy. However, beginning in 2000, FPC does estimate the cost of O&M incurred to make non-separated wholesale sales and includes this estimate in the price charged to the wholesale customer. For the year 2000, this O&M price component produced revenues of $2,251,905.

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5. For each year from 1998 to 2000, please provide the amount of O&M expense that FPC incurred to sell its non-separated wholesale energy that was charged to its fuel cost recovery clause.

Response: None. These expenses were and continue to be charged to and recovered through FPC's base rates.

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In Re: Calculation of Gains and Appropriate Regulatory Treatment For Non-Separated Wholesale Energy Sales by Investor-Owned Electric Utilities

Docket No. 010283-EI

Submitted for Filing: August 21, 2001

FLORIDA POWER CORPORATION'S RESPONSE TO PUBLIC COUNSEL'S FIRST SET OF INTERROGATORIES PROPOUNDED TO FPC

Florida Power Corporation hereby files answers to Public Counsel's First Set of Interrogatories Propounded to Florida Power Corporation as follows:

1. Please give a clear definition of incremental fuel costs and detail how the utility determines incremental fuel cost. Provide a detailed example of such calculation. If there are numerous methodologies used by the utility, detail each methodology and explain the circumstance under which such methodology would be used.

Response:

A. Incremental Fuel Cost.

Coal: Each month incremental spot coal purchases that are being purchased for the following month plus the cost of transportation to transport the spot purchases are averaged to derive an incremental cost of coal for Crystal River 1&2 and 4&5. If there are no spot purchases for the month, quotes for spot coal, or published spot market indicators are evaluated and the incremental cost is based on the cost which would be incurred if the spot purchases were made.

Oil: For each plant that burns fuel oil an estimate is made of the cost to purchase additional oil. Each site has a normal supply source, fuel type, sulfur grade and a contract pricing mechanism that is used to calculate the incremental costs. If significant supply is being purchased or is planned to be purchased from somewhere other than the normal supply source, the alternative source pricing would be used. In most cases the price is updated daily based on the prior day's (most current available) price index using the contract pricing formula. For some sites the price changes weekly or monthly depending on how the supply contract pricing works. In all cases, the delivered cost is calculated including transportation and applicable taxes. A typical value for BTU content is used to convert the per barrel or per gallon price to $/mmbtu.

The following is an illustrative example of this methodology (not actual contract prices);
For Anclote Plant - burning 1.5% Sulfur #6 fuel oil -
Prior days market index (interpolated from the 1% & 3% sulfur published prices) plus transportation & taxes = $20.00/bbl.
BTU content = 6.4 million btu/bbl.
$/mmbtu = $3.125/mmbtu ($20.00 / 6.4)

Natural Gas:
For each plant that burns natural gas, the gas must be delivered to the plant site via an interstate pipeline. The cost of incremental supply to each plant consists of the cost of the gas supply (wellhead / supply-area price) plus the cost of interstate pipeline transportation. This formula would hold true for each of FPC's natural gas-fired plants except FPC's Intercession City plant. For the Intercession City plant, an additional transportation charge of $0.10 per MMBtu (in addition to the interstate transportation costs stated above) would be incurred for transportation across Florida Gas Utility's pipeline.

Firm Transportation Demand Charges. FPC subscribes to firm transportation (FT) capacity on Florida Gas Transmission pipeline (FGT). For each MMBtu of firm capacity for which FPC subscribes, FPC must pay a monthly demand charge to FGT. FPC pays this demand charge to FGT each month regardless of whether gas is actually transported using the FT capacity. For this reason, FT demand charges are considered by FPC to be sunk costs. Demand charges would not be included in any calculation of the incremental cost of natural gas.

Wellhead / Supply Area Gas Cost. FPC buys a majority of its supply area natural gas based on a published index such as Inside FERC's Gas Market Report. This index is published at the beginning of each month. The index price represents an average price, as reported by industry participants, for baseload gas that is bought and sold at a particular pipeline location for particular month of gas flow.

FPC also buys a portion of its gas supply area natural gas requirements on a day-ahead or intra-day basis. This gas price is based on overall market conditions as determined by the overall supply and demand situation applicable to the day of gas flow.

Determination of Delivery Method. FPC utilizes three different methods to effectuate delivery of natural gas to its power plants: 1) Utilization of FPC's firm transportation, 2) Utilization of interruptible transportation (if available), and 3) the purchase of natural gas delivered to the plant by independent third parties. When natural gas is required at FPC's plants, FPC looks at each of the above three costs to determine the lowest cost method of delivery. Each of the three methods is described below:

(1) If FCP holds unutilized FT capacity, FPC could use this unutilized transportation capacity to deliver the required incremental gas supply to the applicable plant. The total cost of delivered gas utilizing FT would include the Wellhead / Supply Area Cost (see above section), plus applicable variable transportation costs charged by the interstate pipeline (per interstate tariff). Variable charges include variable commodity (usage) costs plus fuel retention. Currently FGT's fuel rate is 2.4%. An example of total incremental cost using FT on FGT would be as follows:

Assume wellhead cost of \$3.00 per MMBtu
FT commodity (usage) charge per tariff = \$0.0178 per MMBtu
Fuel rate = 2.4%

Total cost = \$3.00 + \$0.0178 + [(3.00/ (1-.024)) - 3.00]
Total cost = \$3.09157 per MMBtu

(2) If interruptible transportation (IT) is available on the pipeline, FPC could utilize IT to make deliveries to the plant. The total cost of delivered gas utilizing IT would include the Wellhead / Supply Area Cost (see above description), plus applicable IT charges under the pipeline's IT rate schedule (tariff). An example of total cost using an IT on FGT would be as follows:

Assume wellhead cost of \$3.00 per MMBtu
IT charge per tariff = \$0.3298 per MMBtu
Fuel rage = 2.4%

Total cost = \$3.00 + \$0.3298 + [(3.00/(1-.024)) – 3.00]
Total cost = \$3.4036 per MMBtu

(3) FPC could purchase natural gas at the plant site (delivered) from independent third parties. To determine the cost of buying delivered gas, FPC calls its suppliers to obtain price offers for gas delivered to the plant site. In many cases, no third parties will offer delivered gas, as all interstate transportation into the state of Florida is being utilized.

B. Incremental Energy Cost.
Incremental Fuel Cost (see above).
Purchased Power: In addition to fuel, SO2 and O&M expenses, purchased power transactions are also incorporated into FPC's incremental energy cost calculation. As an example, pre-arranged energy transactions are included in the incremental energy cost calculations used in the hourly market quotes. These pre-arranged transactions become a part of the total portfolio modeled in trading management applications.

2. Please give a clear definition of incremental SO2 and detail how the utility determines and calculates incremental SO2. Provide a detailed example of such calculation. If there are numerous methodologies used by the utility, detail each methodology and explain the circumstance under which such methodology would be used.

Response:
For each plant that is covered under the SO2 Allowance program an emmision rate (lbs SO2/mmbtu) is estimated based on the sulfur content of the fuel being used at that plant. A market price in $/ton for SO2 Allowances is estimated from the most recent market publications available. The $/ton price for SO2 is then converted to $/lb. A $/mmbtu value is then calculated.

The following is an illustrative example of this methodology (not actual prices); For Anclote Plant – burning 1.5% Sulfur #6 fuel oil, the emmision rate is approximately 1.7lbs SO2/mmbtu.
Most recent Allowance price = $200/ton or $.10/lb.
Incremental SO2 costs = $.17/mmbtu ($.10 x 1.7).

3. Please give a clear definition of incremental O&M costs and detail the type of expenses included in incremental O&M costs. Detail how the utility determines and calculates incremental O&M for each type of incremental O&M expense. Provide a detailed example of such calculation. If there are numerous methodologies used by the utility, detail each methodology and explain the circumstance under which such methodology would be used. Identify each type of incremental O&M expense that is included for recovery in the fuel clause.

Response:
Florida Power Corp. does not include incremental O&M costs in the Fuel Adjustment Clause.

4. For each year from 1998 to 2000, please provide the amount of operation and maintenance (O&M) expense that TECO incurred to sell its non-separated wholesale energy that was recorded as part of its operating expenses.

A. 1998..............................$1,344,921
1999..............................$ 587,681
2000..............................$3,390,763

5. For each year from 1998 to 2000, please provide the amount of O&M expense that TECO incurred to sell its non-separated wholesale energy that was charged to its fuel cost recovery clause.

A. Tampa Electric does not charge fuel-related O&M expenses to its fuel cost recovery clause.

1. Please give a clear definition of incremental fuel costs and detail how the utility determines incremental fuel cost. Provide a detailed example of such calculation. If there are numerous methodologies used by the utility, detail each methodology and explain the circumstance under which such methodology would be used.

A. Incremental fuel costs are the costs of the last megawatt(s) of power from the system. These costs may be comprised of native generation and purchased power.

The incremental fuel costs for a given power sale are calculated by first dispatching the available generation and power purchases for all load of greater priority. Then the generation resources and power purchases are dispatched for the same load plus the power sale. The difference in fuel costs of the two cases is the incremental fuel costs.

Detailed Example:
Assumptions
Native Load = 2,000 MW
Power Sale = 100 MW
Native Generation* = 2,050 MW
Incremental Cost of Last 50 MW of Native Generation = $50/MWh
Hourly Purchases = 50 MW @ $60/MWh

Calculation
Incremental Fuel Cost of 100 MW Sale = (50 MW • $50/MWh) + (50 MW • $60/MWh)= $5,500 per hour

• Includes generation and firm, "must take" block purchases

3. Please give a clear definition of incremental O&M costs and detail the type of expenses included in incremental O&M costs. Detail how the utility determines and calculates incremental O&M for each type of incremental O&M expense. Provide a detailed example of such calculation. If there are numerous methodologies used by the utility, detail each methodology and explain the circumstance under which such methodology would be used. Identify each type of incremental O&M expense that is included for recovery in the fuel clause.

A. Incremental O&M costs are the change in O&M costs when the output of a generating unit is increased or decreased.

Incremental O&M expenses are calculated annually based upon the prior year's actual O&M expenses. Fixed and variable components of O&M expense are calculated using a procedure developed by the Electric Power Research Institute (EPRI). The procedure was published in their Technical Assessment Guide (TAG) Special Report, dated May 1982 (EPRI P-2410-SR). Incremental O&M costs equal variable O&M expenses since variable O&M is the portion of O&M costs that depends on generation output. The fixed component of O&M costs represents costs the utility will incur regardless of whether or not generation output varies.

The EPRI procedure sets fixed O&M costs equal to the capacity factor (%) times total annual O&M expenses. The capacity factor is based on total period hours less hours the units are off line due to economic dispatch during low load periods. The variable component is calculated by multiplying [1 – the capacity factor (%)] by the total annual O&M cost.

No incremental O&M expense is included for recovery in the fuel clause. The O&M expense that is included is not related to Tampa Electric's generating assets. It is solely expense associated with purchased power contracts with cogenerators and Hardee Power Partners.

Detailed Example:

2001 VARIABLE COAL O&M CALCULATION
BASED UPON 2000 COAL O&M INFORMATION

	ADJUSTED MAX NET GWH	ACTUAL NET GEN. GWH
BIG BEND COAL GWH	15,148.0	10,713.1
GANNON COAL GWH	9,942.3	4,355.2
POLK COAL GWH	2,196.0	1,691.0
TOTAL COAL GWH	**27,286.3**	**16,759.3**

	ANNUAL
AVERAGE ADJUSTED COAL CAPACITY FACTOR	61.42%
BIG BEND O&M EXPENSE	$48,552,341
GANNON O&M EXPENSE	$39,494,449
POLK O&M EXPENSE	$22,631,219
TOTAL O&M EXPENSE	$110,678,009
VARIABLE COMPONENT * TOTAL O&M	$42,699,344
ESTIMATED COAL VARIABLE O&M COSTS ($/MWH)	**$2.55**

State of Florida

Public Service Commission

-M-E-M-O-R-A-N-D-U-M-

DATE: September 20, 2000

TO: All Parties of Record

FROM: Cochran Keating, Senior Attorney WCK
Todd Bohrmann, Regulatory Analyst IV WBM

RE: 000001-EI - Fuel and purchased power cost recovery clause and generating performance incentive factor.

Via Facsimile

This memorandum is to confirm and delineate the Commission Staff's proposed methodology, as presented at our September 12, 2000, meeting with the parties, to implement the Commission's recent decision in Docket No. 991779-EI concerning the appropriate application of incentives to wholesale power sales. As stated at the meeting, although the Commission has not yet issued its final order in this docket, Staff believes that implementation of the Commission's decision remains an open issue which should be resolved at this November's fuel hearing.

To implement the Commission's decision in Docket No. 991779-EI, Staff believes that the following issues are appropriate for resolution at this November's fuel hearing:

1. How should the Commission's decision in Docket No. 991779-EI, concerning the application of incentives to wholesale power sales, be implemented?

2. What is the appropriate estimated benchmark level for calendar year 2001 for gains on non-separated wholesale energy sales eligible for a shareholder incentive pursuant to the Commission's decision in Docket No. 991779-EI?

As discussed at the meeting, Staff proposes the following methodology to address the first issue:

1. In its Actual/Estimated True-Up filing and testimony, each utility shall include an estimated value of gains on eligible non-separated wholesale energy sales for the current calendar year (2000) based on actual and estimated data;

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 010283-EI EXHIBIT NO. 3
COMPANY/WITNESS: Florida Power & Light
DATE: 8-31-01

2. In its Projection filing, each utility shall include a forecasted value of gains on eligible non-separated wholesale energy sales for the next calendar year (2001);

3. Each utility shall compare its forecasted value of gains from eligible sales for the next calendar year (2001) to an estimated three-year moving average of such gains. This estimated three-year moving average, or estimated benchmark, will be based on actual gains from eligible sales for each of the previous two calendar years (1998 and 1999) and the estimated gains from eligible sales for the current calendar year (2000). This comparison will be one of numerous inputs that each utility will use to calculate its levelized fuel cost recovery factor for the next calendar year (2001);

4. In its April True-Up filing in the next calendar year (2001), each utility shall indicate its actual gains on eligible non-separated wholesale energy sales for the previous calendar year (2000). Each utility will then re-calculate its three-year moving average based on the actual gains from eligible sales for each of the previous three years (1998, 1999, and 2000) to establish an actual benchmark.

5. Each utility shall record its actual gains from eligible non-separated wholesale energy sales on its Schedule A-6 filed monthly with the Commission. When these actual gains are equal to or less than the utility's actual benchmark, the utility shall credit 100 percent of these gains to its ratepayers through its fuel and purchased power cost recovery clause (fuel clause). When these actual gains are greater than the utility's actual benchmark, the utility shall credit 80 percent of the gains above the benchmark to its ratepayers through its fuel clause. The utility shall credit the remaining 20 percent to its shareholders;

6. Each utility shall reflect any differences between its actual and forecasted gains from eligible sales through its monthly true-up calculations in Schedule A-2;

7. The first estimated benchmark for gains on eligible non-separated wholesale energy sales shall be established at the November 2000 fuel hearing for purposes of calculating a levelized fuel cost recovery factor for 2001. The shareholder incentive shall apply to actual gains on eligible sales made over the actual benchmark for 2001. On a going-forward basis, the difference between actual and forecasted gains on eligible sales shall be "trued-up" at each fuel hearing.

For illustrative purposes, this methodology, using hypothetical data, is presented in table form in the attached document.

If have any questions or comments concerning Staff's proposal, please contact Todd Bohrmann at (850) 413-6445 or Cochran Keating at (850) 413-6193.

WCK
Attachment
cc: Division of Regulatory Oversight
Division of Economic Regulation
i: 000001m6.wck

Proposed Shareholder Incentive Implementation Methodology
Hypothetical Example

Part I Nov '00	A	1998 Actual Gains *	$100.00	
	B	1999 Actual Gains *	$110.00	
	C	2000 Actual/Estimated Gains	$120.00	
	D	2001 Forecasted Benchmark	$110.00	(A+B+C)/3
	E	2001 Forecasted Gains *	$130.00	
	F	2001 Forecasted Ratepayer Credit	$126.00	D+((E-D)*.8)
Part II Apr '01	G	2000 Actual Gains *	$75.00	
	H	2001 Actual Benchmark	$95.00	(A+B+G)/3
Part III Nov '01	I	2001 Actual/Estimated Gains *	$128.00	
	J	2001 Actual/Estimated True-Up	($4.60)	L-F
	K	2002 Forecasted Benchmark	$104.33	(B+G+I)/3
	L	2001 Estimated Ratepayer Credit	$121.40	H+((I-H)*.8)
Part IV Apr '02	M	2001 Actual Gains *	$140.00	
	N	2001 Final True-up	$9.60	O-L
	O	2001 Actual Ratepayer Credit	$131.00	H+((M-H)*.8)
	P	2002 Actual Benchmark	$108.33	(B+G+M)/3

Note: Items marked with an asterisk (*) are values that would be found in a utility filing, but are hypothetical for this example.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power cost recovery clause and generating performance incentive factor.	DOCKET NO. 000001-EI ORDER NO. PSC-00-2169-PHO-EI ISSUED: November 15, 2000

Pursuant to Notice and in accordance with Rule 28-106.209, Florida Administrative Code, a Prehearing Conference was held on November 3, 2000, in Tallahassee, Florida, before Commissioner Lila A. Jaber, as Prehearing Officer.

APPEARANCES:

> JAMES A. MCGEE, ESQUIRE, Post Office Box 14042, St. Petersburg, Florida 33733-4042
> On behalf of Florida Power Corporation (FPC).
>
> MATTHEW M. CHILDS, ESQUIRE, Steel Hector & Davis LLP, 215 South Monroe Street, Suite 601, Tallahassee, FL 32301
> On behalf of Florida Power & Light Company (FPL).
>
> NORMAN H. HORTON, JR., ESQUIRE, Messer, Caparello & Self, P.A., Post Office Box 1876, Tallahassee, Florida 32302-1876
> On behalf of Florida Public Utilities Company (FPUC).
>
> JEFFREY A. STONE, ESQUIRE, AND RUSSELL A. BADDERS, ESQUIRE, Beggs & Lane, 700 Blount Building, 3 West Garden Street, Post Office Box 12950, Pensacola, Florida 32576-2950
> On behalf of Gulf Power Company (GULF).
>
> JAMES D. BEASLEY, ESQUIRE, Ausley & McMullen, Post Office Box 391, Tallahassee, Florida 32302
> On behalf of Tampa Electric Company (TECO).
>
> VICKI GORDON KAUFMAN, ESQUIRE, McWhirter, Reeves, McGlothlin, Davidson, Decker, Kaufman, Arnold & Steen, P.A., 117 South Gadsden Street, Tallahassee, Florida 32301
> On behalf of Florida Industrial Power Users Group (FIPUG).

STEPHEN C. BURGESS, ESQUIRE, Deputy Public Counsel, Office of Public Counsel (OPC), c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida.

WM. COCHRAN KEATING IV, ESQUIRE, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
On behalf of the Commission Staff (STAFF).

PREHEARING ORDER

I. CONDUCT OF PROCEEDINGS

Pursuant to Rule 28-106.211, Florida Administrative Code, this Order is issued to prevent delay and to promote the just, speedy, and inexpensive determination of all aspects of this case.

The parties may make opening statements if they wish. Opening statements, if any, shall not exceed ten minutes.

II. CASE BACKGROUND

As part of the Commission's continuing fuel and purchased power cost recovery clause and generating performance incentive factor proceedings, an administrative hearing is set for November 20-22, 2000, to address the issues set forth in the body of this Prehearing Order. The parties have stipulated to several issues as shown in Section VIII of this Order. Staff is prepared to present the panel with a recommendation at hearing for approval of the stipulated positions set forth herein and will be prepared to make a recommendation at hearing on all other issues. The Commission has the option to render a bench decision on any or all of the issues set forth herein.

III. PROCEDURE FOR HANDLING CONFIDENTIAL INFORMATION

A. Any information provided pursuant to a discovery request for which proprietary confidential business information status is requested shall be treated by the Commission and the parties as confidential. The information shall be exempt from Section 119.07(1), Florida Statutes, pending a formal ruling on such request by the Commission, or upon the return of the information to the person providing the information. If no determination of confidentiality has been made and the information has not been used in the proceeding, it shall be returned expeditiously to the person providing the information. If a determination of confidentiality has been made and the information was not entered into the record of the proceeding, it shall be returned to the person providing the information within the time periods set forth in Section 366.093, Florida Statutes.

B. It is the policy of the Florida Public Service Commission that all Commission hearings be open to the public at all times. The Commission also recognizes its obligation pursuant to Section 366.093, Florida Statutes, to protect proprietary confidential business information from disclosure outside the proceeding.

1. Any party intending to utilize confidential documents at hearing for which no ruling has been made, must be prepared to present their justifications at hearing, so that a ruling can be made at hearing.

2. In the event it becomes necessary to use confidential information during the hearing, the following procedures will be observed:

a) Any party wishing to use any proprietary confidential business information, as that term is defined in Section 366.093, Florida Statutes, shall notify the Prehearing Officer and all parties of record by the time of the Prehearing Conference, or if not known at that time, no later than seven (7) days prior to the beginning of the hearing. The notice shall include a procedure to assure that the confidential nature of the information is preserved as required by statute.

b) Failure of any party to comply with 1) above shall be grounds to deny the party the opportunity to present evidence which is proprietary confidential business information.

c) When confidential information is used in the hearing, parties must have copies for the Commissioners, necessary staff, and the Court Reporter, in envelopes clearly marked with the nature of the contents. Any party wishing to examine the confidential material that is not subject to an order granting confidentiality shall be provided a copy in the same fashion as provided to the Commissioners, subject to execution of any appropriate protective agreement with the owner of the material.

d) Counsel and witnesses are cautioned to avoid verbalizing confidential information in such a way that would compromise the confidential information. Therefore, confidential information should be presented by written exhibit when reasonably possible to do so.

e) At the conclusion of that portion of the hearing that involves confidential information, all copies of confidential exhibits shall be returned to the proffering party. If a confidential exhibit has been admitted into evidence, the copy provided to the Court Reporter shall be retained in the Division of Records and Reporting's confidential files.

IV. <u>POST-HEARING PROCEDURES</u>

Each party shall file a post-hearing statement of issues and positions. A summary of each position of no more than 50 words, set off with asterisks, shall be included in that statement. If a party's position has not changed since the issuance of the prehearing order, the post-hearing statement may simply restate the prehearing position; however, if the prehearing position is longer than 50 words, it must be reduced to no more than 50 words. If a party fails to file a post-hearing statement, that party shall have waived all issues and may be dismissed from the proceeding.

Pursuant to Rule 28-106.215, Florida Administrative Code, a party's proposed findings of fact and conclusions of law, if any, statement of issues and positions, and brief, shall together total no more than 40 pages and shall be filed at the same time.

V. <u>PREFILED TESTIMONY AND EXHIBITS; WITNESSES</u>

Testimony of all witnesses to be sponsored by the parties has been prefiled. All testimony which has been prefiled in this case will be inserted into the record as though read after the witness has taken the stand and affirmed the correctness of the testimony and associated exhibits. All testimony remains subject to appropriate objections. Each witness will have the opportunity to orally summarize his or her testimony at the time he or she takes the stand. Summaries of testimony, if any, will be limited to five minutes. Upon insertion of a witness' testimony, exhibits appended thereto may be marked for identification. After all parties and Staff have had the opportunity to object and cross-examine, the exhibit may be moved into the record. All other exhibits may be similarly identified and entered into the record at the appropriate time during the hearing.

Witnesses are reminded that, on cross-examination, responses to questions calling for a simple yes or no answer shall be so answered first, after which the witness may explain his or her answer.

The Commission frequently administers the testimonial oath to more than one witness at a time. Therefore, when a witness takes the stand to testify, the attorney calling the witness is directed to ask the witness to affirm whether he or she has been sworn.

VI. ORDER OF WITNESSES

As a result of discussions at the prehearing conference, each witness whose name is preceded by an asterisk (*) has been excused from this hearing if no Commissioner assigned to this case seeks to cross-examine the particular witness. Parties shall be notified by Monday, November 13, 2000, as to whether any such witness shall be required to be present at hearing. The testimony of excused witnesses will be inserted into the record as though read, and all exhibits submitted with those witnesses' testimony shall be identified as shown in Section IX of this Prehearing Order and be admitted into the record.

Witness	Proffered By	Issues #
Direct		
*John Scardino, Jr.	FPC	1, 3, 16, 18
Karl H. Wieland	FPC	2-10, 12A-12F, 17-21
*Rebecca J. McClintock	FPC	14, 15
*G. Yupp	FPL	1, 2, 3, 4, 5, 6, 7, 8

Witness	Proffered By	Issues #
*R. L. Wade	FPL	1, 2, 3, 4, 5, 6, 7, 8, 11d
K. M. Dubin	FPL	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11a-11c, 16, 17, 18, 19, 20, 21
*R. Silva	FPL	14, 15
*George M. Bachman	FPUC	1, 2, 3, 4, 5, 6, 7, 8
*M. F. Oaks	GULF	1, 2, 4
T. A. Davis	GULF	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 16, 17, 18, 19, 20, 21
*J. R. Douglas	GULF	14, 15
*M. W. Howell	GULF	1, 2, 4, 9, 10, 16, 17, 19
J. Denise Jordan	TECO	1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 13e, 13f, 16, 17, 18, 19, 20, 21
*Brian S. Buckley	TECO	4, 14, 15
*W. L. Brown	TECO	2, 4, 10
*Rod Burkhardt	TECO	13a, 13b, 13c, 13d

VII. BASIC POSITIONS

FPC: None necessary.

FPL: None necessary.

FPUC: Florida Public Utilities Company has properly projected its costs and calculated its true-up amounts and purchased power cost recovery factors. Those amounts and factors should be approved by the Commission.

GULF: It is the basic position of Gulf Power Company that the proposed fuel factors present the best estimate of Gulf's fuel expense for the period January 2001 through December 2001 including the true-up calculations, GPIF and other adjustments allowed by the Commission.

TECO: The Commission should approve Tampa Electric's calculation of its fuel adjustment, capacity cost recovery and GPIF true-up and projection calculations, including the proposed fuel adjustment factor of 2.500 cents per KWH before application of factors which adjust for variations in line losses; the proposed capacity cost recovery factor of 0.199 cents per KWH before applying the 12CP and 1/13th application methodology; a GPIF penalty of $1,151,236 and approval of the company's proposed GPIF targets and ranges for the forthcoming period. Tampa Electric also requests approval of its proposed seasonal fuel factor program and the company's proposed implementation of the wholesale incentive benchmark mechanism and the calculated benchmark of $4,648,490 for calendar year 2001.

FIPUG: None.

OPC: None.

STAFF: Staff's positions are preliminary and based on materials filed by the parties and on discovery. The preliminary positions are offered to assist the parties in preparing for the hearing. Staff's final positions will be based upon all the evidence in the record and may differ from the preliminary positions.

VIII. ISSUES AND POSITIONS

GENERIC FUEL ADJUSTMENT ISSUES

STIPULATED

ISSUE 1: **What are the appropriate final fuel adjustment true-up amounts for the period January, 1999 through December 1999?**

POSITION:

FPC: $6,442,734 overrecovery
FPL: $96,356,314 underrecovery
FPUC-Fernandina Beach: $302,631 overrecovery
FPUC-Marianna: $43,609 overrecovery
GULF: $4,015,661 overrecovery
TECO: $8,662,661 underrecovery

STIPULATED

ISSUE 2: **What are the estimated/actual fuel adjustment true-up amounts for the period January through December 2000 based upon seven months actual and five months revised estimates?**

POSITION:

FPC: $61,660,541 underrecovery
FPL: $518,005,376 underrecovery
FPUC-Fernandina Beach: $314,792 overrecovery
FPUC-Marianna: $104,942 overrecovery
GULF: $8,668,391 underrecovery
TECO: $34,058,660 underrecovery

STIPULATED

ISSUE 3: **What are the appropriate total fuel adjustment true-up amounts to be collected/refunded during the period January, 2001 through December, 2001?**

POSITIONS:

FPC: $55,217,807 underrecovery. If the Commission approves the stipulated position in Issue 12D, Florida Power should collect $27,608,904 during calendar year 2001.

FPL: $518,005,376 underrecovery. If the Commission approves the stipulated position in Issue 11A, FPL should collect $259,002,688 during calendar year 2001.

FPUC-Fernandina Beach:	$617,423 overrecovery to be refunded.
FPUC-Marianna:	$148,551 overrecovery to be refunded.
GULF:	$4,652,730 underrecovery to be collected.
TECO:	$42,721,321 underrecovery to be collected.

*This issue was stipulated at the prehearing conference. As noted in the Section XI, "Pending Motions", FIPUG subsequently filed a Motion to Amend Prehearing Position on Issue 11A. The resolution of Issue 11A, if different than the position shown as stipulated for Issue 11A, will have a fall-out effect on the amounts in this issue. This issue remains shown as stipulated pending resolution of FIPUG's motion.

ISSUE 4: **What are the appropriate levelized fuel cost recovery factors for the period January, 2001 through December, 2001?**

POSITIONS:

FPC: 2.521 cents per kWh (adjusted for jurisdictional losses), based on FPC's 50% true-up recovery proposal under Issue 3 above. (Wieland)

FPL: 2.925 cents/kwh is the levelized recovery charge to be collected during the period January, 2001 through December, 2001. (Dubin)

FPUC:

Marianna:	2.204 cents/kwh
Fernandina Beach:	1.875 cents/kwh

GULF: 1.820¢/KWH. (Oaks, Howell, Davis)

TECO: The appropriate factor is 2.500 cents per KWH before the normal application of factors that adjust for variations in line losses. (Brown, Buckley, Burkhardt, and Jordan)

FIPUG: No position.

OPC: Accept staff's position.

STAFF:

FPC:	2.520 cents per kWh
FPL:	2.925 cents per kWh

FPUC-Marianna: 2.204 cents per kWh.
FPUC-Fernandina Beach: 1.875 cents per kWh.
GULF: 1.820 cents per kWh.
TECO: 2.500 cents per kWh.

*This issue is not disputed. However, the resolution of Issue 10 may have a fallout effect on the factors set forth in this issue. Therefore, this issue is not shown as stipulated.

STIPULATED
ISSUE 5: **What should be the effective date of the new fuel adjustment charge and capacity cost recovery charge for billing purposes?**

POSITION:

The new factors should be effective beginning with the first billing cycle for January, 2001, and thereafter through the last billing cycle for December, 2001. The first billing cycle may start before January 1, 2001, and the last billing cycle may end after December 31, 2001, so long as each customer is billed for twelve months regardless of when the factors became effective.

STIPULATED
ISSUE 6: **What are the appropriate fuel recovery line loss multipliers to be used in calculating the fuel cost recovery factors charged to each rate class?**

POSITION:

FPC:

Group	Delivery Voltage Level	Line Loss Multiplier
A.	Transmission	0.9800
B.	Distribution Primary	0.9900
C.	Distribution Secondary	1.0000
D.	Lighting Service	1.0000

FPL: See Issue 7.

FPUC: Fernandina Beach
All Rate Schedules 1.0000

Marianna
All Rate Schedules 1.0000

GULF: See table below:

Group	Rate Schedules*	Line Loss Multipliers
A	RS, GS, GSD, GSDT, SBS, OSIII, OSIV	1.01228
B	LP,LPT,SBS	0.98106
C	PX, PXT, SBS, RTP	0.96230
D	OSI, OSII	1.01228

*The multiplier applicable to customers taking service under Rate Schedule SBS is determined as follows: customers with a Contract Demand in the range of 100 to 499 KW will use the recovery factor applicable to Rate Schedule GSD; customers with a Contract Demand in the range of 500 to 7,499 KW will use the recovery factor applicable to Rate Schedule LP; and customers with a Contract Demand over 7,499 KW will use the recovery factor applicable to Rate Schedule PX.

TECO:

Group	Multiplier
Group A	1.0035
Group A1	n/a*
Group B	1.0009
Group C	0.9792

*Group A1 is based on Group A, 15% of On-Peak and 85% of Off-Peak.

ISSUE 7: **What are the appropriate Fuel Cost Recovery Factors for each rate class adjusted for line losses?**

POSITIONS:

FPC:

Delivery		Fuel Cost Factors (cents/kWh)	Time of Use	
Group	Voltage Level	Standard	On-Peak	Off-Peak
A.	Transmission	2.475	3.388	2.064
B.	Distribution Primary	2.500	3.423	2.085
C.	Distribution Secondary	2.525	3.457	2.106
D.	Lighting Service	2.358		

(Wieland)

FPL:

Rate Class	Rate Schedule	Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
A	RS-1,GS-1,SL-2	2.925	1.00198	2.931
A-1*	SL-1,OL-1,PL-1	2.864	1.00198	2.870
B	GSD-1	2.925	1.00191	2.930
C	GSLD-1 & CS-1	2.925	1.00077	2.927
D	GSLD-2,CS-2,OS-2 & MET	2.925	0.99503	2.910
E	GSLD-3 & CS-3	2.925	0.95800	2.802
A	RST-1,GST-1			
	On-Peak	3.213	1.00198	3.219
	Off-Peak	2.798	1.00198	2.803
B	GSDT-1, CILC-1(G)	3.213	1.00191	3.219
	On-Peak	2.798	1.00191	2.803
	Off-Peak			

C	GSLDT-1 & CST-1			
	On-Peak	3.213	1.00077	3.215
	Off-Peak	2.798	1.00077	2.800
D	GSLDT-2 & CST-2			
	On-Peak	3.213	0.99503	3.197
	Off-Peak	2.798	0.99503	2.784
E	GSLDT-3, CST-3/CILC-1(T) & ISST-1(T)			
	On-Peak	3.213	0.95800	3.078
	Off-Peak	2.798	0.95800	2.680
F	CILC-1(D) & ISST-1(D)			
	On-Peak	3.213	0.99431	3.195
	Off-Peak	2.798	0.99431	2.782

*WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

(Dubin)

<u>FPUC:</u>

Marianna:

Rate Schedule	Adjustment
RS	3.859 cents/kWh
GS	3.845 cents/kWh
GSD	3.472 cents/kWh
GSLD	3.317 cents/kWh
OL, OL-2	2.413 cents/kWh
SL-1, SL-2	2.421 cents/kWh

Fernandina Beach:

Rate Schedule	Adjustment
RS	3.464 cents/kWh
GS	3.357 cents/kWh
GSD	3.192 cents/kWh
OL	2.476 cents/kWh
SL, CSL	2.476 cents/kWh

GULF: See table below: (Davis)

		Fuel Cost Factors ¢/KWH		
		Standard	Time of Use	
Group	Rate Schedules*		On-Peak	Off-Peak
A	RS, RSVP, GS, GSD, SBS, OSIII, OSIV	1.842	2.361	1.622
B	LP, SBS	1.786	2.289	1.572
C	PX, RTP, SBS	1.751	2.245	1.542
D	OSI, OSII	1.808	N/A	N/A

*The recovery factor applicable to customers taking service under Rate Schedule SBS is determined as follows: customers with a Contract Demand in the range of 100 to 499 KW will use the recovery factor applicable to Rate Schedule GSD; customers with a Contract Demand in the range of 500 to 7,499 KW will use the recovery factor applicable to Rate Schedule LP; and customers with a Contract Demand over 7,499 KW will use the recovery factor applicable to Rate Schedule PX.

TECO:

	Standard	On-Peak	Off-Peak
Group A	2.509	3.494	2.080
Group A1	2.292	N/A	N/A
Group B	2.502	3.485	2.075
Group C	2.448	3.410	2.030

(Jordan)

FIPUG: No position.

OPC: No position.

STAFF:

FPC:

Group	Delivery Voltage Level	Fuel Cost Factors (cents/kWh) Standard	Time Of Use On-Peak	Time Of Use Off-Peak
A.	Transmission	2.474	3.387	2.063
B.	Distribution Primary	2.499	3.421	2.084
C.	Distribution Secondary	2.524	3.455	2.105
D.	Lighting Service	2.358		

FPL:

Group	Rate Schedule	Average Factor	Fuel Recovery Loss Multiplier	Fuel Recovery Factor
A	RS-1, GS-1, Sl-2	2.925	1.00198	2.931
A-1	SL-1, OL-1, PL1	2.864	1.00198	2.870
B	GSD-1	2.925	1.00191	2.930
C	GSLD-1, CS-1	2.925	1.00077	2.927
D	GSLD-2, CS-2, OS-2, MET	2.925	0.99503	2.910
E	GSLD-3, CS-3	2.925	0.95800	2.802
A	RST-1, GST-1			
	ON-PEAK	3.213	1.00198	3.219
	OFF-PEAK	2.798	1.00198	2.803
B	GSDT-1, CILC-1(G)			
	ON-PEAK	3.213	1.00191	3.219
	OFF-PEAK	2.798	1.00191	2.803
C	GSLDT-1, CST-1			
	ON-PEAK	3.213	1.00077	3.215
	OFF-PEAK	2.798	1.00077	2.800
D	GSLDT-2, CST-2			
	ON-PEAK	3.213	0.99503	3.197
	OFF-PEAK	2.798	0.99503	2.784
E	GSLDT-3, CST-3,			

	CILC-1(T), ISST-1(T)			
	ON-PEAK	3.213	0.95800	3.078
	OFF-PEAK	2.798	0.95800	2.680
F	CILC-1(D), ISST-1(D)			
	ON-PEAK	3.213	0.99431	3.195
	OFF-PEAK	2.798	0.99431	2.782

FPUC-Fernandina Beach:

Rate Schedule	Adjustment
RS	3.464 cents/kWh
GS	3.357 cents/kWh
GSD	3.192 cents/kWh
OL	2.476 cents/kWh
SL, CSL	2.476 cents/kWh

FPUC-Marianna:

Rate Schedule	Adjustment
RS	3.859 cents/kWh
GS	3.845 cents/kWh
GSD	3.472 cents/kWh
GSLD	3.317 cents/kWh
OL, OL-2	2.413 cents/kWh
SL-1, SL-2	2.421 cents/kWh

GULF: See table below:

Group	Rate Schedules*	Fuel Cost Factors ¢/KWH		
		Standard	Time of Use	
			On-Peak	Off-Peak
A	RS, GS, GSD, GSDT, SBS OSIII, OSIV	1.842	2.361	1.622
B	LP, LPT, SBS	1.786	2.289	1.572
C	PX, PXT, SBS, RTP	1.751	2.245	1.542

D	OSI, OSII	1.808	N/A	N/A
*The recovery factor applicable to customers taking service under Rate Schedule SBS is determined as follows: customers with a Contract Demand in the range of 100 to 499 KW will use the recovery factor applicable to Rate Schedule GSD; customers with a Contract Demand in the range of 500 to 7,499 KW will use the recovery factor applicable to Rate Schedule LP; and customers with a Contract Demand over 7,499 KW will use the recovery factor applicable to Rate Schedule PX.				

TECO:

	Standard	On-Peak	Off-Peak
Group A	2.509	3.494	2.080
Group A1	2.292	n/a	n/a
Group B	2.502	3.485	2.075
Group C	2.448	3.410	2.030

*This issue is not disputed. However, the resolution of Issue 10 may have a fallout effect on the factors set forth in this issue. Therefore, this issue is not shown as stipulated.

STIPULATED

ISSUE 8: **What is the appropriate revenue tax factor to be applied in calculating each company's levelized fuel factor for the projection period of January, 2001 through December, 2001?**

POSITION:

FPC:	1.00072
FPL:	1.01597
FPUC-Fernandina Beach:	1.01597
FPUC-Marianna:	1.00072
GULF:	1.01597
TECO:	1.00072

ISSUE 9: **How should the Commission's decision as set forth by Order No. PSC-00-1744-PAA-EI, in Docket No. 991779-EI, issued September 26, 2000, concerning the application of incentives to wholesale power sales, be implemented?**

POSITIONS:

FPC: Agree with staff position. (Wieland)

FPL: FPL believes that the methodology for implementing the application of incentives to wholesale power sales as proposed by Staff and described in Staff's memorandum dated September 20, 2000 is appropriate. (Dubin)

GULF: Gulf agrees with the method proposed by Commission Staff in its letter dated September 20, 2000. (Davis, Howell)

TECO: Agree with staff memorandum. (Jordan)

FIPUG: FIPUG filed a motion for reconsideration and protest on October 11, 2000. The order should not be implemented until these matters are resolved.

OPC: Any incentive mechanism which creates the potential for a protected monopoly to generate additional earnings above the established ROE should also create the symmetrical potential that the monopoly could suffer an earnings reduction, in the event of subpar performance.

STAFF: The methodology set forth in Staff's September 20, 2000, memorandum to the parties is an appropriate method for implementing Order No. PSC-00-1744-PAA-EI. The memorandum is attached hereto as Attachment A.

ISSUE 10: **What is the appropriate estimated benchmark level for calendar year 2001 for gains on non-separated wholesale energy sales eligible for a shareholder incentive as set forth by Order No. PSC-00-1744-PAA-EI, in Docket No. 991779-EI issued September 26, 2000, for each investor-owned electric utility?**

POSITIONS:

FPC: For FPC, the estimated benchmark level is $11,061,127, which is the three-year rolling average annual gain on non-separated wholesale energy sales based on actual data for 1998 and 1999 and estimated data for 2000, subject to true-up in future proceedings. (Wieland)

FPL: $47,377,541, subject to adjustments in the April, 2001 filing. (Dubin)

GULF: $830,000. (Davis, Howell)

TECO: $4,648,490. (Jordan)

FIPUG: FIPUG filed a motion for reconsideration and protest on October 11, 2000. The order should not be implemented until these matters are resolved.

OPC: Agree with FIPUG position.

STAFF: Based on the methodology set forth in Staff's September 20, 2000, memorandum to the parties, the appropriate estimated benchmark levels for calendar year 2001 are as follows:

FPC:	$11,061,127
FPL:	$47,377,541
GULF:	$830,000
TECO:	$4,648,490

COMPANY-SPECIFIC FUEL ADJUSTMENT ISSUES

Florida Power & Light Company

STIPULATED ISSUE 11A: **How should the Commission authorize Florida Power & Light to collect its estimated underrecovery balance projected for December 31, 2000?**

POSITION: The Commission should authorize Florida Power & Light to collect its estimated underrecovery balance of $518,005,376 projected for December 31, 2000, over a two-year period commencing calendar year 2001.

*This issue was stipulated at the prehearing conference. As noted in the Section XI, "Pending Motions", FIPUG subsequently filed a Motion to Amend Prehearing Position on Issue 11A. This issue remains shown as stipulated pending resolution of FIPUG's motion.

ISSUE 11B: **What is the appropriate regulatory treatment for Florida Power & Light's estimated underrecovery balance projected for December 31, 2000?**

POSITIONS:

FPL: FPL proposes to include the remainder of the estimated/actual true-up underrecovery in the fuel factor for the January 2002 through December 2002 period. Additionally, FPL proposes to treat the unrecovered portion of the $518,005,376 as a base rate regulatory asset in 2001 and 2002, rather than the current practice of recovering the commercial paper rate of return through the fuel clause. FPL believes that this treatment is appropriate. (Dubin)

FIPUG: No position.

OPC: Agree with FPL position.

STAFF: Florida Power & Light should classify the unrecovered portion of its estimated underrecovery balance of $518,005,376 projected for December 31, 2000, as a regulatory asset for the two-year period commencing calendar year 2001.

ISSUE 11C: **What is the appropriate regulatory treatment for the $222.5 million payment to settle litigation between FPL and Okeelanta Cogen and Osceola Cogen as approved by the Commission in Order No. PSC-00-1913-PAA-EI, in Docket No. 000982-EI, issued October 19, 2000?**

POSITIONS:

FPL: The appropriate regulatory treatment was approved by the Commission in Order No. PSC-00-1913-PAA-EI. Consistent with this Order, the $222.5 million payment should be reflected as a base rate regulatory asset until December 31, 2001. Additionally, the Order approved that commencing January 1, 2002, the settlement payment would be recovered over a term of five years a follows: 79% through the capacity clause; and 21% through the fuel adjustment clause. Any unamortized amounts during the five-year term would earn interest at the commercial paper rate rather than the overall rate of return. (Dubin)

FIPUG: No position.

OPC: Accept staff position.

STAFF: If Order No. PSC-00-1913-PAA-EI becomes final, this issue should be withdrawn. If only the portion of Order No. PSC-00-1913-PAA-EI addressing recovery of the settlement amount is protested, this issue should be resolved, if necessary, in this docket. If the issue remains, Florida Power & Light should reflect the $222.5 million payment to settle litigation as a base rate regulatory asset from January 1, 2001 to December 31, 2001. Further, Florida Power & Light should begin collection of the settlement payment on January 1, 2002 over a term of five years as follows: 79 percent through the capacity clause; and 21 percent through the fuel clause. Any unamortized amounts during the five-year term would earn interest at the commercial paper rate rather than the higher overall rate of return.

Florida Power Corporation

STIPULATED ISSUE 12A: **Has Florida Power Corporation confirmed the validity of the methodology used to determine the equity component of Electric Fuels Corporation's capital structure for calendar year 1998?**

POSITION: Yes. The annual audit of EFC's revenue requirements under a full utility-type regulatory treatment confirms the appropriateness of the "short-cut" methodology used to determine the equity component of EFC's capital structure.

STIPULATED ISSUE 12B: **Has Florida Power Corporation properly calculated the market price true-up for coal purchases from Powell Mountain?**

<u>POSITION:</u> Yes. The calculation has been made in accordance with the market pricing methodology approved by the Commission in Docket No. 860001-EI-G.

<u>STIPULATED ISSUE 12C:</u> **Has Florida Power Corporation properly calculated the 1998 price for waterborne transportation services provided by Electric Fuels Corporation?**

<u>POSITION:</u> Yes. The calculation has been made in accordance with the market pricing methodology approved by the Commission in Docket No. 930001-EI.

<u>STIPULATED ISSUE 12D:</u> **How should the Commission authorize Florida Power Corporation to collect its estimated underrecovery balance projected for December 31, 2000?**

<u>POSITION:</u> The Commission should authorize Florida Power Corporation to collect its estimated underrecovery balance projected for December 31, 2000, over a two-year period commencing calendar year 2001. The remainder of the estimated/actual true-up underrecovery should be included in the ongoing true-up balance.

<u>STIPULATED ISSUE 12E:</u> **Should the Commission approve Florida Power Corporation's proposed regulatory treatment for its 50 megawatt (MW) wholesale power sale, commencing April 1, 2001?**

<u>POSITION:</u> Yes. This 50 MW wholesale power sale is a firm sale of wholesale capacity and energy with a duration longer than one year. The Commission stated in Order No. 97-0262-FOF-EI, issued March 11, 1997, in Docket No. 970001-EI, that firm wholesale sales one year or longer should be separated on a system average basis. Consistent with Commission policy, Florida Power should separate the capital and O&M costs associated with this 50 MW from the retail rate base on a system average basis. However, because Florida Power will generate this 50 MW at a higher than system average fuel cost, Florida Power should credit the fuel

clause an amount equal to the incremental fuel costs of making this 50 MW wholesale sale.

Tampa Electric Company

<u>STIPULATED ISSUE 13A:</u> **What is the appropriate 1999 benchmark price for coal Tampa Electric Company purchased from its affiliate, Gatliff Coal Company?**

<u>POSITION:</u> $45.07/ton

<u>STIPULATED ISSUE 13B:</u> **Has Tampa Electric Company adequately justified any costs associated with the purchase of coal from Gatliff Coal Company that exceed the 1999 benchmark price?**

<u>POSITION:</u> Yes. Tampa Electric Company's actual costs are below the benchmark as calculated by both Staff and the company; therefore, this issue is moot.

<u>STIPULATED ISSUE 13C:</u> **What is the appropriate 1999 waterborne coal transportation benchmark price for transportation services provided by affiliates of Tampa Electric Company?**

<u>POSITION:</u> $25.85/ton

<u>STIPULATED ISSUE 13D:</u> **Has Tampa Electric Company adequately justified any costs associated with transportation services provided by affiliates of Tampa Electric Company that exceed the 1999 waterborne transportation benchmark price?**

<u>POSITION:</u> Yes. Tampa Electric Company's actual costs are below the benchmark as calculated by both Staff and the company; therefore, this issue is moot.

<u>ISSUE 13E:</u> **Should the Commission approve Tampa Electric's request to implement an experimental pilot program**

that offers optional seasonally-differentiated fuel factors for customers on interruptible rate schedules?

POSITIONS:

TECO: Yes, for the reasons stated and in the manner described in the prepared direct testimony of Tampa Electric witness J. Denise Jordan. (Jordan)

FIPUG: Yes.

OPC: No position at this time.

STAFF: Yes.

STIPULATED ISSUE 13F: **If the Commission approves Tampa Electric's request to implement an experimental pilot program in Issue 13E, what are the appropriate seasonal fuel and purchased power cost recovery factors by rate schedule for January, 2001 through December, 2001?**

POSITION:

Seasonal Fuel Charge Factors (cents per kWh)

Rate Schedule	Non-Summer	Summer
IS-1, IS-3, SBI-1, SBI-3	2.345	2.626
IST-1, IST-3 (on-peak)	2.777	4.020
IST-1, IST-3 (off-peak)	2.173	1.941

ISSUE 13G: **If the Commission approves Tampa Electric's request to implement an experimental pilot program in Issue 13E, what is the appropriate regulatory treatment of any revenue differential that may occur during the pilot program?**

POSITIONS:

TECO: Any differential should be recovered through the normal true-up process. (Jordan)

FIPUG: Agree with TECO position.

OPC: Agree with staff position.

STAFF: The Commission should not allow Tampa Electric at this time to recover any revenue shortfall from the general body of ratepayers through the normal true-up process. The Commission should review the information provided by Tampa Electric in the April 2002 true-up filing and determine in the November 2002 fuel hearing whether the general body of ratepayers benefited from the pilot program and whether Tampa Electric should be allowed to recover any revenue shortfall from the general body of ratepayers commencing January 1, 2003. Any amounts accrued as a result of a revenue shortfall during the two-year pilot would earn interest at the commercial paper rate.

GENERIC GENERATING PERFORMANCE INCENTIVE FACTOR ISSUES

STIPULATED

ISSUE 14: **What is the appropriate Generation Performance Incentive Factor (GPIF) reward or penalty for performance achieved during the period of January, 1999 through December, 1999?**

POSITION:

FPC:	$2,183,063 reward
FPL:	$6,973,751 reward
GULF:	$183,842 reward
TECO:	$1,151,236 penalty

STIPULATED

ISSUE 15: **What should the GPIF target/ranges be for the period of January 2001 through December 2001?**

POSITION: See Attachment B.

GENERIC CAPACITY COST RECOVERY ISSUES

STIPULATED

ISSUE 16: **What are the appropriate final capacity cost recovery true-up amount for the period January, 1999 through December, 1999?**

POSITION:

FPC:	$4,479,766 underrecovery
FPL:	$16,458,284 overrecovery
GULF:	$884,622 overrecovery
TECO:	$94,943 underrecovery

STIPULATED

ISSUE 17: **What are the appropriate estimated/actual capacity cost recovery true-up amounts for the period January, 2000 through December, 2000, which is based upon seven months actual costs and five months revised estimates?**

POSITION:

FPC:	$4,336,561 overrecovery
FPL:	$42,411,275 overrecovery
GULF:	$331,059 underrecovery
TECO:	$2,072,182 overrecovery

STIPULATED

ISSUE 18: **What are the appropriate total capacity cost recovery true-up amounts to be collected/refunded during the period January, 2001 through December, 2001?**

POSITION:

FPC:	$143,205 underrecovery
FPL:	$58,869,559 overrecovery
GULF:	$553,563 overrecovery
TECO:	$1,977,239 overrecovery

STIPULATED

ISSUE 19: **What are the appropriate projected net purchased power capacity cost recovery amounts to be included in the recovery factor for the period January, 2001 through December, 2001?**

POSITION:

FPC:	$325,662,492
FPL:	$427,597,309
GULF:	$17,867,016
TECO:	$34,032,212

STIPULATED
ISSUE 20: **What are the appropriate jurisdictional separation factors to be applied to determine the capacity costs to be recovered during the period January, 2001 through December, 2001?**

POSITION:

FPC:	Base - 97.232%, Intermediate - 70.241%, Peaking - 85.056%
FPL:	99.01014%
GULF:	96.50747%
TECO:	95.93944%

STIPULATED
ISSUE 21: **What are the projected capacity cost recovery factors for each rate class for the period January, 2001 through December, 2001?**

POSITION:
FPC:

Rate Class	Capacity Recovery Factor (cents/kWh)
Residential	1.108
General Service Non-demand	0.834
@Primary Voltage	0.826
@Transmission Voltage	0.817
General Service 100% Load Factor	0.598
General Service Demand	0.703
@Primary Voltage	0.695
@Transmission Voltage	0.688
Curtailable	0.621
@Primary Voltage	0.614
@Transmission Voltage	0.608
Interruptible	0.584
@Primary Voltage	0.578
@Transmission Voltage	0.573
Lighting	0.191

FPL:

Rate Class	Capacity Recovery Factor ($/kW)	Capacity Recovery Factor ($/kWh)
RS1	-	.00527
GS1	-	.00492
GSD1	1.86	-
OS2	-	.00305
GSLD1/CS1	1.87	-
GSLD2/CS2	1.86	-
GSLD3/CS3	1.98	-
CILCD/CILCG	1.96	-
CILCT	1.95	-
MET	1.92	-
OL1/SL1/PL-1	-	.00191
SL2	-	.00340

Rate Class	Capacity Recovery Factor (Reservation Demand Charge) ($/kW)	Capacity Recovery Factor (Sum of Daily Demand Charge) ($/kw)
ISST1D	.24	.11
SST1T	.23	.11
SST1D	.23	.11

GULF:

Rate Class	Capacity Recovery Factor (cents/kWh)
RS, RST, RSVP	.208
GS, GST	.206
GSD, GSDT	.160
LP, LPT	.140
PX, PXT, RTP, SBS	.120
OS-I, OS-II	.025
OS-III	.126
OS-IV	.058

TECO:

Rate Class	Capacity Recovery Factor ($/kWh)
RS	.00256
GS, TS	.00237
GSD, EV-X	.00182
GSLD, SBF	.00165
IS-1, IS-3, SBI-1, SBI-3	.00015
SL/OL	.00028

IX. EXHIBIT LIST

Witness	Proffered By	I.D. No.	Description
Direct			
John Scardino, Jr.	FPC	(JS-1) ______	True-up Variance Analysis
John Scardino, Jr.	FPC	(JS-2) ______	Schedules A1 through A13
Karl H. Wieland	FPC	(KHW-1) ______	Forecast Assumptions (Parts A-C), and Capacity Cost Recovery Factors (Part D)
Karl H. Wieland	FPC	(KHW-2) ______	Schedules E1 through E10 and H1
Rebecca J. McClintock	FPC	(RJM-1) ______	Standard Form GPIF Schedules (Reward/Penalty, January-December 1999)
Rebecca J. McClintock	FPC	(RJM-2) ______	Standard Form GPIF Schedules (Targets/Ranges, January-December 2001)
G. Yupp	FPL	(GY-1) ______	Appendix 1/Fuel Cost Recovery Forecast Assumptions
K. M. Dubin	FPL	(KMD-1 & KMD-2) ______	Appendix I and II Fuel Cost Recovery and Capacity Cost Recovery - Final True-Up Calculation - January, 1999 through December, 1999

Witness	Proffered By	I.D. No.	Description
K. M. Dubin	FPL	(KMD-3 & KMD-4) ______	Appendix I and II/Fuel Cost Recovery and Capacity Cost and Recovery Estimated/Actual True-up for January 2000 through December 2000
G. Yupp, K. M. Dubin, R. L. Wade	FPL	(KMD-5) ______	Appendix II/Fuel Cost Recovery E Schedules, Levelized Fuel Cost Recovery Factors for January 2001 through December 2001
K. M. Dubin	FPL	(KMD-6) ______	Appendix III / Capacity Cost Recovery Factors for January, 2001 through December, 2001
R. Silva	FPL	(RS-1) ______	GPIF, Performance Results January 1999 through December 1999
R. Silva	FPL	(RS-2) ______	GPIF, Targets and Ranges, January 2001 through December 2001
George M. Bachman	FPUC	(GMB-1) ______	Schedules E1, E1-A, E1-B, E1-B1, E2, E7, and E10 (Marianna Division)
George M. Bachman	FPUC	(GMB-2) ______	Schedules E1, E1-A, E1-B, E1-B1, E2, E7, and E10 (Fernandina Beach Division)

Witness	Proffered By	I.D. No.	Description
M. F. Oaks	GULF	(MFO-1) ______	Coal Suppliers January 1999-December 1999
M. F. Oaks	GULF	(MFO-2) ______	Projected vs. actual fuel cost of generated power-March 1991- December 2001
T. A. Davis	GULF	(TAD-1) ______	Calculation of Final True-Up for Fuel and Capacity-January 1999 - December 1999
T. A. Davis	GULF	(TAD-2) ______	Calculation of Estimated True-Up for Fuel and Capacity for 2000
T. A. Davis	GULF	(TAD-3) ______	Calculation of Projected Cost for Fuel and Capacity - January 2001 - December 2001
J. R. Douglas	GULF	(JRD-1) ______	Gulf Power Company GPIF Results - January 1999 - December 1999
J. R. Douglas	GULF	(JRD-2) ______	Gulf Power Company GPIF Targets and Ranges - January 2001-December 2001
M. W. Howell	GULF	(MWH-1) ______	Gulf Power Company Projected Purchased Power Contract Transactions - January 2001-December 2001
J. Denise Jordan	TECO	(JDJ-2) ______	Fuel Cost Recovery January 2000 - May 2000

Witness	Proffered By	I.D. No.	Description
J. Denise Jordan	TECO	(JDJ-3)	Fuel Adjustment Projection January 2000 - December 2000
J. Denise Jordan	TECO	(JDJ-3)	Capacity Cost Recovery, January 2000-December 2000
J. Denise Jordan	TECO	(JDJ-4)	Capacity Cost Recovery, Projected January 2001-December 2001
Brian S. Buckley	TECO	(BSB-1)	Generating Performance Incentive Factor Results January 1999-December 1999
Brian S. Buckley	TECO	(BSB-2)	Generating Performance Incentive Factor Estimated January 2001-December 2001
Rod Burkhardt	TECO	(RB-1)	Transportation Benchmark Calculation- Coal Benchmark Calculation
Various	Staff	Staff-1	Staff's September 20, 2000, memorandum to the parties concerning implementation of the incentive mechanism approved by the Commission in Order No. PSC-00-1744-PAA-EI.

Witness	Proffered By	I.D. No.	Description
Various	Staff	Staff-2	Specified responses to Staff discovery: Interrogatories 1-3 and 11, and Document Request 3 from FPC; Interrogatories 12-14 and Document Request 2 from FPL; Document Request 2 from Gulf; Interrogatories 16-17 and Document Requests 2-3 from TECO; Deposition of FPL witness Yupp

Parties and Staff reserve the right to identify additional exhibits for the purpose of cross-examination.

X. PROPOSED STIPULATIONS

The parties have stipulated to several issues, as shown in Section VIII of this Order. In addition, the parties have stipulated to the following:

> FPL will be incurring costs beginning in 2001 necessary for the St. Lucie Spent Fuel Storage Project. However, FPL is in the process of exploring which alternative or alternatives to use to accomplish this project. All parties agree that FPL is not precluded from seeking recovery of costs associated with the St. Lucie Spent Fuel Storage Project at a later date. However, this does not and is not intended to prejudge the merits of the costs or the appropriate recovery mechanism.

XI. PENDING MOTIONS

The Florida Industrial Power Users Group's Motion for Oral Argument and to Strike Testimony and Motion to Amend Prehearing Position, filed November 9, 2000, is pending.

XII. PENDING CONFIDENTIALITY MATTERS

Tampa Electric Company's Request for Confidential Classification of witness Rod Burkhardt's Exhibit RB-1 is pending.

Based on the foregoing, it is

ORDERED by Commissioner Lila A. Jaber, as Prehearing Officer, that this Prehearing Order shall govern the conduct of these proceedings as set forth above unless modified by the Commission.

By ORDER of Commissioner Lila A. Jaber as Prehearing Officer, this 15th Day of November, 2000.

LILA A. JABER
Commissioner and Prehearing Officer

(S E A L)

WCK

NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

Mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing.

Any party adversely affected by this order, which is preliminary, procedural or intermediate in nature, may request: (1) reconsideration within 10 days pursuant to Rule 25-22.0376, Florida Administrative Code, if issued by a Prehearing Officer; (2) reconsideration within 15 days pursuant to Rule 25-22.060, Florida Administrative Code, if issued by the Commission; or (3) judicial review by the Florida Supreme Court, in the case of an electric, gas or telephone utility, or the First District Court of Appeal, in the case of a water or wastewater utility. A motion for reconsideration shall be filed with the Director, Division of Records and Reporting, in the form prescribed by Rule 25-22.060, Florida Administrative Code. Judicial review of a preliminary, procedural or intermediate ruling or order is available if review of the final action will not provide an adequate remedy. Such review may be requested from the appropriate court, as described above, pursuant to Rule 9.100, Florida Rules of Appellate Procedure.

ATTACHMENT A

State of Florida

Public Service Commission

-M-E-M-O-R-A-N-D-U-M-

DATE: September 20, 2000

TO: All Parties of Record

FROM: Cochran Keating, Senior Attorney
Todd Bohrmann, Regulatory Analyst IV

RE: 000001-EI - Fuel and purchased power cost recovery clause and generating performance incentive factor.

Via Facsimile

This memorandum is to confirm and delineate the Commission Staff's proposed methodology, as presented at our September 12, 2000, meeting with the parties, to implement the Commission's recent decision in Docket No. 991779-EI concerning the appropriate application of incentives to wholesale power sales. As stated at the meeting, although the Commission has not yet issued its final order in this docket, Staff believes that implementation of the Commission's decision remains an open issue which should be resolved at this November's fuel hearing.

To implement the Commission's decision in Docket No. 991779-EI, Staff believes that the following issues are appropriate for resolution at this November's fuel hearing:

1. How should the Commission's decision in Docket No. 991779-EI, concerning the application of incentives to wholesale power sales, be implemented?

2. What is the appropriate estimated benchmark level for calendar year 2001 for gains on non-separated wholesale energy sales eligible for a shareholder incentive pursuant to the Commission's decision in Docket No. 991779-EI?

As discussed at the meeting, Staff proposes the following methodology to address the first issue:

1. In its Actual/Estimated True-Up filing and testimony, each utility shall include an estimated value of gains on eligible non-separated wholesale energy sales for the current calendar year (2000) based on actual and estimated data;

2. In its Projection filing, each utility shall include a forecasted value of gains on eligible non-separated wholesale energy sales for the next calendar year (2001);

3. Each utility shall compare its forecasted value of gains from eligible sales for the next calendar year (2001) to an estimated three-year moving average of such gains. This estimated three-year moving average, or estimated benchmark, will be based on actual gains from eligible sales for each of the previous two calendar years (1998 and 1999) and the estimated gains from eligible sales for the current calendar year (2000). This comparison will be one of numerous inputs that each utility will use to calculate its levelized fuel cost recovery factor for the next calendar year (2001);

4. In its April True-Up filing in the next calendar year (2001), each utility shall indicate its actual gains on eligible non-separated wholesale energy sales for the previous calendar year (2000). Each utility will then re-calculate its three-year moving average based on the actual gains from eligible sales for each of the previous three years (1998, 1999, and 2000) to establish an actual benchmark.

5. Each utility shall record its actual gains from eligible non-separated wholesale energy sales on its Schedule A-6 filed monthly with the Commission. When these actual gains are equal to or less than the utility's actual benchmark, the utility shall credit 100 percent of these gains to its ratepayers through its fuel and purchased power cost recovery clause (fuel clause). When these actual gains are greater than the utility's actual benchmark, the utility shall credit 80 percent of the gains above the benchmark to its ratepayers through its fuel clause. The utility shall credit the remaining 20 percent to its shareholders;

6. Each utility shall reflect any differences between its actual and forecasted gains from eligible sales through its monthly true-up calculations in Schedule A-2;

7. The first e-timated benchmark for gains on eligible non-separated wholesale energy sales shall be established at the November 2000 fuel hearing for purposes of calculating a levelized fuel cost recovery factor for 2001. The shareholder incentive shall apply to actual gains on eligible sales made over the actual benchmark for 2001. On a going-forward basis, the difference between actual and forecasted gains on eligible sales shall be "trued-up" at each fuel hearing.

For illustrative purposes, this methodology, using hypothetical data, is presented in table form in the attached document.

If have any questions or comments concerning Staff's proposal, please contact Todd Bohrmann at (850) 413-6445 or Cochran Keating at (850) 413-6193.

WCK
Attachment
cc: Division of Regulatory Oversight
Division of Economic Regulation
i: 000001m6.wck

ATTACHMENT A

SEPTEMBER 18, 2000, MEMORANDUM TO PARTIES
DOCKET NO. 000001-EI
PAGE 4

Proposed Shareholder Incentive Implementation Methodology
Hypothetical Example

Part I Nov '00	A	1998 Actual Gains *	$100.00	
	B	1999 Actual Gains *	$110.00	
	C	2000 Actual/Estimated Gains	$120.00	
	D	2001 Forecasted Benchmark	$110.00	(A+B+C)/3
	E	2001 Forecasted Gains *	$130.00	
	F	2001 Forecasted Ratepayer Credit	$126.00	D+((E-D)*.8)
Part II Apr '01	G	2000 Actual Gains *	$75.00	
	H	2001 Actual Benchmark	$95.00	(A+B+G)/3
Part III Nov '01	I	2001 Actual/Estimated Gains *	$128.00	
	J	2001 Actual/Estimated True-Up	($4.60)	L-F
	K	2002 Forecasted Benchmark	$104.33	(B+G+I)/3
	L	2001 Estimated Ratepayer Credit	$121.40	H+((I-H)*.8)
Part IV Apr '02	M	2001 Actual Gains *	$140.00	
	N	2001 Final True-up	$9.60	O-L
	O	2001 Actual Ratepayer Credit	$131.00	H+((M-H)*.8)
	P	2002 Actual Benchmark	$108.33	(B+G+M)/3

Note: Items marked with an asterisk (*) are values that would be found in a utility filing, but are hypothetical for this example.

GPIF REWARDS/PENALTIES

January 1999 to December 1999

Utility	Amount	Reward/Penalty
Florida Power Corporation	$2,183,063	Reward
Florida Power and Light Company	$6,973,751	Reward
Gulf Power Company	$183,842	Reward
Tampa Electric Company	($1,151,236)	Penalty

Utility/ Plant/Unit	EAF		Heat Rate	
FPC	Target	Adjusted Actual	Target	Adjusted Actual
Anclote 1	83.8	80.1	10,006	10,135
Anclote 2	94.9	92.1	9,912	9,934
Crystal River 1	76.2	71.3	9,841	9,829
Crystal River 2	85.2	90.9	9,764	9,680
Crystal River 3	80.4	84.8	10,404	10,295
Crystal River 4	90.2	94.1	9,395	9,483
Crystal River 5	83.8	82.1	9,330	9,336
FPL	Target	Adjusted Actual	Target	Adjusted Actual
Cape Canaveral 2	93.6	94.8	9,602	9,774
Fort Lauderdale 4	93.2	95.5	7,290	7,272
Fort Lauderdale 5	93.2	95.4	7,289	7,242
Fort Myers 2	90.0	86.0	9,188	9,211
Manatee 2	88.8	90.9	10,138	10,205
Martin 3	92.3	94.3	7,016	6,792
Martin 4	93.6	85.4	6,926	6,722
Port Everglades 3	80.4	77.7	9,786	9,703
Port Everglades 4	96.0	97.4	9,836	9,839
Riviera 3	94.4	92.3	9,770	9,984
Sanford 4	91.0	93.7	9,737	10,155
Sanford 5	89.9	92.0	9,939	10,347
Scherer 4	86.6	88.8	10,120	10,271
St. Lucie 1	83.6	86.4	10,879	10,804
St. Lucie 2	93.6	96.6	10,895	10,812
Turkey Point 3	93.6	99.1	11,047	11,064
Turkey Point 4	84.3	90.1	11,166	11,076
Gulf	Target	Adjusted Actual	Target	Adjusted Actual
Crist 6	88.4	90.1	10,624	10,528
Crist 7	82.5	85.7	10,232	10,202
Smith 1	75.9	73.3	10,190	9,963
Smith 2	88.8	90.9	10,263	10,085
Daniel 1	81.0	78.1	10,455	10,415
Daniel 2	74.7	71.0	10,264	10,256

GPIF REWARDS/PENALTIES

January 1999 to December 1999

Utility/ Plant/Unit	EAF		Heat Rate	
TECO	Target	Adjusted Actual	Target	Adjusted Actual
Big Bend 1	79.8	77.4	10,230	10,083
Big Bend 2	82.2	81.1	10,247	9,983
Big Bend 3	72.5	68.5	9,992	9,826
Big Bend 4	85.0	79.1	9,938	10,014
Gannon 5	73.6	71.9	10,150	10,670
Gannon 6	71.5	63.7	10,401	10,836

GPIF TARGETS

January 2001 to December 2001

Utility/ Plant/Unit	EAF	Company POF	EUOF	Staff	Heat Rate Company	Staff
FPC						
Anclote 1	78.8	15.6	5.6	Agree	10,091	Agree
Anclote 2	92.8	0.0	7.2	Agree	10,083	Agree
Bartow 3	93.9	0.0	6.1	Agree	10,105	Agree
Crystal River 1	76.4	13.4	10.2	Agree	9,831	Agree
Crystal River 2	84.2	0.0	15.8	Agree	9,788	Agree
Crystal River 3	85.5	11.5	3.0	Agree	10,247	Agree
Crystal River 4	95.4	0.0	4.6	Agree	9,389	Agree
Crystal River 5	87.6	9.6	2.8	Agree	9,360	Agree
Tiger Bay	78.7	15.3	6.0	Agree	7,190	Agree
FPL						
Cape Canaveral 1	84.5	7.9	7.6	Agree	9,581	Agree
Cape Canaveral 2	94.5	0.0	5.5	Agree	9,721	Agree
Ft Lauderdale 4	93.2	3.0	3.8	Agree	7,337	Agree
Ft Lauderdale 5	93.2	3.0	3.8	Agree	7,336	Agree
Manatee 1	78.3	14.2	7.5	Agree	10,066	Agree
Manatee 2	90.1	0.8	9.1	Agree	10,216	Agree
Martin 1	87.7	4.1	8.4	Agree	9,734	Agree
Martin 2	90.9	0.0	9.1	Agree	9,876	Agree
Martin 3	92.5	3.4	4.1	Agree	6,874	Agree
Martin 4	93.1	1.1	5.9	Agree	6,797	Agree
Port Everglades 3	84.5	10.4	5.3	Agree	9,447	Agree
Port Everglades 4	93.7	0.0	6.3	Agree	9,632	Agree
Scherer 4	87.9	8.5	3.6	Agree	10,043	Agree
St Lucie 1	85.7	8.5	5.8	Agree	10,817	Agree
St Lucie 2	85.7	8.5	5.8	Agree	10,821	Agree
Turkey Point 1	92.4	0.0	7.6	Agree	9,319	Agree
Turkey Point 3	86.0	8.5	5.8	Agree	11,121	Agree
Turkey Point 4	93.6	0.0	6.4	Agree	11,095	Agree
Gulf						
Crist 6	78.1	17.8	4.1	Agree	10,502	Agree
Crist 7	76.4	14.0	9.6	Agree	10,184	Agree
Smith 1	88.7	8.8	2.5	Agree	10,113	Agree
Smith 2	87.5	8.8	3.7	Agree	10,058	Agree
Daniel 1	74.5	16.4	9.1	Agree	10,075	Agree
Daniel 2	75.2	16.2	8.6	Agree	9,872	Agree

GPIF TARGETS

January 2001 to December 2001

Utility/ Plant/Unit	EAF				Heat Rate	
	EAF	Company POF	EUOF	Staff	Company	Staff
FPC						
Big Bend 1	69.9	13.4	16.7	Agree	10,118	Agree
Big Bend 2	77.9	5.8	16.3	Agree	9,895	Agree
Big Bend 3	71.8	5.8	22.4	Agree	9,932	Agree
Bif Bend 4	83.9	3.8	12.3	Agree	9,944	Agree
Gannon 5	68.4	7.7	23.9	Agree	10,762	Agree
Gannon 6	67.4	7.7	24.9	Agree	10,596	Agree
Polk 1	78.5	7.7	13.8	Agree	10,146	Agree

APPENDIX A

Order No. PSC-00-1744-PAA-EI
Docket No. 991779-EI
Issued September 26, 2000

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010283-EI EXHIBIT NO. 5
COMPANY/
WITNESS. Dubin
DATE: 8-31-01

Appendix A
Exhibit : ________
FPL Witness: K. M. Dubin
Florida Power & Light Company
Docket No. 010283-EI
April 23, 2001

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Review of the appropriate application of incentives to wholesale power sales by investor-owned electric utilities.	DOCKET NO. 991779-EI ORDER NO. PSC-00-1744-PAA-EI ISSUED: September 26, 2000

The following Commissioners participated in the disposition of this matter:

J. TERRY DEASON, Chairman
E. LEON JACOBS, JR.
LILA A. JABER

APPEARANCES:

JAMES D. BEASLEY, Esquire, Ausley & McMullen, P. O. Box 391, Tallahassee, Florida, 32302,
On behalf of Tampa Electric Company (TECO).

JAMES A. McGEE, Esquire, P.O. Box 14042, St. Petersburg, Florida 33733-4042,
On behalf of Florida Power Corporation (FPC).

JEFFREY A. STONE, Esquire, Beggs & Lane Law Firm, 700 Blount Building, 3 West Garden Street, P.O. Box 12950, Pensacola, Florida 32576-2950,
On behalf of Gulf Power Company (Gulf).

MATTHEW M. CHILDS, Esquire, Steel Hector & Davis LLP, 215 South Monroe Street, Suite 601, Tallahassee, Florida 32301-1804,
On behalf of Florida Power & Light Company (FPL).

STEPHEN C. BURGESS, Esquire, Office of Public Counsel, c/o The Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400.
On behalf of the Citizens of the State of Florida (OPC).

VICKI GORDON KAUFMAN, Esquire, McWhirter Reeves McGlothlin Davidson Decker Kaufman Arnold & Steen, P.A., 117 South Gadsden Street, Tallahassee, Florida 32301
<u>On behalf of Florida Industrial Power Users Group (FIPUG)</u>.

WM. COCHRAN KEATING, IV, Esquire, Florida Public Service Commission, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850
<u>On behalf of the Commission Staff</u>.

<u>ORDER APPROVING INCENTIVE MECHANISM FOR SPECIFIED NON-SEPARATED WHOLESALE POWER SALES BY INVESTOR-OWNED ELECTRIC UTILITIES</u>
<u>AND</u>
<u>NOTICE OF PROPOSED AGENCY ACTION</u>
<u>ORDER ESTABLISHING METHOD FOR CALCULATION OF GAINS ON NON-SEPARATED WHOLESALE POWER SALES AND ESTABLISHING APPROPRIATE REGULATORY TREATMENT FOR REVENUES AND EXPENSES ASSOCIATED WITH NON-SEPARATED WHOLESALE POWER SALES</u>

BY THE COMMISSION:

By Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B, this Commission established a shareholder incentive mechanism to encourage investor-owned electric utilities (IOUs) to make economy energy sales. Prior to the issuance of Order No. 12923, in 1984, the revenues from the sale of economy energy were considered in each IOU's general rate proceeding. By Order No. 12923, this Commission removed these revenues from base rates, and credited the revenues through the Fuel and Purchased Power Cost Recovery Clause (fuel clause). At page 2 of Order No. 12923, we stated that "[t]he chief reason for this proposed treatment was to eliminate the potential for over- or under- recovery of revenues associated with economy energy sales." Further, we authorized the IOUs to keep 20 percent of the gains on these sales as an incentive to "maximize the amount of economy sales and provide a net benefit to the ratepayer." In other words, the incentive was created, in part, to encourage the IOUs to use their excess capacity to make economy sales, with 80 percent of the revenue from those sales being credited to the ratepayers.

At our November 22-23, 1999, hearing in Docket No. 990001-EI, the panel heard arguments about whether this incentive mechanism is still necessary or appropriate. By Order No. PSC-99-2512-FOF-EI, issued December 22, 1999, a proceeding was instituted so that the full Commission could hear this matter. Accordingly, an evidentiary hearing was held on May 10, 2000, and post-hearing briefs were filed by the parties.

I. Appropriateness of Shareholder Incentives

With respect to the question of whether the incentive mechanism approved in Order No. 12923 is still necessary and appropriate, FPC witness Wieland testified that we should continue our policy of providing shareholder incentives to encourage economy sales. Further, witness Wieland testified that because these sales have shifted to more competitive markets outside of the Florida Energy Broker Network (Broker or EBN), with new non-utility participants who retain 100% of the profits, our incentive policy should be updated to reflect current market conditions. FPL argued in its brief that no disputed fact or factual showing has been identified that would sustain the burden of reversing our policy on incentives. Gulf witness Howell also testified that the current shareholder incentive should not be eliminated. Like FPC witness Wieland, witness Howell testified that because today's wholesale market is more competitive, utility economy sales are more difficult to achieve, thus increasing the importance of the incentive to encourage continued participation in the economy energy market. Along with the other IOUs' witnesses, TECO witness L. Brown testified that we should adhere to our existing policy of providing shareholder incentives to encourage non-separated, non-firm wholesale sales.[1] Witness Brown testified that these incentives may provide greater benefits to ratepayers now than when they were first adopted.

In opposition to the IOUs, FIPUG argued in its brief that the current incentive mechanism should be eliminated. FIPUG asserted that we should not provide an additional incentive, beyond the current incentive of a guaranteed return and a captive customer base, for the IOUs to perform their required managerial duties. OPC witness Dismukes also supported elimination of the current incentive. Witness Dismukes testified that factors other than the incentive established in Order No. 12923 are serving as far stronger incentives for Florida's IOUs to maximize their wholesale sales. Further, witness Dismukes testified that the current incentive mechanism is one-sided in that it does not penalize IOUs for substandard performance and that it requires consumers to pay a second time for services for which they are already paying full costs.

---

[1]By Order No. PSC-97-0262-FOF-EI, issued March 11, 1997, we defined non-separated wholesale power sales, stating that "[h]istorically, the Commission has treated sales that are non-firm or less than one year in duration as non-separated sales."

The record shows that prior to the issuance of Order No. 12923, the buying and selling of economy energy was a peripheral function of the system dispatcher. Most economy energy transactions were accomplished over the Broker. After meeting their requirements for firm load, the buying and selling utilities would enter quotes determined by decremental and incremental production costs. A computer program would then match buyers and sellers with the greatest cost savings. The transaction price was based on a split-the-savings methodology. Thus, the record demonstrates that the Broker functioned essentially as a simple cost-based market for short-term excess energy within Peninsular Florida. Buyers and sellers benefitted equally from each transaction made over the Broker due to the split-the-savings pricing methodology.

The parties to this proceeding acknowledge that the wholesale market in Florida is more competitive today than when Order No. 12923 was issued. Changes to the wholesale market were prompted in part by the Public Utilities Regulatory Policy Act; the Energy Policy Act of 1992; FERC Orders 888 and 889; and other federal and state regulatory policy initiatives. These regulatory changes have resulted in a more robust wholesale market in Florida, with additional buyers and sellers. The record demonstrates that this movement toward competition has prompted additional efforts on the part of Florida's IOUs to participate in the wholesale market. For example, IOUs have substantially augmented the trained staff in their marketing departments in recent years. Further, the buying and selling of energy has now become the primary function of a specific group of employees, rather than the peripheral function of the system dispatcher.

The record shows that these increased efforts have produced results. As a whole, the data indicates that utilities have increased their presence in the wholesale market through the increased number of their non-separated wholesale transactions and the increased gains on those transactions in recent years. The record also shows that FPC, FPL, and TECO did not apply the 20 percent shareholder incentive approved in Order No. 12923 to the majority of their non-separated sales made over the last six years. FPC witness Wieland, FPL witness Stepenovitch, and TECO witness L. Brown indicated that their respective companies have interpreted the Order to provide an incentive only on their sales made under FERC Schedules C and X. Witness Stepenovitch indicated, however, that FPL recently discontinued Schedule X sales. As a result, FPC, FPL, and TECO received an incentive on sales associated with only 2.1%, 0.2%, and 6.8% of the gains for 1999, respectively. Gulf interpreted Order No. 12923 more broadly and, according to witness Howell, applied the shareholder incentive to the gains for all of its non-firm, non-separated wholesale sales.

The record indicates that this increase in gains is the result of both the increased efforts to make sales and the ability to charge market-based rates. For example, FPL witness Stepenovitch testified that FPL had increased the number of its contracts from approximately 63 to over 400 in the past three years. FPL received authority from FERC to charge market-based rates for out-of-state sales in 1998, the same year in which there is a dramatic increase in the gains reported by FPL. The record also shows that FPC and Gulf have experienced dramatic increases in gains on non-separated wholesale sales since 1996. Since 1996, FPC has received authority from FERC to charge market-based rates for out-of-state sales, and Gulf, through Southern, has received authority from FERC to charge market-based rates for in-state and out-of-state sales. Only TECO has experienced a recent decline in gains. TECO witness L. Brown explained that the decline in its gains from 1998 to 1999 was due to the lack of capacity resulting from the explosion at its Gannon Unit 6 last April. TECO received authority to charge market-based rates for in-state and out-of-state sales in April 1999.

OPC witness Dismukes testified that these changes to the wholesale market and other changes that have occurred in the electric industry since Order No. 12923 was issued in 1984 now provide the IOUs with the necessary incentives to make non-separated wholesale sales. According to witness Dismukes, "[n]o utility today can afford not to participate in the wholesale markets." Witness Dismukes testified that the IOUs face greater pressure today to keep their rates low due to the threat of customer loss resulting from retail competition and better options for self-generation. Witness Dismukes noted that making economy energy sales and crediting revenues from those sales to retail customers helps the IOUs to keep rates low. Further, witness Dismukes testified that today's more competitive wholesale market provides the IOUs with greater opportunities and flexibility to make these sales. Therefore, OPC argues in its brief that the shareholder incentive established in Order No. 12923 is no longer necessary because there are other incentives driving the IOUs' participation in the wholesale market.

We agree that there are factors other than the 20 percent shareholder incentive that affect the IOUs' participation in the wholesale market. Clearly, as the IOUs' witnesses have readily admitted, they are not going to stop making economy energy sales if we eliminate the shareholder incentive approved in Order No. 12923. However, as all of the witnesses in this proceeding agreed, incentives may be used to prompt a positive response. The IOUs' witnesses testified that a shareholder incentive is an effective tool to drive management to focus on, and devote resources to, sustaining or increasing the level of their economy energy sales and the level of gains on those sales, in turn creating benefits for ratepayers. We agree. Thus, while there is no way to precisely measure the effect of a shareholder incentive on the IOUs' participation in the wholesale market, we find that a properly structured incentive will result in greater management efforts to increase economy energy sales, yielding gains on those sales to the benefit of ratepayers.

Further, as noted above and discussed in part II of this Order, FPC, FPL, and TECO are engaged in a broad range of non-separated wholesale energy sales to which an incentive is not currently applied, although the gains from these sales, which account for over 90 percent of these IOUs' total gains on non-separated sales, are credited to ratepayers to reduce the costs that they would otherwise have to bear. Thus, we find that a properly structured incentive may achieve even greater benefits for ratepayers by encouraging the types of sales from which ratepayers are currently receiving the greatest benefit. In conclusion, we find that the incentive program established in Order No. 12923 should not be eliminated, but should be modified to provide an appropriate incentive structure that reflects the changes in the wholesale market and the electric industry that have occurred since Order No. 12923 was issued and maximizes the potential benefits to ratepayers accordingly.

II. Structure for Shareholder Incentive

Five proposals were presented in this proceeding for the appropriate structure of an incentive on non-separated wholesale power sales on a going-forward basis. These proposals are summarized as follows:

1. FPC witness Wieland proposed a 20 percent shareholder incentive on the gains from all non-separated sales, including firm sales. Witness Wieland proposes to include such sales made under existing Federal Energy Regulatory Commission (FERC) schedules and under new FERC schedules as they are approved.

2. FPL witness Dubin proposed a sliding scale approach to the shareholder incentive. The incentive would be applied to the gains on all non-firm, non-separated sales, including such sales made under newly approved FERC schedules. Under this proposal, FPL's shareholders would receive 20 percent of the first $20 million of gains, 40 percent of the next $20 million of gains, and 50 percent of the gains over $40 million. Witness Dubin stated that the specific thresholds for the

sliding scale apply only to FPL and should be adjusted as appropriate for other IOUs.

3. Gulf witness Howell proposed no change to its current incentive treatment. As noted above, Gulf currently applies the 20 percent shareholder incentive to all non-firm, non-separated sales, including market-priced sales.

4. TECO witness L. Brown proposed a shareholder incentive on the gains from all non-firm, non-separated sales. Under TECO's proposal, the incentive varies based on whether the sale is an in-state or an out-of-state sale. TECO witness D. Brown proposed a 40 percent shareholder incentive for in-state sales, and a 20 percent incentive for out-of-state sales.

5. As stated above, OPC argued that an incentive is not necessary or appropriate. However, as an alternative, OPC witness Dismukes proposed an incentive only on gains from sales made over the Broker. Witness Dismukes suggested a five year moving average to determine a benchmark based on past energy sales. Under this proposal, an IOU would only receive an incentive if the benchmark is exceeded by 25 percent. The proposal would penalize an IOU if its sales are 75 percent of the benchmark or less.

As noted above, FIPUG argued that a shareholder incentive is not appropriate. Therefore, FIPUG did not offer a specific proposal for incentives.

A. Sales Eligible for Shareholder Incentive

As stated above, FPC, FPL, and TECO have applied the incentive approved in Order No. 12923 only to their sales under FERC Schedules C and X. As also noted above, these sales account for only 2.1%, 0.2%, and 6.8% of the total gains on non-separated wholesale sales in 1999 for FPC, FPL, and TECO, respectively. For example, the record shows that of the $59.2 million in gains earned by FPL on non-firm, non-separated wholesale energy sales, FPL received an incentive on sales that resulted in only $41,660 of those gains. FPL witness Stepenovitch testified that 75 to 80 percent of the gains on FPL's total non-separated wholesale energy sales for 1999 are attributed to market-based sales to which FPL does not currently apply a shareholder incentive. As the witnesses for these IOUs noted, the types of non-separated sales that did not qualify for an incentive have the same beneficial effect that Schedule C and X sales have: they reduce the costs that the selling utility's retail customers would otherwise have to bear. Accordingly, we agree that a properly structured shareholder incentive should encourage utility management, on a going-forward basis, to focus on sustaining and increasing the gains from this broader range of non-separated wholesale sales to provide cost reduction benefits to Florida's ratepayers.

FPC witness Wieland testified that both firm and non-firm, non-separated wholesale sales should be eligible for the shareholder incentive. He testified that in today's wholesale market it is difficult to differentiate between firm and non-firm wholesale sales because so many of these sales are made with various levels of "firmness." The record indicates that the recent grants of authority for the IOUs to engage in market-based transactions have provided the IOUs with greater flexibility in structuring wholesale transactions. This flexibility has led to more tailored, negotiated contract terms that provide various levels of commitment from the seller. Thus, we agree with witness Wieland that in today's wholesale market, it will be very difficult, if not impossible, to prevent a shareholder incentive from being applied to sales with a certain degree of firmness.

FPC witness Wieland and FPL witness Stepenovitch both testified that the shareholder incentive should apply to both current and future FERC-approved schedules, as long as the sales made under these schedules are non-separated sales. Over time, utilities may petition the FERC for changes to existing FERC schedules and for new schedules as the market changes. Thus, we agree with FPC witness Wieland that structuring an incentive based only on current FERC schedules may lead to unnecessary difficulties in our administration of the incentive in the future.

All of the IOUs took the position that emergency sales should not be eligible for a shareholder incentive. As stated by FPC witness Wieland, emergency sales are "made upon the request of the buyer, not marketed by the seller." Therefore, emergency sales are less under a seller's control than other types of non-separated wholesale sales. Because emergency sales are primarily determined by the buyer's need for power, rather than the potential for cost savings, we agree that emergency sales should not be eligible for a shareholder incentive.

In summary, we find that to encourage the types of wholesale sales that are currently providing the greatest cost reduction benefit to Florida's retail ratepayers, a properly structured shareholder incentive should apply to all non-separated wholesale sales, firm and non-firm, excluding emergency sales, made under current and future FERC-approved schedules.

B. Level of Shareholder Incentive

As evidenced by the parties' various proposals, there are potentially an unending number of ways to devise an incentive. As FPC witness Wieland testified, there is no 'magic number' for an appropriate incentive level. In establishing an appropriate incentive structure, we believe that the incentive should not be designed to encourage behavior that is already occurring. Therefore, the incentive should be based on some type of threshold that represents the level of sales that would be expected to occur in the absence of an incentive. This threshold should be determined using past data on the gains on non-separated wholesale sales eligible for the incentive. As OPC witness Dismukes testified, any incentive provided for gains below this threshold will create the potential for a free rider effect, rewarding utilities for behavior which is taking place for reasons other than the incentive. We disagree with the IOUs' argument that an appropriate threshold cannot be determined because these sales are difficult to predict. The record shows that FPC, FPL, and TECO employ some type of sales standard in determining the compensation of marketing employees. Gulf has no marketing department, and Southern acts its agent for these sales. As TECO witness L. Brown testified, while it is difficult to establish these standards, it is nevertheless done.

The evidence indicates that the yearly gains on these sales may be erratic due to changes in capacity, or other factors beyond a seller's control, such as the needs of buyers. We agree with OPC witness Dismukes that it is appropriate to use a moving average to determine the threshold to reduce the impact of anomalies in individual years. We find that a three year moving average is appropriate for two reasons. First, as noted above, FERC Orders 888 and 889 have helped increase the volume of wholesale sales in the past three years. Second, Florida's two largest IOUs, FPL and FPC, received FERC approval for out-of-state market-based rates within the past three years. TECO also received approval to make both in-state and out-of-state market-priced sales. As OPC witness Dismukes testified, and as evidenced by the IOUs' level of non-separated wholesale transactions and gains, these factors have substantially impacted the potential gains for the IOUs. These two factors have caused a systemic change in the wholesale market in Florida.

As stated above, OPC witness Dismukes has proposed a five year moving average as part of its proposed reward/penalty methodology. We disagree that five years is an appropriate period. Including years prior to FERC Orders 888 and 889 and the IOUs' authority to engage in market-based transactions fails to recognize the market changes caused by these events and would set the incentive threshold too low. Thus, we believe this approach would reward the IOUs for normal effort, rather than the superior effort that should be required to receive an incentive.

Therefore, we find that a three year moving average of the gains on non-separated sales, firm and non-firm, excluding emergency sales, is an appropriate threshold for the shareholder incentive. All gains at or below this threshold shall be credited to the ratepayers. All gains above this threshold shall be split 80%/20% between ratepayers and shareholders, respectively. We find that this incentive structure will allow ratepayers: (1) to continue to receive the substantial cost reduction benefits achieved through the IOUs' current level of non-separated sales; and (2) to benefit from a credit to the fuel clause of 80 percent of the gains on non-separated sales above the threshold. This incentive structure also minimizes the possibility that the IOUs could be rewarded for behavior that is already occurring. The IOUs are rewarded only for performing better than they performed, on average, over the previous three year period. To the extent an IOU surpasses the threshold, its threshold will increase for the next year. To the extent an IOU does not surpass the threshold, its shareholders will not receive as an incentive any portion of the gains that the IOU does achieve.

As noted above, both FPC witness Wieland and Gulf witness Howell proposed a 20 percent shareholder incentive as an appropriate incentive level. As witness Wieland conceded, the 20 percent figure is subjective in that there is no scientific basis used in selecting that percentage. However, we find that a 20 percent incentive is consistent with Order No. 12923, is reasonable, and should provide utilities with an adequate incentive.

We reject FIPUG and OPC's contention that any shareholder incentive structure should include a penalty for substandard performance, because imposing such a penalty would potentially counteract the incentive. We believe that the incentive approach described above is sufficient to encourage performance. As witness L. Brown testified and witness Dismukes conceded, a utility that does not make an adequate effort to make these sales is experiencing the opportunity cost of forgone profits. Further, we note that the shareholder incentive approved in Order No. 12923 did not include a penalty. Thus, including a penalty would represent a change in Commission policy which we believe has not been adequately justified.

We also reject FPL witness Dubin's sliding scale approach. We are not persuaded that IOU shareholders should receive a higher percentage incentive as gains increase. Witness Dubin admitted that the levels of FPL's sliding scale were subjective and not based on any analysis. Witness Dubin also testified that these levels should apply to FPL alone, and other levels should be developed for other IOUs. Thus, using a sliding scale approach places this Commission in the difficult position of developing the gain levels for the scale for each IOU without any record evidence to support such a determination.

In addition, we reject TECO witness D. Brown's proposal to apply a higher incentive to in-state sales. The record evidence shows that approximately 95 percent of TECO's non-separated wholesale sales revenues are currently earned on in-state sales. Further, unlike FPL and FPC, TECO is authorized to make market-based sales in-state. Thus, providing a higher incentive on these sales would reward TECO for behavior that is already taking place. We are also concerned that providing a higher incentive on in-state sales could result in a perverse incentive for IOUs to make sales with the highest shareholder incentive, rather than the highest gain. Sales with the highest gain benefit the selling utility's ratepayers the most by resulting in the highest credit to ratepayers.

Finally, we reject the "deadband" approach proposed by OPC witness Dismukes. Witness Dismukes' approach calculates a benchmark based on a five-year moving average of sales made on the Broker. Under this approach, the IOU would credit 100 percent of the gains to ratepayers when the current year's sales fall between 75 and 125 percent of this benchmark. If a current year's sales exceed 125 percent of this benchmark, the IOU could retain for its shareholders up to 20 percent of those incremental gains. Conversely, if a current year's sales do not reach 75 percent of this benchmark, the IOU would incur a penalty up to 20 percent of the shortfall. Witness Dismukes proposed this deadband approach in part to reduce the possibility that IOUs would be rewarded for actions beyond their control. As discussed above, we believe that a 20 percent incentive on gains above a three year moving average would address these concerns. Further, we are concerned that the deadband could potentially reduce the impact of a shareholder incentive in encouraging these sales. Thus, we find that this deadband approach is inappropriate.

C. Conclusion

In conclusion, we approve the following as the appropriate structure for a shareholder incentive:

1. The incentive shall apply to the gains from all non-separated wholesale power sales, firm and non-firm, excluding emergency sales, made under current or future FERC-approved schedules.

2. A three year moving average of gains on all non-separated wholesale power sales, firm and non-firm, excluding emergency sales, shall be established each year as the threshold for application of the incentive. All gains below this threshold shall be credited to the ratepayers. All gains above this threshold shall be split 80%/20% between ratepayers and shareholders, respectively.

III. Notice of Proposed Agency Action - Calculation of Gains and Appropriate Regulatory Treatment

NOTICE is hereby given by the Florida Public Service Commission that the action discussed in this part only is preliminary in nature and will become final unless a person whose interests are substantially affected files a petition for a formal proceeding, pursuant to Rule 25-22.029, Florida Administrative Code.

The record of this proceeding indicates that the IOUs calculate total gains differently for similar types of non-separated wholesale power sales. Because the IOUs sell short-term wholesale energy based upon their willingness and ability to sell at or above incremental costs, we believe that the IOUs should measure the costs of these sales on an incremental basis. Accordingly, we find that each IOU shall measure the gain from its non-separated wholesale power sales by subtracting the sum of its incremental costs from the revenue received for each sale. Further, we find that the calculation of incremental costs for these sales shall include, but not be limited to: incremental fuel cost, incremental SO_2 emission allowance cost, incremental O&M cost, and separately-identified transmission or capacity charges.

In addition, we find that the following regulatory treatment for the revenues and expenses associated with each non-separated wholesale power sale is appropriate:

1. Each IOU shall credit its fuel and purchased power cost recovery clause for an amount equal to the incremental fuel cost of generating the energy for each such sale;

2. Except for FPC, each IOU shall credit its environmental cost recovery clause for an amount equal to the incremental SO_2 emission allowance cost of generating the

energy for each such sale. FPC, because it does not have an environmental cost recovery clause, shall credit this cost to its fuel and purchased power cost recovery clause;

3. Each IOU shall credit its operating revenues for an amount equal to the incremental operating and maintenance (O&M) cost of generating the energy for each such sale; and

4. In accordance with Order No. PSC-99-2512-FOF-EI, issued December 22, 1999, in Docket No. 990001-EI, each IOU shall credit its capacity cost recovery clause for an amount equal to any transmission revenues or separately identifiable capacity revenues.

If a person whose substantial interests are affected by our proposed action in this portion of the Order timely files a protest, the issue shall be addressed as part of our Fuel and Purchased Power Cost Recovery proceedings.

IV. Conclusions of Law

This Commisison is vested with jurisdiction over this matter through several provisions of Chapter 366, Florida Statutes, including Sections 366.04, 366.05, and 366.06, Florida Statutes.

Based on the foregoing, it is

ORDERED by the Florida Public Service Commission that the shareholder incentive mechanism approved in Order No. 12923, issued January 24, 1984, in Docket No. 830001-EU-B, is hereby modified as set forth in parts I and II of this Order. It is further

ORDERED that gains on non-separated wholesale power sales shall be calculated as set forth in part III of this Order. It is further

ORDERED that the revenues and expenses associated with non-separated wholesale power sales shall be treated for regulatory purposes as set forth in part III of this Order. It is further

ORDERED that the provisions of part III of this Order, issued as proposed agency action, shall become final and effective upon the issuance of a Consummating Order unless an appropriate petition, in the form provided by Rule 28-106.201, Florida Administrative Code, is received by the Director, Division of Records and Reporting, 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on the date set forth in the 'Notice of Further Proceedings' attached hereto. It is further

ORDERED that this Docket shall be closed after the time for filing an appeal of parts I and II has run or upon issuance of a Consummating Order on part III, whichever occurs later. If a person whose substantial interests are affected by the Commission's proposed action in part III timely files a protest, the issue shall be addressed as part of the Commission's Fuel and Purchased Power Cost Recovery proceedings, and this Docket shall be closed after the time for filing an appeal on parts I and II has run.

By ORDER of the Florida Public Service Commission this 26th day of September, 2000.

/s/ Blanca S. Bayó
BLANCA S. BAY , Director
Division of Records and Reporting

This is a facsimile copy. A signed copy of the order may be obtained by calling 1-850-413-6770.

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NOTICE OF FURTHER PROCEEDINGS OR JUDICIAL REVIEW

The Florida Public Service Commission is required by Section 120.569(1), Florida Statutes, to notify parties of any administrative hearing or judicial review of Commission orders that is available under Sections 120.57 or 120.68, Florida Statutes, as well as the procedures and time limits that apply. This notice should not be construed to mean all requests for an administrative hearing or judicial review will be granted or result in the relief sought.

As identified in the body of this order, our action in part III of this order is preliminary in nature. Any person whose substantial interests are affected by the action proposed in part III of this order may file a petition for a formal proceeding, in the form provided by Rule 28-106.201, Florida Administrative Code. This petition must be received by the Director, Division of Records and Reporting, at 2540 Shumard Oak Boulevard, Tallahassee, Florida 32399-0850, by the close of business on October 17, 2000. If such a petition is filed, mediation may be available on a case-by-case basis. If mediation is conducted, it does not affect a substantially interested person's right to a hearing. In the absence of such a petition, part III of this order shall become effective and final upon the issuance of a Consummating Order.

Any objection or protest filed in this docket before the issuance date of this order is considered abandoned unless it satisfies the foregoing conditions and is renewed within the specified protest period.

Any party adversely affected by the Commission's final action in parts I and II of this order may request: (1) reconsideration of the decision by filing a motion for reconsideration with the Director, Division of Records and Reporting within fifteen (15) days of the issuance of this order in the form prescribed by Rule 25-22.060, Florida Administrative Code; or (2) judicial review by the Florida Supreme Court in the case of an electric, gas or telephone utility or the First District Court of Appeal in the case of a water or wastewater utility by filing a notice of appeal with the Director, Division of Records and Reporting and filing a copy of the notice of appeal and the filing fee with the appropriate court. This filing must be completed within thirty (30) days after the issuance of this order, pursuant to Rule 9.110, Florida Rules of Appellate Procedure. The notice of appeal must be in the form specified in Rule 9.900(a), Florida Rules of Appellate Procedure.

FIPUG Exhibit No. 6

Docket No. 010283-EI

Excerpts From Prefiled Testimony and Exhibits of J. Denise Jordan in Docket No. 010001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 010283-EI EXHIBIT NO. 6
COMPANY/
WITNESS: Florida Industrial Power Users Group
DATE: 8-31-01

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 010001-EI

IN RE: FUEL & PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

ACTUAL/ESTIMATED TRUE-UP

JANUARY 2001 THROUGH DECEMBER 2001

TESTIMONY AND EXHIBITS

OF

J. DENISE JORDAN

AUG 2 1 2001

RECEIVED

CALCULATION OF ESTIMATED TRUE-UP
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2001 THROUGH DECEMBER 2001

SCHEDULE E1-B

		ACTUAL						ESTIMATED						
		Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	TOTAL
A. 1.	Fuel Cost of System Net Generation	35,049,220	25,906,064	28,330,024	26,941,440	27,442,642	36,399,600	35,041,284	36,391,718	32,849,664	30,297,255	27,298,671	28,711,246	370,658,828
2.	Fuel Cost of Power Sold [1]	4,860,627	2,828,366	2,785,635	1,928,904	201,546	1,140,789	2,033,300	1,463,000	872,800	1,718,300	1,292,700	1,010,700	22,136,667
3.	Fuel Cost of Purchased Power	22,623,589	8,185,643	10,471,838	21,799,335	16,795,332	16,405,170	12,819,500	16,103,700	10,909,200	6,737,100	3,413,100	2,488,300	148,751,807
3a.	Demand and Non-Fuel Cost of Purchased Pwr	0	0	0	0	0	0	0	0	0	0	0	0	0
3b.	Payments to Qualifying Facilities	614,083	477,237	865,771	840,934	823,903	851,322	956,400	950,100	911,000	900,200	733,200	711,900	9,636,050
4.	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
5.	Adjustment to Fuel Cost (Ft. Meade/Wau. Wheeling)	(4,145)	(2,961)	(3,158)	(4,064)	(4,381)	(4,558)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(47,267)
5a.	Adjustment to Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	**TOTAL FUEL & NET POWER TRANS.**	**53,422,120**	**31,737,617**	**36,878,840**	**47,648,741**	**44,855,950**	**52,510,745**	**46,779,884**	**51,978,518**	**43,793,064**	**36,212,255**	**30,148,271**	**30,896,746**	**506,862,751**
[1]	Includes Gains													
B. 1.	Jurisdictional MWH Sales	1,604,027	1,292,892	1,209,453	1,232,701	1,303,234	1,580,541	1,649,041	1,626,561	1,675,400	1,498,370	1,294,124	1,286,997	17,253,340
2.	Non-Jurisdictional MWH Sales	59,200	43,339	68,623	71,754	76,402	69,941	84,557	84,910	79,709	57,487	43,408	39,316	778,646
3.	**TOTAL SALES (LINE B1+B2)**	**1,663,227**	**1,336,231**	**1,278,076**	**1,304,455**	**1,379,636**	**1,650,482**	**1,733,598**	**1,711,471**	**1,755,109**	**1,555,857**	**1,337,532**	**1,326,313**	**18,031,986**
4.	**Jurisdictional % of Total Sales**	**0.9644065**	**0.9675662**	**0.9463076**	**0.9449931**	**0.9446216**	**0.9576239**	**0.9512246**	**0.9503877**	**0.9545846**	**0.9630512**	**0.9675462**	**0.9703569**	**-**
C. 1.	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	39,749,385	32,021,651	29,884,053	34,416,247	36,519,851	44,240,442	42,908,569	45,835,998	47,208,010	42,203,613	36,426,773	36,226,917	467,641,509
1a.	Adjustment to Fuel Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
2.	True-up Provision	(3,560,110)	(3,560,110)	(3,560,110)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,463)	(3,426,461)	(41,518,495)
2a.	Incentive Provision	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,867	95,870	1,150,407
2b.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	**FUEL REVENUE APPLICABLE TO PERIOD**	**36,285,142**	**28,557,408**	**26,419,810**	**31,085,651**	**33,189,255**	**40,909,846**	**39,577,973**	**42,505,402**	**43,877,414**	**38,873,017**	**33,096,177**	**32,896,326**	**427,273,421**
4.	Total Fuel and Net Power Transactions (Line A6)	53,422,120	31,737,617	36,878,840	47,648,741	44,855,950	52,510,745	46,779,884	51,978,518	43,793,064	36,212,255	30,148,271	30,896,746	506,862,751
5.	Jurisd. Total Fuel and Net Power Transactions (Line A6*Line B4)	51,520,640	30,708,247	34,898,727	45,027,733	42,371,899	50,285,544	44,498,176	49,399,744	41,804,184	34,874,256	29,169,845	29,980,871	484,539,866
5a.	Jurisdictional Loss Multiplier	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	-
5b.	Jurisdictional Sales Adjusted for Line Losses	51,554,644	30,728,514	34,921,760	45,057,451	42,399,864	50,318,732	44,527,545	49,432,348	41,831,775	34,897,273	29,189,097	30,000,658	484,859,661
5c.	Peabody Coal Contract Buyout Amortization	345,594	343,063	340,532	338,002	335,471	332,940	330,409	327,878	325,347	322,816	320,285	317,754	3,980,091
5d.	Peabody Jurisdictionalized (Line 5c*Line B4)	333,293	331,936	322,248	319,410	316,893	318,831	314,293	311,611	310,571	310,888	309,891	308,335	3,808,200
6.	**JURISD. TOTAL FUEL AND NET POWER TRANSACTIONS INCLUDING PEABODY**	**51,887,937**	**31,060,450**	**35,244,008**	**45,376,861**	**42,716,757**	**50,637,563**	**44,841,838**	**49,743,959**	**42,142,346**	**35,208,161**	**29,498,988**	**30,308,993**	**488,667,861**
7.	Over/(Under) Recovery	(15,602,795)	(2,503,042)	(8,824,198)	(14,291,210)	(9,527,502)	(9,727,717)	(5,263,865)	(7,238,557)	1,735,068	3,664,856	3,597,189	2,587,333	(61,394,440)
8.	Interest Provision	(360,990)	(346,828)	(339,307)	(345,611)	(337,165)	(335,871)	(352,268)	(371,519)	(370,509)	(351,342)	(329,010)	(308,399)	(4,148,819)
9.	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD**													**(65,543,259)**

SCHEDULE E2

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2001 THROUGH DECEMBER 2001

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	
		ACTUAL						ESTIMATED						TOTAL
		Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	PERIOD
1.	Fuel Cost of System Net Generation	35,049,220	25,906,064	28,330,024	26,941,440	27,442,642	36,399,600	35,041,284	36,391,718	32,849,664	30,297,255	27,298,671	28,711,246	370,658,828
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold [1]	4,860,627	2,828,366	2,785,635	1,928,904	201,546	1,140,789	2,033,300	1,463,000	872,800	1,718,300	1,292,700	1,010,700	22,136,667
4.	Fuel Cost of Purchased Power	22,623,589	8,185,643	10,471,838	21,799,335	16,795,332	16,405,170	12,819,500	16,103,700	10,909,200	6,737,100	3,413,100	2,488,300	148,751,807
5.	Demand and Non-Fuel Cost of Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0
6.	Payments to Qualifying Facilities	614,083	477,237	865,771	840,934	823,903	851,322	956,400	950,100	911,000	900,200	733,200	711,900	9,636,050
7.	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
8.	Adjustment to Fuel Cost (Ft. Meade/Wau. Wheeling)	(4,145)	(2,961)	(3,158)	(4,064)	(4,381)	(4,558)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(4,000)	(47,267)
8a.	Adjustment to Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
9.	**TOTAL FUEL & NET POWER TRANSACTIONS**	**53,422,120**	**31,737,617**	**36,878,840**	**47,648,741**	**44,855,950**	**52,510,745**	**46,779,884**	**51,978,518**	**43,793,064**	**36,212,255**	**30,148,271**	**30,896,746**	**506,862,751**
10.	Jurisdictional kWh Sold	1,604,027	1,292,892	1,209,453	1,232,701	1,303,234	1,580,541	1,649,041	1,626,561	1,675,400	1,498,370	1,294,124	1,286,997	17,253,340
11.	Jurisdictional % of Total Sales	0.9644065	0.9675662	0.9463076	0.9449931	0.9446216	0.9576239	0.9512246	0.9503877	0.9545846	0.9630512	0.9675462	0.9703569	-
12.	Jurisdictional Total Fuel & Net Power Transactions (Line 9 * Line 11)	51,520,640	30,708,247	34,898,727	45,027,733	42,371,899	50,285,544	44,498,176	49,399,744	41,804,184	34,874,256	29,169,845	29,980,871	484,539,866
13.	Jurisdictional Loss Multiplier	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	1.00066	-
14.	Jurisdictional Sales Adjusted for Line Losses (Line 12 * Line 13)	51,554,644	30,728,514	34,921,760	45,057,451	42,399,864	50,318,732	44,527,545	49,432,348	41,831,775	34,897,273	29,189,097	30,000,658	484,859,661
15.	Peabody Coal Contract Buyout Amortization	345,594	343,063	340,532	338,002	335,471	332,940	330,409	327,878	325,347	322,816	320,285	317,754	3,980,091
16.	Peabody Jurisdictionalized (Line 15 * Line 11)	333,293	331,936	322,248	319,410	316,893	318,831	314,293	311,611	310,571	310,888	309,891	308,335	3,808,200
17.	**JURISD. TOTAL FUEL & NET PWR. TRANS. INCL. PEABODY (LINE 14+16)**	**51,887,937**	**31,060,450**	**35,244,008**	**45,376,861**	**42,716,757**	**50,637,563**	**44,841,838**	**49,743,959**	**42,142,346**	**35,208,161**	**29,498,988**	**30,308,993**	**488,667,861**
18.	Cost Per kWh Sold (Cents/kWh)	3.2349	2.4024	2.9140	3.6811	3.2778	3.2038	2.7193	3.0582	2.5154	2.3498	2.2795	2.3550	2.8323
19.	True-up (Cents/kWh) [2]	0.2219	0.2754	0.2944	0.2780	0.2629	0.2168	0.2078	0.2107	0.2045	0.2287	0.2648	0.2662	0.2443
20.	Total (Cents/kWh) (Line 18+19)	3.4568	2.6778	3.2084	3.9591	3.5407	3.4206	2.9271	3.2689	2.7199	2.5785	2.5443	2.6212	3.0766
21.	Revenue Tax Factor	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072	1.00072
22.	Recovery Factor Adjusted for Taxes (Cents/kWh) (Excluding GPIF)	3.4593	2.6797	3.2107	3.9620	3.5432	3.4231	2.9292	3.2713	2.7219	2.5804	2.5461	2.6231	3.0789
23.	GPIF Adjusted for Taxes (Cents/kWh) [2]	(0.0060)	(0.0074)	(0.0079)	(0.0078)	(0.0074)	(0.0061)	(0.0058)	(0.0059)	(0.0057)	(0.0064)	(0.0074)	(0.0074)	(0.0068)
24.	**TOTAL RECOVERY FACTOR (LINE 22+23)**	**3.4533**	**2.6723**	**3.2028**	**3.9542**	**3.5358**	**3.4170**	**2.9234**	**3.2654**	**2.7162**	**2.5740**	**2.5387**	**2.6157**	**3.0721**
25.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**3.453**	**2.672**	**3.203**	**3.954**	**3.536**	**3.417**	**2.923**	**3.265**	**2.716**	**2.574**	**2.539**	**2.616**	**3.072**

[1] Includes Gains

[2] Based on Jurisdictional Sales Only

POWER SOLD
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2001 THROUGH JUNE 2001

(1) MONTH	(2) SOLD TO		(3) TYPE & SCHEDULE	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)	(9) TOTAL COST (6)X(7B)
ACTUAL Jan-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	3,001.0	59.3	2,941.7	2.719	2.719	79,988.31	79,988.31
	HPP	SEPARATED	CONTRACT	72,685.0	0.0	72,685.0	2.290	2.980	1,664,699.20	2,166,002.75
	FMPA	JURISD.	SCH. -D	108,285.0	0.0	108,285.0	1.927	1.927	2,086,989.95	2,086,989.95
	VARIOUS	JURISD.	MKT. BASE	18,225.0	0.0	18,225.0	5.646	5.646	1,028,949.57	1,028,949.57
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			202,196.0	59.3	202,136.7	2.405	2.653	4,860,627.03	5,361,930.58
ACTUAL Feb-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	3,193.0	0.0	3,193.0	2.199	2.199	70,217.14	70,217.14
	HPP	SEPARATED	CONTRACT	47,065.0	0.0	47,065.0	2.442	2.997	1,149,167.85	1,410,663.30
	FMPA	JURISD.	SCH. -D	72,580.0	0.0	72,580.0	1.930	1.930	1,400,845.45	1,400,845.45
	VARIOUS	JURISD.	MKT. BASE	7,011.0	0.0	7,011.0	2.969	3.221	208,135.44	225,819.69
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			129,849.0	0.0	129,849.0	2.178	2.393	2,828,365.88	3,107,545.58
ACTUAL Mar-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	3,182.0	10.2	3,171.8	2.749	2.749	87,184.89	87,184.89
	HPP	SEPARATED	CONTRACT	67,575.0	0.0	67,575.0	2.446	3.044	1,652,681.55	2,056,972.20
	FMPA	JURISD.	SCH. -D	50,695.0	0.0	50,695.0	1.931	1.931	979,000.85	979,000.85
	VARIOUS	JURISD.	MKT. BASE	4,422.0	0.0	4,422.0	1.510	2.740	66,767.88	121,161.93
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			125,874.0	10.2	125,863.8	2.213	2.578	2,785,635.17	3,244,319.87
ACTUAL Apr-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	3,212.0	417.4	2,794.6	3.780	3.780	105,622.06	105,622.06
	HPP	SEPARATED	CONTRACT	71,440.0	0.0	71,440.0	2.511	3.218	1,793,914.50	2,298,607.55
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	948.0	0.0	948.0	3.098	3.353	29,367.37	31,784.77
	VARIOUS	JURISD.	SCH. -J	192.0	0.0	192.0	0.000	0.255	0.00	489.60
	TOTAL			75,792.0	417.4	75,374.6	2.559	3.233	1,928,903.93	2,436,503.98
ACTUAL May-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	3,064.0	131.7	2,932.3	2.265	2.265	66,407.04	66,407.04
	HPP	SEPARATED	CONTRACT	1,930.0	0.0	1,930.0	(1.494)	(1.478)	(28,826.80)	(28,523.10)
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	5,986.0	0.0	5,986.0	2.739	2.979	163,965.41	178,327.01
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			10,980.0	131.7	10,848.3	1.858	1.993	201,545.65	216,210.95
ACTUAL Jun-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	2,745.9	266.9	2,479.0	2.346	2.346	58,149.51	58,149.51
	HPP	SEPARATED	CONTRACT	31,617.0	0.0	31,617.0	3.173	3.499	1,003,208.42	1,106,161.60
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	2,323.0	0.0	2,323.0	2.867	3.122	66,611.72	72,535.37
	VARIOUS	JURISD.	SCH. -J	276.0	0.0	276.0	4.645	4.645	12,819.11	12,819.11
	TOTAL			36,961.9	266.9	36,695.0	3.109	3.406	1,140,788.76	1,249,665.59

POWER SOLD
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2001 THROUGH DECEMBER 2001

(1) MONTH	(2) SOLD TO		(3) TYPE & SCHEDULE	(4) TOTAL MWH SOLD	(5) MWH WHEELED FROM OTHER SYSTEMS	(6) MWH FROM OWN GENERATION	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)	(9) TOTAL COST (6)X(7B)
ESTIMATED Jul-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	614.0	0.0	614.0	2.410	2.410	14,800.00	14,800.00
	HPP	SEPARATED	CONTRACT	37,758.0	0.0	37,758.0	2.484	3.639	938,000.00	1,374,000.00
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	18,776.0	0.0	18,776.0	5.755	6.010	1,080,500.00	1,128,400.00
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			57,148.0	0.0	57,148.0	3.558	4.405	2,033,300.00	2,517,200.00
ESTIMATED Aug-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	6,055.0	0.0	6,055.0	1.706	1.706	103,300.00	103,300.00
	HPP	SEPARATED	CONTRACT	37,758.0	0.0	37,758.0	2.494	3.649	941,800.00	1,377,800.00
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	8,833.0	0.0	8,833.0	4.731	4.986	417,900.00	440,400.00
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			52,646.0	0.0	52,646.0	2.779	3.650	1,463,000.00	1,921,500.00
ESTIMATED Sep-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	6,030.0	0.0	6,030.0	1.698	1.698	102,400.00	102,400.00
	HPP	SEPARATED	CONTRACT	26,100.0	0.0	26,100.0	2.418	3.573	631,200.00	932,600.00
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	5,050.0	0.0	5,050.0	2.756	3.012	139,200.00	152,100.00
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			37,180.0	0.0	37,180.0	2.347	3.193	872,800.00	1,187,100.00
ESTIMATED Oct-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	6,055.0	0.0	6,055.0	1.706	1.706	103,300.00	103,300.00
	HPP	SEPARATED	CONTRACT	53,940.0	0.0	53,940.0	2.403	3.558	1,296,300.00	1,919,200.00
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	11,764.0	0.0	11,764.0	2.709	2.964	318,700.00	348,700.00
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			71,759.0	0.0	71,759.0	2.395	3.304	1,718,300.00	2,371,200.00
ESTIMATED Nov-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	5,972.0	0.0	5,972.0	1.680	1.680	100,300.00	100,300.00
	HPP	SEPARATED	CONTRACT	24,012.0	0.0	24,012.0	2.342	3.496	562,300.00	839,500.00
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	23,248.0	0.0	23,248.0	2.710	2.965	630,100.00	689,400.00
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			53,232.0	0.0	53,232.0	2.428	3.061	1,292,700.00	1,629,200.00
ESTIMATED Dec-01										
	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	5,995.0	0.0	5,995.0	1.688	1.688	101,200.00	101,200.00
	HPP	SEPARATED	CONTRACT	2,157.0	0.0	2,157.0	2.304	3.459	49,700.00	74,600.00
	FMPA	JURISD.	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	MKT. BASE	34,605.0	0.0	34,605.0	2.485	2.739	859,800.00	948,000.00
	VARIOUS	JURISD.	SCH. -J	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	TOTAL			42,757.0	0.0	42,757.0	2.364	2.628	1,010,700.00	1,123,800.00
Jan-01 THRU Dec-01	VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00
	VARIOUS	JURISD.	SCH. -D	49,118.9	885.5	48,233.4	2.058	2.058	992,868.95	992,868.95
	HPP	SEPARATED	CONTRACT	474,037.0	0.0	474,037.0	2.458	3.276	11,654,144.72	15,527,584.30
	FMPA	JURISD.	SCH. -D	231,560.0	0.0	231,560.0	1.929	1.929	4,466,836.25	4,466,836.25
	VARIOUS	JURISD.	MKT. BASE	141,191.0	0.0	141,191.0	3.548	3.800	5,009,997.39	5,365,578.34
	VARIOUS	JURISD.	SCH. -J	468.0	0.0	468.0	2.739	2.844	12,819.11	13,308.71
	TOTAL			896,374.9	885.5	895,489.4	2.472	2.944	22,136,666.42	26,366,176.55

PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2001 THROUGH JUNE 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
							CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	MWH FOR OTHER UTILITIES	MWH FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT (7)X(8A)
ACTUAL Jan-01									
	VARIOUS	SCH. J	156,147.0	0.0	4,394.0	151,753.0	8.667	8.667	13,152,110.23
	HPP	IPP	82,250.0	0.0	0.0	82,250.0	11.515	11.515	9,471,478.81
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		238,397.0	0.0	4,394.0	234,003.0	9.668	9.668	22,623,589.04
ACTUAL Feb-01									
	VARIOUS	SCH. J	80,269.0	0.0	0.0	80,269.0	5.429	5.429	4,358,178.78
	HPP	IPP	58,435.0	0.0	0.0	58,435.0	6.550	6.550	3,827,464.64
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		138,704.0	0.0	0.0	138,704.0	5.902	5.902	8,185,643.42
ACTUAL Mar-01									
	VARIOUS	SCH. J	118,293.0	0.0	594.2	117,698.8	5.516	5.516	6,492,321.60
	HPP	IPP	73,141.0	0.0	0.0	73,141.0	5.441	5.441	3,979,516.01
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		191,434.0	0.0	594.2	190,839.8	5.487	5.487	10,471,837.61
ACTUAL Apr-01									
	VARIOUS	SCH. J	274,208.0	0.0	24,996.0	249,212.0	6.536	6.536	16,288,095.35
	HPP	IPP	72,146.0	0.0	0.0	72,146.0	6.235	6.235	4,498,564.75
	VARIOUS	OTHER	17,995.0	0.0	0.0	17,995.0	5.628	5.628	1,012,675.25
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		364,349.0	0.0	24,996.0	339,353.0	6.424	6.424	21,799,335.35
ACTUAL May-01									
	VARIOUS	SCH. J	222,843.0	0.0	8,533.9	214,309.1	4.969	4.969	10,649,774.54
	HPP	IPP	102,327.0	0.0	0.0	102,327.0	4.899	4.899	5,013,263.48
	VARIOUS	OTHER	20,851.0	0.0	0.0	20,851.0	5.430	5.430	1,132,294.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		346,021.0	0.0	8,533.9	337,487.1	4.977	4.977	16,795,332.02
ACTUAL Jun-01									
	VARIOUS	SCH. J	216,266.0	0.0	21,804.2	194,461.8	6.078	6.078	11,820,049.81
	HPP	IPP	95,024.0	0.0	0.0	95,024.0	2.483	2.483	2,359,447.00
	VARIOUS	OTHER	28,079.0	0.0	0.0	28,079.0	7.926	7.926	2,225,673.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		339,369.0	0.0	21,804.2	317,564.8	5.166	5.166	16,405,169.81

PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2001 THROUGH DECEMBER 2001

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH	MWH		CENTS/KWH		TOTAL $
		TYPE	TOTAL	FOR	FOR	MWH	(A)	(B)	FOR FUEL
	PURCHASED	&	MWH	OTHER	INTERRUP-	FOR	FUEL	TOTAL	ADJUSTMENT
MONTH	FROM	SCHEDULE	PURCHASED	UTILITIES	TIBLE	FIRM	COST	COST	(7)X(8A)
ESTIMATED Jul-01									
	VARIOUS	SCH. J	14,757.0	0.0	8,609.0	6,148.0	9.504	9.504	584,300.00
	HPP	IPP	97,535.0	0.0	0.0	97,535.0	4.457	4.457	4,347,100.00
	VARIOUS	OTHER	48,303.0	0.0	0.0	48,303.0	9.033	9.033	4,363,300.00
	VARIOUS	MKT BASED	54,924.0	0.0	0.0	54,924.0	6.418	6.418	3,524,800.00
	TOTAL		215,519.0	0.0	8,609.0	206,910.0	6.196	6.196	12,819,500.00
ESTIMATED Aug-01									
	VARIOUS	SCH. J	35,747.0	0.0	18,711.0	17,036.0	9.049	9.049	1,541,600.00
	HPP	IPP	124,336.0	0.0	0.0	124,336.0	4.458	4.458	5,542,900.00
	VARIOUS	OTHER	44,451.0	0.0	0.0	44,451.0	9.309	9.309	4,137,800.00
	VARIOUS	MKT BASED	66,194.0	0.0	0.0	66,194.0	7.374	7.374	4,881,400.00
	TOTAL		270,728.0	0.0	18,711.0	252,017.0	6.390	6.390	16,103,700.00
ESTIMATED Sep-01									
	VARIOUS	SCH. J	12,257.0	0.0	7,664.0	4,593.0	7.640	7.640	350,900.00
	HPP	IPP	83,469.0	0.0	0.0	83,469.0	4.532	4.532	3,783,200.00
	VARIOUS	OTHER	63,991.0	0.0	0.0	63,991.0	6.744	6.744	4,315,800.00
	VARIOUS	MKT BASED	38,537.0	0.0	0.0	38,537.0	6.382	6.382	2,459,300.00
	TOTAL		198,254.0	0.0	7,664.0	190,590.0	5.724	5.724	10,909,200.00
ESTIMATED Oct-01									
	VARIOUS	SCH. J	11,612.0	0.0	7,308.0	4,304.0	7.642	7.642	328,900.00
	HPP	IPP	53,482.0	0.0	0.0	53,482.0	4.809	4.809	2,572,000.00
	VARIOUS	OTHER	33,214.0	0.0	0.0	33,214.0	4.866	4.866	1,616,100.00
	VARIOUS	MKT BASED	34,481.0	0.0	0.0	34,481.0	6.439	6.439	2,220,100.00
	TOTAL		132,789.0	0.0	7,308.0	125,481.0	5.369	5.369	6,737,100.00
ESTIMATED Nov-01									
	VARIOUS	SCH. J	2,892.0	0.0	1,928.0	964.0	7.645	7.645	73,700.00
	HPP	IPP	28,764.0	0.0	0.0	28,764.0	5.219	5.219	1,501,200.00
	VARIOUS	OTHER	8,310.0	0.0	0.0	8,310.0	5.201	5.201	432,200.00
	VARIOUS	MKT BASED	26,418.0	0.0	0.0	26,418.0	5.322	5.322	1,406,000.00
	TOTAL		66,384.0	0.0	1,928.0	64,456.0	5.295	5.295	3,413,100.00
ESTIMATED Dec-01									
	VARIOUS	SCH. J	1,901.0	0.0	1,416.0	485.0	7.649	7.649	37,100.00
	HPP	IPP	30,293.0	0.0	0.0	30,293.0	5.303	5.303	1,606,500.00
	VARIOUS	OTHER	4,494.0	0.0	0.0	4,494.0	5.401	5.401	242,700.00
	VARIOUS	MKT BASED	7,924.0	0.0	0.0	7,924.0	7.597	7.597	602,000.00
	TOTAL		44,612.0	0.0	1,416.0	43,196.0	5.760	5.760	2,488,300.00
Jan-01 THRU Dec-01	VARIOUS	SCH. J	1,147,192.0	0.0	105,958.3	1,041,233.7	6.308	6.308	65,677,030.31
	HPP	IPP	901,202.0	0.0	0.0	901,202.0	5.382	5.382	48,502,834.69
	VARIOUS	OTHER	269,688.0	0.0	0.0	269,688.0	7.223	7.223	19,478,542.25
	VARIOUS	MKT BASED	228,478.0	0.0	0.0	228,478.0	6.606	6.606	15,093,600.00
	TOTAL		2,546,560.0	0.0	105,958.3	2,440,601.7	6.095	6.095	148,751,807.25

EXHIBIT # 7

I

Combustion Turbine
Peaking Generation

$75

Generation

$25

Firm Purchased
Power

$100

Purchased Power Agreement
(Must Take)

$125

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
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COMPANY/
WITNESS: Kordecki
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II

Combustion Turbine
Peaking Generation

$75

Base Load/Intermediate
Generation

$25

Firm Purchased
Power

$70

Purchased Power Agreement
(Must Take)

$20

III

Base Load/Intermediate
Generation
$25

Purchased Power Agreement
(Must Take)

$125

Commission any accident occurring in connection with any part of its transmission or distribution facilities which:

(a) Involves death or injury requiring hospitalization of nonutility persons; or

(b) Is significant from a safety standpoint in the judgment of the utility even though it is not required by (a).

(6) Each public utility, rural electric cooperative, and municipal electric utility shall (without admitting liability) report each accident or malfunction, occurring in connection with any part of its transmission or distribution facilities, to the Commission within 30 days after it learns of the occurrence, provided the accident or malfunction:

(a) Involves damage to the property of others in an amount in excess of $5000; or

(b) Causes significant damage in the judgment of the utility to the utility's facilities.

(7) Unless requested by the Commission, reports are not required with respect to personal injury, death, or property damage resulting from vehicles striking poles or other utility property.

Specific Authority 350.127(2) FS. Law Implemented 366.04(2)(f), (6) FS. History—New 8-13-87, Amended 2-18-90, 11-10-93, 8-17-97.

25-6.035 Adequacy of Resources.

(1) Each electric utility shall maintain sufficient generating capacity, supplemented by regularly available generating and non-generating resources, in order to meet all reasonable demands for service and provide a reasonable reserve for emergencies. Each electric utility shall also coordinate the sharing of energy reserves with other electric utilities in Peninsular Florida. To achieve an equitable sharing of energy reserves, Peninsular Florida utilities shall be required to maintain, at a minimum, a 15% planned reserve margin. The planned and operating reserve margin standards established herein are intended to maintain an equitable sharing of energy reserves, not to set a prudent level of reserves for long-term planning or reliability purposes. The planned reserve margin for each utility shall be calculated as follows:

$$RM = [(C - L)/L]*100 \text{ where;}$$

"RM" — Is defined as the utility's percent planned reserve margin;

"C" — Is defined as the aggregate sum of the rated dependable peak-hour capabilities of the resources that are expected to be available at the time of the utility's annual peak; and

"L" — Is defined as the expected firm peak load of the system for which reserves are required.

The following shall be utilized as the operating reserve standard for Peninsular Florida's utilities: operating reserves shall be maintained by the combined Peninsular Florida system at a value equal to or greater than the loss of generation that would result from the most severe single generating unit contingency. The operating reserves shall be allocated among the utilities in proportion to each control area's peak hour net energy for load for the preceding year, and the summer gross Florida Reliability Coordinating Council (FRCC) capability of its largest unit or ownership share of a joint unit, whichever is greater. Fifty percent shall be allocated on the basis of peak hour net energy for load and fifty percent on the basis of the summer gross FRCC capability of the largest unit. Operating reserves shall be fully available within fifteen minutes. At least 25% of the operating reserves shall be in the form of spinning reserves which are automatically responsive to a frequency deviation from normal.

(2) Treatment of Purchased Power. Only firm purchase power agreements may be included as a resource for purposes of calculating a planned or operating reserve margin. A utility may petition for waiver of this requirement based on the very high availability of specific non-firm purchases.

(3) Treatment of Shared Generating Units. Only the utility which has first call on the generating unit may count the unit towards its planned or operating reserve margin. A utility has first call on a unit if the unit is available and the utility has the contractual right to dispatch the unit to meet its native load and other firm contractual commitments before any other party to the unit's sharing arrangement. A utility may petition the Commission for approval of other methods demonstrating equivalent reliability on a case by case basis.

(4) Treatment of Non-Firm Load. If non-firm load (i.e., customers receiving service under load management, interruptible, curtailable, or similar tariffs) is relied upon by a utility when calculating its planned or operating reserves, the utility shall be required to make such reserves available to maintain the firm service requirements of other utilities.

(5) Buy-through Power for Interruptible Customers. Interruption of service to non-firm customers is not an emergency. As such, a utility shall not be required to provide buy-through power for another utility's interruptible customers under obligatory emergency interchange schedules.

Specific Authority 366.05(1) FS. Law Implemented 366.03, 366.04(2)(c), (5), 366.055 FS. History—New 7-29-69, Formerly 25-6.35, Amended 9-5-96, 5-29-01.

25-6.036 Inspection of Plant. Each utility shall adopt a program of inspection of its electric plant in order to determine the necessity for replacement and repair. The frequency of the various inspection shall be based on the utility's experience and accepted good practice. Each utility shall keep sufficient records to give evidence of compliance with its inspection program.

Specific Authority 366.05(1) FS. Law Implemented 366.04(2)(c), (5), 366.05(1), 366.055, 366.08 FS. History—New 7-29-69, Formerly 25-6.36.

25-6.037 Extent of System Which Utility Shall Operate and Maintain. Each utility, unless specifically relieved in any case by the Commission from such obligations, shall operate and maintain in safe, efficient, and proper condition, pursuant to the standards referenced herein, all of the facilities and equipment used in connection with the production, transmission, distribution, regulation, and delivery of electricity to any customer up to the point of delivery. The utility is also responsible for the safe, efficient measurement of electrical consumption consistent with test procedures and accuracies prescribed by the Commission.

Specific Authority 366.05(1) FS. Law Implemented 366.03, 366.04(6), 366.05(1), (3) FS. History—New 7-29-69, Amended 4-13-80, Formerly 25-6.37.

25-6.038 Change in Character of Service. If any changes are made by the utility in its existing service characteristics which would impair the safe, efficient utilization of energy by the customer's equipment, the utility shall bear the cost of all changes necessary to adapt the customer's equipment to the new service conditions so that

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