BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 030001-EI

In the Matter of

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE WITH GENERATING PERFORMANCE INCENTIVE FACTOR.
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PROCEEDINGS: HEARING

BEFORE: CHAIRMAN LILA A. JABER
COMMISSIONER J. TERRY DEASON
COMMISSIONER BRAULIO L. BAEZ
COMMISSIONER RUDOLPH "RUDY" BRADLEY
COMMISSIONER CHARLES M. DAVIDSON

DATE: Friday, November 14, 2003

TIME: Commenced at 9:10 a.m.
Concluded at

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida

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APPEARANCES: (As heretofore noted.)

PROCEEDINGS

CHAIRMAN JABER: Okay. Good morning. Let's go ahead and get started this morning. I was looking for staff over there this morning.

Mr. Keating, what do we need to do this morning? Is there a notice that has to be read? Remind me.

MR. KEATING: I don't, I don't believe so. I think we're still sort of in the noticed hearing phase. There was an indication in the prehearing order that the bench decision was possible and that was announced yesterday, so we are still under that notice.

CHAIRMAN JABER: Okay. And how do you propose we go forward this morning? What's more efficient, to take up the proposed stipulations in the back or do you want to go issue by issue starting from the beginning of the prehearing order?

MR. KEATING: I think it would probably be most efficient to go ahead, and if we could go item by item, issue by issue or do the whole block of stipulated issues; but to handle the stipulated issues first that remain, then to move to the company-specific and generic disputed issues that would have effect on the ultimate fallout issues, and then eventually get to the ultimate fallout issues for the fuel and capacity clause.

CHAIRMAN JABER: Okay. I'm assuming you've got that sort of order readily available for us. The proposed

stipulations look like they start on Page 59 of the prehearing order. If we take those up in bulk, can you represent to me that none of those issues go to the policy questions related in 13E in particular and, and, and the closing of the Gannon Units for TECO? That's my only confusion was to try to keep those policy questions together.

MR. KEATING: I can make that representation that all the issues that are identified as stipulated issues in that, towards the end of the prehearing order, I think you said Page 59 or 60, are unrelated to those, either the Gannon shutdown issue or the market price proxy issue.

CHAIRMAN JABER: Okay. Commissioners, the proposed stipulations start on Page 59. It looks like they conclude on Page 66 of the prehearing order. If you don't have specific questions on those proposed stipulations, I would ask for a motion.

COMMISSIONER DAVIDSON: Madam Chair, I would move, move that the Commission accept the proposed stipulations beginning in the middle of Page 59 with Issue 4 continuing through Page 66, concluding near the bottom with Issue 28.

CHAIRMAN JABER: Thank you.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: And a second. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: The proposed stipulations are approved unanimously.

Mr. Keating.

MR. KEATING: And, Chairman, there were -- there was a handout on the first day of the hearing, I think it was provided to the parties and it was provided to the Commissioners, a two-page document entitled "Additional Proposed Stipulations" that listed four issues that had been entered since the prehearing order was issued.

CHAIRMAN JABER: Okay. And those four issues, can you make the same representation? I'm looking at 13F, 13G, 14A and 16A.

MR. KEATING: Yes.

CHAIRMAN JABER: Same representation? They don't go to the policy issues we need to consider separately?

MR. KEATING: That's correct.

COMMISSIONER DAVIDSON: Madam Chair, I move the Commission accept proposed supplemental stipulations 13F, G, 14A and 16A.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: Thank you, Commissioner.

COMMISSIONER BRADLEY: 13F, G and what?

CHAIRMAN JABER: 13F, 13G, 14A and 16A.

COMMISSIONER BRADLEY: I'll second.

CHAIRMAN JABER: Okay. There's been a motion and a

second. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: The proposed stipulations for 13F, 13G, 14A and 16A are approved unanimously.

Mr. Keating.

MR. KEATING: Commissioner, I believe that brings us to, if we continue in the order I suggested, the company-specific and generic issues that remain disputed that may have some affect on the fallout issues that have not, the fallout issues that have not previously been stipulated and approved. And I believe those start, if we go in the orders listed in the prehearing order, with Issue 13E.

CHAIRMAN JABER: And do you have either an oral recommendation or a written recommendation for us on 13E? I'm sure that will generate some questions from us.

MR. FLOYD: We have an oral recommendation.

CHAIRMAN JABER: Okay.

MR. FLOYD: I know you had some legal questions also about that issue, but I'll just deal with the technical questions.

Staff recommends that you adopt in its entirety without change the stipulation entered into between just staff and the company. We think that's a fair way to transition from the current Commission philosophy, which is, uses a proxy that was established, a proxy methodology that was established back

in 1993. And we think that if you want to change and go to a new philosophy, this would require some time to phase out what the company is doing now, what the company's understanding is of the regulatory environment, and go to a different environment. So we wanted to start in 2005 with a new regime. And clearly 2002 and 2003, at least in my technical opinion, is, is under the old proxy, and so we have no problem with that.

The question came up as what do you do with 2004? And we think the best way to do this is to have 2004 as a transition year to allow the company to go out 2004, do RFPs, and then beginning 2005 under the new regime.

CHAIRMAN JABER: Mr. Floyd --

MR. FLOYD: That's our recommendation.

COMMISSIONER DAVIDSON: I have one question just on this, this issue.

In your experience, to the extent you have experience under our new bid rule, does the bid rule contain time frames or parameters from, say, beginning design of the RFP through the solicitation of bids, review, analysis, selection of winners, is that something that occurs in a six-month period, a nine-month period a three-month period? And part two of that is what's your experience on how long it might take to get through an RFP of this nature? Is this a relatively short process or a relatively longer process?

MR. FLOYD: First of all, you mentioned a new bid rule, and I wasn't sure what you had reference to there.

CHAIRMAN JABER: Generation bid rule.

COMMISSIONER DAVIDSON: The generation, the generation bid rule. That's the process that FP&L is going through right now. I'm just trying to get some rough parameters on a time frame as to how long it might take Progress to get through the RFP process, if that's a short process or a long process.

MR. FLOYD: To be honest, I don't have a really good time frame on how bidding for river, I mean, coal transportation contracts take. I'm not that familiar with it. But I'm assured by the company though that, and this is not anything in the record, that these things can be accomplished next year and be ready to go in 2005.

COMMISSIONER DAVIDSON: Did TECO go through an RFP process for its water-borne coal transportation?

MR. FLOYD: Yes, it did.

COMMISSIONER DAVIDSON: How long -- not that Progress would necessarily follow that same procedure, but just taking that as a benchmark, how long was that process, if you recall, from start to finish?

MR. FLOYD: I don't really, I don't really recall. I'll have to go -- maybe somebody here -- about three months, I hear.

COMMISSIONER DAVIDSON: Including the design of the RFP through -- the issuance, I guess, of the RFP through --

MR. FLOYD: I think --

COMMISSIONER DAVIDSON: Okay.

MR. FLOYD: It was less than six months. I don't know exactly how you would break that down.

COMMISSIONER DAVIDSON: Thanks.

CHAIRMAN JABER: Staff, I just, I need to get myself past the procedural aspect of this proposed stipulation. I do have questions on the substance of the issue and the substance of the stipulation. But, Cochran, I want to understand your recommendation. It seems to me that Ms. Davis in her closing arguments yesterday clarified for me that they are recommending that we take the substance of what's in front of us and accept that as our finding. That's different and, frankly, I think, more procedurally correct, if that's what this Commission wants to do, than accepting a proposed stipulation that's only offered by the company and that you might be willing to endorse.

I mean, is -- are you trying to tell me that the substance of the document is what your recommendation is today?

MR. KEATING: That's correct. And to be clear, I think the confusion came from the title on the document, "Proposed Stipulation." That's a title that's been on the document since it was originally drafted. It probably should

have been removed to state, "Agreed Position of Progress and Staff." It was -- we didn't provide it and we didn't intend to, to represent that document as a stipulation that should be approved indicative of any agreement between all of the parties. We understood and Progress understood that not everybody agreed with this.

What that document represented and what it still represents, I believe, is an agreed position. The document represents staff's position and the company's position on the issue. And what staff is recommending is that you approve the substance of that document based on the merits and based on the record that was established through, through testimony.

CHAIRMAN JABER: Okay. That answers my procedural question.

Let me get to the substance of your, your position and, therefore, your recommendation. There were some contradictions between Mr. McNulty's testimony yesterday and what your position is. And I want to understand if you're modifying anything and, if not, why not?

For example, on Page 2 of the handout we have under Number 3A, Number 3, this seems to definitively say that the market price proxy would be based on the following guidelines, and one of the guidelines is that a maximum term of five years be put in place before any review by the Commission. And should that be clarified to explain that any review should

coincide with the expiration of the contract which should not exceed a term of five years? Is that what you're trying to say?

It was explained to us through the hearing, through the course of the hearing that some of these contracts run four years. I don't know if they could actually be negotiated for even a smaller amount of time. I just don't know.

MR. FLOYD: Yeah. I, I may not be answering your question, but I think these, what we agreed to was that this method that's recorded in the so-called stipulation here would only be looked at no sooner than every five years. I don't think every time a contract expired would we come in here and be before you again. But maybe I'm --

CHAIRMAN JABER: Well, why not? See, that is helpful to me. I need to understand why you wouldn't, because it goes back to something Commissioner Davidson said earlier. If, if this process endorses allowing a company to, to use the RFP process and if we accept Mr. McNulty's testimony, which is the Commission should periodically review this process, then why wouldn't you just as a matter of logistics want to time that with the expiration of the contracts?

MR. FLOYD: Well, maybe I'm not understanding. But the, the company should manage this thing such that if it knows a contract is expiring, it does whatever it needs to do to come up with another contract either through RFP, and if that's not

successful, come up with a proposed proxy. And then certainly they would be in here in that case.

My comments just meant that we wouldn't be -- this is kind of a new, new way of doing business in the future, and we wouldn't want this, what's approved today as a method for ongoing would be coming next year and say now we want to change what we're doing and go back to a proxy or this, that and the other unless the Commission found some problem as we go along. So I think maybe I wasn't answering your question a while ago.

Certainly if the company needs to manage this such that it is in a position to have a new contract in place as we go along -- and if it's based on an RFP and if it's competitive, then we're agreeing that that's, you know, that's what would be used.

CHAIRMAN JABER: Well, then if, if that's what will be used, now I question why Number 3 is even necessary. Am I the only one, Commissioners, that has trouble with that term?

COMMISSIONER BAEZ: Well, I -- the more we, the more this gets fleshed out, the more questions pop into my head, one of them being much of the discussion and much of the posturing that's, that's gone on or the explanation of positions is that there is some kind of overlap, maybe overlap is not an accurate word, but there's some kind of interim where, where the review of the benchmark, for example, which is in effect now hasn't really coincided with the termination of a contract. So what

you get in essence is, you know, staff's decision or this Commission's decision to review the, the process or the, or the benchmark, the methodology, while there's still -- and yet there's still a possibility that a new contract can be entered into for, for an indeterminate amount of time, and now all of the sudden we're reviewing a methodology while there's still a contract in place. So we're reviewing it with a view towards the future, and that can be anywhere from, you know, one to five years.

CHAIRMAN JABER: Two years.

COMMISSIONER BAEZ: Whatever the length of the contract is. So I'm having trouble -- I mean, if what we're trying to do is codify a process by which at the end of each contract or, or leading up to the end of a particular contract that was entered into under a certain methodology, that staff's review of the methodology, whether it's appropriate and then they bring it back to us and we approve the methodology, therefore creating some kind of steady ground for the company to proceed, that seems more in line with what I think was suggested or at least what I understood by the, by the --

MR. FLOYD: Now I know the answer to your question.

CHAIRMAN JABER: What is it?

MR. FLOYD: The answer is -- and I wasn't responding. I see the paragraph you're talking about now. A maximum term -- you're talking about where it says, "A maximum term of

five years before subsequent review." We don't want to happen what evidently at least alleged to have happened with this last proxy that was in place since 1993, and there's some record evidence that seems to indicate maybe it's gotten out of line. And when they establish these proxies, we want to review that. If they have a proxy, we want to review that before five years are up.

COMMISSIONER BAEZ: In essence what we're saying is before the next contract --

CHAIRMAN JABER: Is negotiated.

COMMISSIONER BAEZ: -- is negotiated.

MR. FLOYD: Well, it may not be a contract. It may be in lieu of a contract. Maybe they weren't able -- well, they'll have a contract, but it might not have been based on a competitive, what we would call a competitive result, so yes.

COMMISSIONER BAEZ: And again, Mr. Floyd, there has to be some attention, I think we need to pay some attention to what the timing of that review is to offer the company, you know, an ability to, to implement whatever changes would, would be made to the methodology leading into a new contract.

So as a, as an outside limit the five years I don't think causes me any problem. But I think we need to kind of capture, capture the sense that, that there is going to be a review. Whether there's changes or not is left, is left to be determined, but certainly we have to, we have to allow some

time so that the changes can actually take place leading into a new contract.

COMMISSIONER DAVIDSON: Can I jump in? I'm glad you asked that question, Chairman. This clarification helped. I'm sitting here sort of jotting down thoughts that might be included in a potential motion once we get to that stage. But this is, this is not a tough problem. That clarification question was important.

I mean, I think it's our intent and we could express that it's the intent of the Commission that review of any benchmark or process would coincide somehow, whether it's six months before, somehow with the end of the contract that's subject to the benchmark or the process. And I think, one, staff would have a duty to sort of bring that to the Commission's attention. But also the company could be required in some type of -- going forward in this process with each contract it seeks to enter into, either at the beginning or the end, it can, it needs to understand it has a burden to argue why or why, why or why not the benchmark or process works or didn't work. I mean, they have a burden and we have a burden. But I think it's our intent to, to look at this every time some new contract would be entered into, but not necessarily right in the middle of the contract. We do it at the beginning, provide the regulatory certainty, they move forward. But, you know, six months before the end, as Commissioner Baez noted, or

whatever reasonable time period exists, we start looking at this again so they know when they enter into the contract, they either need to do X, Y or Z based on our review of how the process or benchmark is worked in the prior contract.

CHAIRMAN JABER: And it's the companies that are trying to find the vendor. But, frankly, I think it's useful information for anyone who's considering to participate in the process.

And Commissioner Davidson said exactly the magic words, "regulatory certainty." That's all I'm trying to achieve. I think that that takes care of the economics associated with it, it takes care of the regulatory treatment on a going-forward basis for a set period of time going forward. There are no regulatory surprises that way, there are no unexpected consumer affects that way, recognizing that the contract itself comes under scrutiny as it relates to the cost recovery for prudence and reasonableness. I understand that. That's not what I'm talking about right now.

But, Commissioner Davidson, that general framework works for me. It is a timing issue and a regulatory certainty issue. You can think, think about it. And, again, I don't know what we're going to do as this goes forward, but that's a concern I have.

The second one related to Number 1 of the agreed position. Mr. McNulty said he didn't agree with the trans-Gulf

component for the period January 1st, 2005, through March 31st, 2005, that it should equal to 26 percent. I can't remember why he said he had a disagreement with that. Can you elaborate?

MR. FLOYD: I'm not sure exactly, but I do know the reason that he -- he wants to go ahead and, and change in January of 2005 because he thinks that, you know, it's very easy to come up with a proxy beginning then and there's no reason to delay. But the reason we went with this, it was, you know, negotiated that we would allow them a phaseout of three months for that, that particular portion of it. So that was, you know, just part of staff's negotiations with the company.

CHAIRMAN JABER: Okay. Well, again, procedurally we're not bound by that. So set that aside for a moment. And the question -- it begs the question: Is it easy to establish a new methodology starting January 2005?

MR. FLOYD: Yes, it is. And I believe in your conversation with Ms. Davis she, I think, agreed that they would, if that was what Bill's testimony said, that they would comply with that, they would be agreeable to that.

CHAIRMAN JABER: I heard that, too. I heard that, too. Now in that regard, how would you change Number 1?

MR. FLOYD: Exactly the way it's worded in Mr. McNulty's testimony. And I don't remember the words off the top of my head, but I think he said basically you, you go through this process, in 2004 you would do some RFPs. And if

that resulted in competitive results, then you would use that, begin 2005. If there was some portion or all of it that couldn't be established that way, they would propose a proxy to the Commission, and then the Commission would approve that, that proxy.

CHAIRMAN JABER: And, again, I don't --

MR. FLOYD: And that's the same thing that we're saying to do for the rest, beginning in April of 2005. The stipulation says they would follow that methodology. He just backs it up three months, says, lets start this in January of 2005 rather than April.

COMMISSIONER BAEZ: And that's, and that's a question I had unclear in my mind. So -- and just to put it plainly, based on the new benchmarks there, there would be, according to Mr. McNulty's testimony or suggestion, there would be three months approximately of the existing contract that would be in jeopardy of some sort, depending on, on how they, on what side of the, of the benchmark they fall on? I mean, is that --

MR. FLOYD: Right. And I, I don't have the same concern that Mr. McNulty had about, on the contracts. I think I'm just looking at it from a ratepayer standpoint that a new proxy could be developed. And it's well -- I mean, you know, this stipulation is giving a year to phase out of the current regulatory environment. Certainly it could be started in January of 2005, and I don't see any concern there at all.

COMMISSIONER BAEZ: But I just -- what Mr. McNulty is suggesting is that as of the effective date of the new proxy or the new, the new methodology, there would still, there's still recognized a portion of an existing contract that was, that was created based on the prior methodology.

MR. FLOYD: Right.

COMMISSIONER BAEZ: So, and the new methodology would be applicable to those last three months of the existing contract. Is that -- that's what Mr. McNulty is suggesting?

MR. FLOYD: I believe so. I think he's talking about, you know, that's a contract with Progress Fuels, an affiliate, and that's a risk that Progress Fuels takes. You know, this Commission establishes what's the prudent proxy to apply to the company, and I think you, you can do that. Maybe that gets into a legal question, but that's my opinion that we have no concern about that.

CHAIRMAN JABER: And, again, I come back to Ms. Davis acknowledged that that would be acceptable.

MR. FLOYD: Right.

CHAIRMAN JABER: And the only reason I'm focused on that provision is, again, if we accept Mr. McNulty's testimony as is, he says costs are excessive, the margin is excessive. And, I mean, I know we can debate what crosses the line for excessive, but if we accept that testimony, then the sooner you put a new mechanism in place, the sooner you've addressed that

concern.

MR. FLOYD: Right. I don't personally accept that testimony. I don't agree with it. I don't agree that the word "excessive" should be applied to a Commission-approved proxy.

CHAIRMAN JABER: And let's see. The other questions on the language you've given us -- again, the last sentence on Number 1, "No regulatory action taken will be effective regarding the current market price proxy as it applies to 2004 before or for the trans-Gulf component prior to March 2005." Now I know we've just talked about whether that should be modified, but aren't they subject, aren't those years subject to true-up anyway?

MR. FLOYD: They're subject to true-up, but we're saying the proxy, whatever the proxy is, if they use that, that's the correct number.

CHAIRMAN JABER: Okay.

MR. FLOYD: I mean, we have more --

CHAIRMAN JABER: I understand. But the costs associated with the implementation of that contract, they have to go through the, the review, the reasonable and prudent review in terms of cost recovery; right?

MR. FLOYD: We're not really looking at the costs because the Commission said, don't look at costs. Look at the proxy that we've established. I thought you were just talking about general true-ups in the fuel hearing we'll still have,

but it wouldn't be trueing up this proxy number unless you, unless you vote to change it.

CHAIRMAN JABER: I'm not talking about the proxy number either.

Mr. Keating.

MR. KEATING: And just to add to that, what's trued up with regard to the market price proxy, this company, for this year's hearing they have to make a projection of what their water-borne coal transportation recoverable costs are for 2004. We've got -- and right now we're under this market price proxy mechanism. So they're going to make that projection based on what they project the market price proxy to be.

What they will true-up is when they have actual data for that year and have the actual indices to escalate the market price proxy. They will true-up the difference between what they projected the proxy to be and, and what it actually was based on the actual indices. They don't -- we don't go back and look at the costs underlying that service.

CHAIRMAN JABER: Thank you, Mr. Keating. But it's your explanation, the true-up of the actuals versus projected, that I need your assurance is not affected by this sentence in Number 1.

MR. KEATING: It was not intended to be.

CHAIRMAN JABER: Okay. And under Number 4 of the language.

COMMISSIONER DAVIDSON: Chairman, on that prior one, perhaps we could just add that sentence for clarification, that what you just explained, Mr. Keating, that the true-up between estimated and actual is not affected by this for clarification.

CHAIRMAN JABER: Sounds good, so there's no confusion later.

And on Number 4, staff, "Water-borne coal transportation service contract or market price proxy that the Commission has approved will be deemed reasonable for cost recovery purposes."

Now that on its face might contradict what you just said, Roland, so you need to elaborate on what you guys think that first sentence means. And then my second question is, will it be deemed reasonable each year in the proceeding?

MR. FLOYD: Yeah. The way I read that is just that once we set it, you know, we're not going to go back on our word and say, uh-oh, the costs, looks like, exceeded or weren't as much as the proxy, so we're going to -- I think we're just guaranteeing them they'll have cost recovery, you know, for any contract that's approved or a proxy that's approved, that that's a number that they can rely on. And unless there's some kind of a mistake, you know, or something like that -- I'm not sure whether I got the essence of your question. I think they're just saying, look, once we do this, we can rely on this for cost recovery in these cost recovery hearings. That's all

I see in it.

CHAIRMAN JABER: Mr. Keating, that ties back to the question I asked you earlier. I want to be real clear what it is we're providing if we accept the agreed position as modified, what we are agreeing to provide certainty for: Acceptance of the proxy, guidelines and an RFP process or assurances that all costs associated with that automatically will be recovered. And that's a huge consideration for me because I don't want acceptance of this agreed position to eliminate our obligation to look at costs from a reasonable and prudent review standpoint.

MR. KEATING: And I believe if it's not clearly stated in the document, that that is the intent is that no contractual costs, no -- whether, whether, whether the cost recovery be based on the contractual price or a market price proxy, if we, if we find for a particular component of the transportation that there's no, there's no competitive price that can be achieved through bidding, that in either event the Commission would approve that before it's allowed for cost recovery purposes.

CHAIRMAN JABER: I think I need you to say that one more time.

MR. KEATING: Again, this is referring to paragraph four. The intent of that paragraph -- and, and I'll have to look at it again. I hoped that, I hoped it was more clear than

maybe it is, was that -- in looking at the second sentence, "The fuel cost charged to Progress Energy pursuant to such a contract, referring to a contract entered into under the terms of this stipulation, were a market price proxy, both the contract and the market price proxy being subject to Commission approval, would be subject to Commission review for reasonableness and prudence." And with that language we, we hope to capture what I think your concern is.

CHAIRMAN JABER: You're saying the second sentence modifies what you've got in the first one?

MR. KEATING: Yes.

CHAIRMAN JABER: Let me ask you this: Why do you need the first sentence?

Let me tell you what concerns me, Roland. You said just a few minutes ago that the RFP process will get reviewed, they should be able to rely on our approval of the RFP process and the resulting contract for the sake of establishing the proxy and the contract. Set that aside for a moment.

This first sentence says, "That contract market price proxy will be deemed reasonable for cost recovery purposes." You just told me that had nothing to do with cost recovery, the process for cost recovery. It's actually the fuel costs that come under scrutiny and true-up each year, and that's the second sentence. So my question to you is maybe the first one is not even important.

MR. FLOYD: I don't know. I think, I think what the company would like to know is that once we approve these things, we approve the proxy, we approve a contract, that it can recover these costs. I mean, it's a Commission-approved proxy, and they want assurance that they can recover these in the cost recovery. So I'm, I'm not fully understanding your question. I apologize.

COMMISSIONER DAVIDSON: And, and I may not be either. Is it, is it just the intent of that first sentence that if we approve a contract pursuant to either the RFP or, in the absence of that, some agreed upon process, that the company would be able to recover pursuant to that RFP or agreed upon process. I mean, is there anything different? I mean, once we approve something, they're going -- that's how they'll recover. If it's an RFP, then they'll recover their costs pursuant to that. And if it's a process like the proxy, they'll recover pursuant to that. Is that what that sentence means?

CHAIRMAN JABER: But only to add on to Commissioner Davidson's clarification, only reasonable and prudent costs.

MR. FLOYD: Right. But I think we're going to determine when we look at that contract if it's reasonable or not, we better say something at the time they submit the contract for approval and they lay out the costs and we say we approve this. And then later on, I don't think a year later we can say, as long as they manage the contract prudently and

abide by the terms of the contract -- now I'm getting, I guess I'm in Cochran's area here, so I'll defer to him.

CHAIRMAN JABER: Isn't that, Mr. Keating, the whole purpose behind recommending a time line and a process for you all to evaluate their RFP process and how, and our review of the proxy model prior to that?

MR. KEATING: I believe that's correct. And I believe the second sentence was added there on paragraph four for this reason. There was a concern that was raised by staff that Progress Energy or, I'm sorry, Progress Fuels could enter into a contract that may have been conducted pursuant to a competitive bidding process, but perhaps they got a bunch of bids that we don't think have anything to do with the market rate, we would still want to be able to look and determine whether the costs incurred under that contract appeared to be reasonable.

CHAIRMAN JABER: And that's what I'm trying to ensure. And if you think the combination of the first sentence and the second sentence do that for us, that's fine. I'm telling you reading this cold when we got it day before yesterday and again this morning, what you just said didn't get captured for me.

The signal we should send, if we accept this agreed position, is you're going to have certainty well in advance of entering into negotiations and contracts of what the

methodology you use to negotiate should be. You should be able to, in fact we may want you to engage in an RFP process. Because as McNulty goes on and on in his testimony, he feels there is a competitive market for transportation of coal and that that should generate better prices, great. But in doing all of that, we will look at the costs that come through those contracts for reasonableness and prudence. That's all I'm trying to capture.

MR. FLOYD: I think I agree with you and probably didn't word it -- this is probably not worded exactly the way you want it. But we're open to modifying it however you think clarifies that. We're just, we're really just trying to give the company assurance that once the Commission approves these things, they will get cost recovery, which maybe goes without saying. But companies are very nervous about when they enter into contracts, and they want to be sure that when the Commission approves it, they'll get recovery. I guess that's beyond, beyond my expertise on contracts.

CHAIRMAN JABER: Mr. Keating, what threw me off were the words "will be deemed reasonable," that the contract and the market price proxy the Commission approves will be deemed reasonable for cost recovery. That's what's throwing me off. "Will be deemed reasonable" sounds like a guarantee, as you said, Mr. Floyd, and I don't, I don't necessarily agree with that.

COMMISSIONER BAEZ: Can I ask a question?

CHAIRMAN JABER: Go ahead.

COMMISSIONER BAEZ: I guess is, is there a concern -- well, I'm trying to match two things up in my head: How we review these contracts and with what frequency and under what circumstances. And take, for instance, a purchased power agreement. When you, when you approve, when a purchased power agreement gets approved, there's some kind of ongoing review. Is it anything different than what you're suggesting here?

MR. FLOYD: No. It's exactly, I think it's exactly analogous to that, Commissioner, and we do have ongoing review. But once we approve that contract, as long as they manage the contract in accordance with the terms and they charge the price, they pay the prices that are in the contract according to the escalators and so forth, there's that kind of ongoing review. But we don't go back later and say, oh, I wish we had used a different escalator here or --

COMMISSIONER BAEZ: Is that what your, Madam Chairman, is that what your concern is or is that where you're trying to be, or is it something different?

CHAIRMAN JABER: That's where I'm trying to be. No. That's where I'm trying to be.

COMMISSIONER BAEZ: Okay. Okay.

CHAIRMAN JABER: And it brings me back to that question: Why do you need the first sentence?

MR. FLOYD: It's Commission policy as far as I know, so maybe you don't need it. But I know the Commission -- I've been here 20 years and they've said these things over the years, you know.

COMMISSIONER DAVIDSON: Let me ask you this. So, I mean, is it your intent that these costs will be deemed reasonable so long as the company manages the contract in accordance with the terms of the contract?

MR. FLOYD: I couldn't have said it better.

COMMISSIONER DAVIDSON: Meaning we're not precluding ourselves, if they go outside the contract, we're not precluding ourselves from looking at reasonableness. But what we're saying is if the contract says you do one through ten and you, in fact, do one through ten, then we're going to accept that. We will deem that as reasonable because we've approved it. But if you do 12, 13 and 14, maybe not.

MR. FLOYD: Exactly.

CHAIRMAN JABER: Well, can those two sentences be reworded to capture that?

MR. FLOYD: Yes, they can.

CHAIRMAN JABER: Okay. Commissioners, that's all the questions I have for now. I've got questions from McNulty's testimony and from the closing arguments, but I'd like to give someone else a chance. Do you have any questions?

COMMISSIONER DEASON: No, I don't have questions on

the stipulation, proposed stipulation. I can just say right now I can't support it. So I just want to let -- make sure that's clear. I mean, I appreciate the time we're spending trying to fine-tune it, but my problem is more severe than simply word changes and massaging it. I have a problem with, with the process we're following here.

CHAIRMAN JABER: Okay. Well, then if it's okay with, with that, let me get to those questions then I have about the closing arguments and the substance. And that's why, Commissioner Deason, I was real clear to say upfront, while I have questions on this, I don't, I don't know necessarily what we'll do as a result of this vote. But I don't think that that discussion hurt anything.

With regard to the closing argument, staff, Mr. Twomey suggests that we don't have enough evidence in the record to understand what the baseline adjustments would be for 2002, 2003 and even 2004, if we want to make those adjustments. And, again, not knowing what the Commission will do this morning, is that a true statement that if this Commission wanted to entertain adjustments related to changing the proxy methodology, that we don't have enough testimony in the record to make those sorts of adjustments?

MR. FLOYD: Are you wanting a legal answer or -- I can give you my view, if you want to hear it.

CHAIRMAN JABER: Give me both of your views,

Mr. Floyd. I mean, I know you're going to come up with a Floyd methodology for us; right?

MR. FLOYD: No. No. You know, as I said a while ago, I know you caveat this as if we wanted to adjust 2002. I personally would have to think long and hard. I don't know how you would do it, how you would go in and get the numbers.

I think one of the things you need to be careful about is that, you know, no witness is supporting any such thing. And although some numbers may be there, you can -- and I suppose you can use them various ways. I don't think there's any basis in the record for going back and, and really establishing some penalty, if you want to call it that. That's my view on it. I wouldn't know exactly how you would do that.

CHAIRMAN JABER: I thought that -- and, again, all of this is in the spirit of just fleshing out some options. I thought that McNulty went the farthest in terms of options because he does come out and say even for the first five years of the proxy, the costs, and I understand you disagree with that, but his testimony was the costs were excessive, the margin was excessive. He came up with a number. Because I can't remember if it's confidential or not, I won't say what that number is. But he came up with a current margin number and he said on its face that was excessive. And when posed cross-examination questions, he said, but I couldn't tell you what the baseline should be.

MR. FLOYD: Right.

CHAIRMAN JABER: That's very uncomfortable as I sit here today to know a very polished, informed staff witness has told us that the numbers are excessive, you should make adjustments, you should make changes as soon as possible, but I don't know what those numbers should be. And it makes you wonder whether we should have a separate proceeding or additional evidence to delve into that a little bit more.

MR. FLOYD: Right. And that's your -- you know, it's up to you. But I can tell you, and you know this from working here, that, you know, Bill reports to me, and I totally disagreed with a lot he had in his testimony. But we allow staff room to give their professional opinions on things.

CHAIRMAN JABER: Yeah. And somehow that gave his testimony greater weight, Roland. I don't know.

MR. FLOYD: That's fine.

CHAIRMAN JABER: Let me let you finish your thought, and then Commissioner Bradley has a question.

COMMISSIONER BRADLEY: A statement.

MR. FLOYD: No. I would just -- I'm sorry. I guess I'm through.

CHAIRMAN JABER: Okay. Commissioner Bradley.

COMMISSIONER BRADLEY: I don't, I don't have a question. I have a statement.

CHAIRMAN JABER: Do you want to wait then until we

get rid of the questions? It's up to you.

COMMISSIONER BRADLEY: Yeah. No. I'll wait until after we entertain all the questions and then I'll make a statement.

MR. KEATING: Madam Chairman, could I sort of add my response as well?

CHAIRMAN JABER: Okay. Go ahead, Mr. Keating.

MR. KEATING: You had asked if we could both give our response on what, what evidence we have.

CHAIRMAN JABER: Go ahead, Mr. Keating.

MR. KEATING: As I recall, we do have through Mr. McNulty's testimony and through our auditor's testimony, we do have cost information for 2002. I mean, that -- and we do have testimony from Bill that he wouldn't expect things to change dramatically. That may serve as a base.

Now what -- I'm not sure we have anything real definitive on what sort of margin is appropriate above that base. But you do have the cost information for 2002 that's, that's, I think -- I can't remember on cross-examination of Mr. Portuondo if he challenged any of Bill's numbers there, but I think they're largely unchallenged as costs.

CHAIRMAN JABER: Yeah. As I recall Mr. Portuondo's testimony, you all can correct me if I'm wrong, he said, while we may not agree with every single thing Mr. McNulty has said, in the spirit of trying to reach a compromise, we haven't taken

issue with all of these. And that's helpful, too. I have to believe that if there were, if there was a strong disagreement with the costs, we would have known that more affirmatively.

What about for 2003? Do you feel like the testimony in the record supports enough information to make an adjustment there?

MR. KEATING: I don't know. I don't know. I think we -- I think what we have is the 2002 cost data. The 2003 may be different. I don't know. I'm trying to recall. I don't believe there's any extensive discussion on whether those costs would be the same. I know Mr. McNulty said that he didn't believe there would be any dramatic change in his margin calculation for the next few years, which would tell me that the costs and the market price proxy are probably going to, in his opinion, be relatively the same position they are now or have the same relative difference. But, but there is no, there's no audited cost data for 2003.

CHAIRMAN JABER: Okay. And then my final question goes to Ms. Davis's closing argument. She, I think, acknowledged that making adjustments back to 2002 was not retroactive ratemaking, but the retroactive nature of adjustments would be fundamentally unfair in her opinion to the company who's entered into contracts and, and negotiations based on that '93 proxy model.

My question to you, I left you with a thought

yesterday, is does this constitute retroactive ratemaking? Have you had an opportunity to take a look at that?

MR. KEATING: I have, Commissioner. And after looking at the applicable case law and considering the market price proxy mechanism, I believe that going back to 2002 and 2003 today would amount to retroactive ratemaking.

CHAIRMAN JABER: Would amount?

MR. KEATING: It would be retroactive ratemaking, and I'll explain.

In general -- generally speaking, the rule on retroactive ratemaking provides that a rate setting body like the Commission cannot, when it sets rates, adjust for past losses or gains to either the utility or the consumer. The idea is that the Commission only looks forward when setting its rates.

The basis behind the rule against retroactive ratemaking is to provide certainty. And we've had some discussion about providing certainty going forward with what's in the stipulation this morning. It provides certainty to both the utility and the consumer. It goes both ways.

Now the market price proxy mechanism is, is unique from other fuel cost recovery -- other fuel costs that go through the clause. Typically, this is the law in Florida and in other jurisdictions, the rule on retroactive ratemaking does not apply to fuel cost recovery proceedings or these adjustment

type proceedings because it's understood by both the utility and the consumer going in, just as it is with an interim rate setting procedure, that those rates that are set are subject to true-up, that the costs will be reviewed for prudency and are subject to true-up.

The case in Florida that, that set that precedent here is Gulf Power versus PSC in 1986 where the Supreme Court upheld the disallowance of costs incurred pursuant to a contract that Gulf had entered that the Commission found was imprudent.

CHAIRMAN JABER: You confused me on something you said. Let me interrupt you.

You think the adjustments that go through the clause don't constitute retroactive ratemaking. You're talking about the true-up part doesn't constitute retroactive ratemaking.

MR. KEATING: That's correct.

CHAIRMAN JABER: But somehow adjustments, adjustments for in this case 2002 and 2003 would --

MR. KEATING: Only for -- and I'm not saying that all the costs -- almost every other cost that goes through the clause is subject to that true-up mechanism. The market price proxy mechanism is different. It's not a typical fuel clause item because the market price proxy by its design is deemed the utility's reasonable cost.

Unlike almost every other cost that goes through the

clause, Progress Fuels' costs for water-borne coal transportation service provided by Progress Fuels is not, under the market price proxy mechanism, subject to an annual, to an annual prudence review. Progress Energy's cost is the market price proxy. And what we do in each year's fuel hearing, as we discussed before, is determine whether the market price proxy was properly calculated pursuant to the original 1993 stipulation between the utility and the consumer advocate at the time. Any true-up, as we discussed, is to ensure that the proper calculation took place based on the actual indices that escalate the market price proxy. That was the intent of the market price proxy; it was to establish a simple method to determine the reasonableness of an affiliate, the cost associated with an affiliate transaction.

In researching the issue, I did find that to varying degrees different jurisdictions have carved out an exception to the retroactive ratemaking rule for extraordinary gains or losses. Now Florida has not adopted such an exception. The closest that Florida has come was in a 1979, 1979 case, Richter versus Florida Power Corporation, where the Florida Supreme Court upheld the mechanism established to refund to ratepayers past rates paid as a result of an illegal procurement scheme devised by the utility's consultant.

Now here with the Progress Energy market price proxy there's no hint of illegality, so I think it's clearly

distinguishable from that case. And any gain that was achieved was as a result of, one, the market price proxy mechanism that was established by stipulation and, two, Progress Fuel's ability to keep its costs below that proxy.

All that said, there's no case directly on point with the facts of the present case to allow us to easily determine whether adjusting Progress's recoverable amount for coal transportation service provided by its affiliate in light of the existing market price proxy amounts to retroactive ratemaking. But it's my opinion that the concept of retroactive, the rule against retroactive ratemaking, that is to provide certainty to the consumer and to the utility on what the rate is to be paid and what the rate is to be recovered as applied to the market price proxy mechanism would make reaching back to 2002 and 2003 to date retroactive ratemaking.

CHAIRMAN JABER: Commissioners, take us forward. Commissioner Deason, what --

COMMISSIONER DEASON: Let me follow up on that --

CHAIRMAN JABER: Go ahead.

COMMISSIONER DEASON: -- since we're on the subject of retroactive ratemaking.

Refresh my memory. When was this issue first raised concerning Progress Energy's water-borne coal transportation cost and the adequacy of the proxy?

MR. KEATING: It was raised -- I believe it was first

raised after it was originally established in the 2002 fuel hearing, last year's fuel hearing. That was raised as an issue by --

COMMISSIONER DEASON: It was established as an issue, it was listed as an issue for the 2002 hearing which took place approximately a year ago.

MR. KEATING: Correct.

COMMISSIONER DEASON: And the decision was to basically defer it to until this year's fuel proceeding; correct?

MR. KEATING: Right. And my recollection was that staff had raised the issue. Staff had conducted some discovery and realized that if we were going to, to provide any sort of recommendation, we would need additional work on the issue. We came to an agreement that the issue would continue to be reviewed through the fuel docket. There was no, there was no indication one way or the other whether it should be modified or, or not. It was simply a matter of staff and then the parties, if they wished, to continue to review that issue.

COMMISSIONER DEASON: Okay. And it was raised by staff. It was not raised by any other party.

MR. KEATING: That's correct.

COMMISSIONER DEASON: Madam Chairman, I, I respect the legal opinion we've just heard, and certainly I'm not an attorney, but I disagree with it.

I think that what we have in front of us here is a question of -- I don't think retroactive ratemaking applies to fuel adjustment, period, and I'd hate to set a precedent that says that it does. But what we've got to do is do something that's reasonable, and I think that there should -- the utilities we regulate should be able to have reasonable reliance on our decisions. I think the fact that we established a proxy, that that, that it should, we should abide by it until we change it. But I think the fact that the issue was raised in 2002 put everyone on notice that we have questions, we want to review the matter, we think that there may be some faults, we think there may be a better way of doing it.

So I would have no problem retaining jurisdiction over these amounts for 2003 forward because it was the 2002 proceeding when it was raised as an issue. We decided to defer it. I would -- not because we are prohibited by some strict interpretation of retroactive ratemaking, I just think it's bad regulatory policy for us to try to continue to assert jurisdiction all the way back to amounts that were recovered in 2002.

Now I think the Commission has some discretion and flexibility as to whether we want to retain jurisdiction over these amounts in 2003. I think we, we certainly can because of the fact that the issue was raised by our staff during the time

period when we were establishing fuel adjustment recovery factors for the year 2003. So to an extent I agree with Mr. Keating, but I think it's not so much a strict legal interpretation as what's good, sound regulatory policy. So that's where I would be.

I would -- and I indicated earlier that I had, I had problems with the stipulation. I think that's -- I agree that's probably a bad term to apply to this. This is a position on an issue that two parties agree to. That's all it is.

But the problem that I have -- first of all, I want to state right here that I want to commend staff. They were the party that raised this issue to begin with. I think that is a fact that we should not fail to recognize. They raised the issue. They carried the burden in this proceeding to try to come -- they sponsored a witness, a very capable witness who did a very good job on the stand, I want to congratulate Mr. McNulty, came forward, pursued it. I think our staff has done an outstanding job.

The position they've taken with this, this two-page resolution of the issue, I think there are a lot of good things in here. The problem that I have goes back to something that we discussed yesterday, and that is that the burden lies on the company. I would feel much comfortable if the utility came forward with the witness and said, we agree there are problems

with the proxy, here is how we propose to do it, and it would clearly be their burden. Our staff, the consumer advocates, the Commission question the witness on their methodology because it is their burden.

I know that -- and I want to commend Progress Energy, too, for coming forward, recognizing that there may be a legitimate problem with the proxy we've been using, working with our staff, coming forward with this. I'm not being critical of what's in here. I would just prefer that the burden be squarely on Progress Energy, they sponsor a witness, they meet their burden, we come forward with a, a process, with a proxy or a bidding process or whatever it's going to be that we can have confidence in, they can reasonably rely upon, give the consumer advocates the opportunity to fully explore that, not through a staff witness but through the company witness who is sponsoring it for his own company saying this is the correct methodology. That's what I'm more comfortable with.

Now to get there we're going to have to have another hearing and have that company witness sponsor that. I don't know that we have to wait until November; maybe we can do it sooner. I think the sooner, the better. I have -- as a regulator I am uncomfortable continuing to retain jurisdiction over monies for long periods of time because I think it creates uncertainty, which is bad for customers, it's bad for the company, it's bad for investors. Uncertainty is bad.

At the same time, we have the responsibility to protect customer interests. That's why I think that we can retain the jurisdiction over the 2003 amounts. It may be at the end of the day that we determine that the, that we do not want to require any of those monies to be refunded. But that's, that's -- I would rather make that determination after we've heard the company witness and hear their sponsorship of the correct methodology. That's what I would prefer.

CHAIRMAN JABER: Let me just say, Commissioner Bradley, you want to make a statement. I've been requested to take a, just a short five-minute break. Let's do that. We're going to come back with your statements, and I'll react to both. Five minutes.

(Recess taken.)

CHAIRMAN JABER: Let's get back on the record.

Commissioner Bradley, you asked to make a statement.

COMMISSIONER BRADLEY: Yes. And let me preface my statement with this comment. It's just a statement, and I'm open for suggestions or any modification that a Commissioner might want to, to make. And I've listened to all the discussion that has occurred between staff and my fellow Commissioners, and pretty much what I've concluded is this: Basically I don't know why we need to decide how we're going to determine water-borne coal transports today. In my opinion, the establishment of a new docket would allow us time to fully

establish a record upon which we can make a fully informed decision.

Specifically, we on the Commission are charged with setting just, reasonable and compensatory rates. These rates must be just and reasonable for both the utility and the ratepayers, which requires us to balance the interests of all groups. It is obvious to me from the testimony we heard over the last two days that the current market price proxy system in place for Progress Energy's water-borne coal transportation system is broken. It is not obvious to me from the record that we -- not that we, but what -- that is, it is not obvious to me from the record what can be done to fix this system.

As a matter of fundamental fairness, I'm not comfortable going back to the years 2002 and 2003 and modifying the amounts for which Progress seeks recovery. For good or ill, all the parties to this docket established a system which the Commission put in place through an order issued in 1993, which has not been modified. On the other hand, going forward I know of no reason why we cannot modify the order today to prevent this broken market price proxy system from distorting future costs. Requiring development of a new procedure to take effect in 2004 will provide fairness to both Progress Energy and its ratepayers.

I am aware from the testimony and the record that Progress Energy has a contract in place which runs through

2005. It has been my experience, however, that Florida utilities generally include regulatory out clauses in their contracts, and in any event, the water-borne transportation contract is with an affiliate of Progress Energy Florida. I'm not convinced, however, that this matter should be addressed in the TECO coal transport docket, which we broke out of this hearing earlier. I believe the issues between TECO and Progress Energy are sufficiently different to warrant the establishment of separate dockets for each; therefore, I would make the following motion, subject to comment and modification from my fellow Commissioners.

Number one, that we allow Progress Energy Florida recovery of the water-borne coal transportation costs as are established in this record for the years 2002 and 2003.

Number two, that we modify Order PSC-931331-FOF-EI, which established the market proxy system such that the current market proxy system will cease to operate beginning January 1st, 2004.

Number three, that we direct staff to open a new docket to establish a new system for calculating the just, reasonable and compensatory rate for Progress Energy-Florida's water-borne coal transportation, which system will begin on January the 1st, 2004, and continue for such a term and under such conditions as this Commission will establish a subsequent order in that new docket.

CHAIRMAN JABER: You want some feedback?

COMMISSIONER BRADLEY: Yes.

CHAIRMAN JABER: Okay. Let me let other Commissioners react, and then I'll -- Commissioner Davidson.

COMMISSIONER DAVIDSON: Thank you, Madam Chair.

I, too, have listened closely to all the parties, all the testimony, all the evidence here. I believe the Commission has clearly the responsibility, the fiduciary obligation to the public to change any previously approved benchmark or proxy mechanism when warranted. It's been over ten years since this proxy has been implemented and reviewed. It was entirely appropriate for staff to review this proxy. They did a great job and, as a result, it seems that it's clearly time for some type of change.

I want to talk about the proxy for a minute. The Commission has, in my view, by use of this proxy said that any amounts incurred or recovered through strict application of the proxy are reasonable. They're reasonable not necessarily because folks agree with the underlying facts and circumstances of the cost, but they're reasonable because they comply with a Commission-approved, binding and currently in effect proxy; in effect a social contract that this Commission entered into. We can all sit here and disagree with, with the cost, but we can't disagree that that proxy is a binding authority of this Commission that has the weight of, I would say, a judicial

opinion. It is binding. The companies rely on it. Do we need to change it? Yes.

I would note that under this proxy the company carried not just the benefit of recovering more through the proxy, but the company also carried the risk that their costs would exceed the proxy. This is exactly the reason for the use of a proxy. But for the proxy, we don't know where Progress would be on its water-borne coal transportation cost. Maybe the cost would be the same, maybe the cost would be lower without the proxy, maybe the cost would be higher. We just don't know.

Commissioner Deason pointed out that perhaps through the use of the proxy the company has had an incentive to reduce costs. Now are those costs higher than some benchmark? Perhaps yes. But are they within the terms of the proxy? The evidence indicates yes. I have to say that as I sit here from a, from a legal standpoint, from the perspective of trying to give regulatory certainty, I agree with Mr. Self (sic). I think we would pillage the notion to sort of go back on something that we have approved and is binding to say, well, we don't really like how it's worked out over the past few years, so we're going to modify it with 20/20 hindsight.

I've listened to Commissioner Bradley's motion, and I agree with prong three, that we do need a new system. I agree with most of prong one. I would modify it to extend

application of the proxy to any water-borne coal transportation contracts entered into prior to the date that we say this proxy is no longer applicable. So if that would be today's date, it would be if there are contracts entered into for water-borne coal transportation on or before, well, let's say prior to November 14th, the proxy would apply. If there is a contract entered into tomorrow, the proxy would not apply. We would just default to, to a nonproxy case and the company would have the burden of, of, of establishing that. So I would -- that would modify prong two to the extent that the proxy would cease to operate. It would be in effect for any contracts in effect now and it would cease to -- it would not be in effect for any contracts entered into today or thereafter, including in all of 2004. So if there is a new load, if there's a new water-borne coal transportation service that Progress needs to enter into on January 1st, the proxy would not apply. Rather -- and I suppose until a method is applied, it would be a default, a default standard for cost recovery.

I do understand sort of the equities of this case. But, again, it's easy for us to sort of focus on one side because of the environment we're in. Had the market been different and had the cost exceeded the proxy, we would have been in a completely different situation. I suspect we would have heard from the company, you know, this isn't fair and, and we need to be able to recover more. And I hope this Commission

would have, for the very same reasons that I've articulated today, said, nope, the proxy is applicable, this is where we stand, this is the, what we entered into, and until we change it, this is what you're bound by.

CHAIRMAN JABER: Let me get some clarification from you. Extend the application of the proxy prior to today's date; anything entered into before November 13th, November 14th, would apply throughout the entire term of the contract. Okay.

Commissioner Deason and then Commissioner Baez.

COMMISSIONER DEASON: Well, I just have a question on the, Commissioner Davidson's amendment or modification.

When you say extend application, you're saying extend application of the proxy, or you're saying that you would recognize that whatever the contract costs are, that those would be recognized? Which is it?

COMMISSIONER DAVIDSON: And perhaps I was unclear. I apologize.

It would be to allow the proxy to be the guiding mechanism of cost recovery for contracts entered into prior to today. Any contract after today is not subject to the proxy. So rather than -- the notion is to try and tie, as Mr. Self (sic.) was speaking of early on, the notion of the proxy or the benchmark to a contract that's entered into under that proxy or a benchmark.

So if there is a new contract that would be entered into today, tomorrow or January, today, tomorrow -- I apologize, Mr. Floyd -- today, tomorrow, or January, that the proxy would not apply. It would only apply to contracts entered into before today.

COMMISSIONER DEASON: So the, the --

COMMISSIONER DAVIDSON: The measure of reasonableness would be under the proxy.

COMMISSIONER DEASON: The reasonableness -- the test for reasonableness would be under the proxy, and it would be assumed to be reasonable for recovery of transportation under any existing contract until that contract expired.

COMMISSIONER DAVIDSON: Yes.

COMMISSIONER DEASON: So that would have the effect of continuing to use the proxy as late as March 31st of 2005?

COMMISSIONER DAVIDSON: For a contract entered into prior to our decision to say the proxy is no longer valid.

COMMISSIONER DEASON: Well, the next contract -- there is -- there's at least one contract that does not expire until March 31st, 2005. Are there contracts that go beyond March 31st, 2005?

MR. KEATING: It's our understanding that the March 31st, 2005, is the contract that ends the latest. I don't know of any others and I don't think any others were identified in the record that go beyond that point.

COMMISSIONER DAVIDSON: And if there was no proxy in effect from November 14th forward, is it your understanding, staff, that if there was no proxy, that just a default standard would, would apply and staff would just have to evaluate reasonableness and prudency the best way possible?

MR. KEATING: The reason I pause as I think through this is there's a layer in here because we've got -- the contracts you're referring to are the contracts between Progress Fuels, the affiliate, and the actual suppliers, and there's a contract between Progress Energy and Progress Fuels, as I understand it, that says that Progress Fuels will be paid whatever the market price proxy rate is.

COMMISSIONER DAVIDSON: Well, let me ask it this way. Assuming the proxy is not in effect after today and, therefore, it won't apply to any contract between anybody that is not signed as of today, if this approach was adopted, how would you assess reasonableness and prudency?

MR. KEATING: Well, I guess to follow up on what I was going to say before, if we look at --

COMMISSIONER DAVIDSON: Well, give me -- let me -- I mean, does the Commission have a default standard? I mean, does the Commission assess reasonableness and prudency generally?

MR. KEATING: The proxy --

COMMISSIONER DAVIDSON: Yes or no on that.

MR. KEATING: I'm sorry?

COMMISSIONER DAVIDSON: Yes or no to that, to costs generally.

MR. KEATING: I'm sorry. Could you please restate that so I can make my yes or no the right yes or no?

CHAIRMAN JABER: Okay. The question, the question, Cochran --

COMMISSIONER DAVIDSON: Assuming there's no proxy --

CHAIRMAN JABER: Or do you have a default --

MR. KEATING: Assuming there's no proxy, we would judge the costs incurred by Progress that it pays to Progress Fuels to procure these services like we would any other costs.

COMMISSIONER DAVIDSON: That's all. I mean, that's what I needed to know.

MR. KEATING: Okay.

CHAIRMAN JABER: Let me ask you, Commissioner Davidson, as a follow-up in trying to just evaluate, you know, the support for the modification.

Does your idea -- is your idea affected at all or your concern addressed if a hearing could be scheduled such that it doesn't have, the issue doesn't have to wait until November?

The reason I'm asking that, Commissioner Davidson, I think I understand what you're trying to accomplish, which is providing certainty on a proxy, right or wrong, that was

approved in an order respecting contracts that have already been put in place because of that negotiation due to the proxy. Can we accomplish the same thing -- I'm looking for a way to, to uncomplicate the issues in terms of timing. Can we accomplish the same thing if a hearing could be held April/May and a final decision shortly thereafter? I mean --

COMMISSIONER DAVIDSON: Well, the hearing would go to the Issue 3, wouldn't it, the docket for the new system, opening a docket for a new system? I think perhaps having that --

CHAIRMAN JABER: But couldn't it -- yes, that's the way Commissioner Bradley posed it. But in terms of feedback, couldn't that proceeding also delve into how the order should be modified? I guess all along what I thought Mr. Twomey and others were advocating and Commissioner Bradley in the spirit of what he was articulating is that the order should be modified. How we should modify it could also be subject to a new proceeding.

COMMISSIONER DAVIDSON: Well, I don't, I don't -- I'm not troubled with ruling from the bench on the first two prongs of the motion today. I do think that we need to get to the new system as soon as possible. But my, my approach would be that for anything signed and dotted as of yesterday basically, November 13th, November 14th, I think it -- I don't want folks to rush out and sign something today, so as of yesterday.

Anything signed as of yesterday would be subject to the existing proxy. The existing proxy doesn't have to be modified in order to apply to those contracts that are signed, sealed and delivered. Anything not signed, sealed and delivered is subject to just the ordinary review, and how that's done will have to just be addressed in a case. But the first two prongs, what's covered by that, my view is we don't need a hearing on. I don't think -- I guess my modification to prong 2 would be we're not modifying the order. We're just saying it is not applicable to contracts entered into November 14th or later. So if they enter into a contract January 1st, the order doesn't apply.

CHAIRMAN JABER: Okay. Then I don't think we're saying different things. The actual modification of the order then would be delved into in a proceeding.

See, here's, here's why I'm asking. The order --

COMMISSIONER DAVIDSON: But not the decision on, on this case as it pertains to contracts in effect now. The company can walk away knowing that for any contract signed as of yesterday, this is what will happen. For any contract signed today or later, who knows. It's up in the air.

CHAIRMAN JABER: Now let me ask you a question about the 2003 revenues. In the spirit of what you just said, providing certainty with regard to the proxy, let's separate that out from the issue of costs recovered associated with

implementation of the negotiations and the proxy.

2003 costs are subject to true-up. I am completely comfortable with exercising our jurisdiction to capture the 2003 revenues. Commissioner Bradley spoke of not wanting to do that for 2002 or 2003. I'm comfortable with doing it for 2003.

Have, have you spoken to that?

COMMISSIONER DAVIDSON: Well, I believe Mr. Floyd answered that earlier. His answer -- I would take his answer, and that is for this process there isn't really a, sort of a true-up. But the question is whether or not what is sought complies with the terms of the proxy. Either it does or it doesn't. So there's sort of a true-up within the terms of the proxy, but, but that proxy amount itself doesn't change.

COMMISSIONER DEASON: Let me see if I understand.

CHAIRMAN JABER: Commissioner Deason.

COMMISSIONER DEASON: As I understand what you're trying to accomplish, and I'm not supporting or criticizing, I'm just trying to understand, is that the effect of what you're proposing would be to continue to have the proxy standard for cost recovery apply until 12/31/05, I mean, until March --

COMMISSIONER BAEZ: 3/31/05.

COMMISSIONER DEASON: I'm sorry. 3/31/05. That's the effect of your --

COMMISSIONER DAVIDSON: If that's the last -- if

that's the termination or expiration date of the contract, that would be it. And if there are other contracts that expire sooner, then it would be sooner. And if there are new contracts, it wouldn't apply at all. So it's tied completely to the expiration of a contract entered into while the proxy was a binding order of this Commission.

COMMISSIONER DEASON: And I think that has the effect of continuing to use the proxy until 3/31/05. Is that correct, staff, or --

MR. FLOYD: Commissioner Deason, I would like to say this --

COMMISSIONER DEASON: Can you answer my question, yes or no? Is it -- I'm just trying to understand. Is that the effect of what Commissioner Davidson has proposed?

MR. FLOYD: Yes. Yes. That's true.

COMMISSIONER DEASON: Okay.

MR. FLOYD: The point I'd like to make on your proposal though, I'm not sure there's enough in the record to do what you want to do. In other words, it sounded kind of simple, but the proxy to Progress Fuels is one number. Progress Fuels has several contracts in there, but that proxy, of course, was originally designed based on several components, maybe four or so. And so now you've got to figure out how you unwind that or prorate it or whatever, and I think we get back into what Commissioner Deason was saying. We may need some

additional evidence or something to really -- or at least we're going to have to rehuddle and decide how we would --

COMMISSIONER DAVIDSON: Well, it may be in there we expect a Floyd methodology. I'm just trying to -- I'm not comfortable extending the proxy to new contracts. I'm not comfortable extending it to new contracts.

MR. FLOYD: I understand. But I'm just saying as contracts expire though, how does that affect the proxy? I don't know as I sit here. Maybe we could huddle someplace and decide exactly how you would unwind it. Because the proxy is one number, as I understand it, and then you'd have to do some kind of proration, I guess, which --

COMMISSIONER BAEZ: Why, why --

MR. FLOYD: And, again, I'm not a witness here, so I can't testify how this should be done.

COMMISSIONER BAEZ: Can you -- Mr. Floyd -- I'm sorry, Madam Chairman. I've got a question.

CHAIRMAN JABER: Commissioner Baez.

COMMISSIONER BAEZ: Yeah. This is the first I've heard of proration, and I want you to explain that to me. What is it that you're referring to?

MR. FLOYD: Well, I can't explain it, I can't explain it because I don't know exactly how, what Commissioner Davidson's plan is. I just threw that out as you may have to do some kind of proration. I don't know.

COMMISSIONER BAEZ: Well, it seems, it seems to me, and, Commissioner Davidson, you can correct me if I'm wrong, and I'm going to ask a legal question after, but it seems to me that all he's suggesting, if I understood it correctly, was that no existing contracts that the -- that the market proxy not be changed for any existing contract. And we've said that the last existing contract or the existing contract with the greatest duration remaining is March 31, '05. All he's suggesting is to try and hold every, all existing contracts, hold them as they are based on what is in effect now.

MR. FLOYD: I think Cochran wants to speak to that. But I'm just saying I don't think the proxy applies contract by contract by contract.

MR. KEATING: The proxy applies to the contract -- it applies to the relationship between Progress Fuels and Progress Energy. Progress Fuels has, has separate contracts for each component of its water-borne transportation service. Those are the, those are the separate, separate contracts that end at various times.

Now I think, I think three of the four of those or at least two of the four of those end at the end of 2004. There's one that carries on for three months into 2005. The market price proxy is not set for each of those components, and that's why Mr. Floyd said you may have to prorate three of those in.

COMMISSIONER BAEZ: I see what you mean. Let me ask

you, let me ask you this, and this kind of dovetails it to some of the concerns that I had hearing the rest of the Commissioners' comments. Is it legally possible for us to drive a stake in the ground today, which I think there's some, there's some sense of it, and put the company on notice that, that any, any renewal contract, whether it's a subcontract or, you know, a portion, one of those legs that you were talking about, would be subject to whatever the result of possibly -- would be subject to the result of whatever this proxy or whatever this new methodology is modified to? Can we legally do that?

MR. KEATING: Could I get you to repeat the question? I'm just not sure I completely understood.

COMMISSIONER BAEZ: Okay. It doesn't sound like we have enough to modify today to say this is what we want it to be or this is how we want it to be. For that reason, there's been more than one suggestion of a separate, of a separate proceeding in order to define what that modification is going to look like, what that new order is going to look like.

Can we -- could we today say whatever, again, based on the, based on the notion that all existing contracts are held in place without change, any new contract would be subject to whatever the result of that additional proceeding would be?

MR. KEATING: I think that's fair. I think that, I think that puts the, puts the company on notice that whatever

new contracts it enter into are going to be subject to this.

COMMISSIONER BAEZ: To this to be determined? I don't --

MR. KEATING: This new procedure.

COMMISSIONER BAEZ: Let me, just -- Commissioner Deason, just let me --

MR. KEATING: If I understand what you're asking correctly, I think the answer is yes.

COMMISSIONER BAEZ: It sounds like you understand what I'm -- but I'm sure Commissioner Deason is seeing it, seeing something that I'm missing.

I did want to say this as to the 2003 -- I mean, I heard what you said, Commissioner Deason. My concern, my concern is this. Yes, they're subject to true-up. I think there's a misunderstanding or there's some miscommunication between the staff and the Commission as to exactly what is applicable to that or what exactly is encompassed in the word "true-up" as it pertains to these market proxy contracts.

The 2003 revenues, maintaining jurisdiction over them, I have a problem with for this reason. I'm not sure that our discussion in 2002 when we decided to defer evaluation of the market proxy is enough in my mind to constitute putting the, having put the company on notice. I think it's more -- you know, we can argue whether it was implied or not. I'm just not comfortable saying I implied putting revenues or putting

amounts at risk or under, you know, subject to. So I have a concern there, which is why if we had to vote on it, I guess I would support extending it, you know, holding, holding the 2003 outside of whatever this, this is.

Going a little further, I tend to agree -- I'm also uncomfortable with just saying, well, you know what, the contracts were with affiliates, so we don't have to, we don't have to treat them as such. I have a concern with that.

I think the fact that, you know, if it's a contract, it's a contract. If we're calling it a contract, then let's treat it like that. I think we owe that, that creation some kind of, some kind of duty to, to maintain it viable, which is why I think I would support holding the, the idea of holding the contracts, assuming we can do it functionally, the idea of holding whatever existing contracts are out there whole or keeping them under the current regime.

I think we do need a new docket because I think there is much information that can come in so that we can really decide what the best methodology is. If it turns out to be a new market proxy, we're going to need new numbers. If it turns out to be an RFP process, I think we need to flesh that out as well because that creates a whole -- I mean, we've been through RFP process questions before. I think we need to clear some of those similar questions up.

But that's what -- so I guess what I'm suggesting is

that assuming we can drive a stake in the ground based on what Mr. Keating said, I'm not sure -- I don't know if that's acceptable to, to what Commissioner Davidson is seeking to modify, but I think I could support something like that, assuming it was legally supportable.

CHAIRMAN JABER: Okay. Commissioner Deason.

COMMISSIONER DEASON: First of all, let me say that I think your points made on the year 2003 are very well made. I have some difficulty, too. 2003 is a difficult question for me. I came down on the side of at least retaining jurisdiction over that until after the conclusion of the additional proceeding to resolve that. I understand what you're saying, and the fact that we identified an issue may not be sufficient. It's only now that we've had testimony, we've made a decision that we think we're convinced that there's a problem with the existing proxy and we need to change it. So it, it could be argued that if we're going -- that we're not changing the proxy or we're not actually making a decision to change the proxy until now so that 2003 recovery should be under the existing proxy. I understand that.

The difficulty I'm having is that we seem to be putting emphasis on the contracts and tying everything to contracts and recovery under the contracts. The use of the proxy, I think, is not tied to the contracts. It's tied to a period of time for a given year. The -- that's the reason we,

we made that, that split is because the contracts were with affiliated companies, we weren't confident in the contracts themselves, we could depend upon them. We wanted something that could best capture market forces, so we came up with a market proxy that would be applied to the transportation services that were rendered under contract, but the proxies are not tied to the contract period of time. I think the proxies, we've used those as just calendar years. Those are calendar year concepts. Am I mistaken on that?

MR. FLOYD: Correct.

COMMISSIONER DEASON: Okay. So the fact that we broke away and we started using a proxy, I think that that was, I think it was a good thing. It involved market forces. I think it gave an incentive for companies to go and sign the very best contracts they could because if they beat the proxy, they keep it, and if they, if they don't beat the proxy, they eat it. I mean, that's, that's a pretty good incentive to go out and sign the very best contracts you have.

So I don't see -- I don't see the nexus or the requirement to continue applying the existing proxy based upon the termination of existing contracts. I don't see that. Now maybe I'm missing something, but I don't see that. And I think it could cause some calculation problems as well, as staff indicated. That's why I would prefer that if we're going to change the proxy, that we do it on a calendar-year basis, that,

following Commissioner Baez's argument, that we would find that 2002, 2003, those costs are finalized except for normal true-up amounts, that is, comparing actual to projected, those type things, not comparing costs to proxy amounts, and that we go ahead and put the stake in the ground and indicate that for '04 that we may, we may -- we're going to have to come up with a number, a projected number to base '04 recovery factors upon, but make it understood that the actual true-up for '04 is going to be based upon the new methodology that comes out of the new docket. That's what I would prefer.

COMMISSIONER DAVIDSON: The, the nexus, I think, between the proxy and the contracts comes through the notion of cost recovery. But for the proxy again, we don't know where the company would be in terms of its, of its cost. I mean, it has utilized this proxy in entering into these contracts; perhaps it would have done the exact same thing, perhaps not.

For me it's a clear legal stake to tie it to a contract that was subject to the proxy when it was entered into. And to subject contracts after that date, even though there may be overlapping in time with contracts that are subject to the proxy, not to the proxy.

COMMISSIONER DEASON: See, the contract -- as I understand it, the contract is not subject to the proxy. It's just that whatever services are provided under the contract when it comes to cost recovery, the tool that we use to analyze

the reasonableness of that is the proxy. I don't think --

COMMISSIONER DAVIDSON: I understand.

COMMISSIONER DEASON: I would be surprised if that contract even mentions the term "proxy." It's a contract provision of transportation services and they agree on a price. And however that price is determined, they determine it. But it's not based upon our proxy.

MR. KEATING: I think the contract between Progress Energy and Progress Fuels, that's the one that says Progress Fuels will be paid the market price proxy amount, whatever that may be.

COMMISSIONER DEASON: I'm talking about the ultimate provider of service.

MR. KEATING: Right.

COMMISSIONER DEASON: Okay.

MR. KEATING: The supplier contracts, I can't imagine, I don't recall, but I can't imagine they refer to the market price proxy.

COMMISSIONER DEASON: Yeah. I have no problem with the agreement between two affiliates being based upon our proxy, but that's not really the real substance here. The substance is the contract between Progress affiliate and the actual transportation provider. That's the concern, it seems to me. And I don't think that contract is based upon our proxy. I would think Progress, in fact, they would have the

incentive to, to sign the very best contract that they could because they're at risk. If they don't meet at least -- if they have to pay more than they're going to recover in the proxy, they have to eat it. And if they, and if they get the service for less than they're going to recover under the proxy, they're just being good businessmen. They're, they're reacting to the incentive that the proxy places out there for them.

CHAIRMAN JABER: Commissioners, let me try to move this along. We had, Commissioner Bradley, a motion, but you wanted some feedback, so I don't know that we've officially articulated it as a motion.

I think we heard Commissioner Davidson throw out an idea as an amendment to it. Let me react to that and say if we just need to vote up or down on that original motion, we will. And if it fails, we'll take, we'll take a second motion up.

Let me back to the very, go back to the very beginning and say I agree with Commissioner Deason, and I am a lawyer. I don't think this does rise to the level of retroactive ratemaking to make -- whether we make adjustments to 2002 or 2003 or hold revenues subject to refund, I don't think that that constitutes retroactive ratemaking. I don't think it applies in a fuel cost recovery proceeding. And you said yourself there isn't a case directly on point. Maybe we find out through this case. I don't know. So that, that -- it's good we addressed it. I don't have that concern.

I also don't have a concern with, for the 2003 revenues, exercising jurisdiction in that regard because when we do that, no one is harmed. The decision to refund or credit, if that comes to fruition, I'm not proposing be done until after a full evidentiary proceeding where all parties involved in the proceeding have an opportunity to respond, file testimony. And you know what, and maybe even an opportunity to file briefs on whether that was a proper application of the law. But we don't have that opportunity here today.

Customers are protected when you retain jurisdiction, a company is protected when you retain jurisdiction. I think doing it 2003 is a more clear-cut approach than, than trying to do it for 2002.

The modification of the order, I've been interested in that issue from, frankly, when we started talking about separating the TECO issue. I asked this question the other day. We weren't -- I was not on the Commission when that order was issued. I want to learn and hear more from all of the stakeholders in the process about how that order should be modified. That issue is so important as a policy question that I want full feedback on how to modify the order. If we attempt to expedite the proceeding, as we have hopefully with TECO -- I've been looking at the calendar to see if even the TECO hearing can be moved up. Right or wrong, trying to talk, tie the proxy to the contract, I'm not commenting on whether that

was correct or not correct, but I think if we expedite a proceeding that, that takes into account how the order should be modified, then whatever contracts are in effect now are in effect now and whatever modifications to the order are appropriate we would address in a full evidentiary proceeding.

With regard to opening a new docket, absolutely, I would agree with that. I've gone back and forth, Commissioners, on whether that should be consolidated with the TECO proceeding. Commissioner Bradley, you asked about that. For the simple reason of administrative efficiency, the parties are the same other than the utility. The parties that are, that are intervening and taking issue with, with this issue are the same for TECO and Progress. There's something to be said about that administrative efficiency. You could also bet that the companies will be following the proceeding even if they're separate. So I can't imagine that whoever has a hearing first, TECO or Progress, that they won't be at each other's hearing watching anyway.

I'm indifferent. We can certainly try to find two different hearing dates, if you want. But I am looking at it from an administrative efficiency standpoint. Maybe, maybe we have one day for one company and a second day for another company. But there is something to be said that there are similar parties; not the same parties, but similar parties.

Commissioner Bradley, I don't -- do you want to go

ahead and officially make your motion and see how the vote is? But I have kind of told you where I am.

COMMISSIONER BAEZ: Can I ask a question, Madam Chair, before we get into the motions?

CHAIRMAN JABER: Commissioner Baez.

COMMISSIONER BAEZ: There was -- I think it was Mr. Beasley that pointed out yesterday the, the idea that consolidating or holding the hearings as one would create some confidentiality problems because some of the suppliers to, I think it might be both of these companies or that there are competitors as between each other, and I just wondered if we need to really consider that, whether it -- and I don't purport to understand necessarily what he meant. I don't understand, I'm not familiar with the relationships or their participation with each other, but I think, you know, we need to hold that. And it may be that it is not as efficient as, as we would hope.

CHAIRMAN JABER: Right. But here's what I'm not clear on. And, again, I just, I just don't know. What I'm not clear on is how that concern is alleviated by having two separate hearings. The fact is at some point in time those separate proceedings are happening, you know, simultaneously. You're going to have prehearing statements, you're going to have testimony filed, you'll have some similar discovery, I'm sure. So the confidential nature of what -- the concern related to confidentiality exists in both proceedings whether

you consolidate them or not.

MR. KEATING: I would just add, I guess if you have one proceeding, one docket, both utilities are parties to the docket. Both utilities need to be invited to every meeting, even if it's a meeting to discuss confidentiality.

COMMISSIONER BAEZ: That's really, that's really -- if it's -- if what you're talking about is having, having the hearings, the physical hearings on a consolidated basis, maybe that's not so much of a problem. But to have --

CHAIRMAN JABER: Yeah. What we did here.

COMMISSIONER BAEZ: Not make them a same docket, that's not what you're suggesting.

CHAIRMAN JABER: That's a good question. No. I had -- I really envisioned -- and thank you for clarifying that, I really envisioned a process that was very similar to this. They're on the same hearing track in the sense of dates, when things are due, because those parties are working on it anyway. If, if you want to have them in two different dockets, that's a ministerial issue. I don't see that being a problem.

MR. KEATING: And I think that would, that would resolve the concerns. I mean, obviously part of the problem in pursuing these issues that staff has had is we want to try to compare the two, but we have trouble using one's number and providing it to the other company because of that confidentiality concern. But I think doing it in two dockets

on a consolidated hearing track would resolve those concerns.

CHAIRMAN JABER: You had those confidentiality concerns as it relates to the fuel hearing. I mean, everyone had confidential numbers. And was it chaotic to maintain from an administrative standpoint?

MR. KEATING: Well, typically we invite all the parties to every meeting we have on any company-specific issue in the fuel hearing. But the practice has typically been that only the utility whose issue is at stake or is being discussed in that meeting is who shows up. It's sort of a, an unspoken gentleman's agreement, I guess, that the other typically --

COMMISSIONER BAEZ: Or lady's agreement.

MR. KEATING: -- the companies aren't going to send a representative to listen in. But that's, that's how it's been handled in the fuel docket.

COMMISSIONER BAEZ: Madam Chair, I don't want to make this any more complicated than it is. I just wanted to raise the point that there were concerns expressed in terms of confidentiality that, that should be considered one way or the other.

CHAIRMAN JABER: Commissioner Bradley, just to help you out if you want to renew your motion, what I would envision is that the proceedings could have two different dockets. In fact, the TECO docket has already been opened and it has already received a hearing date. I don't know if it changes or

not, but the hearing date is currently May 26th and May 27th. So I don't take issue with whether it should be a separate docket. I just think it would be more efficient to have the hearings together like we do here.

COMMISSIONER DAVIDSON: Well, comment, and I think that would go to prong three of Commissioner Bradley's motion. And sitting here listening, I do think that sort of a legal stake based on the expiration of a contract is, is clean, but I also understand and appreciate the issues raised here.

So what I would do at this point based on, on Commissioner Bradley's motion is second the motion that, to allow cost recovery for 2002 and 2003 under the proxy, modify the order regarding the market proxy so that it would cease to operate January 1st, 2004, as Commissioner Bradley indicated, and direct staff to open a new and separate docket for the Progress Energy case separate from TECO. So I would second that motion.

CHAIRMAN JABER: Okay.

COMMISSIONER BAEZ: And, but I think we can still contemplate, I mean, Commissioner Bradley, along your motion, we can still contemplate dates that may coincide in terms of -- I'm just trying to get some efficiencies, allow us some flexibility to get some efficiencies because we do have a very busy, you know, hearing schedule, so.

CHAIRMAN JABER: At some point I think staff coming

to the prehearing officers -- which is another thing to think about. Do you want two separate prehearing officers? I'm pleased to say that I don't have to think about that when it comes to this one, so.

COMMISSIONER BAEZ: Shame on you.

COMMISSIONER DAVIDSON: Or maybe you do.

CHAIRMAN JABER: I think not. I think not. But who's counting.

COMMISSIONER BAEZ: You know, one good turns deserves another, Madam Chairman.

CHAIRMAN JABER: And there's such a thing as payback.

COMMISSIONER BAEZ: There is.

CHAIRMAN JABER: There is. So I think if we leave that as a flexibility for staff to come and work with the prehearing officers on consolidation at the appropriate time, if there is an appropriate time, that's fair.

COMMISSIONER BRADLEY: I would be amenable to the suggested modifications that have been --

CHAIRMAN JABER: All right. Great.

COMMISSIONER BRADLEY: -- included as a part of the second.

CHAIRMAN JABER: Okay. There's been a motion and a second. Just in the interest of disclosure, I'm not going to support it but for the reasons already articulated. So motion and a second.

COMMISSIONER DEASON: Let me just, before we vote, let me say, it would be my preference to retain jurisdiction for 2002; however, it's not part of the motion. I understand the need for regulatory certainty. I also understand that perhaps just raising the issue doesn't rise to the same level as making a determination, which I think we are today, that the proxy should cease at a date certain. For those reasons then, I'm going to support the motion and recognize that the proxy, except for normal true-up matters, that the proxy would be the standard for 2002, 2003.

CHAIRMAN JABER: Okay. I think you misspoke, so let me give you an opportunity. You said you would have preferred to --

COMMISSIONER DEASON: I'm sorry.

CHAIRMAN JABER: -- address 2002. You mean 2003.

COMMISSIONER DEASON: I meant 2003. I had 2002 written here. I have no problem that 2002 is a closed matter. In fact, what we're doing now is just the final true-up for 2002. It's not really a policy issue in front of us.

2003, I would prefer to retain the jurisdiction. That's a very close call in my mind. I understand the reason for not doing that, and, namely, regulatory certainty. And there is a legitimate question in my mind. It's just raising an issue that gets deferred, if that is the same as making a finding, which we are now, that the existing proxy should cease

at a date certain. For those reasons, I can support the motion and I will be voting in support of the motion.

CHAIRMAN JABER: Okay. And just to clarify, I really would have preferred leaving open the issue of whether the order got modified today. I really would have wanted to place the burden back on the utility to show us whether it needed to be modified and how. Saying all of that, there's been a motion and a second. All those in favor, say aye.

COMMISSIONER DAVIDSON: Aye.

COMMISSIONER BAEZ: Aye.

COMMISSIONER DEASON: Aye.

COMMISSIONER BRADLEY: Aye.

CHAIRMAN JABER: Opposed. Nay in part. I may actually do a written opinion on this issue, Mr. Keating, because I'm not dissenting as it relates to the entire motion, just very limited in nature, as I've already articulated.

Okay. Now does that -- does that resolve 13E in the entirety?

MR. KEATING: I believe it does. And before we move on, I just, I do want to be clear in preparing an order that I've, that I've captured the motion.

CHAIRMAN JABER: Go ahead.

MR. KEATING: I think what I heard seconded was, was Commissioner Bradley's original motion to allow Progress recovery of the water-borne coal transportation costs for 2002

and 2003 per the proxy with Commissioner Deason's modification as it will be trued up in the course of the fuel hearings as it usually would. Two, that we're modifying our prior order to end the proxy as of January 1st, 2004. And then three, to open new docket to establish the appropriate rate for 2004.

COMMISSIONER DEASON: And let me raise -- I mean, I supported the motion. I think it's right. But at some point we're going to have to establish under what basis are we going to project transportation costs for recovery in 2004. So staff may want to give that some thought.

MR. KEATING: Yeah. We'll need to think about that before we get to those fallout issues.

CHAIRMAN JABER: Repeat what you thought the motion was. Just go back and read what you just said.

MR. KEATING: Okay. As I had written, Commissioner Bradley's original motion was to allow recovery of the costs incurred for 2002 and 2003 per the proxy to be trued up as they would normally be through the fuel clause, modify the existing order to end the proxy as of January 1st, 2004, and open a new docket to establish the 2004 appropriate rate. And I believe part of that would be to establish what we do going forward.

CHAIRMAN JABER: Okay. Okay.

MR. KEATING: Thank you.

CHAIRMAN JABER: And in your opinion, that completely resolves 13E.

MR. KEATING: Yes.

CHAIRMAN JABER: Okay. What's our next issue?

MR. KEATING: I had skipped an issue earlier. I apologize. I wanted to do these in order. And Issue 12 was not identified as a stipulated issue either in the stipulated issue section of the prehearing order or in the handout that we've, the four issues we discussed earlier.

Staff can recommend approval. We had already had agreement with Gulf, Progress Energy and Tampa Electric on that issue. We can also agree with FPL's position as stated. This starts on the bottom of Page 22 of the prehearing order. So that we would agree with all four companies on Issue 12 and recommend approval of those positions.

COMMISSIONER BAEZ: Move Issue 12.

CHAIRMAN JABER: There's a motion to approve staff on Issue 12.

COMMISSIONER DEASON: Second.

CHAIRMAN JABER: And a second. All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Issue 12 is approved.

MR. KEATING: The next issue is Issue 13I concerning the Gannon shutdown. I'm sorry. Issue 17. We do have, we do have an Issue 13I, I think we do.

CHAIRMAN JABER: We have a 13I.

MR. KEATING: And what staff's recommendation is, this is an issue raised by Progress Energy that essentially they've asked us to establish a methodology to apply for determining incremental costs to be recovered through clauses on a generic basis, and what staff has taken the position of and what we would recommend is that we have two issues established in this proceeding to determine incremental costs: One for incremental hedging costs and, two, for the incremental security costs. At this time those are the only two incremental costs that are being flowed through the fuel and capacity clauses, so we felt that this issue could be addressed under those two -- the parties would have had the opportunity to address that issue under those two separate issues. And it's still our position that the Commission should determine incremental, recoverable incremental costs separately for the hedging and separately for the security. And if those methodologies happen to be the same, then we have sort of a generic methodology.

CHAIRMAN JABER: Commissioners, do you have a motion on 13I?

COMMISSIONER DEASON: Well, I have a question.

CHAIRMAN JABER: Go ahead.

COMMISSIONER DEASON: Reading the issue and the position, it seems like the purpose of this is to try to, at this point to go ahead and establish that the 2002 MFRs should

be the baseline. Is that staff's position or do you, do you find fault with that?

MR. KEATING: I think I'll need to let the technical staff speak to that.

COMMISSIONER DEASON: If it, if it's security cost or whatever of some future cost in the future, that we would go back to 2002 MFRs.

MR. FLOYD: Right. We agree with that. It's 2002. And, Dale, you want to speak to that?

MR. MAILHOT: That's correct. We agree that 2002 is the appropriate base year. The only thing that's kind of pending is in Issue 30 was the testimony of staff Witness Brinkley where whether or not you should take what's in your base year and gross it up --

COMMISSIONER DEASON: Yeah. I understand the gross-up issue is separate.

MR. MAILHOT: Right. And I'm not sure, that may have an influence on this issue.

COMMISSIONER DEASON: So are you saying that we don't have to vote on 13I, that it is all addressed within Issue 30?

MR. FLOYD: That's what we had recommended.

CHAIRMAN JABER: Okay. Well, then is a motion necessary at all?

MR. FLOYD: I don't -- well, Cochran.

CHAIRMAN JABER: We can just find no ruling is

necessary for 13I.

14A we've addressed. 14 -- what about 14B?

MR. KEATING: 14B was brought to my attention. I thought this was one of those issues that had been shown as stipulated. It had not been. And I believe there's really been no disagreement on this issue among the parties, and staff can agree to FPL's position.

MR. FLOYD: That's correct.

COMMISSIONER DEASON: I move adoption of staff's recommendation.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: There's been a motion and a second to approve staff on Issue 14B.

All those in favor, say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: What's the next issue, staff?

MR. KEATING: I believe that now takes us to Issue 17I. And, again, this is the Gannon shutdown related issue.

MR. HAFF: Commissioners, staff recommends that the replacement costs, fuel costs associated with Gannon's or TECO's decision to cease operation at Gannon Units 1 and 4 were reasonable. The amount of additional O&M dollars required to keep or to maintain the operational status of Gannon Units 1 through 4 to the end of 2004 were high and would not likely have been a prudent use of TECO's O&M dollars.

Further, there's no evidence that TECO had ever planned to run the Gannon Units 1 through 4 through the end of 2004. TECO's decision to shut down Gannon Units 1 and 4 did cause some replacement fuel costs to be incurred. However, I don't believe there's any convincing evidence that TECO's management was imprudent in incurring these costs, and for this reason staff recommends the replacement fuel costs associated with the shutdown of Gannon Units 1 through 4 were reasonable.

CHAIRMAN JABER: Let me ask staff, it was hard for me to keep these issues separate because we heard a lot of argument related to the degree that any replacement fuel costs increased because of the early shutdown, but there were O&M savings, that there should be an offsetting regulatory treatment of that. And I know that that's really the combination of a number of issues.

So my general question to you is, do you believe there are O&M savings? And specifically I'd bring your attention to that scenario exhibit. And then if there were O&M savings, do you know, without revealing confidential information, do you know what those savings were, and should they be offset with any increased replacement fuel costs?

MR. HAFF: Well, we're -- the offset issue is 17L, and I'll go on and say that I don't believe they should be offset.

But back to the issue of O&M savings, what, what I

believe that, that exhibit -- the scenarios we looked at yesterday showed some O&M savings from not operating Gannon as had been originally planned through the end of 2003 was my understanding. But I don't believe what was captured in that number was an additional amount of O&M dollars that was stated in the record as $37 million to $57 million that would have had to have been spent just to make Gannon operate until the end of 2004. And that was an additional amount because of the age of the Gannon Units and because of what was described as the patch-and-go O&M that TECO did to keep Gannon running, it was determined there would be additional O&M dollars that were never budgeted that would have had to have been spent just to keep Gannon operating until the end of -- Gannon 1 through 4 operating until the end of 2004.

I might want to add here that there was no evidence in the record -- it was discussed that when, when the outages necessary to make those modifications would have incurred even more replacement fuel costs, and that was never quantified in the record, but it is certainly a reality that would have occurred.

CHAIRMAN JABER: Commissioners, do you have any questions or a motion?

COMMISSIONER DEASON: I have a question.

CHAIRMAN JABER: Commissioner Deason.

COMMISSIONER DEASON: Yeah. Okay. It's your

position that even though -- you're saying there were no O&M savings as a result of the early shutdown of Gannon Units 1 through 4; is that your position?

MR. HAFF: I believe there were, there were -- I don't know that there was O&M savings. What my position is is there was O&M that was never, that would not have been spent. In other words, the $37 million to $57 million was money that was never budgeted, and so it was never projected to be spent to repair Gannon.

COMMISSIONER DEASON: And I realize that. And -- but there was -- we had discussion yesterday concerning various scenarios.

MR. HAFF: Uh-huh. Right.

COMMISSIONER DEASON: And Ms., I believe it was Ms. Jordan indicated that of the, of the scenarios, that Scenario 5 on a confidential Exhibit MJM-5 came closest to matching the reality of the situation, and there was a number there.

MR. HAFF: That's correct. Okay.

COMMISSIONER DEASON: Do you agree or disagree with that number?

MR. HAFF: I agree, I agree with that number. I know what you're saying now.

COMMISSIONER DEASON: Okay. So that number represents O&M savings from the early shutdown of Gannon Units 1 through 4?

MR. HAFF: Yes. It was savings between when they actually shut down the unit and when they had originally planned to shut down Units 1 through 4, which would have been sometime during 2004, I believe.

COMMISSIONER DEASON: And it's also your position that the decision to, to close down the units on the expedited time basis, the early closing of those units was a prudent decision.

MR. HAFF: Yes, it was.

COMMISSIONER DEASON: And by doing that, it also avoided the incurrence of additional O&M that would be necessary to keep the plants running. So you have no, no problem with the, the managerial decision to close the units when they were closed.

MR. HAFF: No, I do not.

COMMISSIONER DEASON: But you do agree that MJM-5 Scenario 5 is a legitimate number.

MR. HAFF: Yes. There was -- we weren't able to find anything to controvert that number, and there was no evidence at the hearing, I believe, that questioned the validity of that number. It was a planning number, so, which is why Ms. Jordan said it was the closest to what happened in reality.

COMMISSIONER DEASON: But it's also your position, even though that in your mind is a legitimate number, that based upon policy or principle or, or whatever that you would

not offset increased fuel costs due to the early closing of those plants by the O&M savings.

MR. HAFF: I would not. I would not.

COMMISSIONER DEASON: And why is that?

MR. HAFF: I, I look at what TECO did in shutting down Gannon as a -- you know, the Units 1 through 4 would not have been needed for reliability purposes in 2004 anyway because Gannon, Gannon 5 was shut down and became Bayside 1, the new combined cycle unit that came online in May of this year. Bayside 2 is due to come online in January of 2004. And to have spent the $37 million to $57 million in additional O&M for Gannon's 1 through 4 just to run until the end of 2004 would have -- I guess in my mind I would have questioned them had they done that because it would have not been needed for reliability purposes. They could have made some wholesale sales, I guess. But the consent decree, my understanding is it requires coal operation to Gannon to end by December 31st of 2004.

COMMISSIONER DEASON: So you're saying that the decision to shut down the units were driven by a number of factors -- I know we had concerns about reliability and safety. But you're indicating it was, the decision to close down was to avoid the incurrence of additional O&M which would not prolong the life of the plant because it was going to have to be shut down anyway.

MR. HAFF: That's exactly correct.

COMMISSIONER DEASON: Well, and I understand that and that's a good point.

I guess part of the difficulty I'm having with this issue is one of regulatory philosophy. And I'm maybe -- you know, the facts are as they are and there are some extenuating circumstances here, and we explored those fully during the last two days. But what I can't get away from is the, is the fact that this Commission has always tried to encourage wise decisions regardless of whether cost recovery is under a base rate standard or based upon a fuel standard, that we want the best economic decision.

And let's flip it for a moment. If there were a decision that TECO's management had to make, and these are just off the board numbers, so they could make a decision that would save $20 million in fuel costs over the next year, but to do that they had to incur $10 million of additional O&M that otherwise would not occur, we would expect them to do that because that's a $10 million net savings to customers.

They don't have the incentive to do that though because it's a dollar/dollar recovery of the fuel. So they would recover the 20 additional fuel cost and they would not have to incur the $10 million of, of O&M. I think I got my numbers right. But what we would expect them to do is say, we're going to do the right thing. And, oh, by the way, since,

since we're going to have to incur these additional O&M costs above what was in our last base rate proceeding to get these additional fuel savings, we think it's only fair that we net the two and we flow through such that we flow through -- the net benefit is $10 million. Do you understand what I'm saying?

MR. HAFF: Yes.

COMMISSIONER DEASON: And what I'm hearing here is we're saying, well, when it's the opposite situation, when there's fuel costs, that we're not willing to look at the entire picture and decide what's the best economic decision and give the right incentive to the company to make the right decision so that the, the ultimate net benefit can be achieved to everyone's benefit. And maybe there could be some type of a -- you know, we've been fairly ingenious in the past, I think, and creative, some type of split-the-savings approach, give incentives so that the benefit is achieved.

But what I hear you saying in this case is that we're not there because to have the, the scenario where these plants could continue to operate, that the additional O&M would far outweigh any O&M savings in the equation.

MR. HAFF: The best numbers we have in this case, you are correct.

COMMISSIONER DEASON: But do you understand the philosophical concern that I have, that we need --

MR. HAFF: Yes, I absolutely do.

COMMISSIONER DEASON: And I heard testimony that troubled me some is that I heard testimony, oh, this is a bad adjustment or you're doing things, you're combining base rate adjustments and you're combining fuel and we need to keep them separate. I don't think that's true.

We need to look in making decisions that create the best bottom line and best overall economic benefit for everyone. And if there are hurdles that need to be overcome, regulatory hurdles because we traditionally do some things in a base rate proceeding and we do other things in fuel proceeding, we need to look beyond that and be creative and try to figure out the best way to make the right decision to give the correct incentives so that everyone is made better off. Do you agree with that?

MR. HAFF: Yes, I agree with that.

COMMISSIONER DEASON: But you say in this situation, the scenario here is factually different?

MR. HAFF: I just believe that this is a different unique scenario due to the fact that the age of the Gannon Units cause them to eventually have to either be repaired and refurbished at some substantial cost with a short-term gain until the end of 2004 or bring them down and buy some replacement energy in the interim until Bayside 1 and/or Bayside 2 come into service.

And I guess some other evidence that kind of

confirmed TECO's statements that the Gannon Units were becoming more and more unreliable is that they took them out of service in March as part of a planned shutdown, and some unique weather, hot weather came along and they had to try to bring them back up to meet load and they had trouble keeping them online and eventually tripped off-line. And that just kind of cemented in my mind the status, the operational status of the Gannon Units and told me that indeed there was going to need to be some repairs made to make these units run. And I had trouble reconciling the spending of substantial capital and O&M dollars just to make it run until the end of 2004, which may not have been needed anyway. And that was -- and I had the same trouble, you know.

COMMISSIONER DAVIDSON: But what I'm hearing is they -- the right decision was to shut them down.

MR. HAFF: I don't believe it was an imprudent decision. I mean, it appears in hindsight, I hate to use that, but when they tried to bring them back up, they were unreliable. So shutting them down appeared to be the right decision.

COMMISSIONER DAVIDSON: But on the sort of dichotomy of prudent and imprudent, you would say it was a prudent decision.

MR. HAFF: Yes. Yes.

COMMISSIONER DAVIDSON: So then the only issue is

what to do with the savings, if any. So -- and really I'm sitting here listening to Commissioner Deason and I agree with much of what he says. I mean, it's a delicate balance.

MR. HAFF: Sure.

COMMISSIONER DAVIDSON: You want to do what's right for the consumers, what's right for the company. You don't want to remove an incentive to save money. But as I sit here, that incentive should, that incentive should be there regardless of what we do. As a business you should be out there trying to, to be efficient and save money. And sometimes it may be tough for regulated utilities to have that same sort of drive that competitive facilities might. And that's, that's no comment on the regulated utility business. But operating in a, in a highly competitive market provides different incentives than operating in a regulated market. But I share some of Commissioner Deason's concerns here. I'm trying to draw that right balance.

MR. FLOYD: Can I just add one, one thing to this? I understand your concern, Commissioner Deason. And but also I wouldn't minimize and I don't want to overplay it either, the, one of the reasons for shutting down is safety. And we also don't want to send any incentive that, you know, if we shut this down for safety reasons or reliability reasons, you're going to take a hit in the fuel clause.

And although I know there was some questions that

Commissioner Davidson had on the score card, it looked like they're meeting their goals, it looks like they're meeting their goals; however, that patch-and-go kept them in a situation where they could meet their lowered goals. But if something had happened and they decided we're going to keep running this thing and then people get killed, and I'm not doing that as a scare thing, but I'm just saying it's easy at a power plant, they have been killed down there before, then we would have said, wait a minute, you guys should have shut those things down. They were 47 years old. Why didn't you shut them down sooner? When you went in this patch-and-go mode, you should have just shut them down. So there is a balance. I completely understand. But I certainly wouldn't want them to -- if they have a situation like that in the future, especially on these really old plants that they were going to shut down anyway because of the consent decree, I think that we wouldn't want to send any signal that if they have that kind of situation, to not feel like, well, if we do this, are we going to -- now maybe that's not, maybe that's not the total picture, but I think it's part of it. I think safety was part of the issue, and that was in the record. And I think probably they should have shut it down when they did, at least I'd give them any benefit of the doubt on that.

COMMISSIONER DAVIDSON: Could I ask one follow-up on that?

CHAIRMAN JABER: Sure, Commissioner Davidson.

COMMISSIONER DAVIDSON: Can we apply a but for test to this scenario for a moment? And there are two prongs. But for the early shutdown of the Gannon Units, are there elements sought to be recovered here that would not be recovered? I think the answer is yes. And the opposite side is but for the shutdown of the Gannon Units, are there savings somehow associated with those costs that we're not also bringing into the, into the analysis? Sort of looking at the cost side and the savings side using a but for, a but for test.

MR. FLOYD: Mike, do you -- I don't know, I don't know enough of the details on that.

MR. HAFF: The first but for test, I guess, was there were -- the decision to shut down Gannon had some costs; is that what your first one was?

COMMISSIONER DAVIDSON: What I'm trying to get at is some pairing up of the costs and the savings resulting from the shutdown and somehow trying to marry those up so that we're not just passing on costs or just passing on savings, but there's some pairing up of those two elements.

MR. HAFF: Right. And the -- to shut down Gannon Units 1 through 4 when they did did result in some O&M savings, as the confidential exhibit showed yesterday. It also resulted in the not spending of additional O&M that was never budgeted but would have had to have been expended to make them run.

And one of the things I'm trying to remember if I mentioned earlier, to shut these units down to make these maintenance changes, there's a lot of time that they'll be down to make these changes. There's replacement fuel that has, may or may not need to be purchased in the interim that has not even been quantified.

But I would suggest if, if you're -- if you take the position that they should have shut these units down, made the repairs and then brought them up, you would have some replacement fuel associated with that as well. But to answer your question --

CHAIRMAN JABER: Mr. Haff, I was going to say, could you get back to the question?

MR. HAFF: Back to his question. And there would have -- the exhibit showed there would have been some O&M savings that had been budgeted for 2003 to shut down Gannon Units 1 through 4 when they did, and it did result in some fuel costs that went up. And it's been a lot of different numbers in the record as to what they are.

I, like Ms. Jordan, I tend to agree with the exhibit that you saw yesterday as the closest number to reality. And it was, if I recall, I guess I can, that it was higher than the O&M savings, if I'm not mistaken. But that doesn't capture the cost to bring the units where they could run until the end of 2004, which would have been upwards of $57 million additional.

CHAIRMAN JABER: But why is that factor? I wanted to bring you back to that earlier when you were responding to Commissioner Deason. I like the idea of applying a but for test, that's very appropriate, because to think about trying to reconcile the scenario we have today, which is, right or wrong, the units were shut down. That has an effect. That has an effect in increasing replacement fuel costs and that has an effect, I think Ms. Jordan agreed because she walked me through the exhibit, of some amount of net savings, and we talked about how those savings were contemplated to go back in the budget. Do you remember that?

MR. HAFF: Yes. The O&M savings?

CHAIRMAN JABER: Yeah.

MR. HAFF: Okay.

CHAIRMAN JABER: Those amounts are a direct effect of shutdown of the four Gannon Units.

MR. HAFF: Uh-huh.

CHAIRMAN JABER: The fact that another scenario could have existed if the units remained online I just don't see the significance of. Because that sort of comparison we don't have, nor is the company asking us to do any offsetting as it relates to that.

The question I think we have in front of us is the units were shut down. We know that that resulted in increased replacement fuel costs. We know that that's resulted in some

savings on O&M. Philosophically speaking, costs are shared, savings should be shared. Isn't it less complicated to just net it? It credited -- either it gets credited through the fuel proceeding or it's an increase through the proceeding. But the netting, I think, is a good matching principle.

And as justification for that, maybe we do apply a but for test. But the reality -- the reason I like that so much is because what triggered the effect of those two things was the shutdown of the units.

MR. FLOYD: Commissioner Jaber, my, my thought on it is this. I know, Commissioner Deason, we, maybe we don't have a black and white line between fuel clause and base rates, but we have tried to keep it somewhat separate. In fact, in the order that came out last time on hedging and security you even found -- if you read the order, it'll say, we found this nexus between fuel savings and security. Because, say, if somebody bombs a nuclear plant, then you've got these high replacement costs. So, therefore, finding this nexus, and this was the argument that the Commissioners put forward, because we find this nexus, we think it's appropriate to recover this through the fuel clause.

All the time utilities are doing things that generate O&M savings. Under what conditions do we want to call them in and say, okay, you've had some savings this year in your O&M at Big Bend 2. We're going to kind of offset some fuel here.

CHAIRMAN JABER: Are they all the time closing down for --

COMMISSIONER DEASON: I need to respond. I need to respond. You're missing my point entirely. Okay? I'm not advocating that we go out and just look at savings a company may achieve and then say we're going to flow it through the fuel clause.

What I'm saying is that if management has a decision that they have to make such as closing a plant down or incurring some type of additional capital expenditure which increases efficiency or something, they should make that decision based upon sound economics, what is best from an overall economic perspective. They should not base that decision upon, well, we know that we can get immediate recovery through the fuel clause, so let's do it, or they shouldn't say, oh, this is going to increase our O&M budget and we're not going to recover that until the next rate case, so let's don't do it. That shouldn't be -- the reason that we distinguish between cost recovery from one method to another shouldn't be the reason that management makes the decision. The reason -- management should make the decision upon the best economics.

If they have a scenario out there where they can incur $10 million more in O&M which creates $20 million in fuel savings, they should do it. Wouldn't you agree with that?

MR. FLOYD: Yes, sir.

COMMISSIONER DEASON: But the way we do things, the way we're structuring it, management -- and I hope that management would do the right thing and I have confidence that they would. But we need to be very clear to them that we should be able to look at a situation like that, and if we're going to achieve $20 million in fuel savings by them incurring $10 million in O&M, that we probably should be creative and net those two so they're made whole on their O&M side and customers get the $10 million in savings. And what I see here is, to some extent, is the reverse. But there are facts and extraordinary and extenuating circumstances here concerning the closure of these plants which I think probably mitigate or eliminate the need for an offset. But I'm willing to hear Chairman Jaber's arguments on the offset.

But holding everything else equal, if it were a situation, what it appears we have here, and I'm just picking numbers out of the air again because I don't want to, you know, divulge any confidential information, but if we have a situation where there is a $20 million increase in fuel cost and a $10 million, and that increase in fuel cost resulted in a $10 million savings in O&M, let's net that. It's just the reverse. It's just going in the opposite direction. Shouldn't we reverse -- shouldn't we net that as well? That's the basic philosophical regulatory question that I have.

MR. FLOYD: Yes, sir. And I guess I did read more

into what you were stating a while ago. I think you were limiting it to this particular situation. I was thinking you were speaking more broadly, and --

COMMISSIONER DEASON: If there is a finite decision that has to be made, whether it's to expend more capital dollars or do something different O&M or it's to close a plant or even build a new, you know, maybe make some modification to existing plant, the decision to either do that, that capital project should be based upon overall economics, not based upon the system of the cost recovery that the regulator imposes.

CHAIRMAN JABER: Commissioner Deason, you made reference to additional argument. I -- what I propose, what I was going to react to your statement, Mr. Floyd, and say is this is not your everyday net savings of the company, as you started your sentence, Mr. Haff just acknowledged, and I think you agree this is an extraordinary situation where four units have to come down. We're talking about consent decrees by not only our state Environmental Protection Agency, but the federal government. I can't second guess, I really can't second guess whether those units should have come down when they did even looking at the exhibits and even looking at the EAF chart and the OPA charts and taking into account all of that, especially because most of the charts we looked at through the exhibits had all six units. And it is -- until you start to see what the separate effect on all, on those charts is, it's hard to

second guess. But I don't even -- I don't want to reach that point. I don't think we should have to second guess.

The company made a management decision. I commend them for taking into account -- the scenario chart I thought was great. Taking into account customer impact and net savings I think was the right thing to do. I want to maximize opportunities.

Saying that, I would propose, Commissioners, that we take up the two issues together. Philosophically I can't separate the replacement cost increases with any net savings. And I know the numbers are confidential, but I think we can structure a motion, if it's your pleasure, that allows staff to do the appropriate netting.

It would be my, it would be my preference to have the -- to recognize the costs as reasonable, the replacement fuel costs as reasonable, recognize that there are savings, use the scenario exhibit MJM-5 as the best that we have and to do the netting. And, again, recognizing this is an extraordinary circumstance, I like the application of the but for test as rationale for doing it.

COMMISSIONER DAVIDSON: And, Chairman, of course I'm going to sit and listen to, to what everyone has to say on this. But I do view this as a unique situation. It's not your typical just our saving a little O&M here because of some new efficiency procedure. There was a very sort of clear point in

time a decision was made, this is what's going to be done. And I'm with you; we can't second guess that. I mean, that's not, that's not our role. In my view there's plenty of evidence to support the company's decision to, to shut down those units.

But that said, at some point, whether it's in this fuel proceeding or another, that net has to occur. You have costs on one side of that, the scale, the decision, and you have savings on the other, and it just doesn't make economic sense to me to somehow not tie those two together somewhere.

Now I've heard concerns from staff that the fuel proceeding is not the appropriate venue for that. It strikes me as it is since the costs that are sought to be recovered in the fuel proceeding and the savings relate to the very same incident. It's not as if the savings result from something completely different and unrelated to the event which is giving rise to this request for money. So for that reason, even though this type of savings might typically not be the type that you see in a fuel proceeding, because it is tied to the very same event -- what, what was it that they taught us in law school? Seen off common nucleus of operative facts?

CHAIRMAN JABER: I missed that day.

COMMISSIONER DAVIDSON: But this is arising from the same transaction.

COMMISSIONER BAEZ: (Inaudible. Microphone off.)

COMMISSIONER DAVIDSON: Pardon?

COMMISSIONER BAEZ: (Inaudible. Microphone off.)

COMMISSIONER DAVIDSON: UF, premiere law school.

CHAIRMAN JABER: Well, we didn't even bother to take that up apparently.

COMMISSIONER DAVIDSON: But that's, that's why I see it as something that's entirely appropriate for this proceeding because it is tied to that very same event, pursuant to which the company is seeking to recover costs in a fuel proceeding. It's unlike other types of O&M savings perhaps that might not be related to fuel clauses.

CHAIRMAN JABER: Before we go on, let me make sure the two issues we are talking about, 17I and 17L.

MR. HAFF: That's correct.

CHAIRMAN JABER: Commissioner Davidson asked if there was any other feedback, he'd be willing to listen. Commissioners, that's fine, or we can entertain a motion.

MR. HAFF: Before -- Madam Chairman, I guess a question I have, if we're talking about using MJM-5 to make the offset, those numbers are confidential. I'm just wondering if the net sum or difference of those numbers is also confidential, and I don't know.

CHAIRMAN JABER: Well, you're asking the wrong people. You're asking the wrong people. And I did hear you all say that MJM-5 was the best indication of what those savings are.

MR. HAFF: Yes. Uh-huh.

CHAIRMAN JABER: I think the question to pose back to your counsel is if you reveal what the offsetting amount is, are you somehow -- I'm answering my own question, I think you do somehow reveal -- if you know A and C, then you're going to figure B out. But what, what do you do, Cochran, when it comes to confidential information in orders? Do you attach a separate appendix that is held confidential by the agency?

MR. KEATING: I don't know. I've personally not seen an order that contained confidential information in it.

CHAIRMAN JABER: And there might be a reason for that.

MR. KEATING: Yes.

MR. HAFF: Well, the number is going --

CHAIRMAN JABER: Why can't we -- why can't any sort of motion we entertain be general in the sense that the offsetting as indicated in confidential exhibit whatever the number was will occur?

COMMISSIONER BRADLEY: Madam Chair --

CHAIRMAN JABER: Okay. Hang on. Let me just finish the thought. But it will occur and the company shall provide proof of that reconciling, you know, reconciling of the numbers to you all? Think about that. Commissioner Bradley.

COMMISSIONER BRADLEY: Yes, just for a question. Is there -- this is a rather unique situation. Is there anything

in the history of this process that might give us a precedent in order to make a ruling from?

CHAIRMAN JABER: You mean --

COMMISSIONER BRADLEY: In other words, has this ever occurred before?

CHAIRMAN JABER: The confidential part?

COMMISSIONER BRADLEY: No. This, this process.

CHAIRMAN JABER: The offsetting?

COMMISSIONER BRADLEY: Yes. Offsetting the closing of plants and, and --

CHAIRMAN JABER: I think the closest that I could --

COMMISSIONER BRADLEY: The closing being related to the fuel adjustment.

CHAIRMAN JABER: Right. The closest I could come to is cases in water and wastewater -- and, Commissioner Deason, you may come up with other examples. But we've -- there have been dismantlements of plants, there have been offsetting between water and wastewater, for example, so it's not uncommon.

Commissioner Deason, can you think of other examples?

COMMISSIONER DEASON: Well, we've had situations --

COMMISSIONER BRADLEY: You're the historian.

COMMISSIONER DEASON: Well, sometimes my history is murky. But we've had situations where we have, we've flowed through savings through fuel adjustment because it was the

right economic decision to make. I think such as what -- we had an oil backout, which I think is probably the best example that comes to mind. There were capital expenditures associated with getting coal by wire and things like displacing oil generation within Florida, which would require a rate case and a rate base proceeding and establish recovery for those capital expenditures. We felt it was more expedient and appropriate to tie the two together and allow recovery of those capital expenditures through some type of accelerated amortization or depreciation through the fuel clause, and it was to the net -- to the extent there were fuel savings which could be quantified, we allowed those to be netted in the fuel clause. Am I describing that correctly in a nutshell?

MR. MAILHOT: Yes. That's the best example we could think of where we've allowed a fairly large cost really to be flowed through fuel because there were fuel savings related to it.

CHAIRMAN JABER: Would you like that -- to the degree that the majority of the Commissioners believe the offsetting is appropriate, Commissioner Bradley, do you want them to footnote that example in the decision?

COMMISSIONER BRADLEY: I think that would be appropriate.

CHAIRMAN JABER: Okay.

MR. KEATING: And the Commission's sort of, I guess,

the guidelines for what gets recovered through the fuel clause has as the last paragraph a provision that allows costs associated with, with projects that are determined to result in fuel savings. I'm paraphrasing that. But I don't know if that came after some of the examples that Commissioner Deason gave, but that's something that, that does exist and is currently in effect.

COMMISSIONER DEASON: I'm sorry. Could you repeat that? I didn't catch that.

MR. KEATING: I believe it's a 1995 order; it sort of sets out a laundry list of the types of costs that are recoverable through the fuel clause. And there's -- the last numbered paragraph in that laundry list says, "Other projects that the utility can demonstrate fuels savings associated with that project."

CHAIRMAN JABER: Let me go back to the legal question. Ms. Helton, I saw you get up. It seems to me that if we refer to the confidential exhibit and keep any decision general with regard to numbers and just establish the formula for offsetting --

MS. HELTON: I think that should be sufficient. And there is a provision in 252.206 that if someone wants to review that confidential information, I think there's a burden that they have to meet to do that. But if there were a legitimate need, it could, it could be done.

CHAIRMAN JABER: Commissioners, what do you think?

COMMISSIONER DAVIDSON: Is -- Chairman, is it Scenario 5 of that confidential exhibit that would be the formula?

CHAIRMAN JABER: Scenario 5 is what I had in mind. That was the one, that was the one Ms. Jordan testified was the closest to what actually happened with the shutdown of the four units. Is that your recollection?

MR. HAFF: That's correct, yes.

CHAIRMAN JABER: Commissioner Deason, do you agree with that? It was Scenario 5.

COMMISSIONER DEASON: That was the testimony, yes.

COMMISSIONER BRADLEY: Madam Chair, just for my purposes, we've had a lot of discussion and I'd like to have staff -- we aren't at the point of a motion yet, are we?

CHAIRMAN JABER: No. No.

COMMISSIONER BRADLEY: Okay. I need to have someone summarize where we are right now, what staff initially recommended, and summarize where we are as it relates to the closing and cost recovery, fuel cost recovery.

COMMISSIONER DAVIDSON: Well, on that, Commissioner, if it's all right after staff summarizes, I can read what I would propose but I'm not making yet as a motion on the two issues as to how it would relate to, to where staff says we are.

COMMISSIONER BRADLEY: Okay.

CHAIRMAN JABER: And, Commissioner Davidson, did I answer your question? Okay.

Staff, the question to, from Commissioner Bradley is would you summarize what you initially recommended and summarize what you believe we just discussed as it relates to the offsetting.

MR. HAFF: Okay. Staff originally recommended that, that the replacement fuel costs were prudent, the replacement fuel costs associated with shutting down Gannon Units 1 through 4 when TECO did, in fact, do so, acknowledging that there was some O&M savings in the confidential exhibit and also acknowledging that there would -- one of the reasons we recommended prudence was because of the cost to repair Gannon.

My understanding of, of what you all want, what the Commission wants to do is to offset O&M savings to the company per MJM-5 exhibit by the estimated increase in replacement fuel costs and offset that number with the difference either flowing to the customers, which I believe it will happen because the replacement fuel costs were greater, and that that net number be the amount that goes into setting their fuel factor.

CHAIRMAN JABER: Commissioner Davidson, you want to throw out what you think can be a motion?

COMMISSIONER DAVIDSON: Yes. And, Commissioners, staff, parties, it would be based on really a wording of Issue

17I at Page 31 of the prehearing order, the draft, and Page 33. And the motion, if and when made, would read, "Motion jointly on Issues 17I and 17L as follows: First, that the Commission find on Issue 17I that the replacement fuel costs associated with TECO's decision to cease operations at its Gannon Units 1 through 4 prior to December 31st, 2004, are reasonable, but that, relating to Issue 17L, utilizing Scenario 5 of Confidential Exhibit MJM-5, the Commission offset TECO's requested fuel cost increase by the O&M savings that resulted from its decision to cease operations at Gannon Units 1 through 4 prior to December 31st, 2004," and that would have not resulted -- strike that -- "and which savings would not have resulted but for such decision to cease operations." It just adds the but for component to that to make clear that if there is -- there's something unrelated, but it's really using confidential Exhibit MJM-5.

CHAIRMAN JABER: Commissioner Bradley.

COMMISSIONER BRADLEY: I was going to say that I second the motion unless there's some additional discussion. I'll second the motion.

COMMISSIONER DAVIDSON: Well, if it's a -- I wasn't going to make it a motion until people commented just so we could --

COMMISSIONER BRADLEY: Okay. I'll withdraw my second so we can get, receive comment.

CHAIRMAN JABER: Commissioner Baez.

COMMISSIONER BAEZ: Question as to the proposed motion. No. Is that fair?

CHAIRMAN JABER: The language proposed.

COMMISSIONER BAEZ: Right. Just going back to some of the confidential information, I mean, does -- would we have to designate an amount so then -- just as guidance to Commissioner Davidson or on the motion anyway? If it would have to be --

CHAIRMAN JABER: I don't -- that was the dialogue with legal staff. I think the answer is no. Staff, you've heard, you've heard the language. Is there anything in that language that gives you a concern?

MR. KEATING: Not in that language. Where I would have a potential concern is --

COMMISSIONER BAEZ: On the factors.

MR. KEATING: -- the numbers would show up in the fallout issues, the amounts would get recovered to the factors. Now once you allocate those amounts into factors --

COMMISSIONER BAEZ: You can back them out.

MR. KEATING: I don't know, I don't know -- I think somebody who probably, you know, set their heart to it could back it out. I don't know how difficult that would be.

COMMISSIONER BAEZ: That's, I think -- I don't know how to deal with that, but that was something I was thinking

about.

CHAIRMAN JABER: Well, let me see if we can handle it this way. Commissioner Davidson, I can support your motion the way it is.

Let me ask you, the but for language, I wonder if we're, we could be clearer in putting the but for language up closer to the replacement fuel cost increase, because while those costs are reasonable, they would not have incurred but for the closing of the units, and then closing off your language with MJM-5 Scenario 5. In other words, paraphrasing it would read something like: The replacement fuel costs articulated in Issue 17I were, but for closing of the units were reasonably incurred, were incurred reasonably, and then they should be offset in a similar fashion by the, by the net savings in O&M. And maybe that clarifies for staff that whatever those replacement fuel costs are, whatever they are as a fallout number is what applies here, but that the O&M savings that we've got in the exhibit are to be applied.

COMMISSIONER DAVIDSON: That works. If, if we could perhaps before the motion is made just take two minutes so I can draft this out.

CHAIRMAN JABER: Yeah.

COMMISSIONER BAEZ: I'm not, I'm not sure that that, I'm not sure that that necessarily addresses this end scenario that Mr. Keating --

MR. KEATING: I'm sorry. I was trying to address the scenario while that discussion was taking place with the staff, so I missed part of that discussion.

CHAIRMAN JABER: Let's do this. It's 12:00. Let me let Commissioner Davidson work on that language and maybe show it to you all as well, staff. You think through how that language could be applied. I think you understand what we're trying to achieve.

MR. KEATING: Yes.

CHAIRMAN JABER: And, Commissioner Deason, I recognize we haven't heard from you yet, so if you have any concerns, this might be a good time to say something.

COMMISSIONER DEASON: I'm just enjoying the discussion at this point.

COMMISSIONER DAVIDSON: He's going to surprise us all at the end.

CHAIRMAN JABER: You all can't say I didn't try.

Okay. Let's just take a ten-minute break and we'll come back.

(Recess taken.)

CHAIRMAN JABER: Let's get back on the record. Commissioner Davidson, you wanted time to work on language for a possible motion.

Staff, you were going to think through your concern on the fallout calculations.

Let's start with Commissioner Davidson.

COMMISSIONER DAVIDSON: The motion would read, "A motion jointly on Issues 17I and 17L as follows: On Issue 17I that the replacement fuel cost at issue in 17I --" strike that.

The motion would be that the Commission find on Issue 17I and 17L as follows: First, that on Issue 17I, the replacement fuel cost at issue in 17I would not have been incurred but for TECO's decision to cease operations at its Gannon Units 1 through 4 prior to December 31st, 2004.

Second, on Issue 17I, that the replacement fuel costs associated with TECO's decision to cease operations at its Gannon Units 1 through 4 prior to December 31st, 2004 are reasonable.

Third, on Issue 17L, that the O&M savings at issue in 17L would not have been incurred but for TECO's decision to cease operations at its Gannon Units 1 through 4 prior to December 1st, 2004.

And, four, on Issue 17L, that utilizing Scenario 5 of Confidential Exhibit MJM-5, the Commission offset TECO's requested fuel cost increase by the O&M savings that resulted from its decision to cease operations at its Gannon Units 1 through 4 prior to December 31st, 2004. The motion would also include a direction to staff working with the prehearing officer to issue an order on this motion on Issue 17I and 17L that keeps confidential information confidential.

COMMISSIONER BRADLEY: And I will reinstate my second. I will second the motion.

CHAIRMAN JABER: And, staff, as it relates to discussion, the reason Commissioner Davidson, I think, added the language about keeping that information confidential is because you have expressed concern about that. Have you had an opportunity to address that concern?

MR. KEATING: We have discussed that. And the concern that I had stated is that you could see the difference, when you go back and compare the fallout numbers to what TECO's proposed fallout numbers are on those issues. As I understood, that would affect the fallout amounts reflected in Issue 5, the projected amounts to recover for 2004. And I think what we could simply say is use Tampa Electric's number as stated, less the amount to be adjusted per your decision on Issues 17I and L. Somehow tie those together without giving the number adjustment.

Now, eventually you get -- from that amount you get to Issue 6, which provides a levelized fuel cost-recovery factor. I think we could show that as Tampa Electric's number and, again, say as adjusted by the vote on Issues 17I and L. What we eventually get to is the fuel cost-recovery factors by rate class, where you take that levelized fuel cost-recovery factor and allocate that by rate class. I'm hopeful, and I would probably like to get some feedback from the company. I

think if -- those are the numbers that are the actual rates by rate class. I think those numbers are probably pretty important for everybody to know and not be confidential.

I think at that level of detail it may be pretty darn difficult to get back to the difference. Like I said before, somebody that really wanted to put their heart to it may, but I think the parties who have an interest in that number are the ones who have seen it and who are here today.

COMMISSIONER DEASON: Let me, if I may. This may kind of tie into a question and a point for discussion, and it may help -- if the Commission sees merits in it, it may help with the confidentiality question, I'm not sure. I understand the basis for the motion, and I think it is sound. I think that there are legitimate reasons for the offset. However, I think there are legitimate reasons not for an offset, as well. Not the least of which, of course, are concerns about reliability and safety. Also, the question about the significant amounts of additional O&M that would have had to have been expended to keep the plants on-line to avoid the replacement fuel costs.

So you have got O&M costs going way up to avoid increased fuel, but by making your decision to avoid the increased O&M and incur additional fuel costs, you have O&M savings on the other hand. You know, when I initiated this discussion my question was, you know, I wanted to make sure

that we have policies in place which gives management the necessary comfort, and direction, and incentive to make the right economic decision.

I think TECO's management made the right economic decision. It would have been foolish to have kept the plants on-line to have gotten X amount of fuel savings to have incurred two or three X in additional O&M costs. That would not be the correct economic decision to make. So here, again, you know, I understand the basis for the motion. There are, as a result of the decision to close the plants earlier than required by the settlement, that O&M savings did accrue.

This may be a situation where we want to entertain a question of sharing. Sharing in the sense that we would not pass through 100 percent of the O&M savings, but recognizing that the correct economic decision was made by management and recognizing that there should be some type of a sharing. And, Commissioners, to avoid disclosing confidential information, we could look at MJM-5 ourselves up here, see what that number is, refresh our memories, and then just come up with a number that we would say we want to offset. It could be, you know, 50/50, 80/20, 20/80, 60/40, whatever you all are comfortable with, but we would come up with a number and just put that in the order. And that way there is no confidential information being divulged.

CHAIRMAN JABER: I understand what you are trying to

accomplish. I think we should discuss it. My only concern in that regard is tying the concept, the application of the compromise to the record. And the only reason I keep coming back to that exhibit in Scenario 5 is because we clearly have Ms. Jordon's testimony. It's not that I don't think a percentage might be appropriate, as well, but we don't have any testimony --

COMMISSIONER DEASON: What I'm saying, we would not make a percentage, we would all just look at that number again and among ourselves we say, you know, one dollar, or $99, or $9 million, or whatever number dollar we want to offset. Whatever we feel comfortable, we include that number in the order and that is a number that we came up with. It is not a confidential number.

CHAIRMAN JABER: Let's ask if that is legally permissible. I always thought that pulling a number out of the air -- I don't mean that as a criticism, but pulling a number out of nowhere, is that --

COMMISSIONER DEASON: Well, this is plowing new ground, that's for sure.

MR. KEATING: And that was my first -- that came to mind.

CHAIRMAN JABER: It's not like we have a range. And actually maybe --

COMMISSIONER BAEZ: Well, you do have a range, don't

you?

COMMISSIONER DEASON: The range is zero to whatever MJM-5 says.

CHAIRMAN JABER: Yes. Isn't there a case -- Commissioner Deason inspired me. Isn't there a case that seems to suggest in ratemaking where you have evidence in the record that shows a range, that the Commission can exercise its discretion and use its own judgment based on its expertise that something in the middle of that range is appropriate. And for those of you that learned under Noreen, you know which case I'm talking about.

MR. KEATING: I don't think I learned that one under Noreen.

COMMISSIONER DEASON: You were absent that day.

CHAIRMAN JABER: Mary Anne, do you remember? I can't think of the name of the case, but I know it was upheld.

MS. HELTON: I think you're right. I can't remember the name of the case, either.

COMMISSIONER DEASON: I think it had to do with return on equity, though, where you had two experts, you know, one saying 10 and one saying 14, and if the Commission said 12 we had a basis to substantiate 12. Even through neither witness was saying 12, one saying 10, one saying 14.

MS. HELTON: I think that would be a perfectly reasonable resolution for you. You have a lot of discretion in

ratemaking. I think it is an unreasonable expectation that if you have two numbers offered by two different parties that you have to pick one of those numbers. Obviously, you have expertise that you need to use and give judgment to those numbers based on the testimony of those two witnesses, plus the rest of the evidence in the record. So I don't think you are bound by a particular number just because that is the number that was proffered by a particular witness.

CHAIRMAN JABER: But Commissioner Davidson's motion, the logic behind the motion still serves, Commissioner Deason, as the rationale but for the closure of the units. And, again, not passing judgment on the timing of the closure, but the truth is those replacement fuel costs increased because of that closure. The O&M savings, there has been acknowledgement that there were O&M savings, so I still adhere to the philosophy that there should be an offsetting. Whether you call that sharing, taking the exact number in a confidential nature, or something in a range, I will stay open to, keep an open mind. But, just as long as Legal tells us that it is legally defensible, I will be fine with that.

COMMISSIONER DAVIDSON: And I'm in the same position, Chairman. I think some type of incentive plan, sharing plan, I mean, philosophically makes sense. The facts here strike me as a little bit different. I agree that TECO made the right decision. If a plant is unsafe and unreliable, it is prudent

to shut that plant down. I also agree that it would not have made economic sense not to have shut down and invested more money. That said, if it is prudent to shut down because of safety, then whatever cost or gains sort of come out of that safety/reliability decision really don't affect the prudency. It is not because it is unsafe and we can save money, or it is unsafe and we are going to have to spend more money, it is unsafe and unreliable, therefore, we are shutting down.

It is a bit different than the scenario where a business changes for economic reasons the nature of its operation, builds out some new facility, does something different. Makes an investment, incurs a risk on that investment. Builds a new facility, does something different and innovative. From what we heard from TECO, these plants had to be shut down. It wouldn't have mattered if the costs, you know, were under the O&M savings, were far above the O&M savings. The plants for safety and reliability had to be shut down. That's something you can't really put a dollar value on.

So, while I'm not at all opposed to the will of the majority here to apply some type of sharing, that sharing notion seems to have somewhat less applicability where you have a safety type reason as opposed to sort of just a business strategy, financial planning, some other type of reason.

CHAIRMAN JABER: Like the wholesale economic sales.

COMMISSIONER DAVIDSON: Right, exactly.

CHAIRMAN JABER: Let me throw this out as an idea, Commissioners. While we don't want to reveal the exact number, I think it is safe to remind folks that the O&M net savings identified in Scenario 5 of MJM-5 will not result in a wash with the replacement fuel costs. That is safe to go ahead and get out there. It is not a wash. It truly is an offset, and there will be -- there is an amount, you know, that has to flow through.

COMMISSIONER DAVIDSON: You mean it's a sharing? It's not a complete offset, it's a partial offset.

CHAIRMAN JABER: Yes. And that is exactly my point, that to some degree the logic behind your motion is a sharing. And while it doesn't necessarily identify a percentage, they are not two equal numbers is what I'm trying to say. Recognizing that, how about we skip these two issues, go through the rest of the decision-making process, let staff look at the exhibit again and maybe they can come back and give us a number rather than -- because I don't know how, frankly, to have a dialogue among the five of us looking at that number.

COMMISSIONER BAEZ: It sounds like fun.

CHAIRMAN JABER: It would be fun, but we have had a lot of fun this morning. So I think what I would like to do, especially, Mr. Keating, apparently --

COMMISSIONER BAEZ: We can just TP it.

COMMISSIONER DEASON: We can have a bidding. You

know, $5 going once, $5 going twice.

CHAIRMAN JABER: I personally believe you all are doing this to me on purpose. I think if we TP these two issues, get through the rest of the decision-making process, take a lunch break, and come back and let staff give us some options. What do you think?

COMMISSIONER DEASON: I'm all for lunch. That is a good idea.

CHAIRMAN JABER: Good. So temporarily, staff, 17I and 17L. And do you understand what I want you all to do?

MR. HAFF: Come back with a number.

MR. KEATING: You are so good.

MR. HAFF: A reasonable number somewhere between -- within the range of that Exhibit MJM-5.

COMMISSIONER DAVIDSON: Well, I think the number that I would have in mind would be between zero and a complete offset of 100 percent, something in that range.

MR. HAFF: That's what I had in mind, too.

COMMISSIONER DAVIDSON: And whatever those different scenarios might be. And to the extent staff could identify without identifying the numbers, this would be in that range of zero to complete wash, this would be roughly a 10/90 split, an 80/20, a 30/70, if that can be done without divulging confidential information.

CHAIRMAN JABER: That is one option. The option I

want to explore, though, is one that more closely ties with the exhibit. Because, again, I am worried about the range being closed by that exhibit as opposed to -- but that is two approaches. That is two options. Commissioner Deason.

COMMISSIONER DEASON: When Commissioner Davidson said a complete wash, did he mean a complete wash of all additional fuel costs, or up to 100 percent of the amount on MJM-5?

COMMISSIONER DAVIDSON: No, what I meant was to the extent the savings, whatever amount we are talking about, let's say we are talking about 100 units of savings. That would offset 100 units of cost. That would be the complete offset, not the entire fuel cost. Just whatever amount of offset would be offset by the savings.

CHAIRMAN JABER: And the costs you are referring to is certainly what I am referring to.

COMMISSIONER DAVIDSON: The but for cost.

CHAIRMAN JABER: Exactly. The replacement fuel costs that were increased.

COMMISSIONER DAVIDSON: The costs identified in the motion. Just the but for costs from the decision to close early.

CHAIRMAN JABER: Staff, do you understand?

MR. HAFF: I believe so.

CHAIRMAN JABER: So the next issue, Mr. Keating?

MR. KEATING: The next Issue is 17J.

MR. FLOYD: Commissioners, our recommendation was that if you found the shutdown prudent, that any gain or loss on the surplus coal just be passed through the fuel clause. That is a normal type procedure for fuel expenses.

CHAIRMAN JABER: Commissioners, a motion?

COMMISSIONER DEASON: I move staff's recommendation.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: There has been a motion and a second to approve staff on 17J. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: 17J is approved. 17K, staff.

MR. FLOYD: The same thing with K. Although we were told there would be none, I think Commissioner Jaber pressed that point yesterday about dead freight. But let's just say if there are, they would be passed through the fuel clause.

CHAIRMAN JABER: I have trouble with that, though. There was nothing more than getting over there and beating Ms. Jordon into agreeing one more time for the purposes of the record that there would be no dead freight charge. I don't know what else to do. I agree with their position; this is moot based on the evidence in the record.

MR. KEATING: Commissioners, if you make that finding, I believe if any dead freight charges do come to be recovered through the fuel clause at any point it is an open question then.

CHAIRMAN JABER: And the witness acknowledged that there wouldn't be, but if you are really interested in looking at it again, it will be readily itemized, readily available to you. I mean, at some point you have to -- she said it four times.

MR. KEATING: I understand.

CHAIRMAN JABER: More than four times. Commissioners, what do you think?

COMMISSIONER DEASON: No, I agree. There is no need -- dead freight doesn't exist for this fuel proceeding. We have had testimony that there is not going to be. There is no reason to make a decision other than to say that if dead freight happens in the future, it has to be identified as an issue, the amount quantified, and we will make a decision in the future.

CHAIRMAN JABER: So that is a motion?

COMMISSIONER DEASON: That's a motion.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: And a second. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: That resolves 17K.

MR. KEATING: Next is Issue 17M.

MR. FLOYD: Commissioners, our position on this issue is really unchanged and it would be our recommendation that we

agree that the only witness on this was Witness Jordan, and we agree with the testimony filed by Witness Jordan. The other witness only suggested that we review this sale of the Hardee Power Station. I'm just checking to see if this is the one on the sale. And that, you know, we will review that. We will do that if you so direct us, but nothing was raised in the hearing that was brought to our attention, at least, that particularly needed review. We understand that the contract did not change.

CHAIRMAN JABER: Commissioners, do you have a motion?

COMMISSIONER DEASON: Move staff's recommendation.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN JABER: And a second. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: 17M is approved.

MR. KEATING: I believe that takes us to Issue 30.

CHAIRMAN JABER: Because the fallout issues you want to keep until the end, correct?

MR. KEATING: Correct.

CHAIRMAN JABER: Okay. So Issue 30.

MR. KEATING: I'm sorry, I did skip Issue 24.

CHAIRMAN JABER: Right.

MR. KEATING: And I believe on Issue 24 we were in agreement with each of the companies as shown in the prehearing order with the exception of Florida Power and Light, and it is

my understanding that staff now agrees with Florida Power and Light Company's number on that issue.

CHAIRMAN JABER: And the capacity cost-recovery factors are not affected by the two issues we have temporarily passed, correct?

MR. FLOYD: Right.

COMMISSIONER DEASON: Move staff's recommendation.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN JABER: All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Issue 24 is approved. What about 26, staff?

MR. KEATING: It may be that we want to go on to Issue 30. There is, I think, potentially an adjustment that could be made for some of the fallout capacity issues, based on what you do in Issue 30, if you do approve the adjustment that was suggested in the staff testimony.

CHAIRMAN JABER: What is your recommendation on Issue 30?

MR. MAILHOT: Issue 30 we would like to discuss for a minute. Issue 30 concerns the method for determining incremental costs.

COMMISSIONER DAVIDSON: Could you speak up?

MR. MAILHOT: Yes. Issue 30 concerns the method for determining incremental costs. Staff and the companies

generally agree on the actual method for measuring the costs in the base year. And the base year is generally, for most companies, its most recent test year. The difference between staff and the companies on this issue is whether or not an adjustment needs to be made to, quote, gross-up the amount that was included in the last test year to a more current number based on the current year's sales. Witness Brinkley testified to that concept. We think it is appropriate. We think that an adjustment should be made.

Up to this point in time we have always assumed, for example, if the amount of the expense in the last rate case was $100 and that rate case was five years ago, that we were still recovering exactly $100 in base rates even though base rate revenue has increased, obviously, since the time of the last test year. So what we are suggesting now is that you consider that growth in revenues which has occurred since the time of the last test year when calculating the amount that is being recovered through base rates today. It's pretty straightforward.

COMMISSIONER DEASON: A question.

CHAIRMAN JABER: Commissioner Deason.

COMMISSIONER DEASON: We had testimony which indicated that one of the complications or difficulties with applying this gross-up is for those companies which have a revenue sharing plan, and that there is an argument -- I think

there is an argument against the gross-up period, but then in addition there is an argument of fairness for those companies that have a revenue sharing plan that it is not fair, because under that plan a certain portion of revenue growth is shared back to customers. What is your position on that?

MR. MAILHOT: I think that it would be reasonable, if you were to do the gross-up calculation, that when you are calculating the revenues for the current year that you reflect or reduce those revenues by any amount which the company has refunded through the sharing planning, or for whatever reason. I mean, some companies have sharing plans where they have to refund if they had any other kind of incentive plan where they had to revenue revenues. If the company does not have those revenues in the year that you are trying to measure, then they shouldn't be considered in the gross-up. I mean, you should reduce the current year's revenues for any refund.

COMMISSIONER DEASON: So there could be an adjustment made -- an adjustment that could be readily made. The numbers are available to calculate the percentage that -- the amount of any revenue growth that had to be refunded, and you would take the net amount to calculate revenue growth to determine the gross-up.

MR. MAILHOT: Right. It's a simple calculation because we know the amount of any refunds that are made.

CHAIRMAN JABER: Any other questions or a motion?

COMMISSIONER DEASON: Move staff's modified recommendation.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: Motion and a second to approve staff's modified recommendation on Issue 30. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Issue 30 is approved. Staff.

MR. KEATING: I believe we are on 31A.

MR. LEE: On Issue 31A, I believe the company indicated that they agreed with Staff's position.

CHAIRMAN JABER: Staff, so Issues 26, 27, and 29 we need to come back to after these specific issues?

MR. KEATING: I'm sorry?

CHAIRMAN JABER: Issues 26 through 29 we need to come back to after we vote out these specific issues?

MR. KEATING: Yes.

CHAIRMAN JABER: Okay. Commissioners, Issue 31A staff is saying the company agrees with staff's position. What is your motion?

COMMISSIONER DEASON: Move staff.

COMMISSIONER BRADLEY: Second.

CHAIRMAN JABER: All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Issue 31A is approved. 32A.

MR. LEE: 32A is similar. I think there is no disagreement with staff's position.

COMMISSIONER DEASON: Move staff's recommendation.

COMMISSIONER BRADLEY: Second.

CHAIRMAN JABER: All those in favor say aye. Issue 32A is approved.

MR. LEE: 34A is the same, the company agreed with staff.

COMMISSIONER DEASON: Move staff on 34A.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Issue 34A is approved.

MR. LEE: Issue 26 is a fallout of Issue 24, so staff agrees with FPL's amount.

CHAIRMAN JABER: You said staff agrees with who?

MR. LEE: FPL amount. And the other three companies are stipulated.

CHAIRMAN JABER: Okay.

MR. KEATING: For Issues 26, 27, and 29, the remaining capacity clause fallout issues, those issues are shown stipulated with respect to all the companies except for FPL in the prehearing order.

CHAIRMAN JABER: Okay. Commissioners.

COMMISSIONER DEASON: Is there going to be any change

for FPL? Are there any issues that are going to change the amount as filed?

MR. LEE: Only on 27. I think there is a qualifying statement just similar to TECO consistent with the resolution on Issue 30, if there is any adjustment that needs to be done.

CHAIRMAN JABER: For Issue 27, FPL?

MR. LEE: That's right.

CHAIRMAN JABER: Any adjustment -- the adjustments we made to the security issue would need to be reflected in the final FPL amount?

MR. LEE: That will be trued up in the next year.

COMMISSIONER DEASON: I can move staff.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: A motion and a second to approve staff. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Next issue.

MR. KEATING: 29.

MR. MAILHOT: Any resulting adjustments from Issue 27 will be reflected in FPL's capacity factor, final capacity factors.

COMMISSIONER DEASON: Move staff.

COMMISSIONER BRADLEY: Second.

CHAIRMAN JABER: All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Issue 29 is approved. Let me go back and make sure you all captured the vote for Issue 26 and 27, just for the record.

COMMISSIONER DEASON: That was my understanding, we were discussing both issues.

CHAIRMAN JABER: Exactly. And that the motion incorporated both issues just for purposes of the record.

Okay. What is next, staff?

MR. KEATING: I believe it brings us back to the only remaining issues are the fuel factor fallout issues, amounts and factors. And it may be that before we go through those -- we could go through those for all the companies except for Tampa Electric, because we still have 17I and L pending. We can do that at this time, or we can wait until we go through 17I and L, and then quickly go through those fallout issues for all the companies.

CHAIRMAN JABER: I think we probably have people that have been waiting in the room for quite sometime. I know, Commissioners, it may not be the most efficient way, but how about we go back to those fuel factors issues and separate the companies. Which issues are those, Cochran?

MR. KEATING: Those are Issues 1, 2, 3, 5, 6, and 8.

CHAIRMAN JABER: 1, 2, 3, 5, 6, and 8.

MR. KEATING: Yes.

CHAIRMAN JABER: Staff has a recommendation on Issue

1? It is really just FPL and Progress left on that issue, right?

MR. KEATING: That's true. We have already -- you have already approved the stipulations for FPUC and Gulf on those issues.

COMMISSIONER DEASON: I don't recall making any decisions that would affect the normal true-up, but I may be mistaken.

MR. KEATING: I do have a note. There is one for Progress Energy that is going to affect the projected -- as we discussed before, projected coal transportation dollars to include in the true-up amount.

COMMISSIONER DEASON: But Issue 1 is the 2002 final true-up.

MR. KEATING: That's right. Issue 1 and Issue 2, I would think, are unaffected by --

COMMISSIONER DEASON: And we are making no adjustments to 2002 transportation costs.

MR. FLOYD: That's right.

CHAIRMAN JABER: Motion?

COMMISSIONER DEASON: Well, I would move staff if staff is comfortable that there is no reason for a modification to their recommendation.

MR. FLOYD: Nothing was changed in the numbers as represented here is our recommendation.

COMMISSIONER DEASON: Move staff.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: There has been a motion and a second to approve staff on Issue 1 as it relates to FPL and Progress. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Issue 1 is approved.

MR. FLOYD: Cochran asked me just to clarify, we are agreeing with the company numbers there since we didn't have it ready.

CHAIRMAN JABER: Right.

COMMISSIONER BRADLEY: That includes who?

CHAIRMAN JABER: Progress and FPL. Because remember TECO, we are separating them out because whatever we do with 17I and 17L may have an effect on this.

COMMISSIONER BRADLEY: Okay.

COMMISSIONER DEASON: But couldn't we also -- I mean, is there anything that -- 17I and L is not going to effect 2002 for TECO.

MR. FLOYD: That's right.

COMMISSIONER DEASON: So could we also go ahead and approve TECO, as well?

CHAIRMAN JABER: If you guys need more time -- because we really want to do this right -- you need to just tell me if you need a break. Because we are just reacting to

what you are telling us. You told me to separate TECO out for 1, 2, 3, 5, 6, and 8. If that is not correct --

MR. KEATING: And when I told you that, I was not -- you're right, I did not pull out those issues that aren't affected by 17I and L.

CHAIRMAN JABER: Okay. Commissioners, how about we -- well, let's just have a new motion to approve TECO's position on Issue 1. How about that?

COMMISSIONER BAEZ: So moved.

COMMISSIONER DEASON: Second.

CHAIRMAN JABER: There has been a motion and a second to approve staff's position on the TECO Issue 1. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Issue 2. And, again, please take your time. Issue 2.

MR. FLOYD: And that would be the same, you are not changing any numbers for 2003. I believe that was your vote.

COMMISSIONER DEASON: So your recommendation would be the numbers as filed for FPL, Progress, and TECO?

MR. FLOYD: Right.

COMMISSIONER DEASON: Second.

CHAIRMAN JABER: There is a motion and a second. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Issue 2 is approved. Issue 3.

COMMISSIONER DEASON: Issue 3 is a fallout based upon 1 and 2, is it not?

MR. FLOYD: This is a projected for 2004.

COMMISSIONER DEASON: Oh, I'm sorry.

MR. KEATING: Issue 3, I believe, is just a fallout of the sum of 1 and 2. Issue 5 is the projection for 2004.

COMMISSIONER DEASON: Okay. That's what I thought. Issue 3 is just the total true-up amount.

MR. KEATING: Correct.

COMMISSIONER DEASON: I can move -- and I assume your recommendation is consistent with 1 and 2?

MR. FLOYD: Right.

COMMISSIONER DEASON: I move staff's recommendation.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: And just for purposes of the record, 17I and 17L have no affect on Issue 3 for TECO, is that right?

MR. KEATING: That is my understanding. If they affect Issue 3, they would have to affect Issue 2, as well.

CHAIRMAN JABER: Okay.

COMMISSIONER DEASON: Issue 3 is just the total true-ups for 2002 and 2003 that is going to be collected in 2004.

MR. KEATING: That's correct.

CHAIRMAN JABER: All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Issue 3 is approved.

MR. KEATING: And Issue 5 we will have to -- these are the ones that will start affecting Tampa Electric, so our recommendation will just be for FPL and Progress at this point.

CHAIRMAN JABER: And what is your recommendation?

MR. FLOYD: The numbers as appear under the company position.

COMMISSIONER DEASON: Move staff.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN JABER: All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Issue 5 is approved for FPL and Progress.

COMMISSIONER DEASON: I'm sorry, just back up a second. With Progress there is the question as to what projected 2004 coal transportation costs are going to be included, so we need to reconsider the vote on Progress.

CHAIRMAN JABER: Yes, but it is only the true-up amount, isn't it?

COMMISSIONER DEASON: No, these are projected amounts in Issue 5.

COMMISSIONER BAEZ: I move to reconsider.

MR. FLOYD: You're right.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN JABER: There has been a motion to reconsider and a second. All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Okay. So we are back on Issue 5. And, staff, what is the recommendation for Issue 5?

MR. FLOYD: Okay. The recommendation for all issues except PEF are the numbers as stated on Issue 5 there.

CHAIRMAN JABER: Roland, I can't hear you.

MR. FLOYD: I'm sorry. We are recommending that the numbers as stated under the company positions on Issue 5 are correct. I think we were going to look at PEF separately. Although we are going to have to have a projected amount, and I guess what you could do is approve that and true it up later depending on what comes out of a future hearing. So you have got to have something to go forward with.

MR. KEATING: And my suggestion would be that that is what you do. That what we have in the record in terms of a projected amount of the coal transportation costs for 2004, although it is based on a market price proxy that we said we don't want to continue through 2004, is all we have for purposes of establishing costs for purposes of setting the factor. And it has been stated already that that is going to be subject to true-up in a subsequent proceeding where we would determine the appropriate rate.

MR. FLOYD: In other words, unless you want the

company to go back and redo their numbers some way, and I don't think you could do that now because we don't know the exact -- this is the best estimate that we have for setting rates now, so it is subject to true-up.

CHAIRMAN JABER: Commissioners, let me let you all comment on this. You may recall this relates a little bit to what I dissented on. Just to remind you what the motion was, it was to modify the order so that the proxies cease January 1th, 2004, I think. That's what I wrote down.

COMMISSIONER DEASON: Right.

CHAIRMAN JABER: And so what is your pleasure here? But the motion did make clear that any true-up amounts would be dealt with.

COMMISSIONER DEASON: That's correct. And the way I understood the motion was that it would cease to be the standard for cost-recovery. It didn't mean than it could not be used as a means of projecting costs that would be ultimately trued-up based upon a new methodology.

MR. FLOYD: Exactly.

COMMISSIONER DEASON: So for simplicity, I think it would be appropriate just for projection purposes to use what was projected, that would be the proxy, realizing that is not going to be the cost-recovery standard. It could be if we go through the proceeding and say the existing standard should be reinstated. I doubt that. But just for realizing it is just

going to be used for projection purposes, I think it would be appropriate to continue that.

CHAIRMAN JABER: Would you do me a favor and separate the motion company-by-company.

COMMISSIONER DEASON: On Issue 5?

CHAIRMAN JABER: Yes, since I want to be consistent on the Progress issues.

COMMISSIONER DEASON: Okay. I think that we can move the amount as stated for Florida Power and Light.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: As it relates to Issue 5 on Florida Power and Light it is approved unanimously.

COMMISSIONER DEASON: For Progress we can also move that amount realizing that that projection is based upon the use of a proxy to estimate or project 2004 coal transportation costs. And that we would be utilizing that for projection only, and that we would be using some different standard for actual cost-recovery as a result of a future proceeding.

COMMISSIONER DAVIDSON: Second.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: There is a motion and a second to accept the Progress number on Issue 5 with the caveat Commissioner Deason just articulated. All those in favor say

aye.

COMMISSIONER DAVIDSON: Aye.

COMMISSIONER BRADLEY: Aye.

COMMISSIONER DEASON: Aye.

COMMISSIONER BAEZ: Aye.

CHAIRMAN JABER: Opposed, nay. And, again, my dissent is limited to having an opportunity to review the order and the proxy in its entirety in a separate proceeding and to take a look at capturing 2003 revenues.

COMMISSIONER DEASON: Now, I think we need to discuss something at this point for TECO. And maybe it is a fine point that I missed earlier. The open issues for TECO relate to whether we are going to recognize any O&M savings that were incurred. Part of those savings were incurred in 2003, and I assume part of those savings will be incurred in 2004.

If the Commission does decide to make an offsetting adjustment in the open issues, would part of that be part of a true-up number, or is it all going to be accounted for prospectively?

MR. FLOYD: I don't know as I sit here. I don't know how we would --

COMMISSIONER DEASON: Did you understand the question?

MR. FLOYD: I understand the question.

COMMISSIONER DEASON: Part of the O&M savings are

attributable to 2003. We are in a true-up phase for 2003, not a projection phase.

MR. FLOYD: And Mike may know the numbers for the different years, I don't know. We may have to get together and decide on that one, I don't know.

COMMISSIONER DEASON: We may need to reconsider, then the true-up amount for TECO for 2003, I don't know.

MR. HAFF: I will say this, the exhibit, the confidential exhibit we are referring to only is for 2003. So the dollars in this exhibit would be strictly for 2003. I don't know if I answered your question, but if any adjustment needed to be made, it would be made for only the 2003 factor.

COMMISSIONER DEASON: Maybe you all need to think about it.

CHAIRMAN JABER: Yes. And that would relate to Issue 2, Commissioner Deason?

COMMISSIONER DEASON: Yes. And if we need to reconsider it, we will. It just hit me that maybe -- I don't know what the amount of the adjustment, if any, is going to be recognized, and in what period of time it is going to be recognized. And it could have an impact on whether it is to be used for 2004 projections, or if it is to be used for a 2003 true-up.

MR. FLOYD: And we haven't thought about that, and I think maybe we should do that in the break, if you will allow

us.

CHAIRMAN JABER: Uh-huh. Issue 2, and if it affects Issue 2 you told us earlier it would also affect Issue 3, wouldn't it?

COMMISSIONER DEASON: It would.

COMMISSIONER DAVIDSON: Is it possible we have now sort of reopened a lot of these issues, that we just give staff an opportunity during the lunch break to address everything that could possibly be affected and come back with clear recommendations, so we are not backing and forthing on all of these issues. This is not terribly productive.

MR. KEATING: Well, I think we could still, in the interest of having those parties who no longer have any outstanding issues, give them the opportunity to head out of here, we could still go through and move positions for Progress and FPL for Issues 6 and 8, and then we would just be left with the Tampa Electric issues. But, yes, I think during the break it would be good for staff to sit down and make sure we are clear on all the fallouts of your votes on Issue 17I and L. And this may be a good point for me to mention, slightly off point, but I have been told that Tampa Electric has waived confidentiality on that Exhibit MJM-5, so the confidential numbers we have been trying to tiptoe around are available for us to discuss now.

CHAIRMAN JABER: Great.

COMMISSIONER DEASON: Okay. Now, Issues 6 and 8 we can go ahead and dispose of those for Progress and FPL?

CHAIRMAN JABER: Uh-huh.

COMMISSION STAFF:

MS. DRAPER: That is correct. And we do agree with the company numbers.

COMMISSIONER DEASON: I move staff's recommendations on Issues 6 and 8 for FPL and Progress Energy.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN JABER: All those in favor say aye.

(Unanimous affirmative vote.)

CHAIRMAN JABER: Issues 6 and 8 are approved for Progress and FPL.

Commissioner Davidson makes a good point, though, and it gives me an opportunity to remind you all, again, as we go through these, if you need more time, let's err on the side of caution, okay? So, with that, Mr. Keating.

MR. KEATING: I believe that leaves us with Issues 17I and L, potentially reconsideration on 2 and 3, and then 5, 6, and 8 for Tampa Electric Company.

CHAIRMAN JABER: That's what I have.

MR. KEATING: And that reconsideration on 2 and 3 would be limited to Tampa Electric Company.

CHAIRMAN JABER: Yes. And just in case you find something else, any other issue that has to be reconsidered

consistent with our discussion, I will count on you to let us know.

Commissioners, how about we take a full hour break? Come back at 2:00.

(Lunch recess.)

CHAIRMAN JABER: Let's get back on the record. Mr. Keating, we temporarily passed on Issues 17I and 17L. And before we adjourned for the break, you said that TECO agreed to waive confidentiality on Scenario 5 of MJM-5. It looks like you've passed that out to the Commissioners. So what would you recommend?

MR. KEATING: Well, first, there was an outstanding question about whether based on the record that's established in this proceeding the Commission could establish some sort of sharing of the O&M savings. Now, I know that was something that Commissioner Deason had offered, and I want to make sure that that's something -- before I give an opinion on that, that's something that's still -- are interested in pursuing because I wasn't sure if that was offered solely to avoid the complications of dealing with the confidential testimony or not.

CHAIRMAN JABER: Well, I think there was consensus on what I pointed out, that the offsetting that Commissioner Davidson and I discussed between 17I and 17L was a sharing in and of itself because the amounts to be offset are not equal.

Now, I don't know what that percentage equates to. But, Commissioner Deason, do you have anything more to add to that?

COMMISSIONER DEASON: No. We can just kind of see how the discussion goes. If we need further information from staff, I can ask for it.

MR. KEATING: Okay.

CHAIRMAN JABER: So in the spirit of recognizing it's sharing however you look at it, what would be your recommendation?

MR. KEATING: My recommendation would be that you can on this record establish some sharing of those savings. I think you have record testimony and some opinions that have been stated already today from the bench that the economic decision that Tampa Electric made was perhaps a good economic decision. There may have been some safety reasons for shutting down the units. Those are some factors that I think you can take into consideration in determining what percentage of these costs -- I'm sorry, of these O&M savings could be credited to the fuel clause.

You have competing testimony on the amount of costs that could be credited to the fuel clause from zero dollars to the maximum amount. So in summary, I think you do have record testimony, record evidence that would allow you to support a decision on some sort of sharing of these O&M savings.

CHAIRMAN JABER: Let's take it one at a time. With

regard to the proposed language that might turn into a motion from Commissioner Davidson, now that we know what the O&M savings is in the exhibit, we can easily put that number into Commissioner Davidson's motion; right?

MR. KEATING: Yes.

CHAIRMAN JABER: Okay. So, Commissioner Deason, that takes care of the concern related to confidentiality, but do you still want to explore other options on the percentages?

COMMISSIONER DEASON: Well, I guess that it would be helpful to get some type of feedback from other Commissioners as to whether there's any desire to discuss savings -- sharing savings other than the sharing concept that's already been -- it's inherent in this analysis in the fact that we don't have a one for one offset between O&M savings and increased fuel costs.

COMMISSIONER DAVIDSON: I would be interested in knowing are there other examples in which this savings mechanism has been utilized, and are there typical percent allocations to the participants that are used in the most similar circumstances. Again, I understand Scenario 5 represents sharing. If this is typical -- if this might be typical of a scenario, I'm fine with Scenario 5. If there's something more typical that the Commission has done in the past such as some other split, I'd be interested in hearing about that as well.

COMMISSIONER DEASON: Well, the Commission has, as an example, and there may be others, I think the Commission has a policy when it comes to off-system sales. We have a sharing there. We have recently established a threshold level that must be exceeded, a target, for lack of a better term, and then once that target is exceeded, there's a sharing, which is, I believe, 80 percent to the ratepayer and 20 percent to the stockholder. That's just an example.

CHAIRMAN JABER: And it's a three-year average as a threshold.

COMMISSIONER DEASON: Staff may be -- I'm sure there's probably others.

MR. FLOYD: Right. We had the broker -- when the broker was in operation, there was a sharing with same percentages, 80/20, there.

CHAIRMAN JABER: The only reason I find Scenario 5 to be acceptable to me, although I wouldn't set aside the possibility of discussing other options, I like the simplicity of this. We do have an exhibit. It is in the record. The company has waived confidentiality. I like the simplicity of being able to point to numbers in the record. And --

COMMISSIONER DAVIDSON: And I like the fact, I mean, that it is evidence in the record. It's not just sort of coming up with that. But that's why I asked. I mean, I also don't think it would be arbitrary if there was some typical

type of methodology that the Commission has used to take whatever those savings are and say, notwithstanding that Scenario 5 is record evidence, we would also have the discretion to do some other type of a split. Again, I'm very comfortable with Scenario 5, but I'm trying to just see if there's some other standard that we have used that if we used in this case, it would be consistent with practice and would also be applicable in similar type scenarios that arise in the future.

I mean, this Scenario 5 is related to this case, so we're not sort of opening the door to some new type of sharing in unforeseen cases. Because we'd be basing it on Scenario 5, it would be related to the facts and circumstances of this case, which may be wise, or perhaps we want to articulate a more general sharing policy.

COMMISSIONER DEASON: I don't think there's really -- I think it's -- staff can correct me if I'm wrong. It's my opinion that it's just something that's kind of within our discretion. There's nothing magical about 80/20 other than that it's a policy the Commission has adopted and has been used and applied to a certain set of circumstances. It has seemed to have worked relatively well. I concede that and agree that this is a number that is evidence. It is what it is. There's not 100 percent offset one to the other, so to some extent, there is kind of an inherent -- a supposed inherent amount of

sharing.

I just fall back to what I said earlier in the discussion is that these -- I'm convinced that TECO management made the right decision in closing the plants when they did. And it was made for the right considerations, both economic and noneconomic considerations and that there are savings. And there can be an argument made that the fact that the correct decision was made, there should be some recognition of that with some type of a sharing approach beyond what's inherent. I'm not saying that we -- I think we have the discretion to do it either way. I'm not really wed to one or the other. I just felt it was important to at least raise the question and see, first of all, what staff's feedback was, whether we had that discretion, which I think that we do, and whether the facts of this case are such that some discretion we wish to exercise.

CHAIRMAN JABER: Do we have, staff, the amount of replacement fuel costs associated with the decision to shut the four units down is also a confidential number?

MR. HAFF: It's actually -- my understanding is it's the top number under Scenario 5, 17,605,000.

CHAIRMAN JABER: Okay. You know, I'm not good in terms of the percentages, but what would you say, recognizing that we believe there is some sharing in the practice of offsetting those two amounts, what would you say it works out to be?

MR. HAFF: What that number --

CHAIRMAN JABER: Percentage-wise, yes, a rough estimate.

MR. HAFF: 80/20.

CHAIRMAN JABER: There you go. You think it works out 80/20?

MR. HAFF: What do you mean? What the ratio of these are you mean?

CHAIRMAN JABER: Yeah.

MR. HAFF: Oh, no. I might need to clarify a little something. My understanding is that the fuel and purchased power clause impact which relates to replacement fuel is already in TECO's number in one of the other issues, the fuel adjustment issue. So if there's any adjustment, my recommendation would be that it based of off the net savings at the bottom of 10,521,000. In other words, you already have in the totality of fuel number the replacement fuel. And so I would recommend --

COMMISSIONER DEASON: There's some debate as to what the replacement fuel is depending upon which witness and what facts you assume and that sort of thing. We know what the fuel costs are. We know that the plants were shut down; the fuel costs were incurred. It's a question of how much do you attribute additional fuel costs out of that total you attribute to the fact the plants were shut down. I know that Ms. Jordan,

she had an exhibit attached to her rebuttal testimony. And she had a number calculated there which is not confidential, which, I think, was 8.21 million --

MR. HAFF: 8.5 million.

COMMISSIONER DEASON: -- or 8.12 or something, but that was on clarification that -- questions that I asked. That was for 2003 only. It did not capture additional costs for 2004, which would be projected costs anyway. And I asked her, I said, well, you know -- she said that -- well, she didn't know the exact amount. The total incremental fuel costs with the closings would certainly be in excess of 8.2 million, and the 2004 amount probably would be greater than the 2003 amount. So even if you just double the 2003 amount, you're over 16 million. So one could argue that the total incremental fuel costs are somewhere in the neighborhood of $20 million, according, you know, in rough numbers according to Ms. Jordan's testimony.

MR. HAFF: Right.

COMMISSIONER DAVIDSON: Commissioner Deason, in your mind, are we now at sort of the point where we're either going to offset by 10,521,000 or, say, 80 percent of that, 80 percent to the customers, 20 percent to the investor? And I'll tell you, I could support that if a motion was made. I'm fine with either scenario. Either of those, I believe, are within our discretion. So if you move to apply an 80/20 split based on

this incentive rationale, I could support that.

COMMISSIONER DEASON: I was hoping you'd make a motion. I'm kidding.

COMMISSIONER BRADLEY: (Inaudible. Microphone off.)

COMMISSIONER DEASON: Well, we've used that in the past.

CHAIRMAN JABER: Yes.

COMMISSIONER DEASON: I'm willing to make that motion. I think there's some reluctance on the Chair's part. And maybe we should hear from you a little bit more at this point. I'm still open --

CHAIRMAN JABER: Right. Let me tell you what's nagging at me. First and foremost, I will support 80/20 because that is the will of the majority, and in terms of dollars at the end of the day, it may not have a tremendous impact. It's the offsetting that's important to me.

What is nagging at me, Commissioners, is the procedural aspect. There is something to be said about having an issue on whether there should be an offset and having testimony come in from all the parties on, yes, there should be on offset; no, there shouldn't be one. And for the people that said, yes, there should be an offset, it was offsetting the entire amount of O&M savings by the increased replacement costs. The 80/20, while we've applied it in the situation of the wholesale economic sales, people came prepared to discuss

what the percentages were. I don't think that was necessarily the case in this proceeding. You may recall that the percentages that we voted out a couple of years ago on those economic sales were really just modifying a procedure we already had in place that related to percentages. We established the threshold and that was new. That's what's nagging at me.

I don't want to hold the majority up. I like the simplicity of having two definitive numbers in the record. That's what parties testified to. As it related to TECO, they testified that no offset was appropriate. As it related to the consumer advocates, they said offsetting was appropriate and here's the methodology you should use. I like the definitiveness of that.

COMMISSIONER DEASON: And I agree that we have -- it's my humble nonlegal opinion that we could either offset 100 percent or offset zero percent, and we have evidence in the record that would withstand an appeal. We have very adequate testimony from the consumer advocates saying that there should be 100 percent offset. We have very compelling evidence from the company indicating that there should be no offset.

COMMISSIONER DAVIDSON: And that to me, Commissioner, is the critical fact. I mean, we've got that range, and we've got to make a decision. That's why I'm comfortable with the 80/20. I do understand also and appreciate the simplicity, but

based on the facts before us, we do have sort of those competing requirements. And I think sort of based on the equities and the circumstances, the fact that a good decision was made to close these, that that sharing based on the facts of the case and having done it in prior cases would be good policy. So again, I'm comfortable with that. I don't have any discomfort at all. I'm also comfortable with just going straight through with Scenario 5.

COMMISSIONER DEASON: Well, I'm willing to make a motion, and we'll just see how it goes. I'm kind of flexible on this thing too. I guess to some extent we're plowing new ground. I think this is probably the first example that I can recall where we have identified a situation where we have increased fuel costs which have created O&M savings. Before it's been just the opposite. We've had initiatives taken that have reduced fuel costs, and we wanted to offset -- recognize the rate base impacts. This is kind of the reverse of that.

I'm willing to make a motion and certainly willing to discuss it further if necessary. I would move that we would recognize the amount in Scenario 5 of Exhibit MJM-5 as O&M savings, and that we would attribute 80 percent of that savings to the ratepayers, which would be whatever that number calculates to be, something in excess of $8 million would be a reduction in fuel costs that would be passed through to customers.

COMMISSIONER DAVIDSON: Second.

COMMISSIONER DEASON: And before -- just one second. Staff, we need some feedback as to whether that number is somehow going to be used in a 2003 true-up, or is that going to be part of a 2004 projection?

MR. MAILHOT: Okay. We believe that that savings, that most or all of that savings occurred in the second half of 2003, and so what we would recommend is that when the company do its final 2003 numbers, that it just reflect that savings, like, one-sixth each month for the last six months of 2003. Effectively, you end up with the same point, you know, down the road. It's just there's a slight difference in interest, but we think it's a little bit better matching as to when the savings actually occurred.

COMMISSIONER DEASON: So it would be part of the true-up for 2003; is that correct?

MR. MAILHOT: Correct. And that will be finalized next November.

COMMISSIONER DEASON: Finalized next November.

MR. MAILHOT: Right.

COMMISSIONER DEASON: Now, when you say "finalized," just the question -- we're not going to go back and try to recalculate whether there's a change to the 10.521 million. We're taking that number as -- based upon the evidence we've taken, we're not going to be truing-up the 10.521 million.

MR. MAILHOT: No, we're not going to attempt to do that.

COMMISSIONER DEASON: You're talking true-up in just the normal sense of truing-up that we normally do every fuel adjustment proceeding.

MR. MAILHOT: Right, because at this point in time we haven't finalized 2003. We still have a lot of estimated numbers in there, but we're going to assume that whatever you vote today is the number for that point.

COMMISSIONER DEASON: Okay. All right. And that would be part of my motion as well, that that would be the procedure for recognizing that amount of sharing.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN JABER: Okay. There's a motion and a second to accept Scenario 5 of MJM-5 as it relates to the net savings but to take 80 percent of that savings and apply as a reduction in fuel costs for the benefit of ratepayers and thereby recognizing 20 percent for the shareholders, and that the procedure for the true-up would be as articulated by staff, that we recognize that the last six months of 2003 will be affected.

All those in favor say "aye."

(Simultaneous affirmative responses.)

CHAIRMAN JABER: The motion carries unanimously. And we should say that that addresses 17I and 17L.

MR. KEATING: And I think we are back to then the fallout issue. I think you're going to have to vote to reconsider your vote for Tampa Electric on Issue 2, the appropriate fuel adjustment true-up amounts for 2003.

COMMISSIONER DEASON: I so move we reconsider.

COMMISSIONER DAVIDSON: Second.

CHAIRMAN JABER: There's been a motion and a second to reconsider Issues 2 and --

COMMISSIONER DEASON: 2 and 3, I would think.

CHAIRMAN JABER: -- 3.

MR. KEATING: Yes.

CHAIRMAN JABER: All those in favor say "aye."

(Simultaneous affirmative responses.)

CHAIRMAN JABER: We're on Issue 2.

MR. KEATING: Commissioners, what you can do here is, for purposes of simplicity, I believe you could go ahead and vote the Tampa Electric position less the amount that you've determined should be credited without having to calculate that specific amount right now and put it in front of you.

CHAIRMAN JABER: I can't hear you, Mr. Keating.

MR. KEATING: I'm sorry. I think what you could probably do is vote the Tampa Electric position on Issue 2 less the amount that you determine should be credited for 2003, and we can conduct that calculation. And I would propose as we get to the fallout issues on the factors that perhaps you -- I

think we have done this before, allow staff the authority to administratively approve those as they're provided to the company -- as provided by the company after the hearing.

CHAIRMAN JABER: And that would be consistent with what Mr. Mailhot was saying, that it would be one-sixth each month for the last six months?

MR. KEATING: Yes.

COMMISSIONER DEASON: Let's take a break. Can we do that?

CHAIRMAN JABER: Sure.

COMMISSIONER DEASON: Just five minutes.

CHAIRMAN JABER: Five-minute break.

(Brief recess.)

CHAIRMAN JABER: Okay. Let's get back on the record. Mr. Keating, we were asking some clarification on Issues 2 and 3 and how the fallout calculations would apply to TECO.

MR. FLOYD: Maybe we need Dale to confirm this, but my -- I'm not an accountant, but what I heard suggested was you make this adjustment in 2003 over this last six-month time frame and however that flows through to the 2004 numbers, it will happen on these spreadsheets. And there's nothing particularly to true-up about that, but I think what Dale was saying when they come in with true-up stuff and they see we're going to be looking at their filings and so forth and make sure that all of this is done properly, now maybe we don't have to

wait until next year, maybe we'll see that part of it now, but every time they file something, we check and make sure everything is kosher. Now, that is my non-accountant summary of what we just did.

Dale.

MR. MAILHOT: Yeah, I think that's the situation. I mean, our view is that the company will make this calculation, make the adjustment right now; we'll reflect it in the 2003 true-up number, the dollar amount that's in today's issues so that that number is, whatever, $8 million less. That $8 million will flow through to the 2004 factors that are charged starting in January. My comment about the true-up is really just the fact that they will be refiling 2003's information later on.

COMMISSIONER DEASON: Let me ask you this question. Is it easier or is there some reason why we shouldn't just lower the 2004 projections? Don't we get to the same place? Isn't it much easier with having to worry about trying to go back and true-up 2003 numbers? It's just part of 2004. We're recognizing an adjustment that's going to be part of 2004 recovery.

MR. MAILHOT: It really doesn't matter and you should get to the same place. The only reason we were suggesting 2003 is because that's where the additional purchased power costs are reflected is in 2003, and we're saying the savings actually

occurred in 2003.

COMMISSIONER DEASON: But part of the -- I mean, we had testimony yesterday from Ms. Jordan indicating that there's going to be a substantial amount of additional fuel costs in 2004. So it's really hard to say which period it gets logged into.

MR. MAILHOT: That's fine. I mean, I was just under the understanding that it occurred in 2003. Whichever year is just fine.

COMMISSIONER DEASON: Well, I'm for simplicity as long as we get to the end result in a fair fashion, and I think that just recognizing the adjustment as part of 2004 projections would be fine. Of course, obviously it's subject to true-up, but not the amount, not the 10.521 million which the 80 percent is being applied to, but just the normal true-up that we incur through the fuel adjustment process. Is that workable?

MR. MAILHOT: Yes. It really doesn't matter which year you reflect it in. The only difference between the two years is the interest calculation. I mean, that's the only difference that will occur. You could put it in 2002, 2003, 2004, or 2005. The fact is it's going to be reflected in 2004's factors. I believe that's what you want.

COMMISSIONER DEASON: Then maybe --

CHAIRMAN JABER: And you want that -- it goes back to

the matching principle. You want that so that to the degree there's an effect on customers' bill --

MR. MAILHOT: But it doesn't matter that much because it's going to be reflected in 2004's factors.

CHAIRMAN JABER: Okay.

COMMISSIONER DEASON: Ms. Chairman, maybe you can help me. Do we need to reconsider something, or are we on reconsideration?

CHAIRMAN JABER: We're on reconsideration. We haven't taken a vote on Issues 2 or 3. The question posed to them is what staff just answered. How would the effect of the true-up be had on 2003 was the question they just addressed.

COMMISSIONER DEASON: Okay. If we recognize the adjustment as a result of Issues 17I and 17L, if we recognize that adjustment as being applied to 2004 factors, there's no need to recalculate the true-up for TECO in Issues 2 and 3; is that correct?

MR. FLOYD: I think that's correct.

CHAIRMAN JABER: Let me ask you this. There's going to be an order that memorializes our vote; right? And parties have an opportunity to file a motion for reconsideration if they need to on that order; right?

MR. KEATING: That's right.

CHAIRMAN JABER: Okay.

MR. FLOYD: And, Commissioner Deason, by your

simplistic approach -- or simple approach -- and I agree with it. In fact, that's --

COMMISSIONER DEASON: It's simplistic. I'm a simplistic person.

MR. FLOYD: No, and Dale can tell you, I suggested that myself but deferred to him because he knows this accountant stuff --

CHAIRMAN JABER: You just had to go there.

MR. FLOYD: -- but I think we would just do exactly what he said. And then on Issue 5, the number, the 744 million, I think, if Elizabeth agrees with that, would be changed and then that would change the factors for 2004. It may not change the factor because it's such a relatively small amount, but the amount would be to the benefit of the ratepayers.

COMMISSIONER DEASON: Based upon that discussion then -- I think we're on reconsideration of Issues 2 and 3?

CHAIRMAN JABER: We are.

COMMISSIONER DEASON: I think that we had voted to reconsider, but I think we can reinstate our previous vote to recognize the amounts in the prehearing order for TECO for Issues 2 and 3, and that we would make the adjustment in Issue 5. So that would be my motion.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: And a second. All those in favor

say "aye."

(Simultaneous affirmative responses.)

CHAIRMAN JABER: That resolves Issues 2 and 3 unanimously.

And the next issue is 5; right, staff?

MR. FLOYD: Well, as we just mentioned, I think here is where we would make the adjustment and then the spreadsheets would be recalculated reflecting your vote.

COMMISSIONER DEASON: And the actual factors for different rate classes and things of that nature would be -- you would make that calculation, and you'd have the authority to issue those administratively?

MR. FLOYD: Right. That's what we would ask for.

CHAIRMAN JABER: And Issue 5 isn't going to require reconsideration; right? We had already separated TECO out?

MR. KEATING: Yes.

CHAIRMAN JABER: Okay. Do you have motion on 5?

COMMISSIONER DEASON: That's my motion on Issue 5, that we recognize the adjustment for 2004 and give staff the authority to administratively issue the fuel factors to be applied.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: And a second. All those in favor say "aye."

(Simultaneous affirmative responses.)

CHAIRMAN JABER: That resolves Issue 5 unanimously.

MR. KEATING: I think that that may resolve 6 and 8 as well by giving staff administrative authority to approve the fuel factors. Those are the subjects of Issues 6 and 8.

COMMISSIONER DEASON: I so move.

COMMISSIONER BAEZ: Second.

CHAIRMAN JABER: There's been a motion to approve staff's recommendation on Issues 6 and 8. All those in favor say "aye."

(Simultaneous affirmative responses.)

CHAIRMAN JABER: Issues 6 and 8 are approved.

What else, staff?

MR. KEATING: I believe that's all.

CHAIRMAN JABER: Double-check us. Commissioners, let me tell you what I just suggested to Commissioner Deason while we were at break but for everyone's benefit. This fuel hearing, while I have nothing but compliments for staff and all the parties that participated in this fuel proceeding, it was very complicated, meaningful discussion. I don't regret the time we've spent in looking vigorously at each and every issue, and I don't regret how we've ruled on these issues and the separating out some of these issues into separate dockets.

What I'd like for staff to consider for next year, Commissioners, and also for us to consider is somehow knowing, I don't know, maybe three or four months ago or maybe even six

months ago if there was a procedure you all can put in place that allows you to understand what the policy issues will be that may lend themselves better to a separate proceeding or maybe a determination through an agenda process up front that can be incorporated into the hearing at this stage. That is not a criticism, but as I said to Commissioner Deason, I don't see these issues getting less complicated as these market develop. I think they will be more complicated.

And, Commissioner Deason, you can help me out here if you'd like. It seems to me that this administrative process has had its benefits in terms of efficiencies, but some of these issues aren't as routine as they've been in the past. So if we could find a way to keep the issues that are routine in this very expedited process, great, but I don't like the feeling of being rushed, not having a lot of evidence, second guessing. And again, I don't mean that as a criticism. So think about that for next year.

Commissioner Deason.

COMMISSIONER DEASON: Let me say that I agree with what you're saying. And it's difficult on the parties, it's difficult on the staff, it's difficult on the Commissioners to have these very intense, meaningful debates with evidence and cross-examination on these significant policy issues within the confines of this once a year November hearing where we're trying to get fuel factors finalized to be effective January.

And I would just ask Public Counsel, FIPUG, all of the participants, if there's a better way of doing it, let's think about it. Maybe the way we're doing it is best, but it just seems to me that when we start talking about these very significant policy issues, it would be better to have a little bit more -- the luxury of having a little bit more time as opposed to being pressed against this deadline and having to make bench decisions.

I'm not critical of what we've just done. Just like the Chair, I think these issues have been very thoroughly litigated, that the parties did a superb job in presenting their cases, but we did it in a very compressed time frame, and we did not have the luxury of having briefs filed if we thought that would be helpful. We didn't have the luxury of staff analyzing all of that and coming forward with a written recommendation. While I applaud staff for your oral recommendation, I just think that some of these issues would be better addressed in a more traditional atmosphere, if possible. And that's just something to think about.

CHAIRMAN JABER: Yeah, for the future. I mean, this is taking an opportunity now to address something for the future while we can. I mean, you have 12 months' notice. And I love what Commissioner Deason said about challenging all of the stakeholders in this annual process to help us figure out a better way because, frankly, I never dissent on issues lightly.

I prefer a consensus approach. And it bothers me that I dissented on a couple of issues because I wasn't exactly comfortable with the compromised solutions. I'd much rather hear compromised solutions come from stakeholders. That's just the way I am.

Commissioners, if you don't have anything more to add, it sounds like this proceeding can be concluded. Commissioner Baez.

COMMISSIONER BAEZ: No.

CHAIRMAN JABER: Thank you.

(Hearing concluded at 2:45 p.m.)

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STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

WE, LINDA BOLES, RPR, JANE FAUROT, RPR, and TRICIA DeMARTE, RPR, Official Commission Reporters, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

WE FURTHER CERTIFY that we are not relatives, employees, attorneys or counsel of any of the parties, nor are we relatives or employees of any of the parties' attorneys or counsel connected with the action, nor are we financially interested in the action.

DATED THIS 24th DAY OF NOVEMBER, 2003.

LINDA BOLES, RPR
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Chief, Office of Hearing Reporter
FPSC Division of Commissioner Clerk
Administrative Service
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DOCUMENT NO. 1

WITNESS: F. IRIZARRY

DOCKET NO. 030001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2002

FI - 1
DOCKET NO. 030001-EI
FPL Witness: F. Irizarry
Exhibit No.:
Pages 1 - 30
April 1, 2003

DOCUMENT NUMBER-DATE
03021 APR-1 8
FPSC-COMMISSION CLERK

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. Comp. Ex
COMPANY/ FP+L
WITNESS: FI-1 + FI-2
DATE: 11-12-03

DOCUMENT NUMBER 1 INDEX

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2002

DOCUMENT	INDEX OF MANUAL PAGES	TITLES
1	6.203.001	Index of Manual Pages
	6.203.002	GPIF Reward/(Penalty) Table (Actual)
	6.203.003	GPIF Calculation of Maximum Allowed Incentive Dollars (Actual)
	6.203.004	Derivation of System Actual GPIF Points
	6.203.005	Actual Equivalent Availability and Adjustments Summary
	6.203.006	EAF Adjustment Documentation
	6.203.007	Adjustments to Average Net Operating Heat Rates and Adjustments Summary
	6.203.008 - 6.203.029	GPIF Units Points Tables
	6.203.030	Planned Outages Schedules (Actual)

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ACTUAL)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2002

GENERATNG PERFORMANCE INCENTIVE POINTS (GPIF)		FUEL SAVINGS/(LOSS) ($000)		GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+ 10		62,576.00		21,689.51
+ 9		56,318.40		19,520.56
+ 8		50,060.80		17,351.61
+ 7		43,803.20		15,182.66
+ 6		37,545.60		13,013.71
+ 5		31,288.00		10,844.75
+ 4		25,030.40		8,675.80
+ 3	<---------- 3.43	18,772.80	7,449.429 ---------->	6,506.85
+ 2		12,515.20		4,337.90
+ 1		6,257.60		2,168.95
0		0.00		0.00
- 1		6,702.60		(2,168.95)
- 2		13,405.20		(4,337.90)
- 3		20,107.80		(6,506.85)
- 4		26,810.40		(8,675.80)
- 5		33,513.00		(10,844.75)
- 6		40,215.60		(13,013.71)
- 7		46,918.20		(15,182.66)
- 8		53,620.80		(17,351.61)
- 9		60,323.40		(19,520.56)
- 10		67,026.00		(21,689.51)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ACTUAL

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2002

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$ 5,444,138,876
LINE 2	MONTH OF January	2002	$ 5,483,614,440
LINE 3	MONTH OF February	2002	$ 5,464,311,451
LINE 4	MONTH OF March	2002	$ 5,465,713,851
LINE 5	MONTH OF April	2002	$ 5,236,678,201
LINE 6	MONTH OF May	2002	$ 5,264,143,052
LINE 7	MONTH OF June	2002	$ 5,250,553,629
LINE 8	MONTH OF July	2002	$ 5,266,725,156
LINE 9	MONTH OF August	2002	$ 5,284,571,716
LINE 10	MONTH OF September	2002	$ 5,278,515,518
LINE 11	MONTH OF October	2002	$ 5,140,016,047
LINE 12	MONTH OF November	2002	$ 5,108,954,003
LINE 13	MONTH OF December	2002	$ 5,381,760,459
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE1 THROUGH LINE 13 DIVIDED BY 13)		$ 5,313,053,569
LINE 15	25 BASIS POINTS		0.0025
LINE 16	REVENUE EXPANSION FACTOR		60.4594%
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$ 21,969,510
LINE 18	JURISDICTIONAL SALES		95,522,890,000 KWH
LINE 19	TOTAL SALES		96,756,048,000 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)		98.73%
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS		$ 21,689,508

JANUARY THROUGH DECEMBER, 2002

DERIVATION OF SYSTEM ACTUAL GPIF POINTS

PILANT/UNIT	PERFORMANCE INDICATOR	WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
Cape Canaveral 1	EAF	0.60	1.55	.0093
	ANHR	1.12	0.00	.0000
Cape Canaveral 2	EAF	0.43	-8.74	-.0375
	ANHR	1.49	1.22	.0181
Lauderdale 4	EAF	1.37	10.00	.1368
	ANHR	2.27	-7.73	-.1757
Lauderdale 5	EAF	1.35	6.26	.0844
	ANHR	2.17	-1.93	-.0418
Manatee 1	EAF	0.68	10.00	.0681
	ANHR	1.81	0.00	.0000
Manatee 2	EAF	0.63	10.00	.0635
	ANHR	2.83	0.00	.0000
Martin 1	EAF	0.56	-10.00	-.0561
	ANHR	4.05	1.04	.0420
Martin 2	EAF	0.63	-5.28	-.0334
	ANHR	6.42	0.00	.0000
Martin 3	EAF	1.54	5.58	.0861
	ANHR	2.45	-4.68	-.1145
Martin 4	EAF	1.54	10.00	.1544
	ANHR	2.50	-10.00	-.2499
Port Everglades 3	EAF	0.44	-7.91	-.0345
	ANHR	2.34	0.00	.0000
Port Everglades 4	EAF	0.44	10.00	.0443
	ANHR	3.00	0.00	.0000
Putnam 1	EAF	0.23	8.72	.0197
	ANHR	1.16	-5.21	-.0603
Riviera 3	EAF	0.81	10.00	.0808
	ANHR	1.36	0.00	.0000
Riviera 4	EAF	0.54	10.00	.0542
	ANHR	1.08	10.00	.1082
Turkey Point 1	EAF	0.42	10.00	.0417
	ANHR	2.08	-2.64	-.0550
Turkey Point 2	EAF	0.33	10.00	.0332
	ANHR	1.23	0.16	.0020
Turkey Point 3	EAF	8.45	10.00	.8453
	ANHR	1.69	0.00	.0000
Turkey Point 4	EAF	7.75	10.00	.7749
	ANHR	1.20	0.00	.0000
St. Lucie 1	EAF	9.44	10.00	.9442
	ANHR	2.75	0.00	.0000
St. Lucie 2	EAF	8.69	10.00	.8691
	ANHR	4.12	0.00	.0000
Scherer 4	EAF	3.16	-5.93	-.1871
	ANHR	0.84	0.00	.0000
GPIF System Total:		100.00		3.43

ACTUAL EQUIVALENT AVAILABILITY AND ADJUSTMENTS

JANUARY THROUGH DECEMBER, 2002

1	2	3	4	5	6	7	8	9			
	ACTUAL										ACTUAL FUEL SAVINGS/ (LOSS) ($000)
UNIT	FOF	MOF	POF	EAF	TARGET EAF	ADJ TO EAF (1)	ADJUSTED ACTUAL EAF	POINTS FROM TABLES	ORIGINAL PLANNED DATES	ACTUAL DATES	
Cape Canaveral 1	0.26	8.97	0.00	90.8	90.3	0.5	90.8	1.55	NONE	NONE	58.0
Cape Canaveral 2	0.82	9.80	3.72	85.7	88.2	-2.6	85.6	-8.74	04/03/02 - 04/17/02	12/2/2002 - 12/15/2002	(236.4)
Lauderdale 4	0.70	2.19	2.85	94.3	91.8	2.6	94.4	10.00	03/09/02 - 03/18/02	3/22/2002 - 4/02/2002	855.8
Lauderdale 5	0.16	3.72	2.52	93.6	91.9	1.6	93.4	6.26	09/28/02 - 10/07/02	10/25/2002 - 11/03/200	528.4
Manatee 1	0.87	1.68	3.81	93.6	81.5	8.3	89.8	10.00	04/15/02 - 05/12/02	10/22/2002 - 11/04/200	426.5
Manatee 2	0.42	1.64	3.86	94.1	85.4	4.7	90.1	10.00	04/20/02 - 05/19/02	11/07/2002 - 11/21/200	397.3
Martin 1	13.70	1.67	6.14	78.5	89.2	-9.0	80.2	-10.00	11/30/02 - 12/15/02	3/01/2002 - 3/24/2002	(351.1)
Martin 2	0.28	6.38	0.00	93.3	90.8	-1.3	89.5	-5.28	03/02/02 - 03/17/02	NONE	(209.5)
Martin 3	0.37	3.31	0.82	95.5	94.9	1.4	96.3	5.58	NONE	5/17/2002 - 5/22/2002	539.1
Martin 4	0.49	1.07	9.25	89.2	87.9	6.3	94.2	10.00	04/20/02 - 05/14/02	4/21/2002 - 4/30/2002	965.9
Port Everglades 3	1.19	6.19	3.84	88.8	94.3	-2.0	92.3	-7.91	NONE	11/09/2002 - 11/22/200	(216.0)
Port Everglades 4	0.75	0.64	9.24	89.4	86.0	4.7	90.7	10.00	11/02/02 - 12/01/02	4/07/2002 - 5/11/2002	277.2
Putnam 1	2.15	6.39	1.77	89.7	84.7	2.2	86.9	8.72	10/26/02 - 11/30/02	2/26/2002 - 3/04/2002	123.5
Riviera 3	0.25	3.25	4.12	92.4	84.4	11.9	96.3	10.00	NONE	4/08/2002 - 4/23/2002	505.9
Riviera 4	0.58	2.25	19.05	78.1	93.1	3.4	96.5	10.00	NONE	01/01/2002 - 2/23/2002	339.5
Turkey Point 1	0.95	2.77	0.00	96.3	85.4	3.7	89.2	10.00	11/30/02 - 12/27/02	NONE	261.0
Turkey Point 2	0.67	0.49	11.23	87.6	94.3	4.4	98.7	10.00	NONE	2/25/2002 - 4/07/2002	207.8
Turkey Point 3	0.00	0.00	0.36	99.6	93.6	6.4	100.0	10.00	NONE	NONE	5289.6
Turkey Point 4	0.23	0.00	4.27	95.5	86.0	5.6	91.6	10.00	03/25/02 - 04/24/02	3/23/2002 - 4/07/2002	4849.2
St. Lucie 1	0.08	0.00	7.39	92.5	86.0	5.7	91.7	10.00	09/30/02 - 10/30/02	9/30/2002 - 10/24/2002	5908.3
St. Lucie 2	0.00	0.00	0.30	99.7	93.6	6.4	100.0	10.00	NONE	NONE	5438.7
Scherer 4	1.52	3.53	11.38	83.6	84.4	-1.2	83.2	-5.93	11/09/02 - 12/22/02	11/09/2002 - 12/20/200	(1165.0)
											24793.6

(1) EQUIVALENT AVAILABILITY ADJUSTMENT DUE TO PLANNED OUTAGE ACTUAL DURATION VERSUS TARGETED DURATION
SEE 6.203.006 FOR FORMULAS AND CALCULATION DATA

EQUIVALENT AVAILABILITY ADJUSTMENTS
JANUARY THROUGH DECEMBER, 2002

	ACTUAL				TARGETS		ADJUSTED ACTUAL
PLANT / UNIT	PH	EFOH	EMOH	EPOH	POF%	EPOH	EAF%
Cape Canaveral 1	8760	22.8	786.2	0.0	0.0	0.0	90.8
Cape Canaveral 2	8760	71.7	858.3	325.6	3.8	332.9	85.6
Lauderdale 4	8760	61.3	192.1	249.5	2.7	236.5	94.4
Lauderdale 5	8760	14.4	325.6	221.2	2.7	236.5	93.4
Manatee 1	8760	76.4	147.6	333.5	7.7	674.5	89.8
Manatee 2	8760	36.4	143.6	337.9	7.9	692.0	90.1
Martin 1	8760	1200.3	146.7	538.0	4.1	359.2	80.2
Martin 2	8760	24.5	559.1	0.0	4.1	359.2	89.5
Martin 3	8760	32.0	269.8	71.5	0.0	0.0	96.3
Martin 4	8760	43.3	93.4	810.3	4.2	367.9	94.2
Port Everglades 3	8760	104.3	542.4	336.0	0.0	0.0	92.3
Port Everglades 4	8760	65.4	56.3	809.6	7.9	692.0	90.7
Putnam 1	8760	188.7	559.7	154.8	4.8	420.5	86.9
Riviera 3	8760	22.2	284.6	360.5	0.0	0.0	96.3
Riviera 4	8760	51.0	197.5	1668.5	0.0	0.0	96.5
Turkey Point 1	8760	82.8	242.5	0.0	7.4	648.2	89.2
Turkey Point 2	8760	58.6	43.3	983.7	0.0	0.0	98.7
Turkey Point 3	8760	0.0	0.0	31.6	0.0	0.0	100.0
Turkey Point 4	8760	19.8	0.0	374.5	8.2	720.0	91.6
St. Lucie 1	8760	6.6	0.0	647.1	8.2	720.0	91.7
St. Lucie 2	8760	0.0	0.0	26.4	0.0	0.0	100.0
Scherer 4	8760	133.3	309.4	996.6	11.8	1033.7	83.2

$$\text{ADJ. ACTUAL EAF\%} = 100\% - POF_T - \frac{(EFOH_A + EMOH_A) \times \frac{PH - EPOH_T}{PH - EPOH_A}}{PH} \times 100\%$$

ADJUSTMENTS TO AVERAGE NET OPERATING HEAT RATES & ADJUSTMENTS SUMMARY

JANUARY THROUGH DECEMBER, 2002

1	2	3	4	5	6	7	8	9	
		ACTUAL		TARGET (2)	ADJUST.(3)		ADJUST.(5)		ACTUAL
UNIT	HEAT RATE (1) FORMULA	NOF %	ANOHR BTU/KWH	ANOHR AT ACTUAL NOF BTU/KWH	TO ANOHR BTU/KWH	TARGET (4) ANOHR BTU/KWH	ACTUAL ANOHR BTU/KWH	GPIF(6) FROM TABLE	FUEL SAV./(LOSS) $000
Cape Canaveral 1	ANOHR = -16.85 x NOF + 10788	65.5	9727	9684	43	9163	9207	0.00	0.0
Cape Canaveral 2	ANOHR = -17.90 x NOF + 10900	64.0	9661	9754	-93	9209	9115	1.22	113.5
Lauderdale 4	ANOHR = -9.46 x NOF + 8271	87.8	7618	7441	177	7351	7528	-7.73	(1099.6)
Lauderdale 5	ANOHR = -11.86 x NOF + 8470	87.2	7535	7436	99	7303	7401	-1.93	(261.8)
Manatee 1	ANOHR = -14.77 x NOF + 11200	53.4	10415	10411	4	9861	9865	0.00	0.0
Manatee 2	ANOHR = -6.62 x NOF + 10668	55.5	10335	10300	35	10054	10088	0.00	0.0
Martin 1	ANOHR = -29.41 x NOF + 11785	57.4	9990	10097	-107	9147	9040	1.04	262.8
Martin 2	ANOHR = -30.12 x NOF + 11702	57.1	10012	9982	30	8884	8914	0.00	0.0
Martin 3	ANOHR = -0.64 x NOF + 6891	93.4	6958	6831	127	6828	6954	-4.68	(716.7)
Martin 4	ANOHR = -4.07 x NOF + 7134	92.2	7028	6759	269	6734	7004	-10.00	(1563.8)
Port Everglades 3	ANOHR = -17.96 x NOF + 11090	66.5	9929	9896	33	9355	9388	0.00	0.0
Port Everglades 4	ANOHR = -24.58 x NOF + 11568	65.3	9933	9963	-30	9192	9162	0.00	0.0
Putnam 1	ANOHR = -32.48 x NOF + 11676	79.2	9261	9104	157	8679	8836	-5.21	(377.3)
Riviera 3	ANOHR = -15.29 x NOF + 11282	61.7	10327	10338	-11	9809	9797	0.00	0.0
Riviera 4	ANOHR = -13.69 x NOF + 11109	66.8	9762	10194	-432	9797	9366	10.00	676.9
Turkey Point 1	ANOHR = -20.37 x NOF + 10909	61.3	9783	9660	123	8960	9083	-2.64	(343.9)
Turkey Point 2	ANOHR = -10.35 x NOF + 10372	62.7	9645	9723	-78	9410	9332	0.16	12.3
Turkey Point 3	ANOHR = -61.99 x NOF + 17338	103.2	10994	10939	55	11137	11193	0.00	0.0
Turkey Point 4	ANOHR = -26.91 x NOF + 13771	101.9	11069	11031	38	11079	11117	0.00	0.0
St. Lucie 1	ANOHR = -15.51 x NOF + 12345	101.1	10795	10777	18	10793	10811	0.00	0.0
St. Lucie 2	ANOHR = -11.94 x NOF + 12021	101.2	10836	10812	24	10826	10850	0.00	0.0
Scherer 4	ANOHR = -8.58 x NOF + 10955	85.0	10225	10226	-1	10098	10097	0.00	0.0
									(3297.6)

1) THESE FORMULAS ARE AS APPROVED BY THE COMMISSION IN THE PROJECTED DATA AND REFLECT ON MONTHLY ACTUAL DATA
2) CALCULATED FROM ANOHR FORMULA IN COLUMN 2 USING ACTUAL NOF IN COLUMN 3
3) ADJUSTMENT TO ANOHR=ACTUAL ANOHR - TARGET ANOHR AT ACTUAL NOF (COLUMN 6 = COLUMN 4 - COLUMN 5).
4) AT TARGET NOF AS APPROVED BY THE COMMISSION IN PROJECTED DATA.
5) AT TARGET NOF, ADJUSTED ACTUAL ANOHR = TARGET ANOHR + ADJUSTMENTS (COLUMN 8 = COLUMN 7 + COLUMN 6).
6) OBTAINED FROM GPIF POINTS TABLES AS APPROVED BY THE COMMISSION IN PROJECTED TARGETS.

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Cape Canaveral 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	374.97	93.30		+10	700.14	9009	
+9	337.47	93.00		+9	630.12	9017	
+8	299.98	92.70		+8	560.11	9025	
+7	262.48	92.40		+7	490.09	9033	
+6	224.98	92.10		+6	420.08	9041	
+5	187.49	91.80		+5	350.07	9049	
+4	149.99	91.50		+4	280.05	9057	
+3	112.49	91.20		+3	210.04	9065	
+2	74.99	90.90		+2	140.03	9072	
+1	37.50	90.60	<- Adj. Act. EAF= 90.76	+1	70.01	9080	
					0.00	9088	
0	0.00	90.30		0	0.00	9163	<- Adj. Act. HR=9207
					(0.00)	9238	
-1	(-37.59)	90.00		-1	(-70.01)	9246	
-2	(-75.18)	89.70		-2	(-140.03)	9254	
-3	(-112.77)	89.40		-3	(-210.04)	9262	
-4	(-150.36)	89.10		-4	(-280.05)	9270	
-5	(-187.95)	88.80		-5	(-350.07)	9278	
-6	(-225.54)	88.50		-6	(-420.08)	9286	
-7	(-263.12)	88.20		-7	(-490.09)	9294	
-8	(-300.71)	87.90		-8	(-560.11)	9302	
-9	(-338.30)	87.60		-9	(-630.12)	9309	
-10	(-375.89)	87.30		-10	(-700.14)	9317	
	WEIGHTING FACTOR =	0.60			WEIGHTING FACTOR =	1.12	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Cape Canaveral 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	268.44	91.22		+10	930.77	8983	
+9	241.59	90.92		+9	837.69	8998	
+8	214.75	90.62		+8	744.62	9013	
+7	187.91	90.32		+7	651.54	9028	
+6	161.06	90.02		+6	558.46	9043	
+5	134.22	89.72		+5	465.39	9058	
+4	107.38	89.42		+4	372.31	9073	
+3	80.53	89.12		+3	279.23	9088	
+2	53.69	88.82		+2	186.15	9104	<- Adj. Act. HR=9115
+1	26.84	88.52		+1	93.08	9119	
					0.00	9134	
0	0.00	88.22		0	0.00	9209	
					(0.00)	9284	
-1	(-27.04)	87.92		-1	(-93.08)	9299	
-2	(-54.08)	87.62		-2	(-186.15)	9314	
-3	(-81.12)	87.32		-3	(-279.23)	9329	
-4	(-108.16)	87.02		-4	(-372.31)	9344	
-5	(-135.20)	86.72		-5	(-465.39)	9359	
-6	(-162.24)	86.42		-6	(-558.46)	9374	
-7	(-189.28)	86.12		-7	(-651.54)	9389	
-8	(-216.32)	85.82		-8	(-744.62)	9404	
-9	(-243.36)	85.52	<- Adj. Act. EAF= 85.59	-9	(-837.69)	9419	
-10	(-270.40)	85.22		-10	(-930.77)	9434	
	WEIGHTING FACTOR =	0.43			WEIGHTING FACTOR =	1.49	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Lauderdale 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	855.80	94.26	<- Adj. Act. EAF= 94.40	+10	1422.72	7143	
+9	770.22	94.01		+9	1280.45	7157	
+8	684.64	93.76		+8	1138.18	7170	
+7	599.06	93.51		+7	995.91	7183	
+6	513.48	93.26		+6	853.63	7196	
+5	427.90	93.01		+5	711.36	7210	
+4	342.32	92.76		+4	569.09	7223	
+3	256.74	92.51		+3	426.82	7236	
+2	171.16	92.26		+2	284.54	7249	
+1	85.58	92.01		+1	142.27	7263	
					0.00	7276	
0	0.00	91.76		0	0.00	7351	
					(0.00)	7426	
-1	(-85.89)	91.51		-1	(-142.27)	7439	
-2	(-171.77)	91.26		-2	(-284.54)	7452	
-3	(-257.66)	91.01		-3	(-426.82)	7466	
-4	(-343.54)	90.76		-4	(-569.09)	7479	
-5	(-429.43)	90.51		-5	(-711.36)	7492	
-6	(-515.32)	90.26		-6	(-853.63)	7506	
-7	(-601.20)	90.01		-7	(-995.91)	7519	<- Adj. Act. HR=7528
-8	(-687.09)	89.76		-8	(-1138.18)	7532	
-9	(-772.97)	89.51		-9	(-1280.45)	7545	
-10	(-858.86)	89.26		-10	(-1422.72)	7559	
	WEIGHTING FACTOR =	1.37			WEIGHTING FACTOR =	2.27	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Lauderdale 5

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	844.77	94.36		+10	1358.46	7103	
+9	760.29	94.11		+9	1222.61	7116	
+8	675.81	93.86		+8	1086.77	7128	
+7	591.34	93.61		+7	950.92	7141	
+6	506.86	93.36	<- Adj. Act. EAF= 93.43	+6	815.07	7153	
+5	422.38	93.11		+5	679.23	7165	
+4	337.91	92.86		+4	543.38	7178	
+3	253.43	92.61		+3	407.54	7190	
+2	168.95	92.36		+2	271.69	7203	
+1	84.48	92.11		+1	135.85	7215	
					0.00	7228	
0	0.00	91.86		0	0.00	7303	
					(0.00)	7378	
-1	(-84.59)	91.61		-1	(-135.85)	7390	<- Adj. Act. HR=7401
-2	(-169.18)	91.36		-2	(-271.69)	7402	
-3	(-253.77)	91.11		-3	(-407.54)	7415	
-4	(-338.36)	90.86		-4	(-543.38)	7427	
-5	(-422.94)	90.61		-5	(-679.23)	7440	
-6	(-507.53)	90.36		-6	(-815.07)	7452	
-7	(-592.12)	90.11		-7	(-950.92)	7465	
-8	(-676.71)	89.86		-8	(-1086.77)	7477	
-9	(-761.30)	89.61		-9	(-1222.61)	7489	
-10	(-845.89)	89.36		-10	(-1358.46)	7502	
	WEIGHTING FACTOR =	1.35			WEIGHTING FACTOR =	2.17	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Manatee 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	426.45	84.53	<- Adj. Act. EAF= 89.85	+10	1133.93	9667	
+9	383.81	84.23		+9	1020.54	9679	
+8	341.16	83.93		+8	907.14	9690	
+7	298.52	83.63		+7	793.75	9702	
+6	255.87	83.33		+6	680.36	9714	
+5	213.23	83.03		+5	566.97	9726	
+4	170.58	82.73		+4	453.57	9738	
+3	127.94	82.43		+3	340.18	9750	
+2	85.29	82.13		+2	226.79	9762	
+1	42.65	81.83		+1	113.39	9774	
					0.00	9786	
0	0.00	81.53		0	0.00	9861	<- Adj. Act. HR=9865
					(0.00)	9936	
-1	(-43.06)	81.23		-1	(-176.99)	9948	
-2	(-86.12)	80.93		-2	(-353.99)	9960	
-3	(-129.18)	80.63		-3	(-530.98)	9972	
-4	(-172.24)	80.33		-4	(-707.98)	9984	
-5	(-215.30)	80.03		-5	(-884.97)	9996	
-6	(-258.36)	79.73		-6	(-1061.97)	10008	
-7	(-301.42)	79.43		-7	(-1238.96)	10020	
-8	(-344.48)	79.13		-8	(-1415.95)	10031	
-9	(-387.53)	78.83		-9	(-1592.95)	10043	
-10	(-430.59)	78.53		-10	(-1769.94)	10055	
	WEIGHTING FACTOR =	0.68			WEIGHTING FACTOR =	1.81	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Manatee 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	397.31	87.90	<- Adj. Act. EAF= 90.13	+10	1769.94	9839	
+9	357.58	87.65		+9	1592.95	9853	
+8	317.85	87.40		+8	1415.95	9867	
+7	278.12	87.15		+7	1238.96	9881	
+6	238.39	86.90		+6	1061.97	9895	
+5	198.66	86.65		+5	884.97	9909	
+4	158.92	86.40		+4	707.98	9923	
+3	119.19	86.15		+3	530.98	9937	
+2	79.46	85.90		+2	353.99	9951	
+1	39.73	85.65		+1	176.99	9965	
					0.00	9979	
0	0.00	85.40		0	0.00	10054	<- Adj. Act. HR=10088
					(0.00)	10129	
-1	(-39.81)	85.15		-1	(-176.99)	10143	
-2	(-79.63)	84.90		-2	(-353.99)	10157	
-3	(-119.44)	84.65		-3	(-530.98)	10171	
-4	(-159.26)	84.40		-4	(-707.98)	10185	
-5	(-199.07)	84.15		-5	(-884.97)	10199	
-6	(-238.88)	83.90		-6	(-1061.97)	10213	
-7	(-278.70)	83.65		-7	(-1238.96)	10227	
-8	(-318.51)	83.40		-8	(-1415.95)	10241	
-9	(-358.33)	83.15		-9	(-1592.95)	10255	
-10	(-398.14)	82.90		-10	(-1769.94)	10269	
	WEIGHTING FACTOR =	0.63			WEIGHTING FACTOR =	2.83	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Martin 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	351.11	91.74		+10	2535.42	8767	
+9	316.00	91.49		+9	2281.88	8798	
+8	280.89	91.24		+8	2028.34	8828	
+7	245.78	90.99		+7	1774.79	8859	
+6	210.67	90.74		+6	1521.25	8889	
+5	175.55	90.49		+5	1267.71	8920	
+4	140.44	90.24		+4	1014.17	8950	
+3	105.33	89.99		+3	760.63	8981	
+2	70.22	89.74		+2	507.08	9011	<- Adj. Act. HR=9040
+1	35.11	89.49		+1	253.54	9042	
					0.00	9072	
0	0.00	89.24		0	0.00	9147	
					(0.00)	9222	
-1	(-35.11)	88.99		-1	(-253.54)	9253	
-2	(-70.21)	88.74		-2	(-507.08)	9283	
-3	(-105.32)	88.49		-3	(-760.63)	9314	
-4	(-140.42)	88.24		-4	(-1014.17)	9344	
-5	(-175.53)	87.99		-5	(-1267.71)	9375	
-6	(-210.64)	87.74		-6	(-1521.25)	9405	
-7	(-245.74)	87.49		-7	(-1774.79)	9436	
-8	(-280.85)	87.24		-8	(-2028.34)	9466	
-9	(-315.95)	86.99		-9	(-2281.88)	9496	
-10	(-351.06)	86.74	<- Adj. Act. EAF= 80.19	-10	(-2535.42)	9527	
	WEIGHTING FACTOR =	0.56			WEIGHTING FACTOR =	4.05	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Martin 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	395.61	93.33		+10	4019.61	8511	
+9	356.05	93.08		+9	3617.65	8541	
+8	316.49	92.83		+8	3215.69	8570	
+7	276.93	92.58		+7	2813.73	8600	
+6	237.37	92.33		+6	2411.76	8630	
+5	197.81	92.08		+5	2009.80	8660	
+4	158.24	91.83		+4	1607.84	8690	
+3	118.68	91.58		+3	1205.88	8719	
+2	79.12	91.33		+2	803.92	8749	
+1	39.56	91.08		+1	401.96	8779	
					0.00	8809	
0	0.00	90.83		0	0.00	8884	<- Adj. Act. HR=8914
					(0.00)	8959	
-1	(-39.68)	90.58		-1	(-401.96)	8989	
-2	(-79.36)	90.33		-2	(-803.92)	9018	
-3	(-119.05)	90.08		-3	(-1205.88)	9048	
-4	(-158.73)	89.83		-4	(-1607.84)	9078	
-5	(-198.41)	89.58		-5	(-2009.80)	9108	
-6	(-238.09)	89.33	<- Adj. Act. EAF= 89.51	-6	(-2411.76)	9138	
-7	(-277.78)	89.08		-7	(-2813.73)	9167	
-8	(-317.46)	88.83		-8	(-3215.69)	9197	
-9	(-357.14)	88.58		-9	(-3617.65)	9227	
-10	(-396.82)	88.33		-10	(-4019.61)	9257	
	WEIGHTING FACTOR =	0.63			WEIGHTING FACTOR =	6.42	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Martin 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	965.50	97.40		+10	1532.74	6642	
+9	868.95	97.15		+9	1379.47	6653	
+8	772.40	96.90		+8	1226.19	6664	
+7	675.85	96.65		+7	1072.92	6675	
+6	579.30	96.40		+6	919.64	6686	
+5	482.75	96.15	<- Adj. Act. EAF= 96.30	+5	766.37	6697	
+4	386.20	95.90		+4	613.10	6708	
+3	289.65	95.65		+3	459.82	6719	
+2	193.10	95.40		+2	306.55	6730	
+1	96.55	95.15		+1	153.27	6741	
					0.00	6753	
0	0.00	94.90		0	0.00	6828	
					(0.00)	6903	
-1	(-96.93)	94.65		-1	(-153.27)	6914	
-2	(-193.86)	94.40		-2	(-306.55)	6925	
-3	(-290.79)	94.15		-3	(-459.82)	6936	
-4	(-387.72)	93.90		-4	(-613.10)	6947	<- Adj. Act. HR=6954
-5	(-484.65)	93.65		-5	(-766.37)	6958	
-6	(-581.58)	93.40		-6	(-919.64)	6969	
-7	(-678.51)	93.15		-7	(-1072.92)	6980	
-8	(-775.44)	92.90		-8	(-1226.19)	6991	
-9	(-872.37)	92.65		-9	(-1379.47)	7002	
-10	(-969.30)	92.40		-10	(-1532.74)	7014	
	WEIGHTING FACTOR =	1.54			WEIGHTING FACTOR =	2.45	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Martin 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	965.94	90.40	<- Adj. Act. EAF= 94.15	+10	1563.77	6548	
+9	869.34	90.15		+9	1407.39	6559	
+8	772.75	89.90		+8	1251.02	6570	
+7	676.16	89.65		+7	1094.64	6581	
+6	579.56	89.40		+6	938.26	6593	
+5	482.97	89.15		+5	781.89	6604	
+4	386.38	88.90		+4	625.51	6615	
+3	289.78	88.65		+3	469.13	6626	
+2	193.19	88.40		+2	312.75	6637	
+1	96.59	88.15		+1	156.38	6648	
					0.00	6659	
0	0.00	87.90		0	0.00	6734	
					(0.00)	6809	
-1	(-96.58)	87.65		-1	(-156.38)	6821	
-2	(-193.16)	87.40		-2	(-312.75)	6832	
-3	(-289.74)	87.15		-3	(-469.13)	6843	
-4	(-386.32)	86.90		-4	(-625.51)	6854	
-5	(-482.91)	86.65		-5	(-781.89)	6865	
-6	(-579.49)	86.40		-6	(-938.26)	6876	
-7	(-676.07)	86.15		-7	(-1094.64)	6887	
-8	(-772.65)	85.90		-8	(-1251.02)	6898	
-9	(-869.23)	85.65		-9	(-1407.39)	6910	
-10	(-965.81)	85.40		-10	(-1563.77)	6921	<- Adj. Act. HR=7004
	WEIGHTING FACTOR =	1.54			WEIGHTING FACTOR =	2.50	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Port Everglades 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	272.89	96.80		+10	1464.31	9086	
+9	245.60	96.55		+9	1317.88	9105	
+8	218.31	96.30		+8	1171.45	9125	
+7	191.03	96.05		+7	1025.02	9144	
+6	163.74	95.80		+6	878.59	9164	
+5	136.45	95.55		+5	732.15	9183	
+4	109.16	95.30		+4	585.72	9203	
+3	81.87	95.05		+3	439.29	9222	
+2	54.58	94.80		+2	292.86	9241	
+1	27.29	94.55		+1	146.43	9261	
					0.00	9280	
0	0.00	94.30		0	0.00	9355	<- Adj. Act. HR=9388
					(0.00)	9430	
-1	(-27.32)	94.05		-1	(-146.43)	9450	
-2	(-54.64)	93.80		-2	(-292.86)	9469	
-3	(-81.97)	93.55		-3	(-439.29)	9489	
-4	(-109.29)	93.30		-4	(-585.72)	9508	
-5	(-136.61)	93.05		-5	(-732.15)	9528	
-6	(-163.93)	92.80		-6	(-878.59)	9547	
-7	(-191.25)	92.55		-7	(-1025.02)	9566	
-8	(-218.58)	92.30	<- Adj. Act. EAF= 92.32	-8	(-1171.45)	9586	
-9	(-245.90)	92.05		-9	(-1317.88)	9605	
-10	(-273.22)	91.80		-10	(-1464.31)	9625	
	WEIGHTING FACTOR =	0.44			WEIGHTING FACTOR =	2.34	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Port Everglades 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	277.16	88.50	<- Adj. Act. EAF= 90.69	+10	1878.32	8886	
+9	249.44	88.25		+9	1690.49	8909	
+8	221.73	88.00		+8	1502.66	8932	
+7	194.01	87.75		+7	1314.83	8955	
+6	166.29	87.50		+6	1126.99	8978	
+5	138.58	87.25		+5	939.16	9001	
+4	110.86	87.00		+4	751.33	9025	
+3	83.15	86.75		+3	563.50	9048	
+2	55.43	86.50		+2	375.66	9071	
+1	27.72	86.25		+1	187.83	9094	
					0.00	9117	<- Adj. Act. HR=9162
0	0.00	86.00		0	0.00	9192	
					(0.00)	9267	
-1	(-27.74)	85.75		-1	(-187.83)	9291	
-2	(-55.48)	85.50		-2	(-375.66)	9314	
-3	(-83.21)	85.25		-3	(-563.50)	9337	
-4	(-110.95)	85.00		-4	(-751.33)	9360	
-5	(-138.69)	84.75		-5	(-939.16)	9383	
-6	(-166.43)	84.50		-6	(-1126.99)	9406	
-7	(-194.16)	84.25		-7	(-1314.83)	9430	
-8	(-221.90)	84.00		-8	(-1502.66)	9453	
-9	(-249.64)	83.75		-9	(-1690.49)	9476	
-10	(-277.38)	83.50		-10	(-1878.32)	9499	
	WEIGHTING FACTOR =	0.44			WEIGHTING FACTOR =	3.00	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Putnam 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	141.66	87.24		+10	724.44	8447	
+9	127.49	86.99		+9	652.00	8463	
+8	113.32	86.74	<- Adj. Act. EAF= 86.92	+8	579.55	8479	
+7	99.16	86.49		+7	507.11	8495	
+6	84.99	86.24		+6	434.66	8510	
+5	70.83	85.99		+5	362.22	8526	
+4	56.66	85.74		+4	289.78	8542	
+3	42.50	85.49		+3	217.33	8557	
+2	28.33	85.24		+2	144.89	8573	
+1	14.17	84.99		+1	72.44	8589	
					0.00	8604	
0	0.00	84.74		0	0.00	8679	
					(0.00)	8754	
-1	(-14.21)	84.49		-1	(-72.44)	8770	
-2	(-28.41)	84.24		-2	(-144.89)	8786	
-3	(-42.62)	83.99		-3	(-217.33)	8801	
-4	(-56.83)	83.74		-4	(-289.78)	8817	
-5	(-71.03)	83.49		-5	(-362.22)	8833	<- Adj. Act. HR=8836
-6	(-85.24)	83.24		-6	(-434.66)	8848	
-7	(-99.44)	82.99		-7	(-507.11)	8864	
-8	(-113.65)	82.74		-8	(-579.55)	8880	
-9	(-127.86)	82.49		-9	(-652.00)	8896	
-10	(-142.06)	82.24		-10	(-724.44)	8911	
	WEIGHTING FACTOR =	0.23			WEIGHTING FACTOR =	1.16	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Riviera 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	505.89	87.90	<- Adj. Act. EAF= 96.35	+10	852.68	9578	
+9	455.30	87.55		+9	767.41	9594	
+8	404.71	87.20		+8	682.14	9609	
+7	354.12	86.85		+7	596.87	9625	
+6	303.53	86.50		+6	511.61	9640	
+5	252.95	86.15		+5	426.34	9656	
+4	202.36	85.80		+4	341.07	9671	
+3	151.77	85.45		+3	255.80	9687	
+2	101.18	85.10		+2	170.54	9703	
+1	50.59	84.75		+1	85.27	9718	
					0.00	9734	<- Adj. Act. HR=9797
0	0.00	84.40		0	0.00	9809	
					(0.00)	9884	
-1	(-50.41)	84.05		-1	(-85.27)	9899	
-2	(-100.83)	83.70		-2	(-170.54)	9915	
-3	(-151.24)	83.35		-3	(-255.80)	9930	
-4	(-201.66)	83.00		-4	(-341.07)	9946	
-5	(-252.07)	82.65		-5	(-426.34)	9961	
-6	(-302.48)	82.30		-6	(-511.61)	9977	
-7	(-352.90)	81.95		-7	(-596.87)	9993	
-8	(-403.31)	81.60		-8	(-682.14)	10008	
-9	(-453.73)	81.25		-9	(-767.41)	10024	
-10	(-504.14)	80.90		-10	(-852.68)	10039	
	WEIGHTING FACTOR =	0.81			WEIGHTING FACTOR =	1.36	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Riviera 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	339.47	95.60	<- Adj. Act. EAF= 96.50	+10	676.90	9592	<- Adj. Act. HR=9366
+9	305.52	95.35		+9	609.21	9605	
+8	271.58	95.10		+8	541.52	9618	
+7	237.63	94.85		+7	473.83	9631	
+6	203.68	94.60		+6	406.14	9644	
+5	169.74	94.35		+5	338.45	9657	
+4	135.79	94.10		+4	270.76	9670	
+3	101.84	93.85		+3	203.07	9683	
+2	67.89	93.60		+2	135.38	9696	
+1	33.95	93.35		+1	67.69	9709	
					0.00	9722	
0	0.00	93.10		0	0.00	9797	
					(0.00)	9872	
-1	(-33.79)	92.85		-1	(-67.69)	9885	
-2	(-67.58)	92.60		-2	(-135.38)	9898	
-3	(-101.38)	92.35		-3	(-203.07)	9911	
-4	(-135.17)	92.10		-4	(-270.76)	9924	
-5	(-168.96)	91.85		-5	(-338.45)	9937	
-6	(-202.75)	91.60		-6	(-406.14)	9950	
-7	(-236.55)	91.35		-7	(-473.83)	9963	
-8	(-270.34)	91.10		-8	(-541.52)	9976	
-9	(-304.13)	90.85		-9	(-609.21)	9989	
-10	(-337.92)	90.60		-10	(-676.90)	10002	
	WEIGHTING FACTOR =	0.54			WEIGHTING FACTOR =	1.08	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Turkey Point 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	261.00	87.95	<- Adj. Act. EAF= 89.16	+10	1304.28	8704	
+9	234.90	87.70		+9	1173.85	8722	
+8	208.80	87.45		+8	1043.42	8740	
+7	182.70	87.20		+7	912.99	8758	
+6	156.60	86.95		+6	782.57	8777	
+5	130.50	86.70		+5	652.14	8795	
+4	104.40	86.45		+4	521.71	8813	
+3	78.30	86.20		+3	391.28	8831	
+2	52.20	85.95		+2	260.86	8849	
+1	26.10	85.70		+1	130.43	8867	
					0.00	8885	
0	0.00	85.45		0	0.00	8960	
					(0.00)	9035	
-1	(-26.08)	85.20		-1	(-130.43)	9053	
-2	(-52.17)	84.95		-2	(-260.86)	9071	<- Adj. Act. HR=9083
-3	(-78.25)	84.70		-3	(-391.28)	9089	
-4	(-104.33)	84.45		-4	(-521.71)	9107	
-5	(-130.41)	84.20		-5	(-652.14)	9125	
-6	(-156.50)	83.95		-6	(-782.57)	9143	
-7	(-182.58)	83.70		-7	(-912.99)	9161	
-8	(-208.66)	83.45		-8	(-1043.42)	9179	
-9	(-234.74)	83.20		-9	(-1173.85)	9197	
-10	(-260.83)	82.95		-10	(-1304.28)	9216	
	WEIGHTING FACTOR =	0.42			WEIGHTING FACTOR =	2.08	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Turkey Point 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	207.84	96.80	<- Adj. Act. EAF= 98.69	+10	768.04	9160	
+9	187.06	96.55		+9	691.24	9178	
+8	166.28	96.30		+8	614.43	9195	
+7	145.49	96.05		+7	537.63	9213	
+6	124.71	95.80		+6	460.82	9230	
+5	103.92	95.55		+5	384.02	9248	
+4	83.14	95.30		+4	307.22	9265	
+3	62.35	95.05		+3	230.41	9283	
+2	41.57	94.80		+2	153.61	9300	
+1	20.78	94.55		+1	76.80	9318	<- Adj. Act. HR=9332
					0.00	9335	
0	0.00	94.30		0	0.00	9410	
					(0.00)	9485	
-1	(-20.72)	94.05		-1	(-76.80)	9503	
-2	(-41.43)	93.80		-2	(-153.61)	9520	
-3	(-62.15)	93.55		-3	(-230.41)	9538	
-4	(-82.87)	93.30		-4	(-307.22)	9555	
-5	(-103.59)	93.05		-5	(-384.02)	9573	
-6	(-124.30)	92.80		-6	(-460.82)	9590	
-7	(-145.02)	92.55		-7	(-537.63)	9608	
-8	(-165.74)	92.30		-8	(-614.43)	9625	
-9	(-186.45)	92.05		-9	(-691.24)	9643	
-10	(-207.17)	91.80		-10	(-768.04)	9660	
	WEIGHTING FACTOR =	0.33			WEIGHTING FACTOR =	1.23	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Turkey Point 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	5,289.63	96.60	<- Adj. Act. EAF= 100.00	+10	1058.34	10967	
+9	4,760.66	96.30		+9	952.51	10977	
+8	4,231.70	96.00		+8	846.67	10986	
+7	3,702.74	95.70		+7	740.84	10996	
+6	3,173.78	95.40		+6	635.01	11005	
+5	2,644.81	95.10		+5	529.17	11015	
+4	2,115.85	94.80		+4	423.34	11024	
+3	1,586.89	94.50		+3	317.50	11034	
+2	1,057.93	94.20		+2	211.67	11043	
+1	528.96	93.90		+1	105.83	11053	
					0.00	11062	
0	0.00	93.60		0	0.00	11137	<- Adj. Act. HR=11193
					(0.00)	11212	
-1	(-635.97)	93.30		-1	(-101.06)	11222	
-2	(-1,271.93)	93.00		-2	(-202.13)	11231	
-3	(-1,907.90)	92.70		-3	(-303.19)	11241	
-4	(-2,543.86)	92.40		-4	(-404.26)	11250	
-5	(-3,179.83)	92.10		-5	(-505.32)	11260	
-6	(-3,815.79)	91.80		-6	(-606.38)	11269	
-7	(-4,451.76)	91.50		-7	(-707.45)	11279	
-8	(-5,087.72)	91.20		-8	(-808.51)	11288	
-9	(-5,723.69)	90.90		-9	(-909.58)	11298	
-10	(-6,359.66)	90.60		-10	(-1010.64)	11307	
	WEIGHTING FACTOR =	8.45			WEIGHTING FACTOR =	1.69	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Turkey Point 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	4,849.17	88.98	<- Adj. Act. EAF= 91.56	+10	748.61	10848	
+9	4,364.26	88.68		+9	673.75	10863	
+8	3,879.34	88.38		+8	598.89	10879	
+7	3,394.42	88.08		+7	524.03	10895	
+6	2,909.50	87.78		+6	449.16	10910	
+5	2,424.59	87.48		+5	374.30	10926	
+4	1,939.67	87.18		+4	299.44	10941	
+3	1,454.75	86.88		+3	224.58	10957	
+2	969.83	86.58		+2	149.72	10973	
+1	484.92	86.28		+1	74.86	10988	
					0.00	11004	
0	0.00	85.98		0	0.00	11079	<- Adj. Act. HR=11117
					(0.00)	11154	
-1	(-582.93)	85.68		-1	(-74.53)	11169	
-2	(-1,165.86)	85.38		-2	(-149.07)	11185	
-3	(-1,748.79)	85.08		-3	(-223.60)	11200	
-4	(-2,331.72)	84.78		-4	(-298.13)	11216	
-5	(-2,914.65)	84.48		-5	(-372.66)	11232	
-6	(-3,497.58)	84.18		-6	(-447.20)	11247	
-7	(-4,080.51)	83.88		-7	(-521.73)	11263	
-8	(-4,663.44)	83.58		-8	(-596.26)	11278	
-9	(-5,246.36)	83.28		-9	(-670.80)	11294	
-10	(-5,829.29)	82.98		-10	(-745.33)	11310	
	WEIGHTING FACTOR =	7.75			WEIGHTING FACTOR =	1.20	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: St. Lucie 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	5,908.28	88.98	<- Adj. Act. EAF= 91.71	+10	1718.50	10673	
+9	5,317.45	88.68		+9	1546.65	10677	
+8	4,726.63	88.38		+8	1374.80	10682	
+7	4,135.80	88.08		+7	1202.95	10686	
+6	3,544.97	87.78		+6	1031.10	10691	
+5	2,954.14	87.48		+5	859.25	10695	
+4	2,363.31	87.18		+4	687.40	10700	
+3	1,772.48	86.88		+3	515.55	10704	
+2	1,181.66	86.58		+2	343.70	10709	
+1	590.83	86.28		+1	171.85	10713	
					0.00	10718	
0	0.00	85.98		0	0.00	10793	<- Adj. Act. HR=10811
					(0.00)	10868	
-1	(-710.36)	85.68		-1	(-168.28)	10872	
-2	(-1,420.72)	85.38		-2	(-336.56)	10877	
-3	(-2,131.09)	85.08		-3	(-504.84)	10881	
-4	(-2,841.45)	84.78		-4	(-673.12)	10886	
-5	(-3,551.81)	84.48		-5	(-841.40)	10890	
-6	(-4,262.17)	84.18		-6	(-1009.68)	10895	
-7	(-4,972.54)	83.88		-7	(-1177.96)	10899	
-8	(-5,682.90)	83.58		-8	(-1346.24)	10904	
-9	(-6,393.26)	83.28		-9	(-1514.52)	10908	
-10	(-7,103.62)	82.98		-10	(-1682.80)	10913	
	WEIGHTING FACTOR =	9.44			WEIGHTING FACTOR =	2.75	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: St. Lucie 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	5,438.72	96.60	<- Adj. Act. EAF= 100.00	+10	2575.64	10716	
+9	4,894.85	96.30		+9	2318.08	10719	
+8	4,350.98	96.00		+8	2060.51	10723	
+7	3,807.11	95.70		+7	1802.95	10727	
+6	3,263.23	95.40		+6	1545.38	10730	
+5	2,719.36	95.10		+5	1287.82	10734	
+4	2,175.49	94.80		+4	1030.26	10737	
+3	1,631.62	94.50		+3	772.69	10741	
+2	1,087.74	94.20		+2	515.13	10744	
+1	543.87	93.90		+1	257.56	10748	
					0.00	10751	
0	0.00	93.60		0	0.00	10826	<- Adj. Act. HR=10850
					(0.00)	10901	
-1	(-653.89)	93.30		-1	(-276.15)	10905	
-2	(-1,307.78)	93.00		-2	(-552.31)	10908	
-3	(-1,961.67)	92.70		-3	(-828.46)	10912	
-4	(-2,615.56)	92.40		-4	(-1104.61)	10916	
-5	(-3,269.45)	92.10		-5	(-1380.77)	10919	
-6	(-3,923.33)	91.80		-6	(-1656.92)	10923	
-7	(-4,577.22)	91.50		-7	(-1933.07)	10926	
-8	(-5,231.11)	91.20		-8	(-2209.23)	10930	
-9	(-5,885.00)	90.90		-9	(-2485.38)	10933	
-10	(-6,538.89)	90.60		-10	(-2761.53)	10937	
	WEIGHTING FACTOR =	8.69			WEIGHTING FACTOR =	4.12	

GENERATING PERFORMANCE INCENTIVE POINTS TABLES
FLORIDA POWER & LIGHT COMPANY
PERIOD OF JANUARY THROUGH DECEMBER, 2002

UNIT: Scherer 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY		AVERAGE HEAT RATE POINTS	FUEL SAVING/(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATES	
+10	1,976.39	86.36		+10	525.27	9960	
+9	1,778.75	86.16		+9	472.74	9966	
+8	1,581.11	85.96		+8	420.22	9972	
+7	1,383.47	85.76		+7	367.69	9979	
+6	1,185.83	85.56		+6	315.16	9985	
+5	988.20	85.36		+5	262.64	9991	
+4	790.56	85.16		+4	210.11	9998	
+3	592.92	84.96		+3	157.58	10004	
+2	395.28	84.76		+2	105.05	10010	
+1	197.64	84.56		+1	52.53	10017	
					0.00	10023	<- Adj. Act. HR=10097
0	0.00	84.36		0	0.00	10098	
					(0.00)	10173	
-1	(-196.62)	84.16		-1	(-52.53)	10179	
-2	(-393.25)	83.96		-2	(-105.05)	10186	
-3	(-589.87)	83.76		-3	(-157.58)	10192	
-4	(-786.49)	83.56		-4	(-210.11)	10198	
-5	(-983.12)	83.36		-5	(-262.64)	10205	
-6	(-1,179.74)	83.16	<- Adj. Act. EAF= 83.17	-6	(-315.16)	10211	
-7	(-1,376.36)	82.96		-7	(-367.69)	10217	
-8	(-1,572.99)	82.76		-8	(-420.22)	10224	
-9	(-1,769.61)	82.56		-9	(-472.74)	10230	
-10	(-1,966.23)	82.36		-10	(-525.27)	10236	
	WEIGHTING FACTOR =	3.16			WEIGHTING FACTOR =	0.84	

ACTUAL OUTAGE SCHEDULE

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2002

PLANT/UNIT	ACTUAL OUTAGES	REASON FOR OUTAGE
Cape Canaveral 1	NONE	
Cape Canaveral 2	12/2/2002 - 12/15/2002	Boiler chemical clean
Lauderdale 4	3/22/2002 - 4/02/2002	Combustion Turbines overhaul
Lauderdale 5	10/25/2002 - 11/03/2002	Combustion Turbines overhaul
Manatee 1	10/22/2002 - 11/04/2002	Exciter/boiler overhaul
Manatee 2	11/07/2002 - 11/21/2002	Boiler overhaul
Martin 1	3/01/2002 - 3/24/2002	Boiler overhaul
Martin 2	NONE	
Martin 3	5/17/2002 - 5/22/2002	Full outage and CT-B Inspection
Martin 4	4/21/2002 - 4/30/2002	CT-A Inspection
Martin 4	5/03/2002 - 5/07/2002	CT-B Inspection
Martin 4	11/13/2002 - 12/14/2002	Full outage and CT-B rotor change out
Port Everglades 3	11/09/2002 - 11/22/2002	Bolier overhaul
Port Everglades 4	4/07/2002 - 5/11/2002	Bolier chemical clean and HP/IP foam clean
Putnam 1	2/26/2002 - 3/04/2002	DCS software upgrade
Riviera 3	4/08/2002 - 4/23/2002	Minor boiler overhaul
Riviera 4	01/01/2002 - 2/23/2002	Boiler/turbine overhaul
Riviera 4	10/25/2002 - 11/12/2002	Chemical cleaning
Turkey Point 1	NONE	
Turkey Point 2	2/25/2002 - 4/07/2002	Turbine overhaul
Turkey Point 3	NONE	
Turkey Point 4	3/23/2002 - 4/07/2002	Refueling
St. Lucie 1	9/30/2002 - 10/24/2002	Refueling
St. Lucie 2	NONE	
Scherer 4	11/09/2002 - 12/20/2002	Tube Shields/Pulverizer

DOCUMENT NO. 1

WITNESS: F. IRIZARRY

DOCKET NO. 030001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2004

FI - 2
DOCKET NO. 030001-EI
FPL Witness: F. Irizarry
Exhibit No.:
Pages 1-27
September 12, 2003

DOCUMENT NUMBER 1 INDEX

FLORIDA POWER & LIGHT COMPANY

JANUARY THROUGH DECEMBER, 2004

DOCUMENT	PAGE NUMBER	TITLE
1	7.201.001	Index
	7.201.002 to 7.201.003	Generating Unit Selection Criteria
	7.201.004	GPIF Reward/(Penalty) Table (Estimated)
	7.201.005	GPIF calculation of Maximum Allowed Dollars (Estimated)
	7.201.006 and 7.201.007	GPIF Target and Range Summary
	7.201.008	GPIF Predicted Unit Heat Rates
	7.201.009	Derivation of Weighting Factors
	7.201.010	Estimated Unit Performance Data
	7.201.011 - 7.201.026	Unit MOF and FOF vs Time Graphs
	7.201.027	Planned Outages Schedule (Estimated)

Table 2.0
POWRSYM Projected System Generation
January Through December, 2004

Name	Capacity (MW)	Service Hours	Net Output MWH	NOF %	% of Total Output	Cumulative % of Total Output	Production Cost ($000)
Ft. Myers Repowered 2	1,441	7,858	10,258,396	91%	11.5	11.5	376,316
St. Lucie 1	845	7,977	6,741,236	100%	7.6	19.1	19,269
Sanford Repowered 4	914	7,785	6,577,092	92%	7.4	26.4	235,018
Sanford Repowered 5	914	7,678	6,218,315	89%	7.0	33.4	227,990
Turkey Point 4	703	8,562	6,020,517	100%	6.8	40.2	18,093
St. Lucie 2	719	7,860	5,647,674	100%	6.3	46.5	16,803
Turkey Point 3	703	7,042	4,950,735	100%	5.6	52.1	14,881
Scherer 4	645	6,938	3,886,183	87%	4.4	56.4	61,717
Martin 4	453	7,822	3,089,719	87%	3.5	59.9	114,271
Martin 3	452	7,717	3,078,007	88%	3.5	63.3	114,924
Lauderdale 5	432	7,710	3,010,072	90%	3.4	66.7	123,155
Martin 1	810	6,248	2,930,328	58%	3.3	70.0	139,842
Martin 2	793	6,955	2,928,927	53%	3.3	73.3	141,221
Lauderdale 4	430	6,984	2,797,514	93%	3.1	76.4	114,142
Manatee 1	798	5,533	2,193,645	50%	2.5	78.9	101,162
Manatee 2	798	5,236	2,054,592	49%	2.3	81.2	94,282
Port Everglades 3	391	6,153	1,736,848	72%	1.9	83.1	76,489
Port Everglades 4	396	5,781	1,654,443	72%	1.9	85.0	73,523
Cape Canaveral 2	396	4,828	1,366,108	72%	1.5	86.5	58,467
Turkey Point 2	396	4,333	1,174,158	68%	1.3	87.9	53,526
Riviera 4	285	5,446	1,129,019	73%	1.3	89.1	53,593
Turkey Point 1	396	4,474	1,126,051	64%	1.3	90.4	51,659
Cape Canaveral 1	396	4,250	1,116,804	66%	1.3	91.6	49,726
Riviera 3	283	5,474	1,090,940	70%	1.2	92.9	53,586
St. Johns River 1	128	7,917	996,424	98%	1.1	94.0	14,699
St. Johns River 2	128	6,674	840,328	98%	0.9	94.9	12,185
Martin SC 8	310	2,671	651,687	79%	0.7	95.7	35,606
Putnam 1	244	3,064	599,677	80%	0.7	96.3	31,666
Putnam 2	244	2,893	566,351	80%	0.6	97.0	28,820
Ft. Myers SC 3	310	2,044	496,174	78%	0.6	97.5	26,855
Ft. lauderdale GT 1-24	719	1,010	486,689	67%	0.5	98.1	42,206
Port Everglades 2	211	2,758	406,517	70%	0.5	98.5	18,905
Port Everglades 1	211	2,720	318,829	55%	0.4	98.9	16,743
Ft. Myers GT 1-12	582	861	310,581	62%	0.3	99.2	29,694
Port Everglades GT 1-12	363	1,331	283,158	59%	0.3	99.5	26,689
Cutler 6	140	2,431	162,537	48%	0.2	99.7	10,211
Sanford 3	140	1,955	149,548	55%	0.2	99.9	8,428
Cutler 5	69	2,270	95,334	61%	0.1	100.0	6,482
Total	18,583	197,243	89,141,157		100.0	100.0	2,692,844

FLORIDA POWER & LIGHT COMPANY
UNITS TO BE USED TO DETERMINE THE
GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY THROUGH DECEMBER, 2004

Cape Canaveral Unit 2

Lauderdale Unit 4

Lauderdale Unit 5

Manatee Unit 1

Manatee Unit 2

Martin Unit 1

Martin Unit 2

Martin Unit 3

Martin Unit 4

Port Everglades Unit 3

Port Everglades Unit 4

Scherer Unit 4

St. Lucie Unit 1

St. Lucie Unit 2

Turkey Point Unit 3

Turkey Point Unit 4

GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY
JANUARY THROUGH DECEMBER, 2004

Generating Performance Incentive Points (GPIF)	Fuel Savings/(Loss) ($000)	Generating Performance Incentive Factor ($000)
+ 10	51,824	23,565
+ 9	46,642	21,209
+ 8	41,459	18,852
+ 7	36,277	16,496
+ 6	31,095	14,139
+ 5	25,912	11,783
+ 4	20,730	9,426
+ 3	15,547	7,070
+ 2	10,365	4,713
+ 1	5,182	2,357
0	0	0
- 1	(5,190)	(2,357)
- 2	(10,381)	(4,713)
- 3	(15,571)	(7,070)
- 4	(20,762)	(9,426)
- 5	(25,952)	(11,783)
- 6	(31,143)	(14,139)
- 7	(36,333)	(16,496)
- 8	(41,524)	(18,852)
- 9	(46,714)	(21,209)
- 10	(51,905)	(23,565)

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ESTIMATED

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2004

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY		$	5,742,134,568
LINE 2	MONTH OF JANUARY	2004	$	5,760,316,047
LINE 3	MONTH OF FEBRUARY	2004	$	5,761,397,741
LINE 4	MONTH OF MARCH	2004	$	5,754,901,660
LINE 5	MONTH OF APRIL	2004	$	5,747,247,330
LINE 6	MONTH OF MAY	2004	$	5,766,000,675
LINE 7	MONTH OF JUNE	2004	$	5,784,486,062
LINE 8	MONTH OF JULY	2004	$	5,799,409,042
LINE 9	MONTH OF AUGUST	2004	$	5,803,057,515
LINE 10	MONTH OF SEPTEMBER	2004	$	5,795,293,454
LINE 11	MONTH OF OCTOBER	2004	$	5,770,307,401
LINE 12	MONTH OF NOVEMBER	2004	$	5,746,714,475
LINE 13	MONTH OF DECEMBER	2004	$	5,995,034,588
LINE 14	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE 1 THROUGH LINE 13 DIVIDED BY 13)		$	5,786,638,000
LINE 15	25 BASIS POINTS			0.0025
LINE 16	REVENUE EXPANSION FACTOR			60.4594%
LINE 17	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 14 TIMES LINE 15 DIVIDED BY LINE 16)		$	23,927,785
LINE 18	JURISDICTIONAL SALES			100,913,605,574 KWH
LINE 19	TOTAL SALES			102,465,675,753 KWH
LINE 20	JURISDICTIONAL SEPARATION FACTOR (LINE 18 DIVIDED BY LINE 19)			98.49%
LINE 21	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS		$	23,565,345

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2004

Plant / Unit	Weighting Factor (%)	EAF Target (%)	EAF Range Max. (%)	EAF Range Min. (%)	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Cape Canaveral 2	0.31	89.8	92.8	86.8	159.3	-159.3
Lauderdale 4	0.25	79.6	82.1	77.1	131.0	-131.0
Lauderdale 5	0.31	89.5	92.0	87.0	161.6	-161.6
Manatee 1	0.26	93.7	96.2	91.2	135.5	-135.5
Manatee 2	0.21	75.2	77.2	73.2	106.7	-106.7
Martin 1	0.29	91.5	94.5	88.5	152.1	-152.1
Martin 2	0.28	92.1	94.6	89.6	144.8	-144.8
Martin 3	0.60	94.6	96.6	92.6	308.6	-308.6
Martin 4	0.63	92.0	94.0	90.0	325.4	-325.4
Port Everglades 3	0.23	92.7	95.2	90.2	121.8	-121.8
Port Everglades 4	0.22	89.7	92.2	87.2	113.1	-113.1
Scherer 4	4.04	84.0	86.0	82.0	2,096.0	-2,096.0
St. Lucie 1	12.31	86.8	89.8	83.8	6,380.7	-6,380.7
St. Lucie 2	10.25	85.4	88.4	82.4	5,311.9	-5,311.9
Turkey Point 3	8.78	75.8	78.8	72.8	4,551.1	-4,551.1
Turkey Point 4	10.82	93.6	96.6	90.6	5,607.1	-5,607.1
	49.80				25,806.6	-25,806.6

GPIF TARGET AND RANGE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2004

Plant / Unit	Weighting Factor (%)	ANOHR TARGET BTU/KWH	ANOHR TARGET NOF	ANOHR RANGE BTU/KWH	ANOHR RANGE BTU/KWH	Max. Fuel Savings ($000's)	Max. Fuel Loss ($000's)
Cape Canaveral 2	1.88	9,528	71.5	9,294	9,761	971.9	-971.9
Lauderdale 4	4.57	7,473	93.3	7,243	7,703	2,369.8	-2,369.8
Lauderdale 5	3.37	7,467	90.5	7,286	7,648	1,745.9	-1,745.9
Manatee 1	1.07	10,427	49.7	10,295	10,559	554.2	-554.2
Manatee 2	2.88	10,384	49.2	10,145	10,624	1,491.9	-1,491.9
Martin 1	7.27	10,130	57.9	9,782	10,478	3,769.5	-3,769.5
Martin 2	6.08	10,086	53.1	9,786	10,386	3,150.7	-3,150.7
Martin 3	3.94	6,885	88.2	6,688	7,082	2,041.1	-2,041.1
Martin 4	6.93	6,844	87.3	6,554	7,134	3,590.7	-3,590.7
Port Everglades 3	2.19	9,819	72.2	9,598	10,039	1,132.7	-1,132.7
Port Everglades 4	3.06	9,859	72.3	9,572	10,146	1,584.1	-1,584.1
Scherer 4	0.74	10,189	86.8	10,050	10,327	385.5	-385.5
St. Lucie 1	0.18	10,860	100.0	10,789	10,931	92.4	-94.6
St. Lucie 2	0.33	10,900	99.9	10,834	10,966	173.1	-178.3
Turkey Point 3	2.21	11,140	100.0	10,994	11,287	1,147.5	-1,174.2
Turkey Point 4	3.51	11,134	100.0	10,967	11,300	1,816.8	-1,863.2
	50.20					26,017.8	-26,098.3

PROJECTED UNIT HEAT RATE EQUATIONS
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2004

				ANOHR Equation					
Plant/Unit	ANOHR	NOF	MW	a coef.	b coef.	Bounds	First	Last	Exclusions
Cape Canaveral 2	9,528	71.5	396	10983	-20.35	233	01-00	12-02	Nov-00
Lauderdale 4	7,473	93.3	430	8944	-15.77	230	01-00	12-02	Dec-00, Jan-01
Lauderdale 5	7,467	90.5	432	8036	-6.29	181	01-00	12-02	Dec-00, Jan-01
Manatee 1	10,427	49.7	798	10967	-10.87	132	01-00	12-02	Jan-00, Feb-00, Apr-00, Nov-00, Oct-02
Manatee 2	10,384	49.2	798	10974	-11.98	239	01-00	12-02	Feb-00, Mar-00, Nov-01
Martin 1	10,130	57.9	810	11620	-25.71	348	01-00	12-02	Feb-01
Martin 2	10,086	53.1	793	11081	-18.75	300	01-00	12-02	No exclusions
Martin 3	6,885	88.2	452	7167	-3.20	197	01-00	12-02	Mar-00, Dec-00
Martin 4	6,844	87.3	453	7114	-3.10	290	01-00	12-02	No exclusions
Port Everglades 3	9,819	72.2	391	11473	-22.91	220	01-00	12-02	Feb-01
Port Everglades 4	9,859	72.3	396	11259	-19.36	287	01-00	12-02	No exclusions
Scherer 4	10,189	86.8	645	11359	-13.48	139	01-00	12-02	Apr-01, Nov-02, Dec-02
St. Lucie 1	10,860	100.0	845	15895	-50.33	71	01-00	12-02	Apr-01, Sep-02, Oct-02
St. Lucie 2	10,900	99.9	719	16796	-59.00	66	01-00	12-02	May-00, Dec-01
Turkey Point 3	11,140	100.0	703	17582	-64.41	147	01-00	12-02	Mar-00, Oct-01, Jul-02
Turkey Point 4	11,134	100.0	703	16972	-58.36	167	01-00	12-02	Sep-00, Oct-00, Jul 02

DERIVATION OF WEIGHT FACTORS

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2004

PRODUCTION COSTING SIMULATION
FUEL COST ($000)

Unit	Performance Indicator	At Target (1)	At Maximum Improvement (2)	Savings (3)	Factor (% Of Savings)
Cape Canaveral 2	EAF	1,853,520	1,853,679	159.3	0.31
Cape Canaveral 2	ANOHR	1,853,520	1,854,492	971.9	1.88
Lauderdale 4	EAF	1,853,520	1,853,651	131.0	0.25
Lauderdale 4	ANOHR	1,853,520	1,855,890	2,369.8	4.57
Lauderdale 5	EAF	1,853,520	1,853,682	161.6	0.31
Lauderdale 5	ANOHR	1,853,520	1,855,266	1,745.9	3.37
Manatee 1	EAF	1,853,520	1,853,655	135.5	0.26
Manatee 1	ANOHR	1,853,520	1,854,074	554.2	1.07
Manatee 2	EAF	1,853,520	1,853,627	106.7	0.21
Manatee 2	ANOHR	1,853,520	1,855,012	1,491.9	2.88
Martin 1	EAF	1,853,520	1,853,672	152.1	0.29
Martin 1	ANOHR	1,853,520	1,857,289	3,769.5	7.27
Martin 2	EAF	1,853,520	1,853,665	144.8	0.28
Martin 2	ANOHR	1,853,520	1,856,671	3,150.7	6.08
Martin 3	EAF	1,853,520	1,853,829	308.6	0.60
Martin 3	ANOHR	1,853,520	1,855,561	2,041.1	3.94
Martin 4	EAF	1,853,520	1,853,845	325.4	0.63
Martin 4	ANOHR	1,853,520	1,857,111	3,590.7	6.93
Port Everglades 3	EAF	1,853,520	1,853,642	121.8	0.23
Port Everglades 3	ANOHR	1,853,520	1,854,653	1,132.7	2.19
Port Everglades 4	EAF	1,853,520	1,853,633	113.1	0.22
Port Everglades 4	ANOHR	1,853,520	1,855,104	1,584.1	3.06
Scherer 4	EAF	1,853,520	1,855,616	2,096.0	4.04
Scherer 4	ANOHR	1,853,520	1,853,905	385.5	0.74
St. Lucie 1	EAF	1,853,520	1,859,901	6,380.7	12.31
St. Lucie 1	ANOHR	1,853,520	1,853,612	92.4	0.18
St. Lucie 2	EAF	1,853,520	1,858,832	5,311.9	10.25
St. Lucie 2	ANOHR	1,853,520	1,853,693	173.1	0.33
Turkey Point 3	EAF	1,853,520	1,858,071	4,551.1	8.78
Turkey Point 3	ANOHR	1,853,520	1,854,668	1,147.5	2.21
Turkey Point 4	EAF	1,853,520	1,859,127	5,607.1	10.82
Turkey Point 4	ANOHR	1,853,520	1,855,337	1,816.8	3.51
	TOTAL			51,824.3	100.00

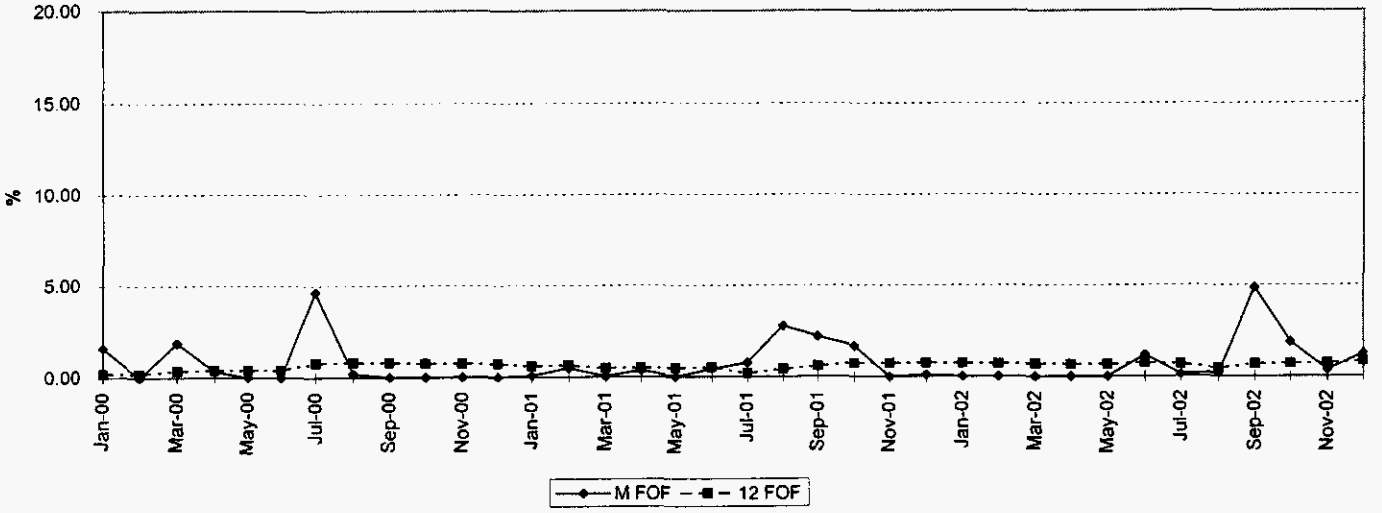
(1) FUEL ADJUSTMENT - ALL UNITS PERFORMANCE AT TARGET
(2) ALL OTHER UNITS PERFORMANCE AT TARGET
(3) EXPRESSED IN REPLACEMENT ENERGY COSTS.

ESTIMATED UNIT PERFORMANCE DATA
FLORIDA POWER & LIGHT COMPANY
PERIOD OF: JANUARY THROUGH DECEMBER, 2004

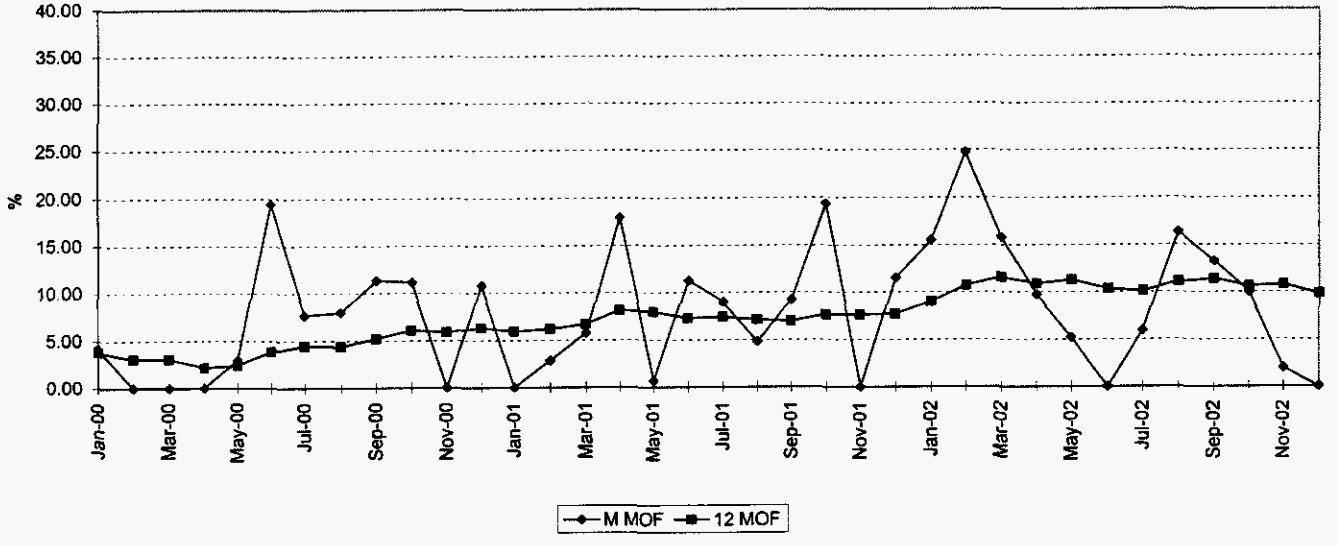
Plant/Unit	EAF	EPOF	EUOF	PH	SH	RSH	UH	EPOH	EFOH	EMOH	NET GEN
Cape Canaveral 2	89.8	0.0	10.2	8784	4828	3060	896	0	176	720	1,366,108
Lauderdale 4	79.6	15.3	5.1	8784	6984	8	1792	1344	176	272	2,797,514
Lauderdale 5	89.5	4.6	5.9	8784	7710	152	922	404	176	343	3,010,072
Manatee 1	93.7	0.0	6.3	8784	5533	2698	553	0	176	378	2,193,645
Manatee 2	75.2	20.5	4.3	8784	5236	1370	2178	1801	176	202	2,054,592
Martin 1	91.5	0.0	8.5	8784	6248	1789	747	0	448	299	2,930,328
Martin 2	92.1	0.0	7.9	8784	6955	1135	694	0	176	518	2,928,927
Martin 3	94.6	1.4	4.0	8784	7717	593	474	123	176	176	3,078,007
Martin 4	92.0	4.0	4.0	8784	7822	259	703	351	176	176	3,089,719
Port Everglades 3	92.7	0.0	7.3	8784	6153	1990	641	0	176	466	1,736,848
Port Everglades 4	89.7	3.8	6.5	8784	5781	2098	905	334	176	395	1,654,443
Scherer 4	84.0	12.0	4.0	8784	6938	439	1407	1056	176	176	3,886,183
St. Lucie 1	86.8	6.8	6.4	8784	7622	0	1162	600	281	281	6,741,236
St. Lucie 2	85.4	8.2	6.4	8784	7502	0	1282	720	281	281	5,647,674
Turkey Point 3	75.8	17.8	6.4	8784	6662	0	2122	1560	281	281	4,950,735
Turkey Point 4	93.6	0.0	6.4	8784	8222	0	562	0	281	281	6,020,517

EPOF = equivalent planned outage factor. EPOF=(EPOH/PH)*100
EUOF = equivalent unavailable outage factor. EUOF=((EFOH+EMOH)/PH)*100
PH = period hours
SH = service hours
RSH = reserve shutdown
UH = unavailable hours . UH=PH-SH-RSH
EPOH = equivalent planned outage hours
EFOH = equivalent forced outage hours
EMOH = equivalent maintenance outage hours

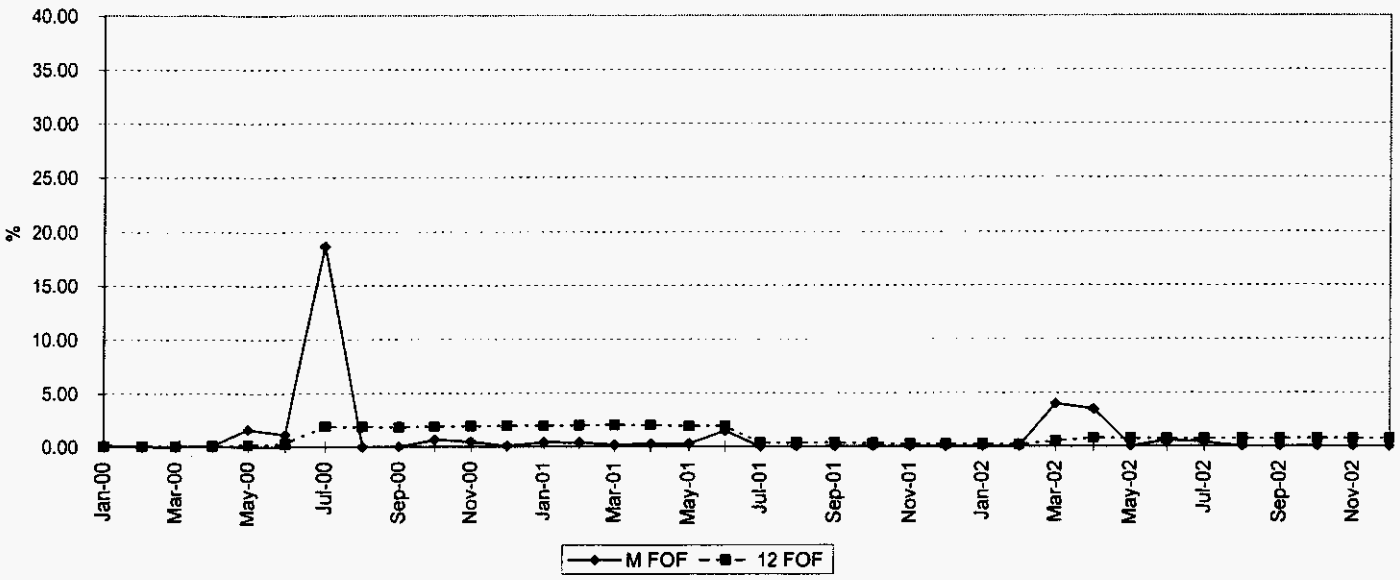
PCC 2
FORCED OUTAGE FACTOR



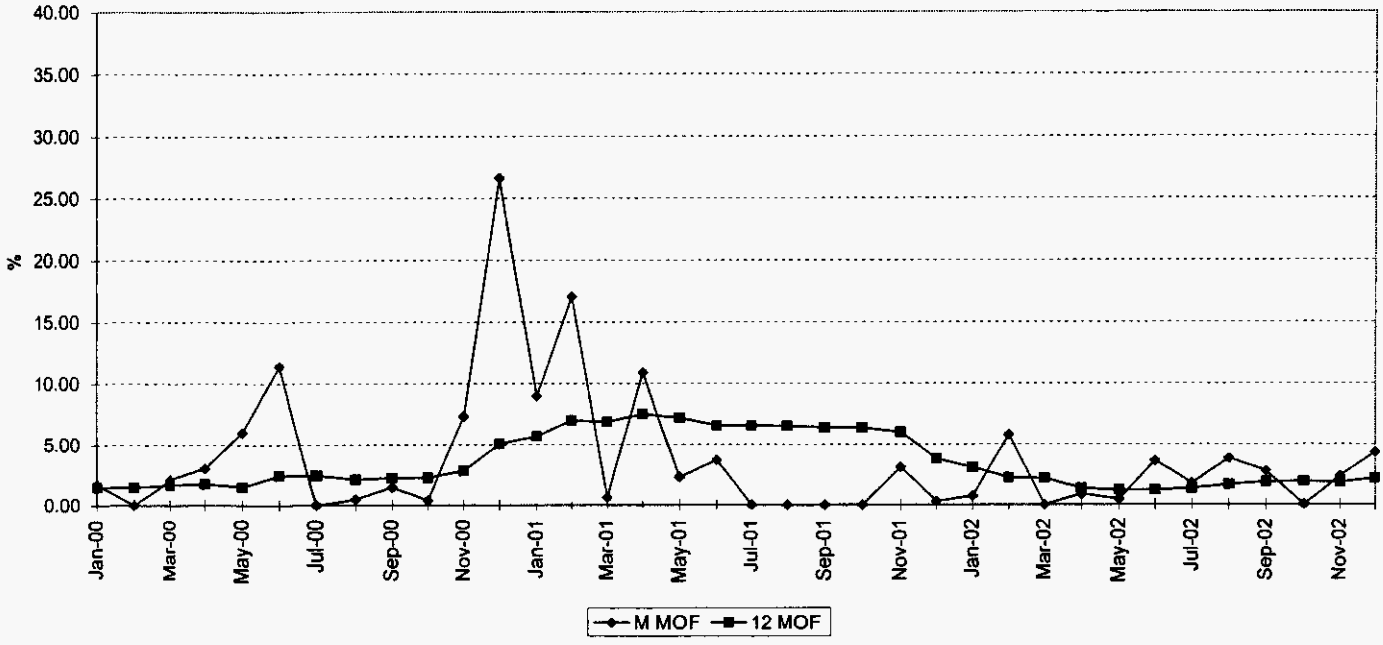
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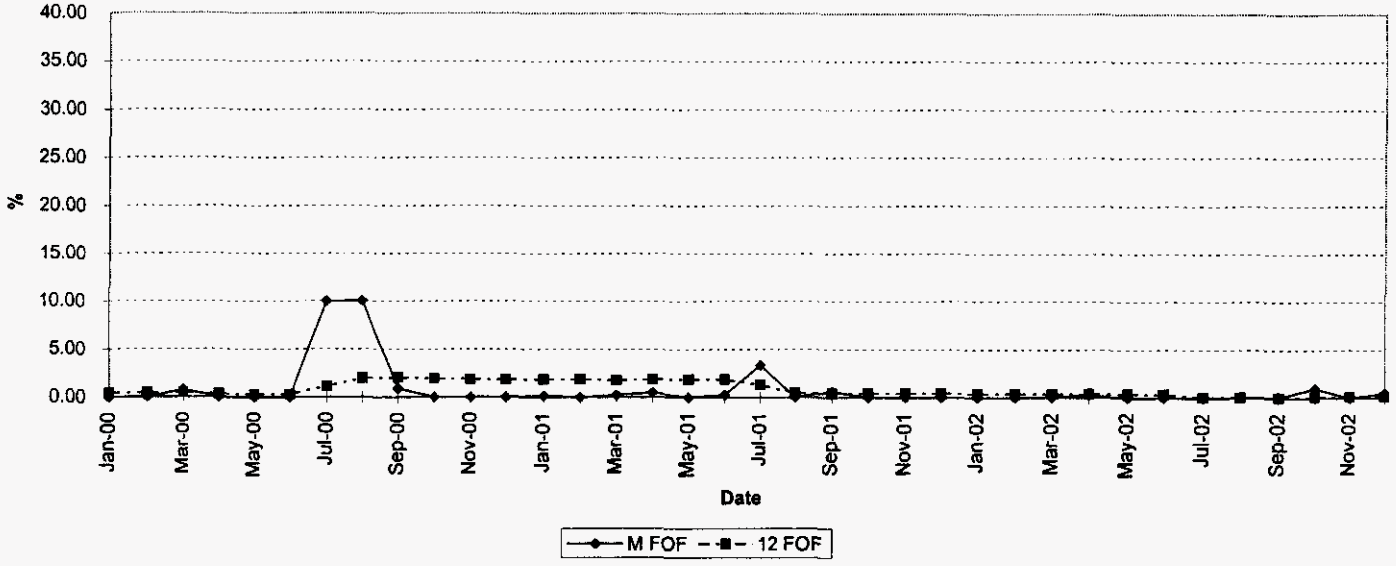
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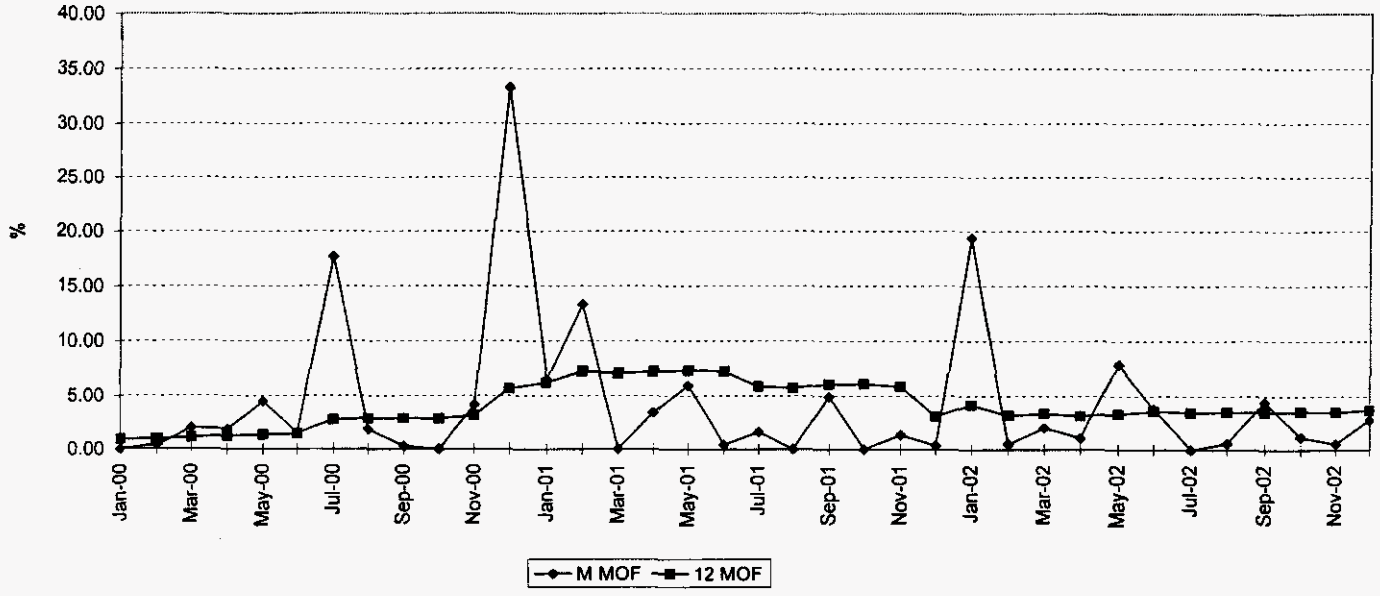
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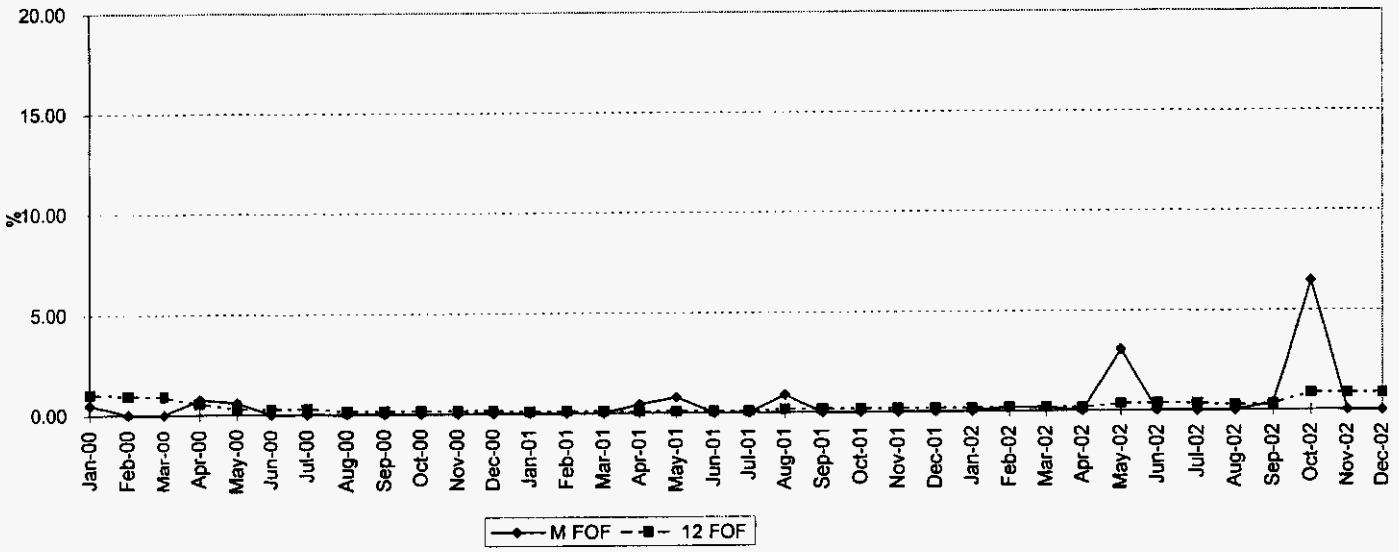
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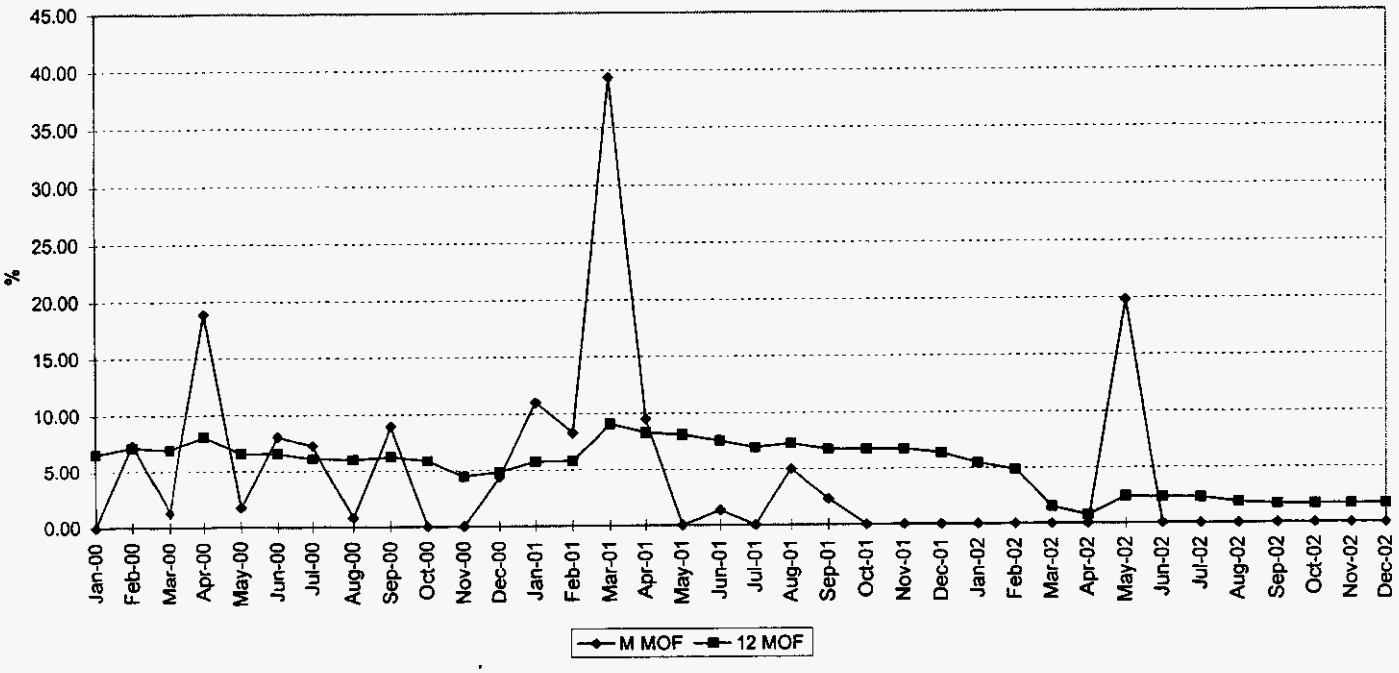
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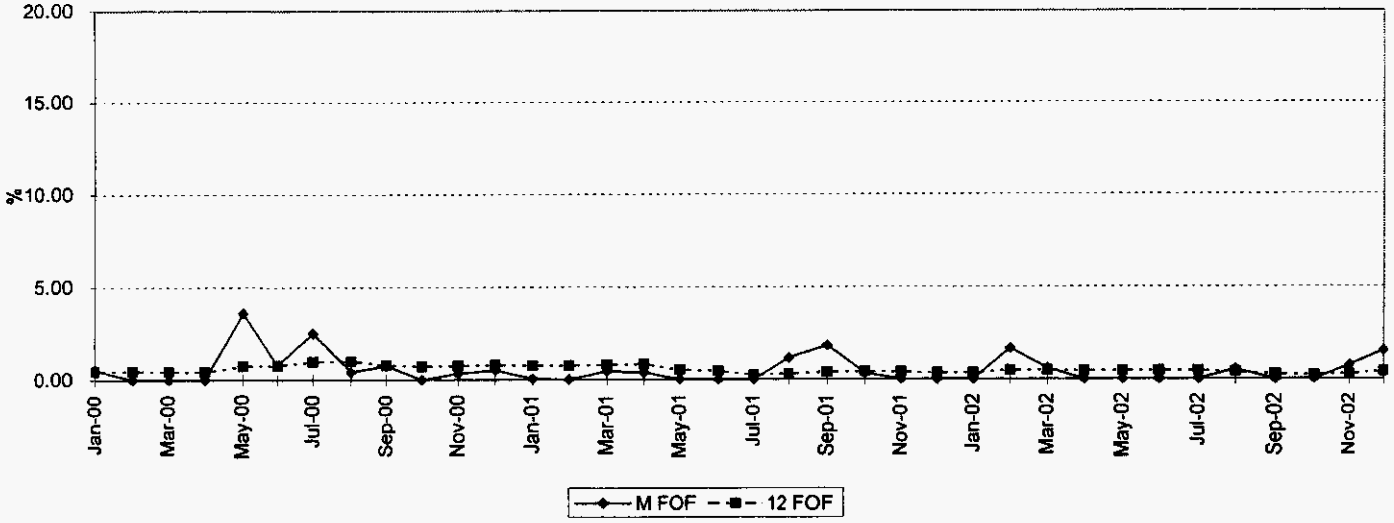
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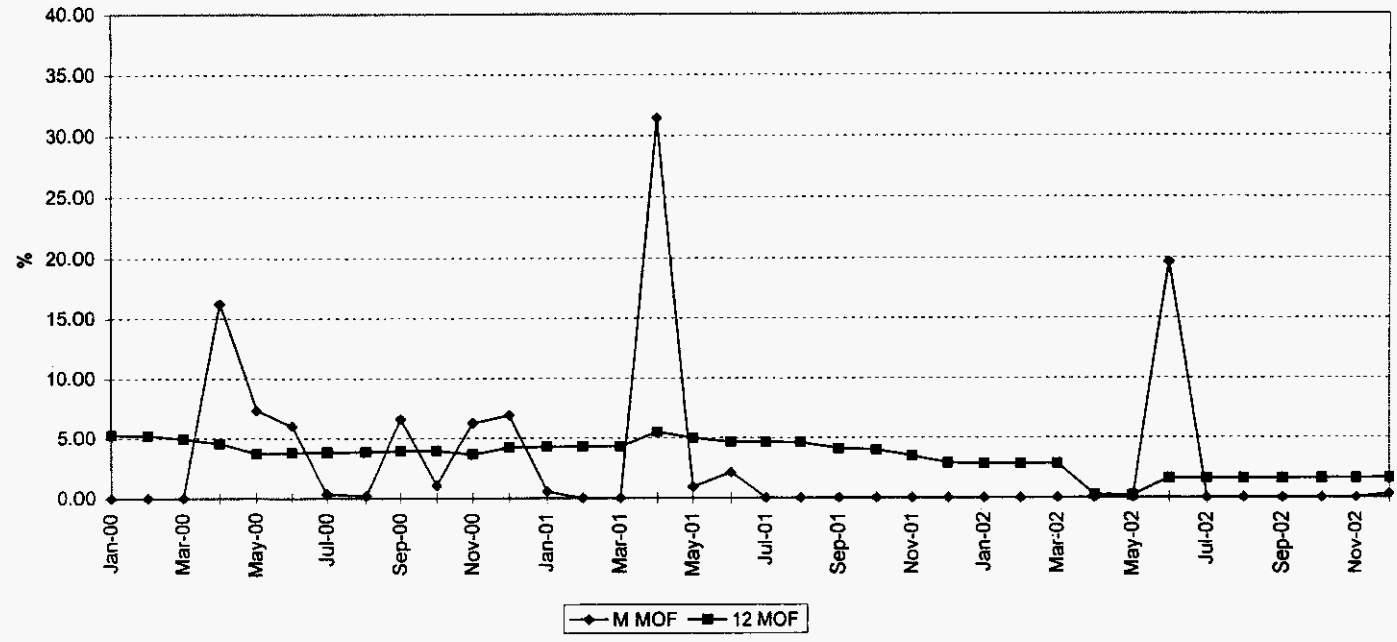
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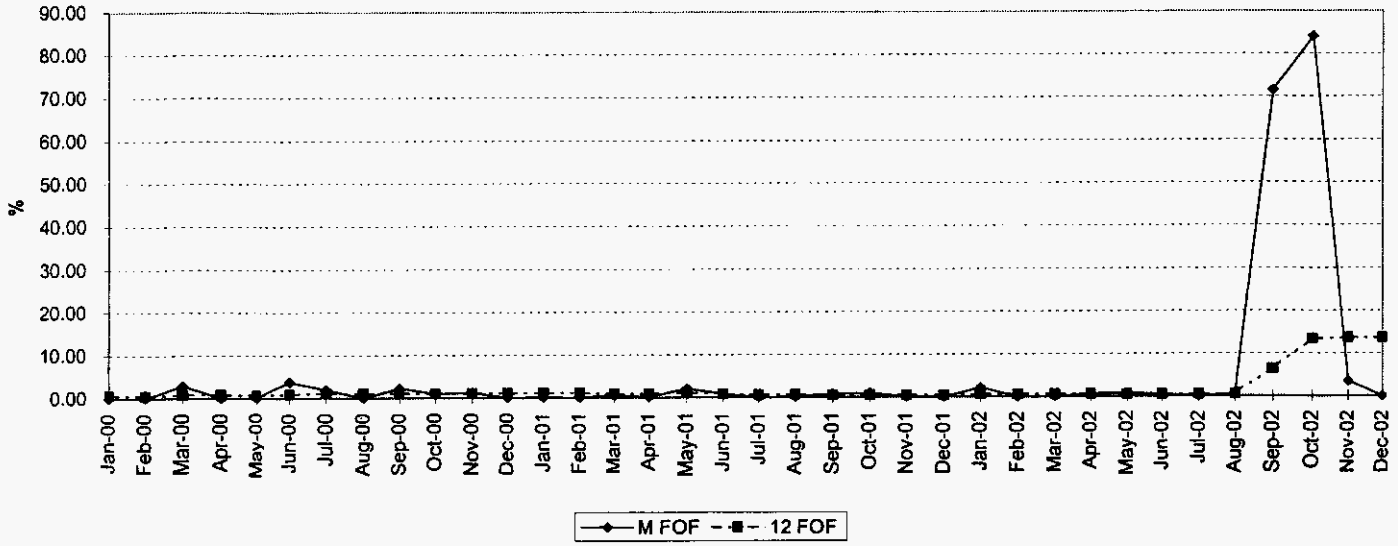
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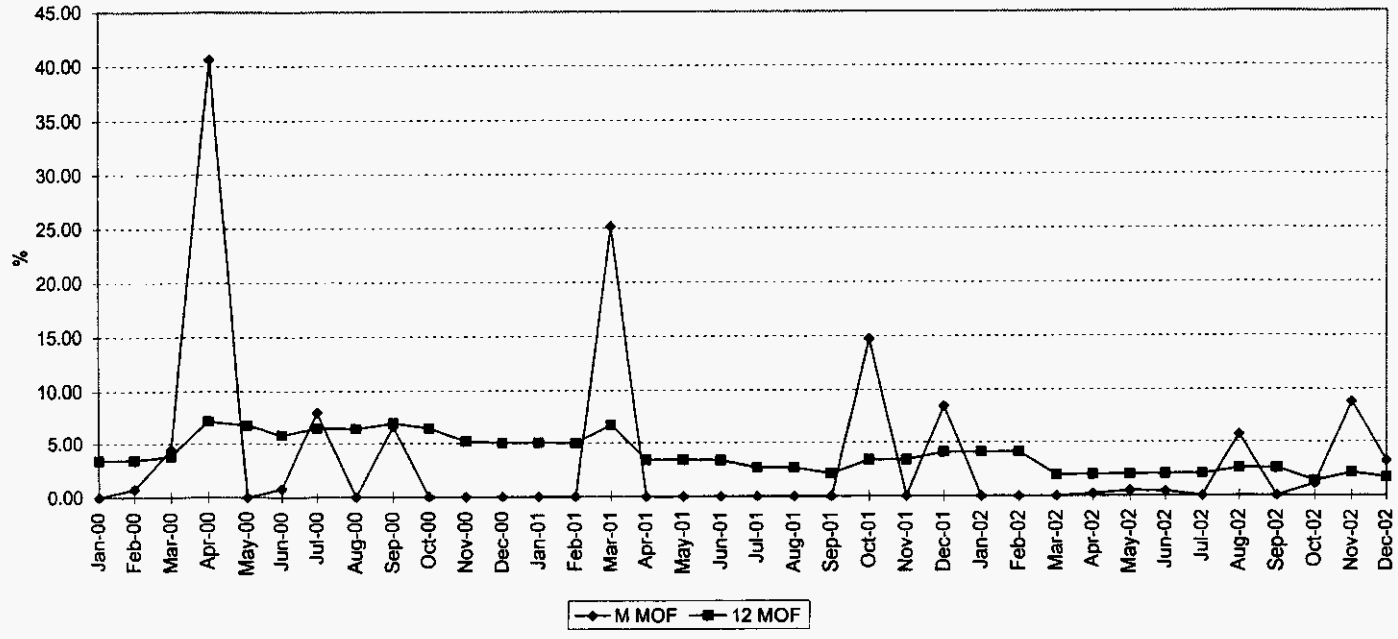
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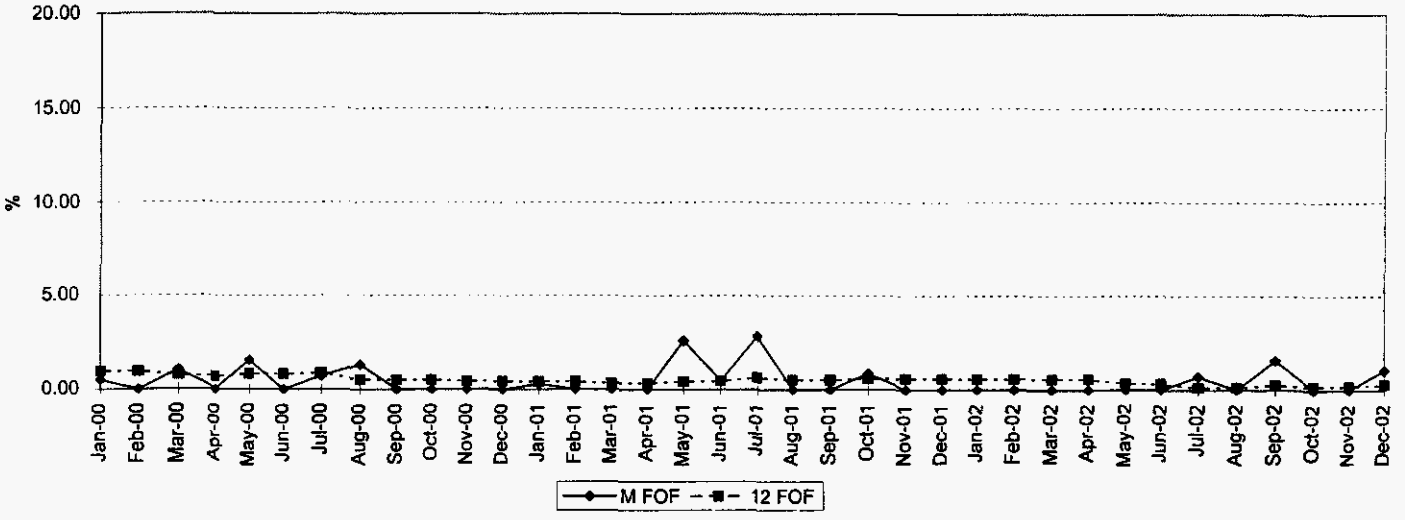
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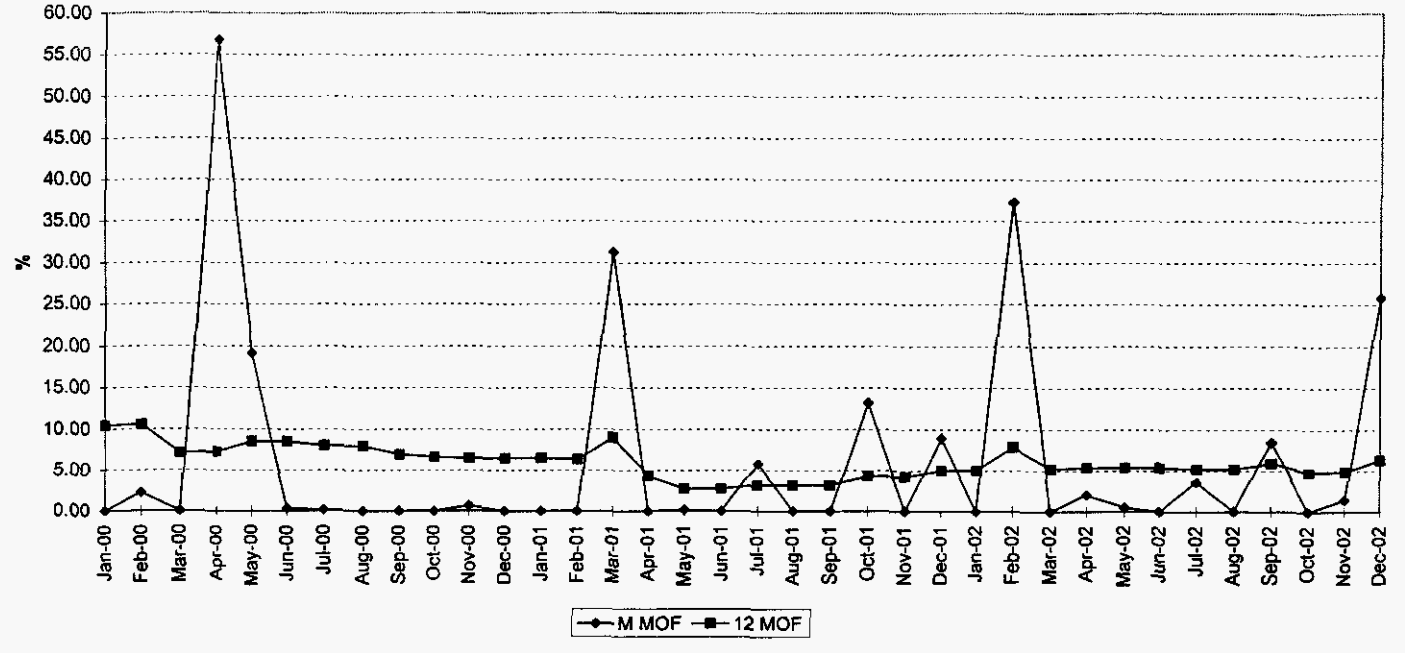
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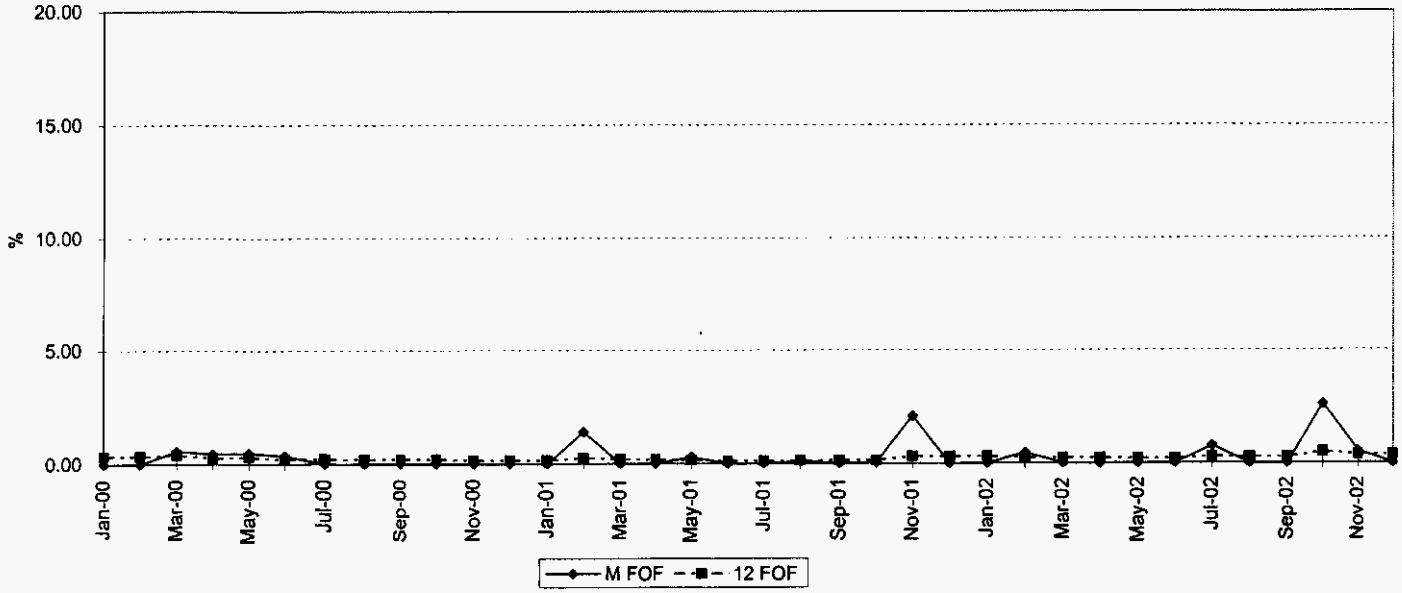
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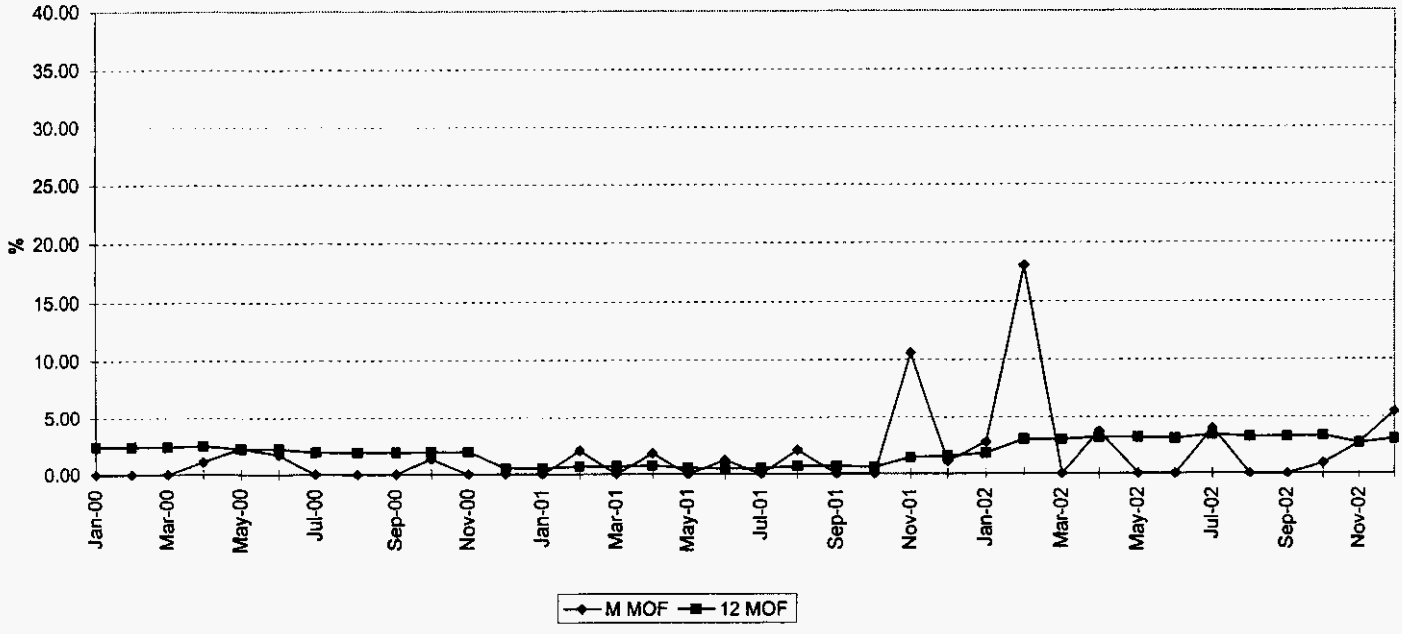
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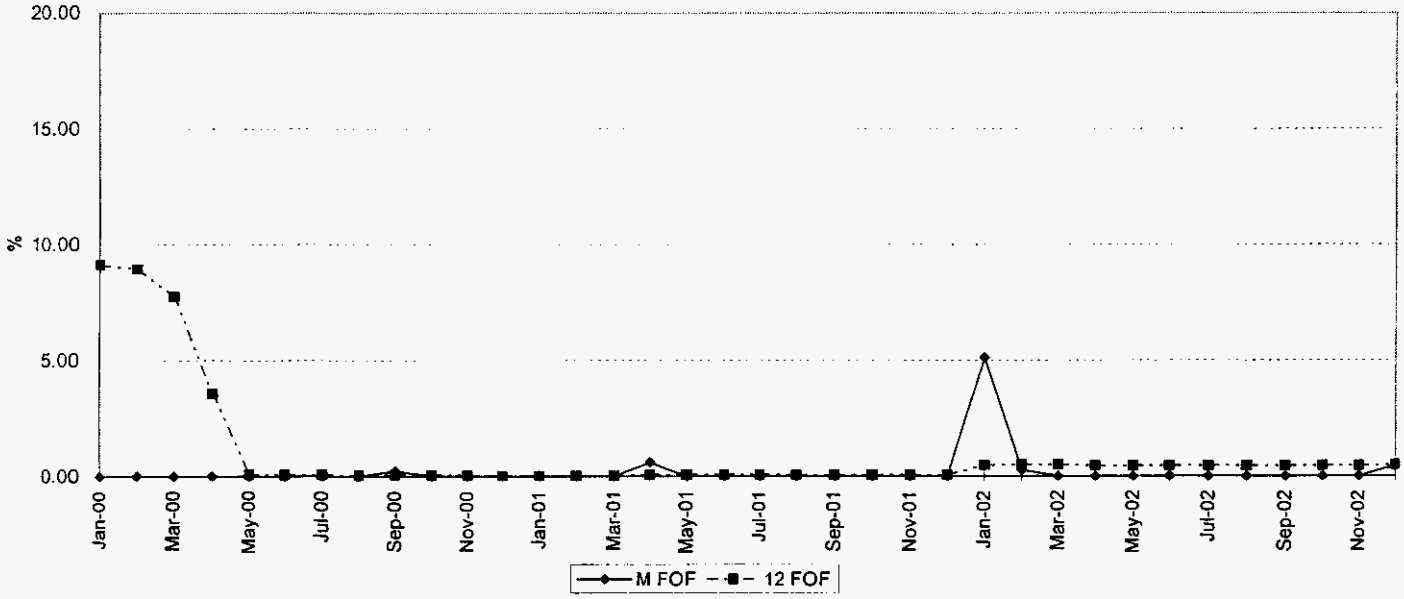
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FORCED OUTAGE FACTOR



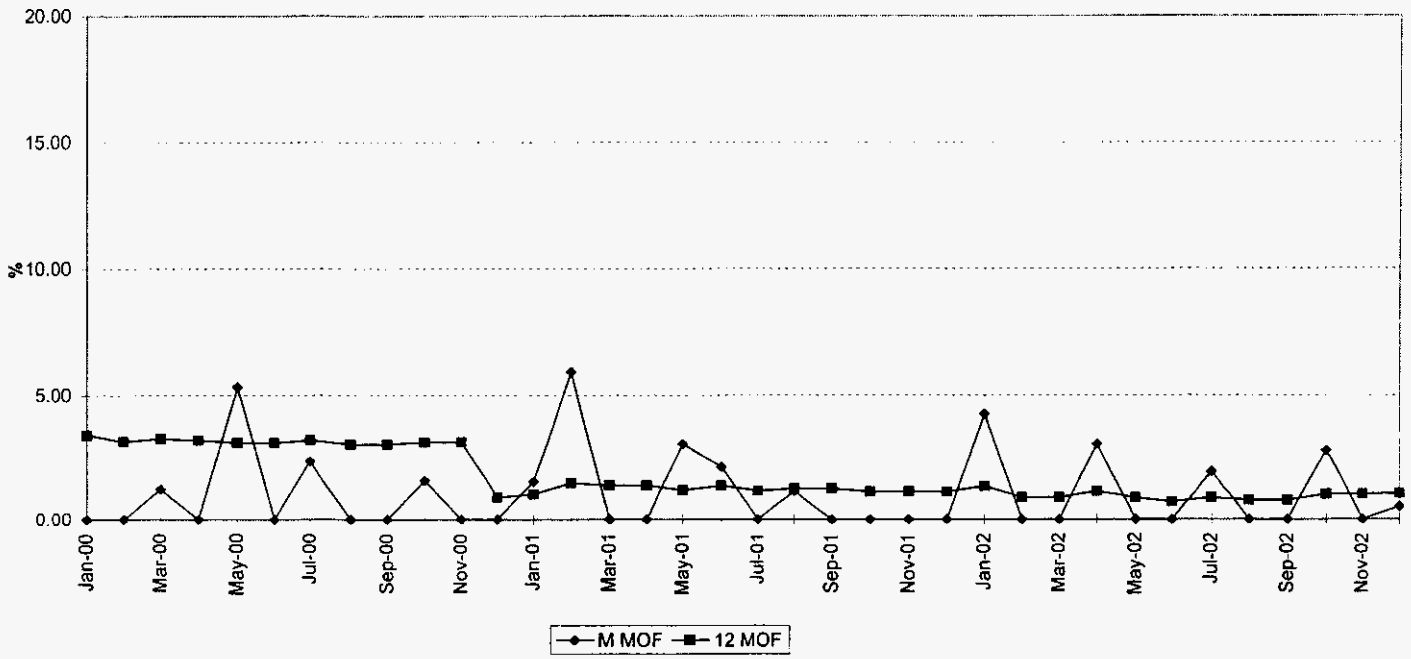
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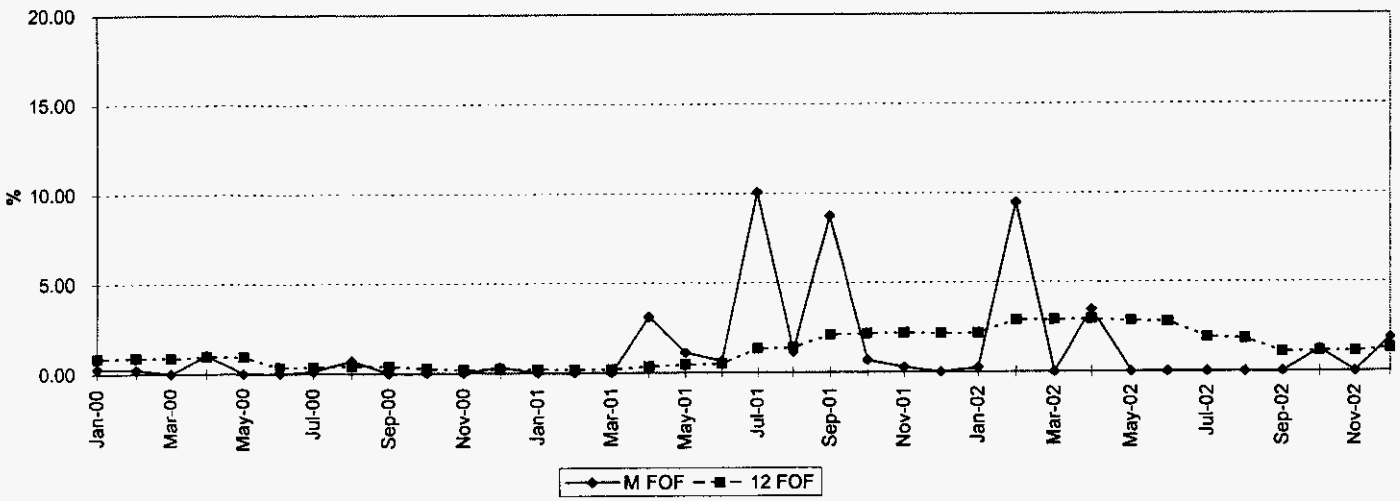
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FORCED OUTAGE FACTOR



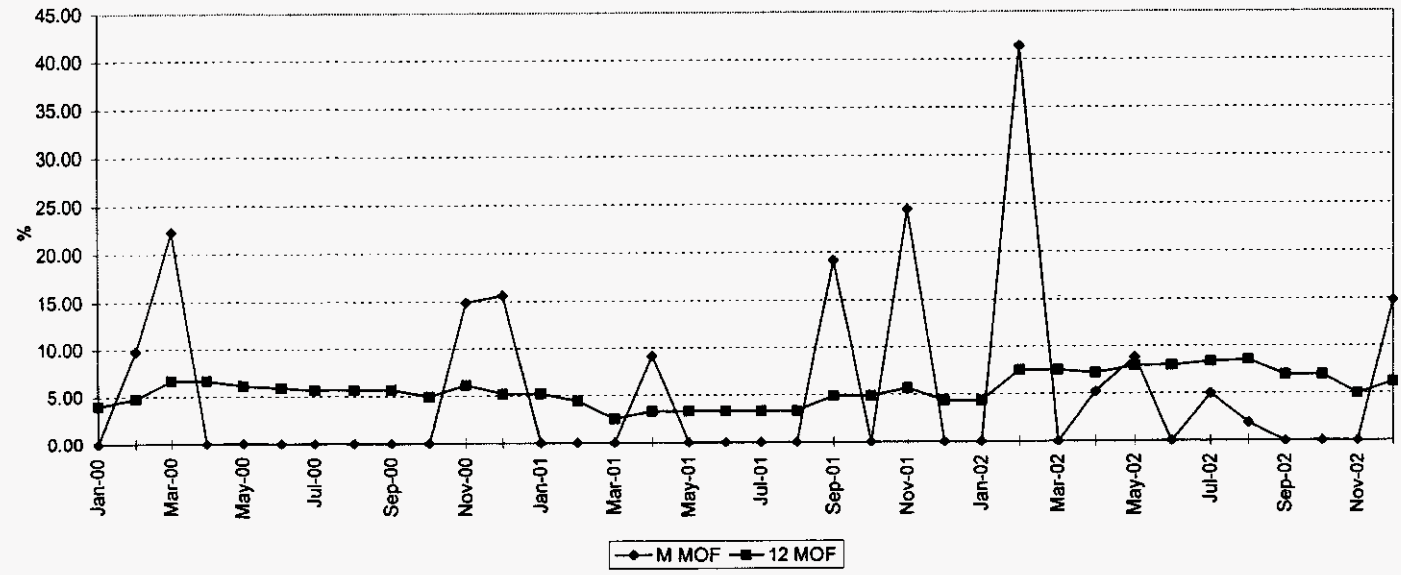
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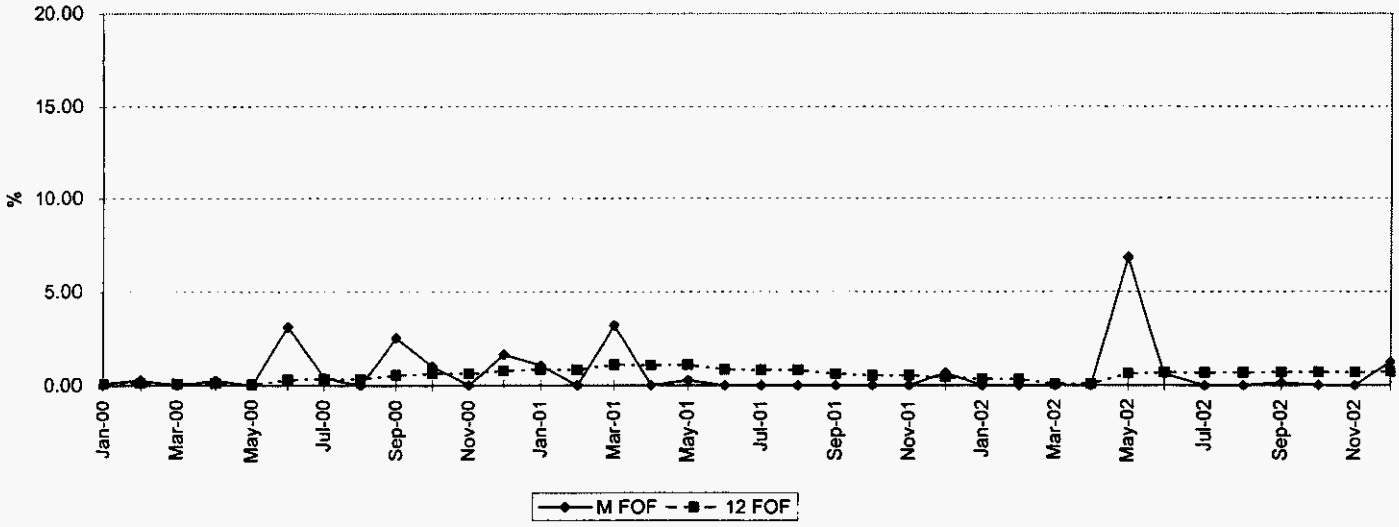
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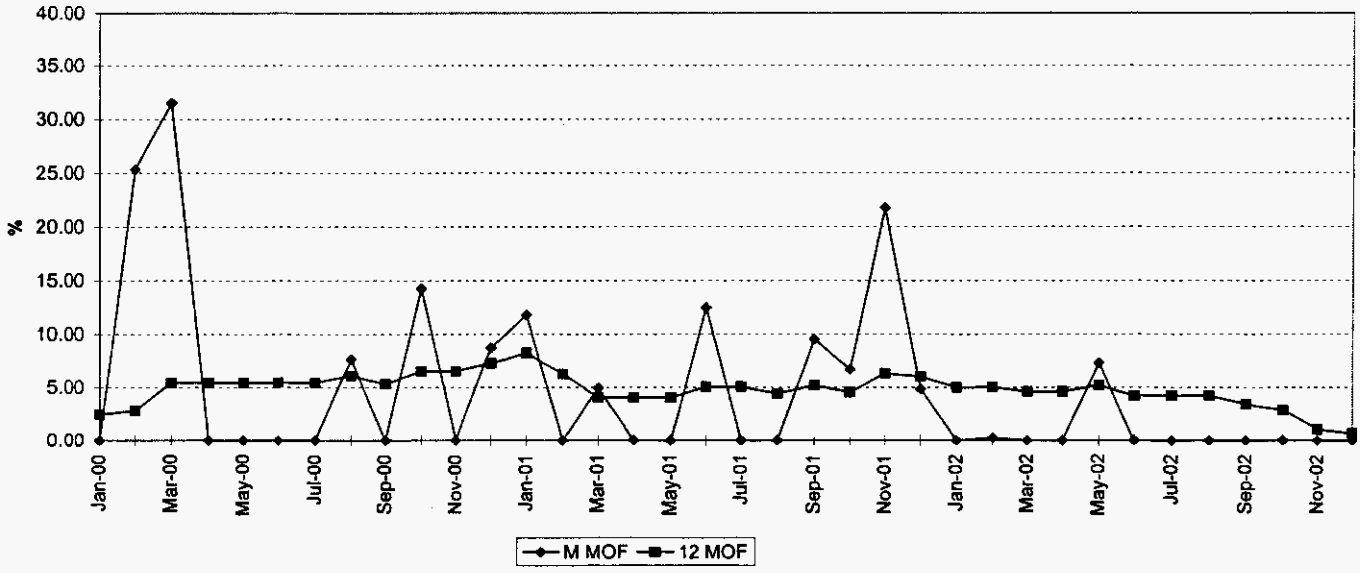
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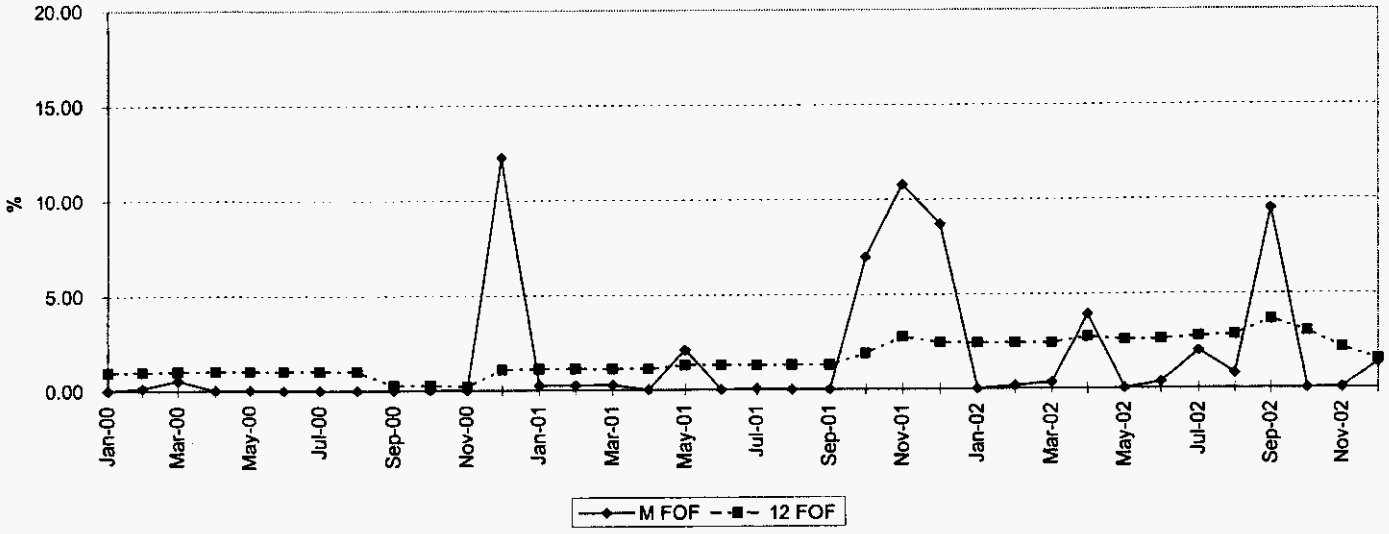
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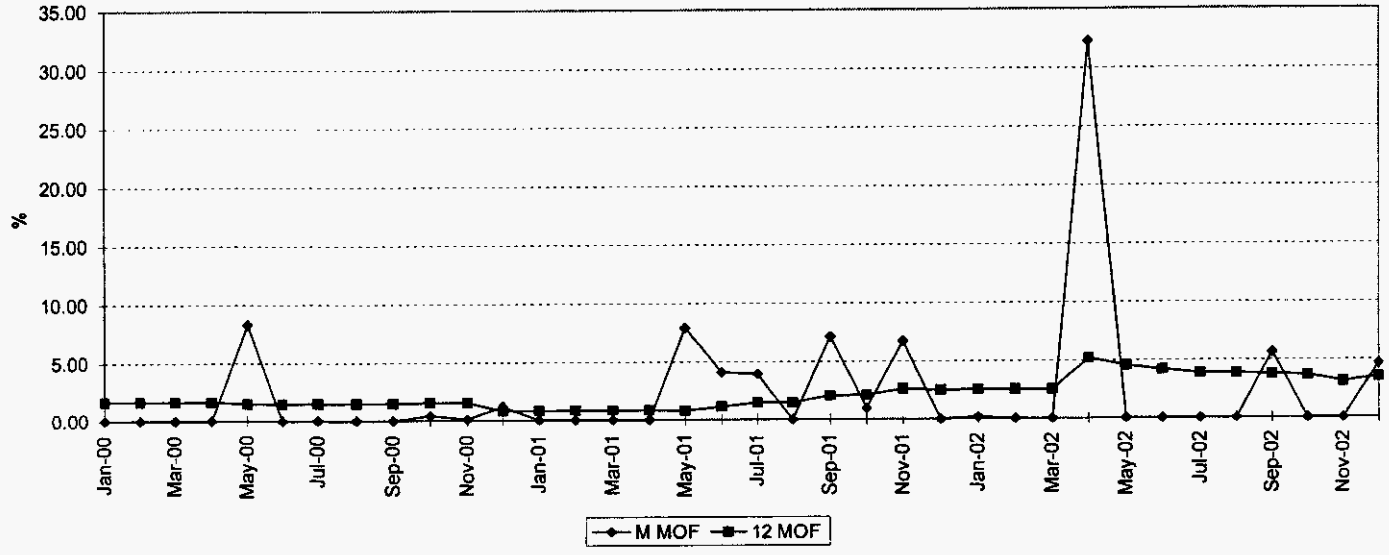
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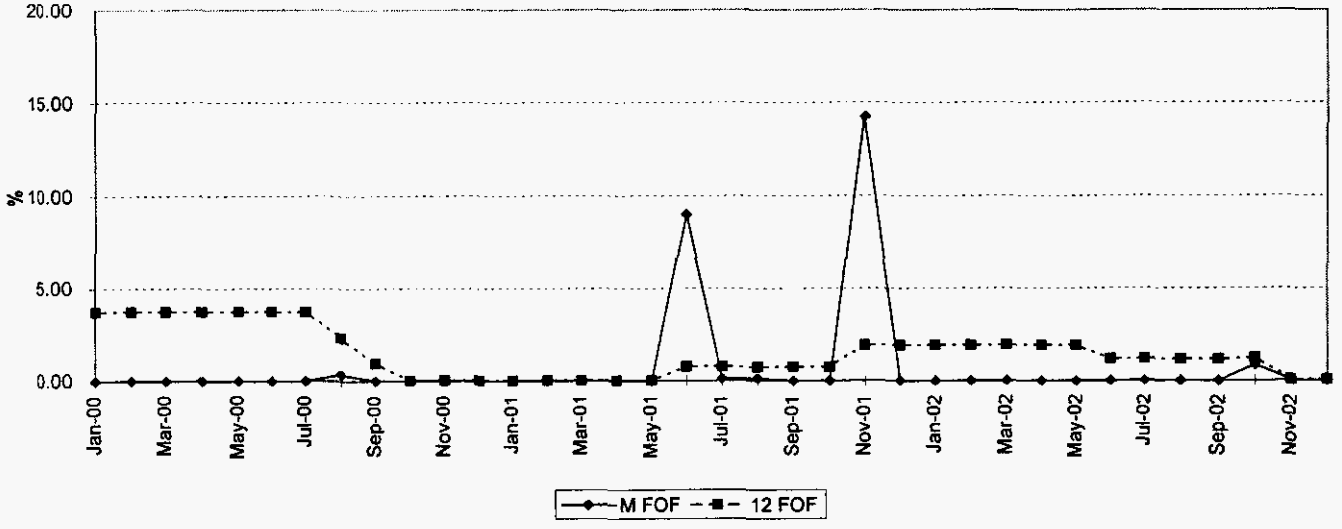
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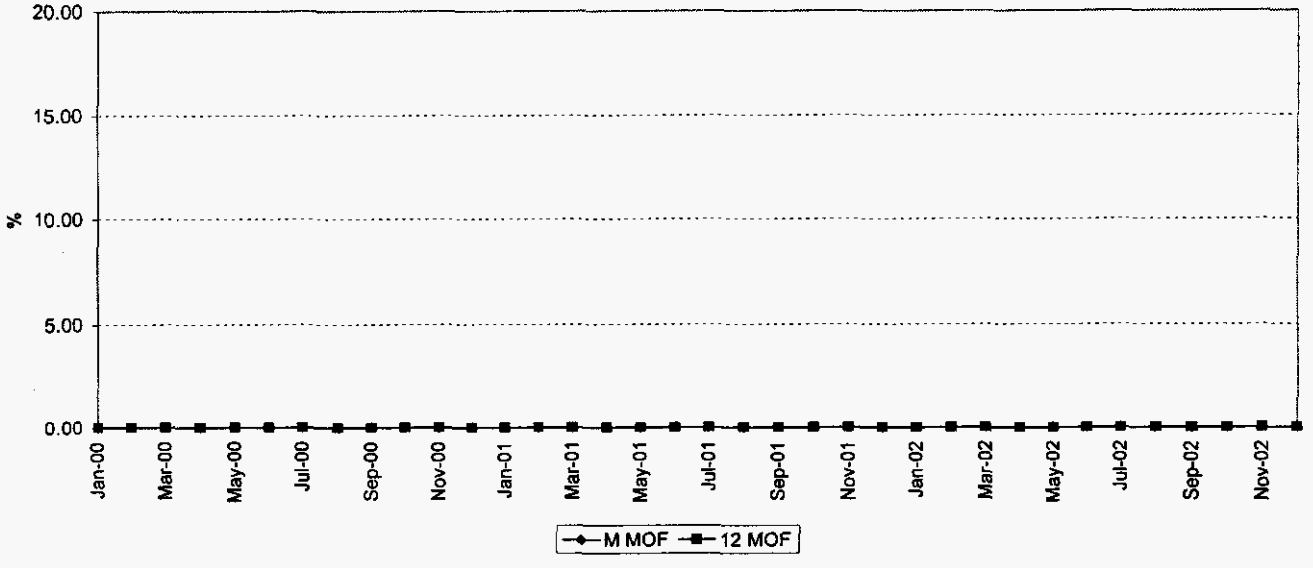
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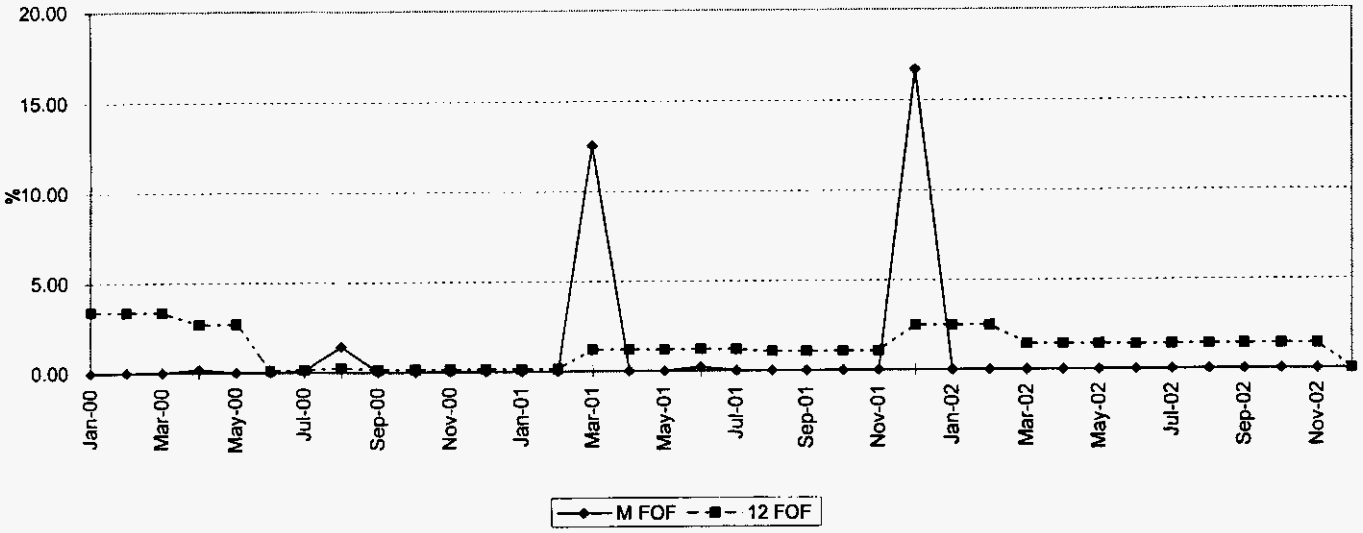
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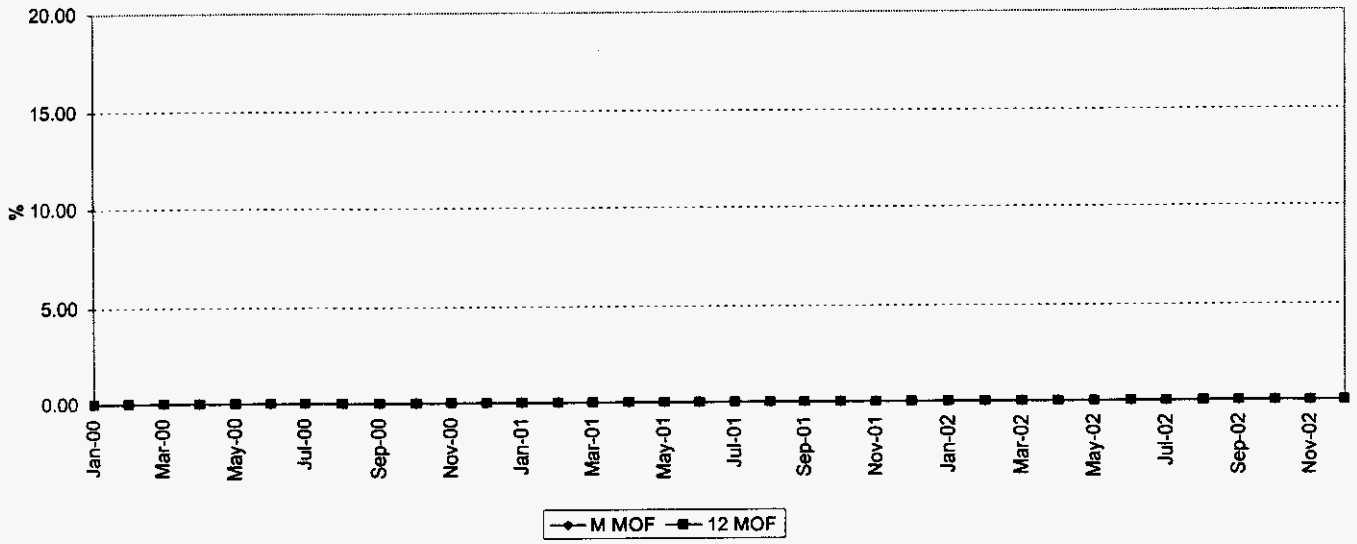
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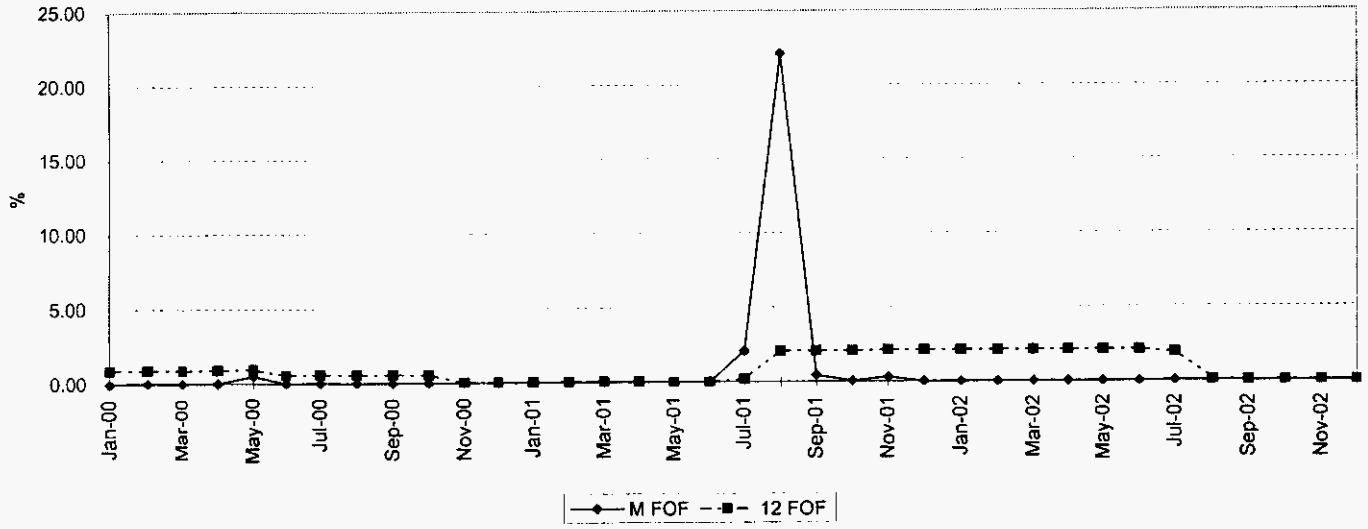
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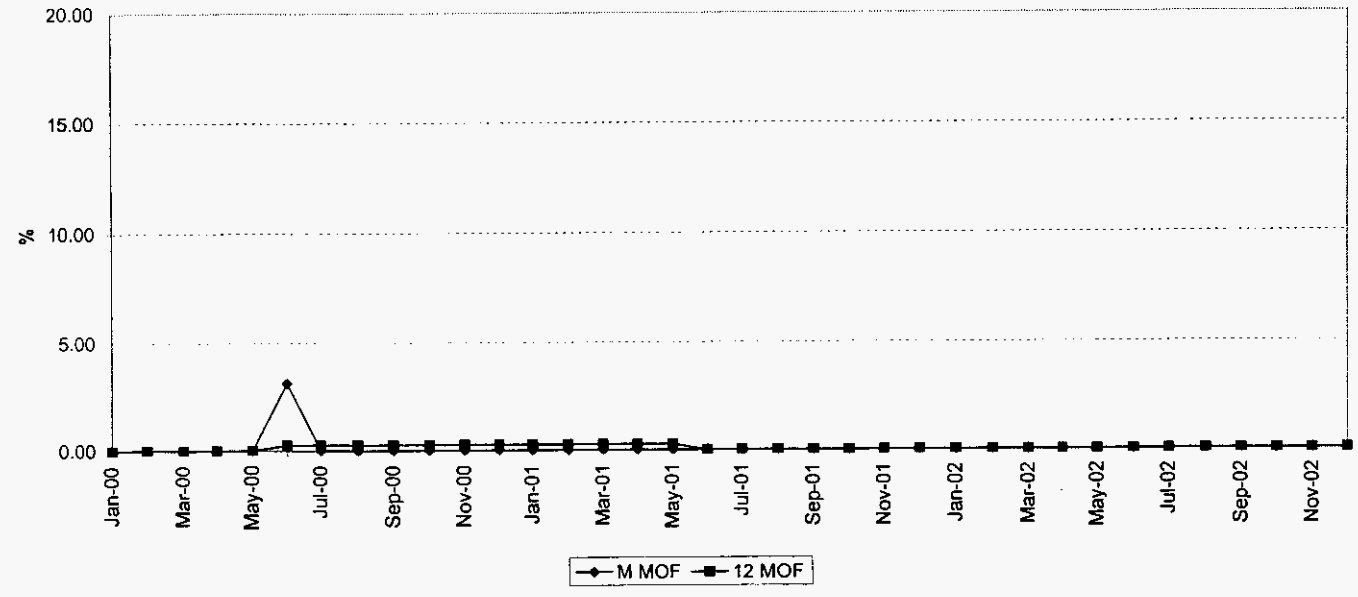
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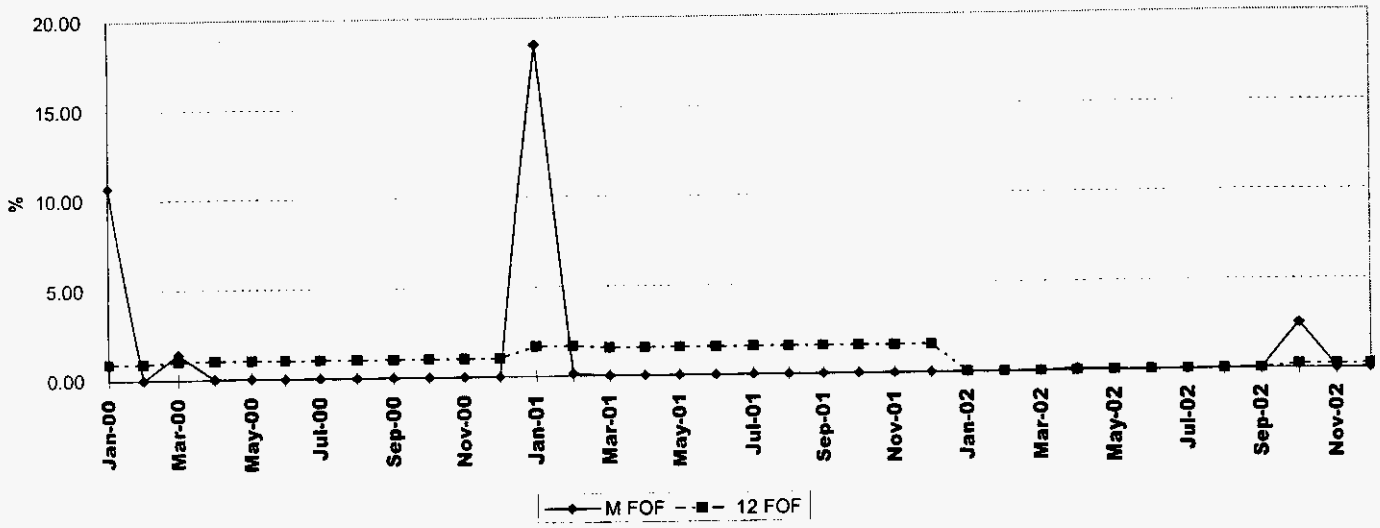
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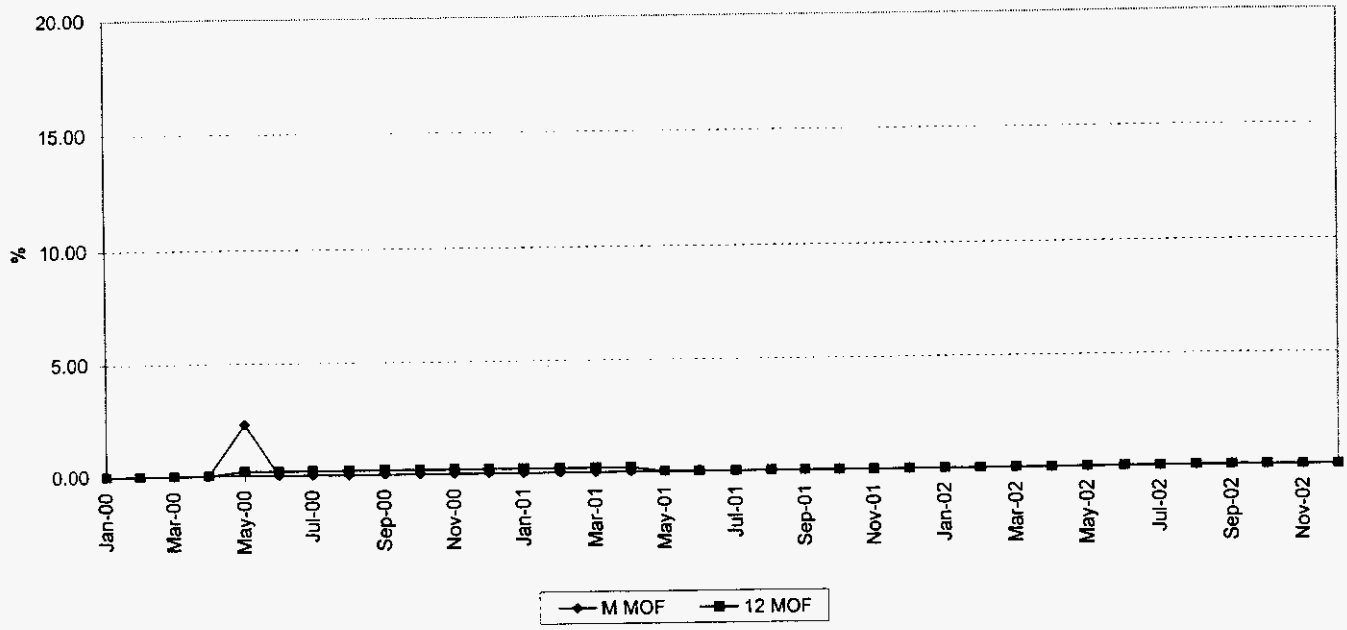
MAINTENANCE OUTAGE FACTOR



PTN 4
FORCED OUTAGE FACTOR



MAINTENANCE OUTAGE FACTOR



PLANNED OUTAGE SCHEDULE (ESTIMATED)

FLORIDA POWER & LIGHT COMPANY

PERIOD OF: JANUARY THROUGH DECEMBER, 2004

PLANT/UNIT	PLAN OUTAGE*	REASON FOR OUTAGE	LR MW**
Cape Canaveral 2	NONE		
Lauderdale 4	02/20/04 - 04/15/04	A/B CT MAJOR / STM TURB / GEN REWIND-100% CURTAILMENT	440
Lauderdale 5	10/16/04 - 11/08/04	B CT HOT PATH (10 DAYS 100% CURT)/A CT MAJOR (24 DAYS @ 50% CURT	313
Manatee 1	NONE		
Manatee 2	02/14/04 - 04/28/04	GENERATOR / BOILER	802
Martin 1	NONE		
Martin 2	NONE		
Martin 3	10/23/04 - 11/01/04	HOT GAS PATH - 50% CURTAILEMENT	233
Martin 4	01/01/04 - 01/29/04	ROTOR - 50% CURTAILMENT	233
Port Everglades 3	NONE		
Port Everglades 4	12/04/04 - 12/17/04	MINOR BOILER	398
Scherer 4	02/28/04 - 04/11/04	HP/IP/BOILER	648
St. Lucie 1	03/22/04 - 04/16/04	Refueling Overhaul	853
St. Lucie 2	11/22/04 - 12/22/04	Refueling Overhaul	726
Turkey Point 3	09/25/04 - 11/29/04	Refueling/reactor vessel head replacement	693
Turkey Point 4	NONE		

*Dates are estimated from breaker open to breaker close

**Load Reduction MW are based on the unit's MW rating during the specified outage period

SCHEDULE E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2003 - DECEMBER 2003
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED

Marianna Division

Under-recovery of purchased power costs for the period January 2003 - December 2003. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2003)(Estimated)	$	(343,777)

Exhibit No._____
DOCKET NO. 030001-EI
Florida Public Utilities Company
(GMB-1)
Page 1 of 6

FLORIDA PUBLIC SERVICE COMMISSION Comp. Ex. 2
DOCKET NO. 030001-EI EXHIBIT NO.
COMPANY/ Florida Public Utilities
WITNESS: Marianna Fernandina Divs.
DATE: 11/12/03

DOCUMENT NUMBER-DATE
07403 AUG 12 8
FPSC-COMMISSION CLERK

GMB-1 + GMB-2

Schedule E1-B

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF PURCHASED POWER COSTS AND
CALCULATION OF TRUE-UP AND INTEREST PROVISION
ESTIMATED FOR THE PERIOD JANUARY 2003 - DECEMBER 2003
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED

MARIANNA DIVISION

			ACTUAL JANUARY 2003	ACTUAL FEBRUARY 2003	ACTUAL MARCH 2003	ACTUAL APRIL 2003	ACTUAL MAY 2003	ACTUAL JUNE 2003	Estimated JULY 2003	Estimated AUGUST 2003	Estimated SEPTEMBER 2003	Estimated OCTOBER 2003	Estimated NOVEMBER 2003	Estimated DECEMBER 2003	Total
Total System Sales - KWH			28,827,986	24,735,931	20,818,498	20,125,552	23,786,208	27,074,157	29,597,651	29,906,195	29,213,493	24,842,921	23,978,095	24,709,672	307,616,359
Total System Purchases - KWH			31,260,827	22,332,595	21,940,443	22,156,036	26,063,006	29,700,478	31,391,000	31,847,000	26,656,000	22,978,000	21,408,000	25,443,000	315,195,385
System Billing Demand - KW			75,955	46,495	43,804	45,602	53,469	62,254	63,700	63,300	54,500	48,900	47,800	57,400	563,279
Purchased Power Rates:															
Base Fuel Costs - $/KWH			0 02120	0 02120	0.02120	0 02120	0 02120	0 02120	0 02120	0 02120	0 02120	0.02120	0 02120	0.02120	
Demand and Non-Fuel															
Demand Charge - $/KW			6.66	6 66	6.66	6 66	6 66	6 66	6 66	6 66	6 66	6.66	6 66	6 66	
Customer Charge - $			550 00	550 00	550 00	550 00	550 00	550 00	550 00	550 00	550 00	550.00	550 00	550 00	
Transformation Charge			34,689	34,689	34,689	34,689	34,689	34,689	31,980	31,980	31,980	31.980	31,980	31,980	
Purchased Power Costs															
Base Fuel Costs			862,730	473,451	465,137	469,708	595,360	629,650	665,489	675,156	595,066	487,134	453,850	539,392	6,682,143
Subtotal Fuel Costs			862,730	473,451	465,137	469,708	595,360	629,650	665,489	675.156	595,066	487,134	453,850	539,392	6,682,143
Demand and Non-Fuel Costs															
Demand Charge			505,860	309,657	291,735	303,709	358,103	414,611	424,242	421,578	363,636	325,674	318,348	382,284	4,417,437
Customer Charge			550	550	550	550	550	550	550	550	550	550	550	550	6,600
Transformation Charge			34,689	34,689	34,689	34,689	34,689	34,689	31,980	31,980	31,980	31,980	31,980	31,980	400,014
Subtotal Demand & Non-Fuel Costs			541,099	344,896	326,974	338,948	391,342	449,850	456,772	454,108	396,166	358,204	350,878	414,814	4,824,051
Total System Purchased Power Costs			1,203,829	818,347	792,111	808,656	986,702	1,079,500	1,122,261	1,129,264	991,252	845,338	804,728	954,206	11,506,194
Sales Revenues															
Fuel Adjustment Revenues		Rates													
Residential	RS	0 03843	586,017	494,553	361,093	328,784	387,741	489,772	521,752	519,803	502,365	408,182	347,920	407,916	5,335,910
Commercial	GS	0.03794	98,593	84,832	77,976	79,144	92,486	92,494	97,318	95,635	91,727	84,403	87,746	84,705	1,057,061
Commercial	GSD	0 03530	247,428	225,551	209,055	209,832	261,582	285,591	312,123	321,917	316,979	278,526	293,488	275,287	3,236,359
Industrial	GSLD	0 03333	119,942	95,429	102,095	105,186	124,327	131,289	138,684	143,036	141,730	123,756	130,405	122,317	1,478,196
Residential	OL,OL-2	0 02705	7,696	7,636	7,682	7,700	7,743	7,711	9,743	9,825	9,259	8,135	7,914	8,152	98,994
Other	SL-1,SL-2,SL-3	0 02709	2,462	2,673	2,575	2,675	2,672	2,666	2,513	2,513	2,513	2,513	2,513	2,513	30,901
Total Fuel Revenues			1,062,137	910,683	760,576	733,321	866,553	989,523	1,082,133	1,092,529	1,066,573	905,515	869,986	900,892	11,240,421
Non-Fuel Revenues			514,310	561,587	492,043	482,654	521,223	571,726	585,067	587,371	575,527	509,085	489,014	507,808	6,477,225
Total Sales Revenue			1,576,447	1,472,270	1,252,619	1,195,985	1,387,776	1,561,249	1,667,200	1,679,900	1,642,100	1,414,600	1,359,000	1,408,500	17,717,646
KWH Sales															
Residential	RS		15,249,788	12,887,214	9,395,891	8,556,743	10,087,584	12,224,121	13,576,690	13,525,968	13,072,195	10,621,433	9,053,352	10,614,570	138,845,532
Commercial	GS		2,595,650	2,235,784	2,055,075	2,085,882	2,174,041	2,437,742	2,565,042	2,529,678	2,417,885	2,224,649	2,312,765	2,232,610	27,857,803
Commercial	GSD		7,008,379	6,388,737	5,921,484	5,943,480	7,409,297	8,089,354	8,842,013	9,119,453	9,038,221	7,890,264	8,314,119	7,798,485	91,761,286
Industrial	GSLD		3,599,087	2,863,485	3,063,583	3,156,274	3,730,635	3,939,530	4,160,947	4,291,507	4,252,339	3,713,066	3,912,527	3,669,876	44,352,805
Residential	OL,OL-2		284,246	282,031	283,766	284,444	286,030	285,005	360,185	355,815	342,278	300,735	292,556	301,358	3,658,449
Other	SL-1,SL-2,SL-3		90,876	98,880	98,729	96,729	98,621	98,405	92,774	92,774	92,774	92,774	92,774	92,774	1,140,684
Total KWH Sales			28,827,986	24,735,931	20,818,498	20,125,552	23,786,208	27,074,157	29,597,651	29,906,195	29,213,493	24,842,921	23,978,095	24,709,672	307,616,359
															Period to Date
True-up Calculation.															
Fuel Revenues			1,062,137	910,683	760,576	733,321	866,553	989,523	1,082,133	1,092,529	1,066,573	905,515	869,986	900,892	11,240,421
True-up Provision		DIVIDED BY 12	6,199	6,202	6,202	6,202	6,202	6,202	6,202	6,202	6,202	6,202	6,202	6,202	74,421
Gross Receipts Tax Refund			0	0				0	0	0	0	0	0	0	0
Fuel Revenue			1,055,938	904,481	754,374	727,119	860,351	983,321	1,075,931	1,086,327	1,060,371	899,313	863,784	894,690	11,165,000
Total Purchased Power Costs			1,203,829	818,347	792,111	808,656	986,702	1,079,500	1,122,261	1,129,264	991,252	845,338	804,728	954,206	11,506,194
True-up Provision for the Period			(147,891)	86,134	(37,737)	(81,537)	(126,351)	(96,179)	(46,330)	(42,937)	69,119	53,975	59,056	(59,516)	(340,194)
Interest Provision for the Period			(155)	(179)	(142)	(191)	(291)	(365)	(426)	(461)	(430)	(354)	(297)	(292)	(3,583)
True-up and Interest Provision															
Beginning of Period			(74,421)	(216,268)	(124,111)	(155,788)	(231,314)	(351,754)	(442,096)	(482,650)	(519,846)	(414,955)	(355,132)	(290,171)	(74,421)
True-up Collected or (Refunded)			6,199	6,202	6,202	6,202	6,202	6,202	6,202	6,202	6,202	6,202	6,202	6,202	74,421
End of Period, Net True-up			(216,268)	(124,111)	(155,788)	(231,314)	(351,754)	(442,096)	(482,650)	(519,846)	(414,955)	(355,132)	(290,171)	(343,777)	(343,777)
															-2.99%
10% Rule															
Interest Provision:															
Beginning True-up Amount			(74,421)	(216,268)	(124,111)	(155,788)	(231,314)	(351,754)	(442,096)	(482,650)	(519,846)	(414,955)	(355,132)	(290,171)	
Ending True-up Amount Before Interest			(216,113)	(123,932)	(155,646)	(231,123)	(351,463)	(441,731)	(482,224)	(519,385)	(414,525)	(354,778)	(289,874)	(343,485)	
Total Beginning and Ending True-up			(290,534)	(340,200)	(279,757)	(386,911)	(582,777)	(793,485)	(924,320)	(1,002,035)	(934,371)	(769,733)	(645,006)	(633,656)	
Average True-up Amount			(145,267)	(170,100)	(139,879)	(193,456)	(291,389)	(396,743)	(462,160)	(501,018)	(467,186)	(384,867)	(322,503)	(316,828)	
Average Annual Interest Rate			1.2800%	1 2600%	1 2150%	1.1850%	1 2000%	1.1050%	1.1050%	1 1050%	1 1050%	1 1050%	1 1050%	1 1050%	
Monthly Average Interest Rate			0.1067%	0 1050%	0 1013%	0.0988%	0 1000%	0.0921%	0.0921%	0 0921%	0 0921%	0.0921%	0 0921%	0 0921%	
Interest Provision			(155)	(179)	(142)	(191)	(291)	(365)	(426)	(461)	(430)	(354)	(297)	(292)	

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SCHEDULE E1-B1

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA DIVISION
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
FOR THE PERIOD JANUARY 2003 - DECEMBER 2003

		DOLLARS				MWH				CENTS/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%
1	Fuel Cost of System Net Generation (A3)					0	0	0	0 0%	0 00000	0 00000	0 00000	0 0%
2	Nuclear Fuel Disposal Cost												
3	Coal Car Investment												
4	Adjustments to Fuel Cost (A2, Page 1)												
5	TOTAL COST OF GENERATED POWER	0	0	0	0 0%	0	0	0	0 0%	0 00000	0 00000	0 00000	0 0%
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A7)	6,682,143	6,385,336	296,808	4 7%	315,195	301,195	14,000	4 7%	2 12000	2.12000	0 00000	0 0%
7	Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8	Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9	Energy Cost of Sched E Economy Purch (A9)												
10	Demand and Non Fuel Cost of Purchased Power (A9)	4,824,051	4,715,365	108,686	2 3%	315,195	301,195	14,000	4 7%	1 53050	1 56555	(0 03505)	-2 2%
11	Energy Payments to Qualifying Facilities (A8a)												
12	TOTAL COST OF PURCHASED POWER	11,506,194	11,100,700	405,494	3 7%	315,195	301,195	14,000	4.7%	3 65050	3 68555	(0.03505)	-1 0%
13	TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					315,195	301,195	14,000	4.7%				
14	Fuel Cost of Economy Sales (A6)												
15	Gain on Economy Sales (A6)												
16	Fuel Cost of Unit Power Sales (SL2 Partpts)(A6)												
17	Fuel Cost of Other Power Sales (A6)												
18	TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0 0%	0	0	0	0 0%	0 00000	0.00000	0 00000	0 0%
19	NET INADVERTENT INTERCHANGE												
20	TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	11,506,194	11,100,700	405,494	3 7%	315,195	301,195	14,000	4 7%	3 65050	3 68555	(0 03505)	-1 0%
21	Net Unbilled Sales	(194,170) *	(711,090) *	516,920	-72 7%	(5,319)	(19,294)	13,975	-72 4%	(0 06312)	(0 23073)	0 16761	-72 6%
22	Company Use	10,586 *	9,214 *	1,372	14 9%	290	250	40	16 0%	0 00344	0 00299	0 00045	15 1%
23	T & D Losses	480,255 *	444,035 *	16,220	3 7%	12,808	12,048	560	4 7%	0 14962	0 14408	0 00554	3 9%
24	SYSTEM KWH SALES	11,506,194	11,100,700	405,494	3 7%	307,616	308,191	(575)	-0 2%	3 74044	3.60189	0 13855	3.9%
25	Wholesale KWH Sales												
26	Jurisdictional KWH Sales	11,506,194	11,100,700	405,494	3 7%	307,616	308,191	(575)	-0 2%	3.74044	3 60189	0 13855	3 9%
26a	Jurisdictional Loss Multiplier	1 000	1.000	0.000	0 0%	1 000	1 000	0 000	0.0%	1 000	1 000	0 00000	0 0%
27	Jurisdictional KWH Sales Adjusted for Line Losses	11,506,194	11,100,700	405,494	3 7%	307,616	308,191	(575)	-0 2%	3 74044	3 60189	0 13855	3.9%
28	GPIF**												
29	TRUE-UP**	74,421	147,999	(73,578)	-49 7%	307,616	308,191	(575)	-0 2%	0 02419	0 04802	(0 02383)	-49 6%
30	TOTAL JURISDICTIONAL FUEL COST	11,580,615	11,248,699	331,916	3 0%	307,616	308,191	(575)	-0 2%	3 76463	3 64991	0 11472	3 1%
31	Revenue Tax Factor									1 00072	1 00072	0 00000	0 0%
32	Fuel Factor Adjusted for Taxes									3.76734	3 65254	0 11480	3.1%
33	FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									3.767	3.653	0.114	3.1%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2003 - DECEMBER 2003
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

Fernandina Beach Division

Over-recovery of purchased power costs for the period January 2003 - December 2003. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2003.)(Estimated)	$	1,302,700

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Schedule E1-B

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF PURCHASED POWER COSTS AND
CALCULATION OF TRUE-UP AND INTEREST PROVISION-EXCLUDING GSLD
ESTIMATED FOR THE PERIOD JANUARY 2003 THROUGH DECEMBER 2003
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED
(EXCLUDES LINE LOSS , EXCLUDES TAXES)

FERNANDINA BEACH		ACTUAL JANUARY 2003	ACTUAL FEBRUARY 2003	ACTUAL MARCH 2003	ACTUAL APRIL 2003	ACTUAL MAY 2003	ACTUAL JUNE 2003	Estimated JULY 2003	Estimated AUGUST 2003	Estimated SEPTEMBER 2003	Estimated OCTOBER 2003	Estimated NOVEMBER 2003	Estimated DECEMBER 2003	Total Estimated
Total System Sales - KWH		36,681,041	35,883,396	30,079,446	25,823,550	32,309,144	35,834,987	41,427,989	42,023,348	39,055,644	35,633,975	33,307,686	32,379,421	420,439,627
JSC Purchases - KWH		375,500	1,443,800	186,100	493,500	606,500	490,400	400,000	400,000	400,000	400,000	400,000	400,000	5,997,800
JEA Purchases - KWH		41,189,041	30,037,862	31,768,475	27,781,129	35,831,879	39,139,653	47,497,622	47,168,035	44,117,372	42,151,196	38,174,846	38,134,810	462,791,521
System Billing Demand - KW		103,309	77,414	64,526	52,685	68,947	72,979	93,373	93,117	92,000	78,106	67,850	83,387	947,993
Purchased Power Rates														
CCA Fuel Costs - $/KWH		0 018700	0 018700	0 018700	0 018700	0 018700	0 018700	0 018700	0 018700	0 018700	0 018700	0 018700	0 018700	
Base Fuel Costs - $/KWH		0 01786	0 01786	0 01786	0.01786	0 01786	0 01786	0.01845	0 01845	0 01845	0.01845	0 01845	0 01845	
Fuel Adjustment - $/KWH		0 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000	0 00000	
Demand and Non-Fuel														
Demand Charge - $/KW		6 00	6 00	6.00	6.00	6 00	6 00	6 00	6 00	6 00	6.00	6 00	6.00	
Customer Charge - $		225 00	225 00	225.00	225 00	225.00	225 00	225.00	225 00	225.00	225 00	225.00	225 00	
Energy Charge (Excl Fuel) $/KWH		0 00164	0 00164	0 00164	0.00164	0 00164	0 00164	0.00105	0 00105	0 00105	0 00105	0 00105	0.00105	
Purchased Power Costs														
CCA Fuel Costs		7,022	26,998	3,517	9,228	11,342	9,170	7,480	7,480	7,480	7,480	7,480	7,480	112,158
JEA Base Fuel Costs		735,836	536,478	567,385	496,171	636,382	699,034	876,331	870,250	813,966	777,690	704,326	703,584	8,417,231
JEA Fuel Adjustment		0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal Fuel Costs		742,858	563,475	570,902	505,399	647,724	708,204	883,811	877,730	821,446	785,170	711,806	711,064	8,529,388
Demand and Non-Fuel Costs														
Demand Charge		619,854	464,484	388,956	316,110	413,682	437,874	560,237	558,701	551,999	468,635	407,099	500,321	5,687,952
Customer Charge		225	225	225	225	225	225	225	225	225	225	225	225	2,700
Energy Charge		67,550	49,262	52,100	45,561	58,436	64,189	49,873	49,526	46,323	44,259	40,084	40,041	607,204
Subtotal Demand & Non-Fuel Costs		687,629	513,971	441,281	361,896	472,343	502,288	610,335	608,452	598,547	513,119	447,408	540,587	6,297,856
Total System Purchased Power Costs		1,430,287	1,077,446	1,012,183	867,295	1,120,067	1,210,492	1,494,146	1,486,182	1,419,993	1,298,289	1,159,214	1,251,651	14,827,245
Less Direct Bllng To GSLD Class														
Demand		77,133	186,171	133,506	17,800	65,019	60,075	132,870	132,870	132,870	132,870	132,870	132,870	1,338,924
Commodity		156,529	148,006	175,509	87,548	115,264	115,263	178,052	181,145	162,816	162,806	191,868	130,121	1,825,227
Net Purchased Power Costs		1,196,325	743,269	703,168	761,947	939,784	1,035,154	1,183,224	1,172,167	1,124,307	982,613	834,476	988,660	11,665,094
Sales Revenues														
Fuel Adjustment Revenues:	Rate													
RS	0 03888	871,948	860,294	436,433	412,448	539,863	644,320	751,010	768,943	698,186	536,699	434,029	514,337	7,062,512
GS	0 03567	96,218	97,244	80,511	84,143	100,913	114,508	81,522	81,199	80,230	77,979	78,073	77,841	1,049,381
GSD	0 03391	263,482	262,062	240,281	263,124	310,553	313,149	331,532	330,301	326,620	327,018	327,375	326,495	3,622,012
OL	0 02909	2,462	2,289	2,653	2,601	939	3,013	2,828	2,833	2,838	3,189	3,068	3,070	31,783
SL,CSL	0 02909	3,258	1,927	1,895	1,927	1,927	1,934	810	811	813	913	878	879	17,972
Total Fuel Revenues (Excl. GSLD)		1,036,368	1,023,836	761,773	764,243	948,195	1,076,924	1,167,702	1,184,087	1,108,689	945,798	843,423	922,622	11,783,660
GSLD Fuel Revenues		233,962	334,177	309,015	105,348	180,283	175,338	310,922	314,015	295,686	315,676	324,738	262,991	3,162,151
Non-Fuel Revenues		635,522	647,937	525,328	522,698	637,222	640,698	733,076	743,396	692,925	538,826	600,139	580,587	7,396,156
Total Sales Revenue		1,905,852	2,005,950	1,596,116	1,392,289	1,765,700	1,892,960	2,211,700	2,241,500	2,097,300	1,800,100	1,768,300	1,766,200	22,543,967
KWH Sales.														
RS		18,228,205	17,913,491	11,839,858	11,189,139	14,482,993	17,479,636	20,374,656	20,861,172	18,941,604	14,560,476	11,775,060	13,953,810	191,600,102
GS		2,699,375	2,726,201	2,257,087	2,358,912	2,829,056	3,210,175	2,285,458	2,276,382	2,249,242	2,186,125	2,188,755	2,182,266	29,419,034
GSD		7,770,388	7,728,762	7,088,187	7,759,830	9,156,557	9,235,133	9,776,835	9,740,530	9,631,568	9,643,700	9,654,223	9,628,267	106,814,360
GSLD		7,810,000	7,370,000	8,740,000	4,360,000	6,740,000	5,740,000	8,866,000	9,020,000	8,107,334	9,102,666	9,554,000	8,479,334	90,889,334
OL		84,818	78,895	91,199	89,422	32,291	103,562	97,208	97,380	97,561	109,820	105,453	105,527	1,092,534
SL,CSL		118,455	86,247	65,136	68,247	86,247	86,479	27,834	27,864	27,935	31,388	30,195	30,217	624,263
Total KWH Sales		36,681,041	35,883,396	30,079,446	25,823,550	32,309,144	35,834,987	41,427,990	42,023,348	39,055,644	35,633,974	33,307,686	32,379,421	420,439,627
True-up Calculation (Excl GSLD)														
Fuel Revenues		1,036,368	1,023,836	761,773	764,243	948,195	1,076,924	1,167,702	1,184,087	1,108,689	945,798	843,423	922,622	11,783,660
True-up Provision		(97,402)	(97,403)	(97,403)	(97,403)	(97,403)	(97,403)	(97,403)	(97,403)	(97,403)	(97,403)	(97,403)	(97,403)	(1,168,835)
Gross Receipts Tax Refund		0	0	0	0	0	0	0	0	0	0	0	0	0
Fuel Revenue		1,133,770	1,121,239	859,176	861,646	1,045,598	1,174,327	1,265,105	1,281,490	1,206,092	1,043,201	940,826	1,020,025	12,952,495
Net Purchased Power Costs		1,196,325	743,269	703,168	761,947	939,784	1,035,154	1,183,224	1,172,167	1,124,307	982,613	834,476	988,660	11,665,094
True-up Provision for the Period		(62,555)	377,970	156,008	99,699	105,814	139,173	81,881	109,323	81,785	60,588	106,350	31,365	1,287,401
Interest Provision for the Period		1,162	1,208	1,338	1,337	1,360	1,277	1,290	1,289	1,289	1,266	1,254	1,229	15,299
True-up and Interest Provision														
Beginning of Period		1,168,835	1,010,040	1,291,815	1,351,758	1,355,391	1,365,162	1,408,209	1,393,977	1,407,186	1,392,857	1,357,308	1,367,509	1,168,835
True-up Collected or (Refunded)		(97,402)	(97,403)	(97,403)	(97,403)	(97,403)	(97,403)	(97,403)	(97,403)	(97,403)	(97,403)	(97,403)	(97,403)	(1,168,835)
End of Period, Net True-up		1,010,040	1,291,815	1,351,758	1,355,391	1,365,162	1,408,209	1,393,977	1,407,186	1,392,857	1,357,308	1,367,509	1,302,700	1,302,700
10% Rule Interest Provision.														5 79%
Beginning True-up Amount		1,168,835	1,010,040	1,291,815	1,351,758	1,356,391	1,365,162	1,408,209	1,393,977	1,407,186	1,392,857	1,357,308	1,367,509	
Ending True-up Amount Before Interest		1,008,878	1,290,607	1,350,420	1,354,054	1,363,802	1,406,932	1,392,687	1,405,897	1,391,568	1,356,042	1,366,255	1,301,471	
Total Beginning and Ending True-up		2,177,713	2,300,647	2,642,235	2,705,812	2,719,193	2,772,094	2,800,896	2,799,874	2,798,754	2,748,899	2,723,563	2,668,980	
Average True-up Amount		1,088,857	1,150,324	1,321,118	1,352,906	1,359,597	1,386,047	1,400,448	1,399,937	1,399,377	1,374,450	1,361,782	1,334,490	
Average Interest Rate		1 2800%	1 2600%	1 2150%	1 1850%	1 2000%	1 1050%	1 1050%	1 1050%	1 1050%	1 1050%	1 1050%	1 1050%	
Monthly Average Interest Rate		0 1067%	0 1050%	0 1013%	0 0988%	0 1000%	0 0921%	0 0921%	0 0921%	0 0921%	0 0921%	0 0921%	0 0921%	
Interest Provision		1,162	1,208	1,338	1,337	1,360	1,277	1,290	1,289	1,289	1,266	1,254	1,229	

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SCHEDULE E1-B1

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
JANUARY 2003 - DECEMBER 2003

	DOLLARS				MWH				CENTS/KWH			
	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%
1 Fuel Cost of System Net Generation (A3)					0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
2 Nuclear Fuel Disposal Cost (A13)												
3 Coal Car Investment												
4 Adjustments to Fuel Cost (A2, Page 1)												
5 TOTAL COST OF GENERATED POWER	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
6 Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	8,417,231	9,105,319	(688,088)	-7.6%	462,792	493,513	(30,721)	-6.2%	1.81879	1.84500	(0.02621)	-1.4%
7 Energy Cost of Sched C & X Econ Purch (Broker)(A9)												
8 Energy Cost of Other Econ Purch (Non-Broker)(A9)												
9 Energy Cost of Sched E Economy Purch (A9)												
10 Demand and Non Fuel Cost of Purchased Power (A9)	6,297,856	6,567,329	(269,473)	-4.1%	462,792	493,513	(30,721)	-6.2%	1.36084	1.33073	0.03011	2.3%
11 Energy Payments to Qualifying Facilities (A8a)	112,158	89,760	22,398	25.0%	5,998	4,800	1,198	25.0%	1.86992	1.87000	(0.00008)	0.0%
12 TOTAL COST OF PURCHASED POWER	14,827,245	15,762,408	(935,163)	-5.9%	468,790	498,313	(29,523)	-5.9%	3.16288	3.16315	(0.00027)	0.0%
13 TOTAL AVAILABLE MWH (LINE 5 + LINE 12)					468,790	498,313	(29,523)	-5.9%				
14 Fuel Cost of Economy Sales (A7)												
15 Gain on Economy Sales (A7a)												
16 Fuel Cost of Unit Power Sales (SL2 Partpts)(A7)												
17 Fuel Cost of Other Power Sales (A7)												
18 TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19 NET INADVERTENT INTERCHANGE (A10)												
20 TOTAL FUEL AND NET POWER TRANSACTIONS (LINES 5 + 12 + 18 + 19)	14,827,245	15,762,408	(935,163)	-5.9%	468,790	498,313	(29,523)	-5.9%	3.16288	3.16315	(0.00027)	0.0%
21 Net Unbilled Sales (A4)	623,878 *	1,215,440 *	(591,562)	-48.7%	19,725	38,425	(18,700)	-48.7%	0.14839	0.28295	(0.13456)	-47.6%
22 Company Use (A4)	15,751 *	13,791 *	1,960	14.2%	498	436	62	14.2%	0.00375	0.00321	0.00054	16.8%
23 T & D Losses (A4)	889,623 *	945,750 *	(56,127)	-5.9%	28,127	29,899	(1,772)	-5.9%	0.21159	0.22017	(0.00858)	-3.9%
24 SYSTEM KWH SALES	14,827,245	15,762,408	(935,163)	-5.9%	420,440	429,553	(9,113)	-2.1%	3.52661	3.66948	(0.14287)	-3.9%
25 Wholesale KWH Sales												
26 Jurisdictional KWH Sales	14,827,245	15,762,408	(935,163)	-5.9%	420,440	429,553	(9,113)	-2.1%	3.52661	3.66948	(0.14287)	-3.9%
26a Jurisdictional Loss Multiplier	1.000	1.000	0.000	0.0%	1.000	1.000	0.000	0.0%	1.000	1.000	0.00000	0.0%
27 Jurisdictional KWH Sales Adjusted for Line Losses	14,827,245	15,762,408	(935,163)	-5.9%	420,440	429,553	(9,113)	-2.1%	3.52661	3.66948	(0.14287)	-3.9%
28 GPIF**												
29 TRUE-UP**	(1,168,835)	(328,323)	(840,512)	256.0%	420,440	429,553	(9,113)	-2.1%	(0.27800)	(0.07643)	(0.20157)	263.7%
30 TOTAL JURISDICTIONAL FUEL COST	13,658,410	15,434,085	(1,775,675)	-11.5%	420,440	429,553	(9,113)	-2.1%	3.24860	3.59305	(0.34446)	-9.6%
31 Revenue Tax Factor									1.01597	1.01597	0.00000	0.0%
32 Fuel Factor Adjusted for Taxes									3.30048	3.65044	(0.34996)	-9.6%
33 FUEL FAC ROUNDED TO NEAREST .001 (CENTS/KWH)									3.300	3.650	(0.350)	-9.6%

*Included for Informational Purposes Only
**Calculation Based on Jurisdictional KWH Sales

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
ESTIMATED FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004

SCHEDULE E1
PAGE 1 OF 2

	MARIANNA DIVISION	(a) DOLLARS		(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)			0	
2	Nuclear Fuel Disposal Costs (E2)				
3	Coal Car Investment				
4	Adjustments to Fuel Cost				
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0		0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	6,606,351		303,032	2.18008
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)				
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)				
9	Energy Cost of Sched E Economy Purch (E9)				
10	Demand & Transformation Cost of Purch Power (E2)	4,755,958		303,032	1.56946
10a	Demand Costs of Purchased Power	4,365,598	*		
10b	Transformation Energy & Customer Costs of Purchased Power	390,360	*		
11	Energy Payments to Qualifying Facilities (E8a)				
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	11,362,309		303,032	3.74954
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	11,362,309		303,032	3.74954
14	Fuel Cost of Economy Sales (E6)				
15	Gain on Economy Sales (E6)				
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)				
17	Fuel Cost of Other Power Sales				
18	TOTAL FUEL COST AND GAINS OF POWER SALES	0		0	0.00000
19	Net Inadvertent Interchange				
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	11,362,309		303,032	3.74954
21	Net Unbilled Sales	0	*	0	0.00000
22	Company Use	9,374	*	250	0.00310
23	T & D Losses	18,598	*	496	0.00615
24	SYSTEM MWH SALES	11,362,309		302,286	3.75879
25	Less Total Demand Cost Recovery	4,365,598	***		
26	Jurisdictional MWH Sales	6,996,711		302,286	2.31460
26a	Jurisdictional Loss Multiplier	1.00000		1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	6,996,711		302,286	2.31460
28	GPIF **				
29	TRUE-UP **	343,777		302,286	0.11373
30	TOTAL JURISDICTIONAL FUEL COST	7,340,488		302,286	2.42833
31	Revenue Tax Factor				1.00072
32	Fuel Factor Adjusted for Taxes				2.43008
33	FUEL FAC ROUNDED TO NEAREST .001 CENTS/KWH				2.430

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
***Calculation on Schedule E1 Page 2

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DOCUMENT NUMBER-DATE
08644 SEP 12 8
FPSC-COMMISSION CLERK

FLORIDA PUBLIC UTILITIES COMPANY
FUEL FACTOR ADJUSTED FOR
LINE LOSS MULTIPLIER
ESTIMATED FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

MARIANNA DIVISION

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*4,380)			(3)*(4)	(1)*(5)	(6)/Total Col. (6)	(7)/Total Col. (7)
	Rate Schedule	KWH Sales	12 CP Load Factor	CP KW At Meter	Demand Loss Factor	Energy Loss Factor	CP KW At GEN.	KWH At GEN.	12 CP Demand Percentage	Energy Percentage
34	RS	141,466,583	59.521838%	54,263.0	1.089	1.000	59,092.4	141,466,583	53.17%	46.80%
35	GS	28,118,739	61.623894%	10,417.7	1.089	1.000	11,344.9	28,118,739	10.21%	9.30%
36	GSD	91,122,304	74.923957%	27,767.1	1.083	1.000	30,071.8	91,122,304	27.05%	30.14%
37	GSLD	37,212,751	86 403429%	9,833.0	1 038	1.000	10,206.7	37,212,751	9.18%	12.31%
38	OL, OL1	3,351,691	247.068649%	309.7	1.089	1.000	337.3	3,351,691	0.30%	1.11%
39	SL1, SL2 & SL3	1,014,422	247.068649%	93.7	1.089	1.000	102 0	1,014,422	0.09%	0.34%
40	TOTAL	302,286,490		102,684.2			111,155 1	302,286,490	100 00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) Tot. Col. 13 * (12)	(14) (13)/(1)	(15) (14) * 1.00072	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocation Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
41	RS	49.07%	3.60%	52.67%	$2,299,360	0.01625	0.01626	0.02430	$0 04056
42	GS	9.42%	0.72%	10.14%	442,672	0.01574	0.01575	0.02430	$0.04005
43	GSD	24.97%	2.32%	27.29%	1,191,372	0.01307	0.01308	0.02430	$0.03738
44	GSLD	8.47%	0.95%	9.42%	411,239	0 01105	0.01106	0.02430	$0 03538
45	OL, OL1	0 28%	0.09%	0 37%	16,153	0.00482	0.00482	0.02430	$0 02912
46	SL1, SL2 & SL3	0.08%	0.03%	0.11%	4,802	0 00473	0.00473	0.02430	$0.02903
47	TOTAL	92.29%	7.71%	100 00%	$4,365,598				

(2) From Gulf Power Co. 2003 Load Research results.
(4) From Fernandina Rate Case.

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SCHEDULE E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2003 - DECEMBER 2003
BASED ON SIX MONTHS ACTUAL & SIX MONTHS ESTIMATED

Marianna Division

Under-recovery of purchased power costs for the period January 2003 - December 2003. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2003)(Estimated)	$	(343,777)
Estimated kilowatt hour sales for the months of January 2004 - December 2004 as per estimate filed with the Commission.		302,286,490
Cents per kilowatt hour necessary to collect under-recovered purchased power costs over the period January 2004 - December 2004.		(0.11373)

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SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

LINE NO.			(a) 2004 JANUARY	(b) 2004 FEBRUARY	(c) ESTIMATED 2004 MARCH	(d) 2004 APRIL	(e) 2004 MAY	2004 JUNE	2004 JULY	2004 AUGUST	2004 SEPTEMBER	2004 OCTOBER	2004 NOVEMBER	(f) 2004 DECEMBER	(g) TOTAL PERIOD	LINE NO.
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	*NUCLEAR FUEL DISPOSAL*														0	1a
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER		561,849	457,102	462,525	457,911	567,484	604,196	675,070	670,738	584,570	507,086	478,084	579,756	6,606,351	3
3a	DEMAND & TRANSFORMATION CHARGE OF PURCHASED POWER		433,734	379,334	311,334	324,924	399,724	433,734	460,934	460,934	413,324	385,724	345,334	426,924	4,755,958	3a
3b	QUALIFYING FACILITIES														0	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		995,583	836,436	773,859	782,835	967,188	1,037,930	1,136,004	1,131,672	997,894	872,810	823,418	1,006,680	11,362,309	5
6	LESS. TOTAL DEMAND COST RECOVERY		401,204	346,804	278,804	292,364	367,194	401,204	428,404	428,404	380,794	333,194	312,804	394,394	4,365,598	6
7	TOTAL OTHER COST TO BE RECOVERED		594,378	489,632	495,055	490,441	599,994	636,726	707,600	703,268	617,100	539,616	510,614	612,286	6,996,711	7
7a	SYSTEM KWH SOLD (MWH)		28,309	25,989	23,123	24,368	23,367	25,750	25,223	25,207	25,234	25,239	25,225	25,252	302,286	7a
7b	COST PER KWH SOLD (CENTS/KWH)		2.09961	1.884	2.14096	2.01264	2.5677	2.47272	2.80538	2.78997	2.44551	2.13802	2.02424	2.4247	2.3146	7b
8	JURISDICTIONAL LOSS MULTIPLIER		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)		2.09961	1.88400	2.14096	2.01264	2.56770	2.47272	2.80538	2.78997	2.44551	2.13802	2.02424	2.42470	2.31460	9
10	GPIF (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)		0.11373	0.11373	0.11373	0.11373	0.11373	0.11373	0.11373	0.11373	0.11373	0.11373	0.11373	0.11373	0.11373	11
12	TOTAL		2.21334	1.99773	2.25469	2.12637	2.68143	2.58645	2.91911	2.90370	2.55924	2.25175	2.13797	2.53843	2.42833	12
13	REVENUE TAX FACTOR	0.00072	0.00159	0.00144	0.00162	0.00153	0.00193	0.00186	0.00210	0.00209	0.00184	0.00162	0.00154	0.00183	0.00175	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		2.21493	1.99917	2.25631	2.12790	2.68336	2.58831	2.92121	2.90579	2.56108	2.25337	2.13951	2.54026	2.43008	14
15	RECOVERY FACTOR ROUNDED TO *NEAREST .001 CENT/KWH*		2.215	1.999	2.256	2.128	2.683	2.588	2.921	2.906	2.561	2.253	2.140	2.540	2.430	15

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SCHEDULE E7

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004

(1)		(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH		PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY	2004	GULF POWER COMPANY	RE	25,773,000			25,773,000	2.179991	3.862891	561,849
FEBRUARY	2004	GULF POWER COMPANY	RE	20,968,000			20,968,000	2.179998	3.989107	457,102
MARCH	2004	GULF POWER COMPANY	RE	21,216,000			21,216,000	2.180077	3.647525	462,525
APRIL	2004	GULF POWER COMPANY	RE	21,003,000			21,003,000	2.180217	3.727253	457,911
MAY	2004	GULF POWER COMPANY	RE	26,028,000			26,028,000	2.180205	3.715952	567,464
JUNE	2004	GULF POWER COMPANY	RE	27,716,000			27,716,000	2.179953	3.744877	604,196
JULY	2004	GULF POWER COMPANY	RE	30,965,000			30,965,000	2.180108	3.668671	675,070
AUGUST	2004	GULF POWER COMPANY	RE	30,766,000			30,766,000	2.180128	3.678320	670,738
SEPTEMBER	2004	GULF POWER COMPANY	RE	26,814,000			26,814,000	2.180092	3.721541	584,570
OCTOBER	2004	GULF POWER COMPANY	RE	23,260,000			23,260,000	2.180071	3.752403	507,086
NOVEMBER	2004	GULF POWER COMPANY	RE	21,931,000			21,931,000	2.179940	3.754580	478,084
DECEMBER	2004	GULF POWER COMPANY	RE	26,592,000			26,592,000	2.180188	3.785650	579,756
TOTAL				303,032,000	0	0	303,032,000	2.180084	3.749540	6,606,351

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SCHEDULE E10

FLORIDA PUBLIC UTILITIES COMPANY
MARIANNA DIVISION
RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1000 KWH

ESTIMATED FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004

	JANUARY 2004	FEBRUARY 2004	MARCH 2004	APRIL 2004	MAY 2004	JUNE 2004	JULY 2004
BASE RATE REVENUES ** $	21.22	21.22	21.22	21.22	21.22	21.22	21.22
FUEL RECOVERY FACTOR CENTS/KWH	4.06	4.06	4.06	4.06	4.06	4.06	4.06
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	40.56	40.56	40.56	40.56	40.56	40.56	40.56
GROSS RECEIPTS TAX	1.58	1.58	1.58	1.58	1.58	1.58	1.58
TOTAL REVENUES *** $	63.36	63.36	63.36	63.36	63.36	63.36	63.36

	AUGUST 2004	SEPTEMBER 2004	OCTOBER 2004	NOVEMBER 2004	DECEMBER 2004	PERIOD TOTAL
BASE RATE REVENUES ** $	21.22	21.22	21.22	21.22	21.22	254.64
FUEL RECOVERY FACTOR CENTS/KWH	4.06	4.06	4.06	4.06	4.06	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	40.56	40.56	40.56	40.56	40.56	486.72
GROSS RECEIPTS TAX	1.58	1.58	1.58	1.58	1.58	18.96
TOTAL REVENUES *** $	63.36	63.36	63.36	63.36	63.36	760.32

* MONTHLY AND CUMULATIVE SIX MONTH ESTIMATED DATA

** BASE RATE REVENUES PER 1000 KWH:

CUSTOMER CHARGE	8.30
CENTS/KWH	12.13
CONSERVATION FACTOR	0.790
	21.22

*** EXCLUDES FRANCHISE TAXES

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

	FERNANDINA BEACH DIVISON	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
1	Fuel Cost of System Net Generation (E3)			
2	Nuclear Fuel Disposal Costs (E2)			
3	Coal Car Investment			
4	Adjustments to Fuel Cost			
5	TOTAL COST OF GENERATED POWER (LINE 1 THRU 4)	0	0	0.00000
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	8,514,672	461,500	1.84500
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)			
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)			
9	Energy Cost of Sched E Economy Purch (E9)			
10	Demand & Non Fuel Cost of Purch Power (E2)	6,533,715	461,500	1.41576
10a	Demand Costs of Purchased Power	6,046,440 *		
10b	Non-fuel Energy & Customer Costs of Purchased Power	487,275 *		
11	Energy Payments to Qualifying Facilities (E8a)	89,760	4,800	1.87000
12	TOTAL COST OF PURCHASED POWER (LINE 6 THRU 11)	15,138,147	466,300	3.24644
13	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)	15,138,147	466,300	3.24644
14	Fuel Cost of Economy Sales (E6)			
15	Gain on Economy Sales (E6)			
16	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)			
17	Fuel Cost of Other Power Sales			
18	TOTAL FUEL COST AND GAINS OF POWER SALES	0	0	0.00000
19	Net Inadvertent Interchange			
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	15,138,147	466,300	3.24644
21	Net Unbilled Sales	0 *	0	0.00000
22	Company Use	14,154 *	436	0.00304
23	T & D Losses	(14,154) *	(436)	-0.00304
24	SYSTEM MWH SALES	15,138,147	466,300	3.24644
25	Wholesale MWH Sales			
26	Jurisdictional MWH Sales	15,138,147	466,300	3.24644
26a	Jurisdictional Loss Multiplier	1.00000	1.00000	
27	Jurisdictional MWH Sales Adjusted for Line Losses	15,138,147	466,300	3.24644
27a	GSLD1 MWH Sales		126,725	
27b	Other Classes MWH Sales		339,575	
27c	GSLD1 CP KW		258,000 *	
28	GPIF **			
29	TRUE-UP (OVER) UNDER RECOVERY **	(1,302,700)	466,300	-0.27937
30	TOTAL JURISDICTIONAL FUEL COST	13,835,447	466,300	2.96707
30a	Demand Purchased Power Costs (Line 10a)	6,046,440 *		
30b	Non-demand Purchased Power Costs (Lines 6 + 10b + 11)	9,091,707 *		
30c	True up Over/Under Recovery (Line 29)	(1,302,700) *		

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

	FERNANDINA BEACH DIVISON	(a) DOLLARS	(b) MWH	(c) CENTS/KWH
	APPORTIONMENT OF DEMAND COSTS			
31	Total Demand Costs (Line 30a)	6,046,440		
32	GSLD1 Portion of Demand Costs (Line 30a) Including Line Losses(Line 27c x $6.18)	1,594,440	258,000 (KW)	$6.18 /KW
33	Balance to Other Classes	4,452,000	339,575	1.31105
	APPORTIONMENT OF NON-DEMAND COSTS			
34	Total Non-demand Costs(Line 30b)	9,091,707		
35	Total KWH Purchased (Line 12)		466,300	
36	Average Cost per KWH Purchased			1.94975
37	Average Cost Adjusted for Line Losses (Line 36 x 1.03)			2.00824
38	GSLD1 Non-demand Costs (Line 27a x Line 37)	2,544,945	126,725	2.00824
39	Balance to Other Classes	6,546,762	339,575	1.92793
	GSLD1 PURCHASED POWER COST RECOVERY FACTORS			
40a	Total GSLD1 Demand Costs (Line 32)	1,594,440	258,000 (KW)	$6.18 /KW
40b	Revenue Tax Factor			1.01597
40c	GSLD1 Demand Purchased Power Factor Adjusted for Taxes & Rounded			$6.28 /KW
40d	Total Current GSLD1 Non-demand Costs(Line 38)	2,544,945	126,725	2.00824
40e	Total Non-demand Costs Including True-up	2,544,945	126,725	2.00824
40f	Revenue Tax Factor			1.01597
40g	GSLD1 Non-demand Costs Adjusted for Taxes & Rounded			2.04031
	OTHER CLASSES PURCHASED POWER COST RECOVERY FACTORS			
41a	Total Demand & Non-demand Purchased Power Costs of Other Classes(Line 33 + 39)	10,998,762	339,575	3.23898
41b	Less: Total Demand Cost Recovery	4,452,000 ***		
41c	Total Other Costs to be Recovered	6,546,762	339,575	1.92793
41d	Other Classes' Portion of True-up (Line 30c)	(1,302,700)	339,575	-0.38363
41e	Total Demand & Non-demand Costs Including True-up	5,244,062	339,575	1.54430
42	Revenue Tax Factor			1.01597
43	Other Classes Purchased Power Factor Adjusted for Taxes & Rounded			1.569

* For Informational Purposes Only
** Calculation Based on Jurisdictional KWH Sales
*** Calculation on Schedule E1 Page 3

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FLORIDA PUBLIC UTILITIES COMPANY
FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

FERNANDINA BEACH DIVISON

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
				(1)/((2)*4,380)			(3)*(4)	(1)*(5)	(6)/Total Col. (6)	(7)/Total Col. (7)
	Rate Schedule	KWH Sales	12 CP Load Factor	CP KW At Meter	Demand Loss Factor	Energy Loss Factor	CP KW At GEN.	KWH At GEN.	12 CP Demand Percentage	Energy Percentage
44	RS	202,706,750	62.965%	73,501.3	1.089	1.000	80,042.9	202,706,750	62.93%	59.69%
45	GS	38,937,515	64.280%	13,829.9	1.089	1.000	15,060.8	38,937,515	11.84%	11.47%
46	GSD	95,828,203	74.244%	29,468.5	1.083	1.000	31,914.4	95,828,203	25.09%	28.22%
47	OL, SL, CSL	2,102,248	290.896%	165.0	1.089	1.000	179.7	2,102,248	0.14%	0.62%
48	TOTAL	339,574,716		116,964.7			127,197.8	339,574,716	100.00%	100.00%

		(10) 12/13 * (8)	(11) 1/13 * (9)	(12) (10) + (11)	(13) Tot. Col. 13 * (12)	(14) (13)/(1)	(15) (14) * 1.01597	(16)	(17) (15) + (16)
	Rate Schedule	12/13 Of 12 CP	1/13 Of Energy	Demand Allocation Percentage	Demand Dollars	Demand Cost Recovery	Demand Cost Recovery Adj for Taxes	Other Charges	Levelized Adjustment
49	RS	58.09%	4.59%	62.68%	$2,790,514	0.01377	0.01399	0.01569	0.02968
50	GS	10.93%	0.88%	11.81%	525,781	0.01350	0.01372	0.01569	0.02941
51	GSD	23.16%	2.17%	25.33%	1,127,692	0.01177	0.01196	0.01569	0.02765
52	OL, OL2, SL1, SL3 & CSL	0.13%	0.05%	0.18%	8,014	0.00381	0.00387	0.01569	0.01956
53	TOTAL	92.31%	7.69%	100.00%	$4,452,000				

(2) From Florida Power & Light Co. 2003 Load Research results.
(4) From Fernandina Beach Rate Case 881056-EI.

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Schedule E1-A

FLORIDA PUBLIC UTILITIES COMPANY
CALCULATION OF TRUE-UP SURCHARGE
APPLICABLE TO LEVELIZED FUEL ADJUSTMENT PERIOD
JANUARY 2004 - DECEMBER 2004
BASED ON SIX MONTHS ACTUAL AND SIX MONTHS ESTIMATED OPERATIONS

Fernandina Beach Division

Over-recovery of purchased power costs for the period January 2003 - December 2003. (See Schedule E1-B, Calculation of Estimated Purchased Power Costs and Calculation of True-Up and Interest Provision for the Twelve Month Period ended December 2003.)(Estimated)	$	1,302,700
Estimated kilowatt hour sales for the months of January 2004 - December 2004 as per estimate filed with the Commission. (Excludes GSLD1 customers)		339,574,716
Cents per kilowatt hour necessary to refund over-recovered purchased power costs over the period January 2004 - December 2004.		0.38363

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SCHEDULE E2

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

LINE NO.			(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(h) JULY	(i) AUGUST	(j) SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) TOTAL PERIOD	LINE NO.
			ESTIMATED													
1	FUEL COST OF SYSTEM GENERATION														0	1
1a	*NUCLEAR FUEL DISPOSAL*														0	1a
2	FUEL COST OF POWER SOLD														0	2
3	FUEL COST OF PURCHASED POWER		719,861	713,153	716,474	717,457	716,480	709,809	683,147	697,800	706,569	707,337	708,104	718,481	8,514,672	3
3a	DEMAND & NON FUEL COST OF PUR POWER		563,246	561,580	516,977	475,899	528,877	596,550	599,340	596,638	592,435	509,115	447,623	541,435	6,533,715	3a
3b	*QUALIFYING FACILITIES*		7,480	7,480	7,480	7,480	7,480	7,480	7,480	7,480	7,480	7,480	7,480	7,480	89,760	3b
4	ENERGY COST OF ECONOMY PURCHASES														0	4
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)		1,290,587	1,282,213	1,242,931	1,200,836	1,252,837	1,313,839	1,289,967	1,303,918	1,306,484	1,223,932	1,163,207	1,267,396	15,138,147	5
5a	LESS TOTAL DEMAND COST RECOVERY		389,183	387,899	345,107	301,973	355,007	423,059	427,367	425,831	419,129	335,765	274,229	367,451	4,452,000	5a
5b	TOTAL OTHER COST TO BE RECOVERED		901,404	894,314	897,824	898,863	897,830	890,780	862,600	878,087	887,355	888,167	888,978	899,945	10,686,147	5b
6	APPORTIONMENT TO GSLD CLASS		344,948	344,949	344,949	344,949	344,949	344,948	344,949	344,949	344,949	344,949	344,949	344,949	4,139,385	6
6a	BALANCE TO OTHER CLASSES		556,456	549,365	552,875	553,914	552,881	545,831	517,651	533,136	542,406	543,218	544,029	554,996	6,546,762	6a
6b	SYSTEM KWH SOLD (MWH)		39,417	39,053	39,233	39,287	39,234	38,872	37,427	38,221	38,696	38,738	38,780	39,342	466,300	6b
7	GSLD MWH SOLD		10,561	10,561	10,562	10,561	10,561	10,562	10,551	10,561	10,561	10,562	10,561	10,561	126,725	7
7a	BALANCE MWH SOLD OTHER CLASSES		28,856	28,492	28,671	28,726	28,673	28,310	26,876	27,660	28,135	28,176	28,219	28,781	339,575	7a
7b	COST PER KWH SOLD (CENTS/KWH) APPLICABLE TO OTHER CLASSES		1.9284	1.92814	1.92834	1.92827	1.92823	1.92805	1.92607	1.92747	1.92787	1.92795	1.92788	1.92834	1.92793	7b
8	JURISDICTIONAL LOSS MULTIPLIER		1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	8
9	JURISDICTIONAL COST (CENTS/KWH)		1.92840	1.92814	1.92834	1.92827	1.92823	1.92805	1.92607	1.92747	1.92787	1.92795	1.92788	1.92834	1.92783	9
10	GPIF (CENTS/KWH)															10
11	TRUE-UP (CENTS/KWH)	(1,302,700)	(0.38363)	(0.38363)	(0.38363)	(0.38363)	(0.38363)	(0.38363)	(0.38363)	(0.38363)	(0.38363)	(0.38363)	(0.38363)	(0.38363)	(0.38363)	11
12	TOTAL		1.54477	1.54451	1.54471	1.54464	1.54460	1.54442	1.54244	1.54384	1.54424	1.54432	1.54425	1.54471	1.54430	12
13	REVENUE TAX FACTOR	0.01597	0.02467	0.02467	0.02467	0.02467	0.02467	0.02466	0.02463	0.02466	0.02466	0.02466	0.02466	0.02467	0.02466	13
14	RECOVERY FACTOR ADJUSTED FOR TAXES		1.56944	1.56918	1.56938	1.56931	1.56927	1.56908	1.56707	1.56850	1.56890	1.56898	1.56891	1.56938	1.56896	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 CENT/KWH		1.569	1.569	1.569	1.569	1.569	1.569	1.567	1.569	1.569	1.569	1.569	1.569	1.569	15

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SCHEDULE E7

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
PURCHASED POWER
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

(1) MONTH	(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL KWH PURCHASED	(5) KWH FOR OTHER UTILITIES	(6) KWH FOR INTERRUPTIBLE	(7) KWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJ (7) x (8) (A)
JANUARY 2004	JACKSONVILLE ELECTRIC AUTHORITY	MS	39,016,852			39,016,852	1.845000	3.288597	719,861
FEBRUARY 2004	JACKSONVILLE ELECTRIC AUTHORITY	MS	38,653,259			38,653,259	1.845001	3.297867	713,153
MARCH 2004	JACKSONVILLE ELECTRIC AUTHORITY	MS	38,833,298			38,833,298	1.844999	3.181422	716,474
APRIL 2004	JACKSONVILLE ELECTRIC AUTHORITY	MS	38,886,538			38,886,538	1.845001	3.068815	717,457
MAY 2004	JACKSONVILLE ELECTRIC AUTHORITY	MS	38,833,581			38,833,581	1.845001	3.206907	716,480
JUNE 2004	JACKSONVILLE ELECTRIC AUTHORITY	MS	38,472,012			38,472,012	1.845001	3.395609	709,809
JULY 2004	JACKSONVILLE ELECTRIC AUTHORITY	MS	37,026,921			37,026,921	1.845001	3.463661	683,147
AUGUST 2004	JACKSONVILLE ELECTRIC AUTHORITY	MS	37,821,164			37,821,164	1.844999	3.427811	697,800
SEPTEMBER 2004	JACKSONVILLE ELECTRIC AUTHORITY	MS	38,296,444			38,296,444	1.844999	3.391970	706,569
OCTOBER 2004	JACKSONVILLE ELECTRIC AUTHORITY	MS	38,338,044			38,338,044	1.845000	3.172963	707,337
NOVEMBER 2004	JACKSONVILLE ELECTRIC AUTHORITY	MS	38,379,644			38,379,644	1.844999	3.011302	708,104
DECEMBER 2004	JACKSONVILLE ELECTRIC AUTHORITY	MS	38,942,064			38,942,064	1.845000	3.235360	718,481
TOTAL			461,499,821	0	0	461,499,821	1.845000	3.260757	8,514,672

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SCHEDULE E8

FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
PURCHASED POWER
ENERGY PAYMENT TO QUALIFYING FACILITIES

ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ. (7) x (8) (A)
JANUARY 2004	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
FEBRUARY 2004	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
MARCH 2004	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
APRIL 2004	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
MAY 2004	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
JUNE 2004	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
JULY 2004	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
AUGUST 2004	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
SEPTEMBER 2004	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
OCTOBER 2004	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
NOVEMBER 2004	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
DECEMBER 2004	JEFFERSON SMURFIT CORPORATION		400,000			400,000	1.870000	1.870000	7,480
TOTAL			4,800,000	0	0	4,800,000	1.870000	1.870000	89,760

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FLORIDA PUBLIC UTILITIES COMPANY
FERNANDINA BEACH DIVISION
RESIDENTIAL BILL COMPARISON

ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

	JANUARY 2004	FEBRUARY 2004	MARCH 2004	APRIL 2004	MAY 2004	JUNE 2004	JULY 2004
BASE RATE REVENUES ** $	19.69	19.69	19.69	19.69	19.69	19.69	19.69
FUEL RECOVERY FACTOR CENTS/KWH	2.97	2.97	2.97	2.97	2.97	2.97	2.97
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000	1.00000
FUEL RECOVERY REVENUES $	29.68	29.68	29.68	29.68	29.68	29.68	29.68
GROSS RECEIPTS TAX	0.51	0.51	0.51	0.51	0.51	0.51	0.51
TOTAL REVENUES *** $	49.88	49.88	49.88	49.88	49.88	49.88	49.88

	AUGUST 2004	SEPTEMBER 2004	OCTOBER 2004	NOVEMBER 2004	DECEMBER 2004	PERIOD TOTAL
BASE RATE REVENUES ** $	19.69	19.69	19.69	19.69	19.69	236.28
FUEL RECOVERY FACTOR CENTS/KWH	2.97	2.97	2.97	2.97	2.97	
GROUP LOSS MULTIPLIER	1.00000	1.00000	1.00000	1.00000	1.00000	
FUEL RECOVERY REVENUES $	29.68	29.68	29.68	29.68	29.68	356.16
GROSS RECEIPTS TAX	0.51	0.51	0.51	0.51	0.51	6.12
TOTAL REVENUES *** $	49.88	49.88	49.88	49.88	49.88	598.56

* MONTHLY AND CUMULATIVE TWELVE MONTH ESTIMATED DATA

** *BASE RATE REVENUES PER 1000 KWH:*

CUSTOMER CHARGE	7.00
CENTS/KWH	12.20
CONSERVATION FACTOR	0.49
	19.69

*** EXCLUDES FRANCHISE TAXES

EXHIBIT NO. _____
DOCKET NO. 030001-EI
FLORIDA PUBLIC UTILITIES COMPANY
(GMB-2)
PAGE 14 OF 14

Florida Public Service Commission
Docket No. 030001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB-1)
Schedule 1
Page 1 of 1

GULF POWER COMPANY
COAL SUPPLIERS
January 1, 2002 – December 31, 2002

Contract Coal Suppliers	Tons Purchased (1)	
Peabody Coal Sales	1,833,240	
Black Mountain Resources	125,025	
Arch Coal Sales - West Elk	691,730	
TOTAL Contract Coal		2,649,995
Spot Coal Suppliers	**Tons Purchased (1)**	
Peabody Coaltrade	225,845	
Consolidation Coal	272,846	
Glencore Ltd.	75,145	
Cyprus Amax Coal Sales	500,914	
TOTAL Spot Coal		1,074,750
GRAND TOTAL COAL PURCHASES		3,724,745

(1) Excludes Plant Scherer: The inventory at Plant Scherer is reported on a BTU basis. Coal inventory expressed in tons is not maintained.

DOCUMENT NUMBER-DATE
03031 APR-1 8
FPSC-COMMISSION CLERK

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. Comp. Ex. 3
COMPANY/ Gulf Power
WITNESS: HRB-1 + HRB-2
DATE: 11-12-03

Florida Public Service Commission
Docket No. 030001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB-1)
Schedule 2
Page 1 of 1

This information has been provided pursuant to the Request for Confidential Classification filed on April 1, 2003.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 030001-EI

Before me the undersigned authority, personally appeared H. R. Ball, who being first duly sworn, deposes, and says that he is the Fuel Manager at Gulf Power Company, a Maine corporation, and that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

H. R. Ball
Fuel Manager

Sworn to and subscribed before me this 1st day of April, 2003

Notary Public, State of Florida at Large

Commission Number:

Commission Expires:

ROLLANDA R. COTHRAN
MY COMMISSION # DD 068475
EXPIRES: February 26, 2006
Bonded Thru Notary Public Underwriters

Florida Public Service Commission
Docket No. 030001-EI
GULF POWER COMPANY
Witness: H. R. Ball
Exhibit No. _____ (HRB-2)
Schedule 1
Page 1 of 1

GULF POWER COMPANY
PROJECTED VS ACTUAL FUEL COST OF SYSTEM NET GENERATION

Cents/KWH Fuel Cost [1]

Period Ending	Projected	Actual	Difference %
March 1994	1.9050	2.0498	7.60
September 1994	1.8662	1.9373	3.81
March 1995	1.8874	2.0388	8.02
September 1995	2.0456	2.0344	(0.55)
March 1996	1.9795	2.0743	4.79
September 1996	2.0405	1.9639	(3.75)
March 1997	1.9282	2.0332	5.45
September 1997	1.9434	1.9431	(0.02)
March 1998	1.8734	1.8647	(0.46)
September 1998	1.5916	1.6361	2.80
December 1999	1.5291	1.5696	2.65
December 2000	1.6048	1.6460	2.57
December 2001	1.5782	1.7218	9.10
December 2002	2.0241	2.0505	1.30
December 2003	1.9638		
December 2004	2.0934		

[1] Line No. 1 from FPSC Schedule A-1

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 030001-EI

Before me the undersigned authority, personally appeared H. R. Ball, who being first duly sworn, deposes, and says that he is the Fuel Manager at Gulf Power Company, a Maine corporation, and that the foregoing is true and correct to the best of his knowledge, information, and belief. He is personally known to me.

H. R. Ball
Fuel Manager

Sworn to and subscribed before me this 12th day of September, 2003

Notary Public, State of Florida at Large

Commission Number:

Commission Expires:

ROLLANDA R. COTHRAN
MY COMMISSION # DD 068475
EXPIRES: February 26, 2006
Bonded Thru Notary Public Underwriters

Florida Public Service Commission
Docket No. 030001-EI
Gulf Power Company
Witness: L. S. Noack
Exhibit No. ___ (LSN-1)

EXHIBIT TO THE TESTIMONY OF

L. S. NOACK

IN FPSC DOCKET 030001-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. Comp. Ex. 4
COMPANY/ Gulf Power
WITNESS: LSN-1 + LSN-2
DATE: 11-12-03

DOCUMENT NUMBER-DATE
03034 APR-18
FPSC-COMMISSION CLERK

I. CORRECTIONS TO REPORTED DATA FOR THE JANUARY 2002 - DECEMBER 2002 PERIOD

Additions and Corrections to Outages Previously Reported
for the January 2002 - December 2002 Period

Date	Unit	Change	Outage Type	Hours	MW	Description

No additions or corrections were made to outages previously reported for the January 2002 - December 2002 period.

II. CALCULATIONS OF EQUIVALENT AVAILABILITY POINTS

Comparison of Forecast and Actual Planned Outages
for January 2002 - December 2002

Unit	Note	Forecast Planned Outage Schedule	Forecast Hours*	Actual Planned Outage Schedule	Actual Hours*
Crist 4	1	10/05/02 - 10/27/02	553.0	11/23/02 - 12/15/02	509.2
Crist 6	2	02/09/02 - 04/07/02	1391.0	02/09/02 - 04/07/02	1368.3
Crist 7	3	03/30/02 - 05/05/02	887.0	03/16/02 - 05/12/02	1274.1
Crist 7	4	-	-	10/26/02 - 11/01/02	350.3
Smith 1	5	04/27/02 - 05/12/02	384.0	03/28/02 - 04/28/02	714.3
Smith 1	6	10/26/02 - 11/03/02	216.0	10/26/02 - 11/03/02	207.8
Smith 2	7	03/02/02 - 03/31/02	720.0	03/02/02 - 04/14/02	1041.7
Smith 2	8	11/09/02 - 11/17/02	216.0	09/02/02 - 09/15/02	317.9
Daniel 1	9	01/26/02 - 02/03/02	216.0	01/26/02 - 02/03/02	195.8
Daniel 2	10	01/19/02 - 04/07/02	1895.0	01/19/02 - 04/19/02	2040.4
Daniel 2	11	-	-	10/06/02 - 10/11/02	153.3

* Planned outage hours in the January 2002 - December 2002 period only.

Notes:
1. The outage date was changed subsequent to the target filing, and it proceeded as scheduled.
2. This outage proceeded as scheduled and was completed ahead of schedule.
3. The outage date was changed subsequent to the target filing, and it proceeded as scheduled with all work completed ahead of schedule.
4. The outage date was changed subsequent to the target filing, and it proceeded as scheduled.
5. The outage date was changed subsequent to the target filing, and it proceeded as scheduled with all work completed ahead of schedule.
6. This outage proceeded as scheduled and was completed ahead of schedule.
7. The outage date was changed subsequent to the target filing, and it proceeded as scheduled.
8. The outage date was changed subsequent to the target filing, and it proceeded as scheduled.
9. This outage proceeded as scheduled and was completed ahead of schedule.
10. The outage date was changed subsequent to the target filing, and it proceeded as scheduled with all work completed ahead of schedule.
11. The outage date was changed subsequent to the target filing, and it proceeded as scheduled.

Calculation of Actual Equivalent Availability
for January 2002 - December 2002
Based on Target Planned Outage Hours
Crist 4

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	10.2	0.0	0.0	0.0	0.0	
	0.0	0.0	8.2	0.0	0.0	9.0	27.4
EFOH	0.0	0.0	1.1	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	1.1
MOH	0.0	16.4	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	16.4
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	8.5	0.0	0.0	0.0	0.0	8.5
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	192.8	316.4	509.2
RSH	593.8	105.8	0.0	0.0	156.4	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	856.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(27.4 + 1.1 + 16.4 + 8.5)}{(8760.0 - 509.2 - 856.0)}$$

EUOR = 0.0072

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] x\ 100$$

Target POH* = 553.0

Target RSH* = 1201.0

$$EA = \left[1 - \frac{(553.0 + 0.0072\ (8760.0 - 553.0 - 1201.0))}{8760.0} \right] \times 100 = 93.1\ \%$$

Note: Please refer to page 11 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2002 - December 2002
Based on Target Planned Outage Hours
Crist 6

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	8.7	0.0	0.0	24.3	0.8	0.0	
	40.0	4.0	0.0	0.0	0.0	28.5	106.3
EFOH	0.0	0.3	0.0	2.4	0.6	0.0	
	0.3	0.0	0.0	0.3	0.0	0.0	3.9
MOH	0.0	0.0	0.0	0.0	126.1	55.0	
	64.3	51.9	0.0	0.0	60.1	0.0	357.4
EMOH	0.0	0.0	0.0	38.5	0.0	0.0	
	0.0	0.0	4.4	0.0	0.0	0.0	42.9
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	480.3	744.0	144.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	1368.3
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(106.3 + 3.9 + 357.4 + 42.9)}{(8760.0 - 1368.3 - 0.0)}$$

$$EUOR = 0.0691$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 1391.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(1391.0 + 0.0691\ (8760.0 - 1391.0 - 0.0))}{8760.0} \right] \times 100 = 78.3\ \%$$

Note: Please refer to page 11 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2002 - December 2002
Based on Target Planned Outage Hours
Crist 7

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	38.4	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	38.4
EFOH	0.0	0.0	0.0	0.0	0.0	0.9	
	0.1	0.0	0.9	0.0	0.7	0.0	2.6
MOH	0.0	0.0	0.0	0.0	110.9	43.6	
	6.4	0.0	45.8	0.0	0.0	0.0	206.7
EMOH	0.0	0.0	0.0	0.0	72.1	1.2	
	0.0	0.0	0.0	0.0	0.0	0.0	73.3
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	0.0	384.2	719.0	170.9	0.0	
	0.0	0.0	0.0	150.3	200.0	0.0	1624.4
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(38.4 + 2.6 + 206.7 + 73.3)}{(8760.0 - 1624.4 - 0.0)}$$

$$EUOR = 0.0450$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] x\ 100$$

Target $POH^* =$ 887.0

Target $RSH^* =$ 0.0

$$EA = \left[1 - \frac{(887.0 + 0.0450\ (8760.0 - 887.0 - 0.0))}{8760.0} \right] \times 100 = 85.8\ \%$$

Note: Please refer to page 11 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2002 - December 2002
Based on Target Planned Outage Hours
Smith 1

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	2.3	26.5	0.0	0.0	0.0	
	0.0	0.0	0.0	17.5	0.0	0.0	46.3
EFOH	2.1	0.0	0.3	1.5	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	3.9
MOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
EMOH	0.0	0.0	0.0	11.9	37.6	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	49.5
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	0.0	114.0	600.3	0.0	0.0	
	0.0	0.0	0.0	149.4	58.4	0.0	922.1
RSH	56.8	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	56.8

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(46.3 + 3.9 + 0.0 + 49.5)}{(8760.0 - 922.1 - 56.8)}$$

EUOR = 0.0128

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 600.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(600.0 + 0.0128\ (8760.0 - 600.0 - 0.0))}{8760.0} \right] \times 100 = 92.0\ \%$$

Note: Please refer to page 11 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2002 - December 2002
Based on Target Planned Outage Hours
Smith 2

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	0.0	0.0	159.3	133.9	345.4	
	131.4	0.0	0.0	33.5	0.0	0.0	803.5
EFOH	0.0	0.5	0.0	0.0	0.0	0.0	
	138.0	236.2	119.8	234.4	224.8	231.7	1185.4
MOH	0.0	0.0	0.0	205.0	0.0	191.5	
	58.9	0.0	30.8	36.2	0.0	0.0	522.4
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	0.0	0.0	717.8	323.9	0.0	0.0	
	0.0	0.0	317.9	0.0	0.0	0.0	1359.6
RSH	154.4	25.7	0.0	4.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	184.1

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(803.5 + 1185.4 + 522.4 + 0.0)}{(8760.0 - 1359.6 - 184.1)}$$

EUOR = 0.3480

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 936.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(936.0 + 0.3480\ (8760.0 - 936.0 - 0.0))}{8760.0} \right] \times 100 = 58.2\ \%$$

Note: Please refer to page 11 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2002 - December 2002
Based on Target Planned Outage Hours
Daniel 1

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	0.0	1.7	0.0	140.5	46.2	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	188.4
EFOH	0.8	0.3	8.1	16.6	5.6	16.3	
	0.1	2.1	6.3	7.5	11.9	5.6	81.2
MOH	0.0	0.0	0.0	128.2	0.0	0.0	
	31.1	0.0	0.0	16.9	0.0	0.0	176.2
EMOH	0.0	0.0	0.0	1.1	0.0	0.0	
	0.0	0.0	0.0	0.0	3.9	0.0	5.0
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	145.0	50.8	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	195.8
RSH	48.3	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	48.3

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(188.4 + 81.2 + 176.2 + 5.0)}{(8760.0 - 195.8 - 48.3)}$$

$$EUOR = 0.0529$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

Target POH* = 216.0

Target RSH* = 0.0

$$EA = \left[1 - \frac{(216.0 + 0.0529\ (8760.0 - 216.0 - 0.0))}{8760.0} \right] \times 100 = 92.4\ \%$$

Note: Please refer to page 11 of this schedule for an explanation of symbols.

Calculation of Actual Equivalent Availability
for January 2002 - December 2002
Based on Target Planned Outage Hours
Daniel 2

Results of Operations

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
FOH	44.3	0.0	0.0	13.8	28.8	3.8	
	16.0	0.0	0.0	5.1	4.4	0.0	116.2
EFOH	2.8	0.0	0.0	11.9	6.3	10.9	
	1.5	3.4	13.6	16.8	74.3	5.8	147.3
MOH	0.0	0.0	0.0	0.0	39.8	0.0	
	70.1	0.0	0.0	0.0	0.0	0.0	109.9
EMOH	0.0	0.0	0.0	0.0	0.0	0.0	
	1.2	0.0	0.0	0.0	0.0	3.5	4.7
PH	744.0	672.0	744.0	719.0	744.0	720.0	
	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
POH	312.8	672.0	744.0	311.6	0.0	0.0	
	0.0	0.0	0.0	153.3	0.0	0.0	2193.7
RSH	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0

$$1.\ EUOR = \frac{(FOH + EFOH + MOH + EMOH)}{(PH - POH - RSH)} = \frac{(116.2 + 147.3 + 109.9 + 4.7)}{(8760.0 - 2193.7 - 0.0)}$$

$$EUOR = 0.0576$$

$$2.\ EA = \left[1 - \frac{(POH^* + EUOR\ (PH - POH^* - RSH^*))}{PH} \right] \times 100$$

$$Target\ POH^* = 1895.0$$

$$Target\ RSH^* = 0.0$$

$$EA = \left[1 - \frac{(1895.0 + 0.0576\ (8760.0 - 1895.0 - 0.0))}{8760.0} \right] \times 100 = 73.9\ \%$$

Note: Please refer to page 11 of this schedule for an explanation of symbols.

Calculation of Equivalent Availability Points
for January 2002 - December 2002

(1) Unit	(2) Equivalent Availability Target*	(3) Actual Equivalent Availability Adjusted to Target Planned Outage Basis**	(4) Minimum or Maximum Attainable Equivalent Availability*	(5) Availability Points***
Crist 4	90.9	93.1	91.7	10.00
Crist 6	77.3	78.3	79.4	4.76
Crist 7	79.7	85.8	82.7	10.00
Smith 1	90.7	92.0	91.4	10.00
Smith 2	86.6	58.2	85.3	-10.00
Daniel 1	88.0	92.4	90.9	10.00
Daniel 2	70.7	73.9	73.0	10.00

* As appropriate from page 5, Schedule 3 of Exhibit to J. R. Douglass's September 20, 2001 GPIF testimony in Docket 010001-EI.

** Refer to pages 3 through 9 of this schedule for calculations.

*** If (3) > (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times 10$$

If (3) < (2)

$$\text{Availability Points} = \frac{(3) - (2)}{(4) - (2)} \times -10$$

Summary of Equivalent Availability Symbols

EA - Equivalent Availability
POH - Planned Outage Hours
EUOR - Equivalent Unplanned Outage Rate
PH - Period Hours
FOH - Forced Outage Hours
EFOH - Equivalent Forced Outage Hours
MOH - Maintenance Outage Hours
EMOH - Equivalent Maintenance Outage Hours
RSH - Reserve Shutdown Hours

III. CALCULATION OF GPIF UNIT HEAT RATE POINTS

Calculation of Average Net Operating Heat Rate Points
for January 2002 - December 2002

Crist 4

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	8687.9	23939.8	36852.9	36701.8	31388.5	34890.8	
	37592.2	36684.2	39397.2	39908.2	23772.9	20038.7	369855.1
BTU/Lb*	11753.4	11806.9	11790.4	11878.4	11974.5	11892.7	
	11783.5	11850.0	11819.8	11731.3	11645.3	11803.1	11817.9
Coal, MMBTU	102112.4	282654.8	434510.4	435958.7	375861.6	414945.8	
	442967.7	434707.8	465667.0	468175.1	276842.6	236518.8	4370922.7
Oil, MMBTU	0.0	723.3	977.4	3502.4	1090.9	490.4	
	253.2	588.7	364.8	90.1	133.5	178.3	8393.0
Gas, MMBTU	1606.0	2721.0	0.0	0.0	423.0	4757.0	
	0.0	0.0	2636.0	913.0	115.0	1404.0	14575.0
Startup, MMBTU **	-400.0	-400.0	0.0	0.0	-400.0	0.0	
	0.0	0.0	0.0	0.0	0.0	-400.0	-1600.0
Total Fuel Consumption, MMBTU	103318.4	285699.1	435487.8	439461.1	376975.5	420193.2	
	443220.9	435296.5	468667.8	469178.2	277091.1	237701.1	4392290.7
Net MWH Generation***	8533	24841	38451	39093	33273	35945	
	37756	38338	41999	42369	26308	20047	386953
Average Net Operating Heat Rate	12108	11501	11326	11241	11330	11690	
	11739	11354	11159	11074	10533	11857	11351

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2002 - December 2002

Crist 6

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	118410.2	30137.8	0.0	89989.1	103896.9	106587.4	
	114629.6	121476.2	141008.7	152854.4	105411.8	115940.6	1200342.7
BTU/Lb*	11729.4	11682.8	0.0	11851.1	11724.1	11896.8	
	11854.1	11845.0	11795.2	11756.9	11788.3	11793.9	11798.0
Coal, MMBTU	1388880.6	352093.9	0.0	1066469.8	1218097.6	1268049.0	
	1358830.7	1438885.6	1663225.8	1797093.9	1242625.9	1367391.8	14161644.6
Oil, MMBTU	2323.4	940.7	0.0	0.0	979.2	1783.1	
	1221.6	1335.2	543.0	300.2	710.4	592.2	10729.0
Gas, MMBTU	8602.0	1730.0	0.0	69002.0	2471.0	40140.0	
	4161.0	2638.0	578.0	0.0	2150.0	1828.0	133300.0
Startup, MMBTU **	0.0	0.0	0.0	-4040.0	-4040.0	-4040.0	
	-12120.0	-4040.0	0.0	0.0	-4040.0	-4040.0	-36360.0
Total Fuel Consumption, MMBTU	1399806.0	354764.6	0.0	1131431.8	1217507.8	1305932.1	
	1352093.3	1438818.8	1664346.8	1797394.1	1241446.3	1365772.0	14269313.6
Net MWH Generation***	123099	31507	0	104009	113976	117887	
	124159	133128	155547	167644	111886	127813	1310655
Average Net Operating Heat Rate	11371	11260	---	10878	10682	11078	
	10890	10808	10700	10721	11096	10686	10887

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2002 - December 2002

Crist 7

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	188330.5	168743.8	97822.2	0.0	117533.7	214549.1	
	255251.3	258984.4	242265.2	216808.0	174467.2	260792.3	2195547.7
BTU/Lb*	11690.8	11832.9	11865.5	0.0	11724.9	11874.4	
	11773.6	11845.9	11899.8	11742.3	11770.8	11805.4	11805.3
Coal, MMBTU	2201734.2	1996728.5	1160709.3	0.0	1378070.9	2547641.8	
	3005226.7	3067903.3	2882907.4	2545824.6	2053618.5	3078757.4	25919122.6
Oil, MMBTU	410.5	501.0	38.9	0.0	2262.0	1395.8	
	2456.0	984.7	1404.1	1173.5	1829.3	2631.6	15087.4
Gas, MMBTU	15652.0	0.0	1664.0	0.0	10740.0	1609.0	
	703.0	0.0	1789.0	0.0	2982.0	0.0	35139.0
Startup, MMBTU **	0.0	0.0	-2256.0	0.0	-4512.0	-2256.0	
	0.0	0.0	-2256.0	0.0	-2256.0	0.0	-13536.0
Total Fuel Consumption, MMBTU	2217796.7	1997229.5	1160156.2	0.0	1386560.9	2548390.6	
	3008385.7	3068888.0	2883844.5	2546998.1	2056173.8	3081389.0	25955813.0
Net MWH Generation***	207969	185501	123254	0	131263	242637	
	286808	294099	277023	253714	195099	301341	2498708
Average Net Operating Heat Rate	10664	10767	9413	---	10563	10503	
	10489	10435	10410	10039	10539	10226	10388

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2002 ~ December 2002

Smith 1

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	73937.3	73167.5	73353.2	10678.9	74696.3	81122.3	
	89761.5	91865.7	91537.9	74514.9	75785.8	87157.9	897579.2
BTU/Lb*	11478.0	11767.1	11890.7	11913.0	11913.8	12180.1	
	11978.0	11572.7	11655.8	11794.4	11828.4	11824.1	11807.5
Coal, MMBTU	848652.3	860969.3	872220.9	127217.7	889916.8	988077.7	
	1075163.2	1063134.2	1066947.5	878858.5	896424.8	1030563.7	10598146.6
Oil, MMBTU	816.2	212.9	169.0	2480.5	557.8	783.4	
	1245.1	314.9	142.2	1011.3	1625.0	460.8	9819.1
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	-964.0	0.0	0.0	-964.0	0.0	0.0	
	0.0	0.0	0.0	0.0	-964.0	0.0	-2892.0
Total Fuel Consumption, MMBTU	848504.5	861182.2	872389.9	128734.2	890474.6	988861.1	
	1076408.3	1063449.1	1067089.7	879869.8	897085.8	1031024.5	10605073.7
Net MWH Generation***	84506	85005	85465	12054	86392	96517	
	104404	104245	104643	85939	86099	99945	1035214
Average Net Operating Heat Rate	10041	10131	10208	10680	10307	10245	
	10310	10201	10197	10238	10419	10316	10244

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2002 - December 2002

Smith 2

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	65753.4	68336.1	3649.6	1387.7	68397.4	18789.5	
	64192.3	84603.9	41924.0	74587.5	78601.6	81473.8	651696.8
BTU/Lb*	11441.9	11764.0	11853.1	11166.6	11858.7	12135.5	
	11865.5	11543.7	11561.2	11708.7	11707.7	11768.4	11707.2
Coal, MMBTU	752343.8	803905.9	43259.1	15495.9	811104.2	228020.0	
	761673.7	976642.0	484691.7	873322.7	920244.0	958816.3	7629519.3
Oil, MMBTU	168.5	1573.7	81.5	1761.4	2544.9	3374.8	
	5479.2	395.4	2451.0	2570.3	579.8	170.4	21150.9
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	-1190.0	0.0	-1190.0	-2380.0	-3570.0	
	-4760.0	0.0	-2380.0	-2380.0	0.0	0.0	-17850.0
Total Fuel Consumption, MMBTU	752512.3	804289.6	43340.6	16067.3	811269.1	227824.8	
	762392.9	977037.4	484762.7	873513.0	920823.8	958986.7	7632820.2
Net MWH Generation***	76365	80475	4237	1238	80027	22122	
	71223	91351	45974	82849	86679	90720	733260
Average Net Operating Heat Rate	9854	9994	10229	12978	10137	10299	
	10704	10695	10544	10543	10623	10571	10409

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2002 - December 2002

Daniel 1

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	156354.0	168664.0	270548.0	139910.0	227550.0	233944.0	
	232286.0	262372.0	279074.0	285526.0	252798.0	269666.0	2778692.0
BTU/Lb*	11584.4	11776.3	11728.3	11518.4	11616.2	11691.2	
	11590.6	11253.1	11380.5	11554.4	11482.3	11629.5	11559.1
Coal, MMBTU	1811267.3	1986237.9	3173068.1	1611539.3	2643266.3	2735086.1	
	2692334.1	2952498.4	3176001.7	3299081.6	2902702.5	3136080.7	32119164.0
Oil, MMBTU	73.1	3535.8	426.4	8468.4	3423.3	2238.2	
	1646.0	13.1	46.8	4091.1	118.2	0.0	24080.4
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	0.0	-2388.7	0.0	-4777.4	-2388.7	0.0	
	-2388.7	0.0	0.0	0.0	0.0	0.0	-11943.5
Total Fuel Consumption, MMBTU	1811340.4	1987385.0	3173494.5	1615230.3	2644300.9	2737324.3	
	2691591.4	2952511.5	3176048.5	3303172.7	2902820.7	3136080.7	32131300.9
Net MWH Generation***	174076	193346	318152	158358	259465	267077	
	266391	291923	315244	330609	293645	314531	3182817
Average Net Operating Heat Rate****	10405	10279	9975	10200	10191	10249	
	10104	10114	10075	9991	9885	9971	10095

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate Points
for January 2002 - December 2002

Daniel 2

	Jan / Jul	Feb / Aug	Mar / Sep	Apr / Oct	May / Nov	Jun / Dec	Total
Pounds Coal (000's)	152738.0	0.0	0.0	134950.0	224050.0	238952.0	
	217678.0	265030.0	281348.0	222732.0	244960.0	262112.0	2244550.0
BTU/Lb*	11585.7	0.0	0.0	11544.6	11605.7	11691.0	
	11572.0	11246.4	11381.7	11474.2	11484.4	11632.3	11512.8
Coal, MMBTU	1769576.6	0.0	0.0	1557943.8	2600257.1	2793587.8	
	2518969.8	2980633.4	3202218.5	2555671.5	2813218.6	3048965.4	25841042.5
Oil, MMBTU	3072.5	0.0	0.0	25993.3	4758.0	968.2	
	5120.8	13.1	23.5	7111.1	1469.6	0.0	48530.1
Gas, MMBTU	0.0	0.0	0.0	0.0	0.0	0.0	
	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Startup, MMBTU **	-2388.7	0.0	0.0	-2388.7	-2388.7	0.0	
	-2388.7	0.0	0.0	-2388.7	0.0	0.0	-11943.5
Total Fuel Consumption, MMBTU	1770260.4	0.0	0.0	1581548.4	2602626.4	2794556.0	
	2521701.9	2980646.5	3202242.0	2560393.9	2814688.2	3048965.4	25877629.1
Net MWH Generation***	187779	0	0	148343	254171	273477	
	248149	294998	313415	256674	289257	312148	2578411
Average Net Operating Heat Rate****	9427	---	---	10661	10240	10219	
	10162	10104	10217	9975	9731	9768	10036

* Weighted average of daily as-burned BTU/Lb values.
** Based on number of unit starts after unit off-line 24 hours or more.
*** Not reduced by off-line station service.

Calculation of Average Net Operating Heat Rate
for January 2002 - December 2002
Adjusted to Target Basis Using Heat Rate
Equations Filed September 20, 2001

Crist 4

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10194	10364	10376	10461	10461	10682	
		10787	10784	10400	10500	10461	10386	
2.	Target Heat Rate	10434	11092	10738	10700	10671	11301	
	at Actual Conditions**	11344	11357	10577	10533	10769	10961	
3.	Adjustment to Actual	-240	-728	-362	-239	-210	-619	
	Heat Rate (1-2)	-557	-573	-177	-33	-308	-575	
4.	Actual Heat Rate	12108	11501	11326	11241	11330	11690	
	(Page 2 of Sched. 3)	11739	11354	11159	11074	10533	11857	
5.	Adjusted Actual	11868	10773	10964	11002	11120	11071	
	Heat Rate (4+3)	11182	10781	10982	11041	10225	11282	
6.	Net MWH Generation	8533	24841	38451	39093	33273	35945	
		37756	38338	41999	42369	26308	20047	
7.	Adjusted Actual Heat Rate for January 2002 - December 2002 $=(\Sigma(5*6)/\Sigma 6)$							10979

* From pages 19 & 20, Schedule 3 of Exhibit to J. R. Douglass's September 20, 2001 GPIF testimony in Docket 010001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are *also shown for convenience on page 17 of this Schedule.*

Calculation of Average Net Operating Heat Rate
for January 2002 - December 2002
Adjusted to Target Basis Using Heat Rate
Equations Filed September 20, 2001

Crist 6

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10522	10502	-	10245	10579	10681	
		10552	10522	10541	10609	10587	10561	
2.	Target Heat Rate	10931	10951	-	10353	10826	11050	
	at Actual Conditions**	10777	10780	10679	10644	10917	10861	
3.	Adjustment to Actual	-409	-449	0	-108	-247	-369	
	Heat Rate (1-2)	-225	-258	-138	-35	-330	-300	
4.	Actual Heat Rate	11371	11260	0	10878	10682	11078	
	(Page 3 of Sched. 3)	10890	10808	10700	10721	11096	10686	
5.	Adjusted Actual	10962	10811	0	10770	10435	10709	
	Heat Rate (4+3)	10665	10550	10562	10686	10766	10386	
6.	Net MWH Generation	123099	31507	0	104009	113976	117887	
		124159	133128	155547	167644	111886	127813	
7.	Adjusted Actual Heat Rate for January 2002 - December 2002 $=(\Sigma(5*6)/\Sigma 6)$							10649

* From pages 21 & 22, Schedule 3 of Exhibit to J. R. Douglass's September 20, 2001 GPIF testimony in Docket 010001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 17 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2002 - December 2002
Adjusted to Target Basis Using Heat Rate
Equations Filed September 20, 2001

Crist 7

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10138	10135	10135	-	10051	10141	
		10330	10285	10338	10282	10147	10136	
2.	Target Heat Rate	10435	10445	10237	-	10268	10274	
	at Actual Conditions**	10443	10391	10423	10321	10249	10209	
3.	Adjustment to Actual	-297	-310	-102	0	-217	-133	
	Heat Rate (1-2)	-113	-106	-85	-39	-102	-73	
4.	Actual Heat Rate	10664	10767	9413	0	10563	10503	
	(Page 4 of Sched. 3)	10489	10435	10410	10039	10539	10226	
5.	Adjusted Actual	10367	10457	9311	0	10346	10370	
	Heat Rate (4+3)	10376	10329	10325	10000	10437	10153	
6.	Net MWH Generation	207969	185501	123254	0	131263	242637	
		286808	294099	277023	253714	195099	301341	
7.	Adjusted Actual Heat Rate for January 2002 - December 2002 $=(\Sigma(5*6)/\Sigma 6)$							10255

* From pages 23 & 24, Schedule 3 of Exhibit to J. R. Douglass's September 20, 2001 GPIF testimony in Docket 010001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 17 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2002 - December 2002
Adjusted to Target Basis Using Heat Rate
Equations Filed September 20, 2001

Smith 1

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10072 10083	9957 10076	10068 10077	10082 10087	9998 9961	10079 10071	
2.	Target Heat Rate at Actual Conditions**	10150 10106	9999 10107	10103 10096	10226 10089	10061 9989	10121 10120	
3.	Adjustment to Actual Heat Rate (1-2)	-78 -23	-42 -31	-35 -19	-144 -2	-63 -28	-42 -49	
4.	Actual Heat Rate (Page 5 of Sched. 3)	10041 10310	10131 10201	10208 10197	10680 10238	10307 10419	10245 10316	
5.	Adjusted Actual Heat Rate (4+3)	9963 10287	10089 10170	10173 10178	10536 10236	10244 10391	10203 10267	
6.	Net MWH Generation	84506 104404	85005 104245	85465 104643	12054 85939	86392 86099	96517 99945	
7.	Adjusted Actual Heat Rate for January 2002 - December 2002 $=(\Sigma(5*6)/\Sigma 6)$							10206

* From pages 25 & 26 , Schedule 3 of Exhibit to J. R. Douglass's September 20, 2001 GPIF testimony in Docket 010001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 17 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2002 - December 2002
Adjusted to Target Basis Using Heat Rate
Equations Filed September 20, 2001

Smith 2

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	9912 10104	9865 10091	9875 10094	10003 10117	10098 10098	10098 10078	
2.	Target Heat Rate at Actual Conditions**	9953 10129	9907 10151	9936 10158	14028 10157	10413 10178	10475 10166	
3.	Adjustment to Actual Heat Rate (1-2)	-41 -25	-42 -60	-61 -64	-4025 -40	-315 -80	-377 -88	
4.	Actual Heat Rate (Page 6 of Sched. 3)	9854 10704	9994 10695	10229 10544	12978 10543	10137 10623	10299 10571	
5.	Adjusted Actual Heat Rate (4+3)	9813 10679	9952 10635	10168 10480	8953 10503	9822 10543	9922 10483	
6.	Net MWH Generation	76365 71223	80475 91351	4237 45974	1238 82849	80027 86679	22122 90720	
7.	Adjusted Actual Heat Rate for January 2002 - December 2002 $=(\Sigma(5*6)/\Sigma 6)$							10309

* From pages 27 & 28, Schedule 3 of Exhibit to J. R. Douglass's September 20, 2001 GPIF testimony in Docket 010001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 17 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2002 - December 2002
Adjusted to Target Basis Using Heat Rate
Equations Filed September 20, 2001

Daniel 1

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	10168 10493	9930 10179	10112 10204	10284 10295	10247 10258	9917 10169	
2.	Target Heat Rate at Actual Conditions**	10587 10619	10282 10354	10232 10256	10332 10164	10302 10348	9951 10287	
3.	Adjustment to Actual Heat Rate (1-2)	-419 -126	-352 -175	-120 -52	-48 131	-55 -90	-34 -118	
4.	Actual Heat Rate*** (Page 7 of Sched. 3)	10405 10104	10279 10114	9975 10075	10200 9991	10191 9885	10249 9971	
5.	Adjusted Actual Heat Rate (4+3)	9986 9978	9927 9939	9855 10023	10152 10122	10136 9795	10215 9853	
6.	Net MWH Generation	174076 266391	193346 291923	318152 315244	158358 330609	259465 293645	267077 314531	
7.	Adjusted Actual Heat Rate for January 2002 - December 2002 $=(\Sigma(5*6)/\Sigma 6)$							9991

* From pages 29 & 30, Schedule 3 of Exhibit to J. R. Douglass's September 20, 2001 GPIF testimony in Docket 010001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 17 of this Schedule.

Calculation of Average Net Operating Heat Rate
for January 2002 - December 2002
Adjusted to Target Basis Using Heat Rate
Equations Filed September 20, 2001

Daniel 2

		Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec	Jan - Dec
1.	Target Heat Rate*	9761 -	-	-	9942	10050	9854	
		10053	10089	9830	9930	9715	9774	
2.	Target Heat Rate	9733 -	-	-	10076	10339	10079	
	at Actual Conditions**	10318	10396	9959	9935	9919	10010	
3.	Adjustment to Actual	28	0	0	-134	-289	-225	
	Heat Rate (1-2)	-265	-307	-129	-5	-204	-236	
4.	Actual Heat Rate***	9427	0	0	10661	10240	10219	
	(Page 8 of Sched. 3)	10162	10104	10217	9975	9731	9768	
5.	Adjusted Actual	9455	0	0	10527	9951	9994	
	Heat Rate (4+3)	9897	9797	10088	9970	9527	9532	
6.	Net MWH Generation	187779	0	0	148343	254171	273477	
		248149	294998	313415	256674	289257	312148	
7.	Adjusted Actual Heat Rate for January 2002 - December 2002 $=(\Sigma(5*6)/\Sigma 6)$							9850

* From pages 31 & 32, Schedule 3 of Exhibit to J. R. Douglass's September 20, 2001 GPIF testimony in Docket 010001-EI.

** Based on target heat rate equation from page 2, Schedule 1 of above mentioned filing using actual rather than forecast variable values. The equations are also shown for convenience on page 17 of this Schedule.

Actual Values of
Target Heat Rate Equation Parameters
for January 2002 - December 2002

	Jan/Jul	Feb/Aug	Mar/Sep	Apr/Oct	May/Nov	Jun/Dec
Crist 4						
AKW * 10^{+3}	56.8	46.0	51.7	54.4	56.6	49.9
	50.7	51.5	59.0	56.9	49.9	47.9
LSRF * 10^{+6}	3454.7	2175.5	2800.8	3150.6	3435.4	2660.2
	2722.6	2814.5	3710.1	3401.5	2569.2	2382.1
Crist 6						
AKW * 10^{+3}	167.4	164.4	0.0	188.9	184.7	177.3
	194.1	193.5	216.0	225.0	169.5	178.6
LSRF * 10^{+6}	32115.5	30681.0	0.0	46902.5	42003.3	35519.1
	43036.0	42815.8	52678.5	56203.4	32275.7	36455.8
Crist 7						
AKW * 10^{+3}	279.5	276.0	383.5	0.0	284.0	358.7
	388.8	395.3	410.9	426.6	375.2	405.0
LSRF * 10^{+6}	90098.4	86318.8	160248.9	0.0	86006.7	143293.2
	162652.5	167021.3	177188.2	188189.6	150957.0	172718.9
Smith 1						
AKW * 10^{+3}	123.0	126.9	141.6	101.6	116.1	134.1
	140.3	140.1	145.3	148.7	130.1	134.3
LSRF * 10^{+6}	15747.6	16454.4	20476.7	11552.8	14856.4	18870.8
	20343.0	20307.3	21733.9	22623.7	17818.6	19024.2
Smith 2						
AKW * 10^{+3}	129.5	124.5	161.7	46.2	131.2	120.8
	128.6	122.8	123.8	122.7	120.4	121.9
LSRF * 10^{+6}	17561.9	16124.3	27836.3	2190.0	19848.4	16783.0
	16794.2	15091.1	15469.2	15106.2	14514.3	14911.4
Daniel 1						
AKW * 10^{+3}	316.1	312.1	427.6	351.7	371.8	370.9
	373.7	392.4	437.8	454.1	407.8	422.8
LSRF * 10^{+6}	117439.2	115738.4	196522.0	147806.2	160672.4	159358.7
	160231.5	169985.6	201186.1	215859.4	179064.4	190851.4
Daniel 2						
AKW * 10^{+3}	485.3	0.0	0.0	376.9	376.3	381.8
	377.2	396.5	435.3	437.6	404.2	419.6
LSRF * 10^{+6}	241867.3	0.0	0.0	166187.8	162519.1	168272.5
	164419.1	174626.2	200893.2	203659.8	177962.0	190090.2

Target Heat Rate Equations

Crist 4 ANOHR = 10^6 / AKW • [449.21 - 12.61 * JAN + 16.96 * JUN + 24.56 * JUL + 27.59 * AUG]

-3640 + 0.10501 * LSRF / AKW

Crist 6 ANOHR = 10^6 / AKW * [187.63 - 85.12 * APR + 32.17 * JUN]

+ 9,810

Crist 7 ANOHR = 10^6 / AKW * [204.45 - 44.16 * MAY + 83.05 * JUL + 67.20 * AUG + 91.16 * SEP + 58.82 * OCT]

+ 9,704

Smith 1 ANOHR = 10^6 / AKW * [43.96 - 17.87 * FEB - 12.85 * MAY - 18.43 * NOV]

+ 9,793

Smith 2 ANOHR = 10^6 / AKW * [410.85 - 30.87 • JAN - 38.46 * FEB - 38.20 * MAR - 18.64 • APR]

+ 4,743 + 0.01678 * LSRF / AKW

Daniel 1 ANOHR = 10^6 / AKW * [-429.41 - 91.37 * FEB - 136.56 * JUN + 105.89 * JUL]

+ 14,936 - 0.00805 * LSRF / AKW

Daniel 2 ANOHR = 10^6 / AKW * [-42.23 + 77.21 * MAY + 79.18 * JUL + 123.19 * AUG - 68.28 * NOV]

+ 13,010 - 0.00640 * LSRF / AKW

Where:

ANOHR	Average Net Operating Heat Rate, BTU/KWH
AKW	Average Kilowatt Load, KW
LSRF	Load Square Range Factor, KW^2
JAN	January, 0 if not January, 1 if January
FEB	February, 0 if not February, 1 if February
MAR	March, 0 if not March, 1 if March
APR	April, 0 if not April, 1 if April
MAY	May, 0 if not May, 1 if May
JUN	June, 0 if not June, 1 if June
JUL	July, 0 if not July, 1 if July
AUG	August, 0 if not August, 1 if August
SEP	September, 0 if not September, 1 if September
OCT	October, 0 if not October, 1 if October
NOV	November, 0 if not November, 1 if November

Calculation of Heat Rate Points
for January 2002 - December 2002

(1)	(2)	(3)	(4)	(5)
Unit	Actual Average Average Net Operating Heat Rate Target*	Net Operating Heat Rate Adjusted to Target Basis**	*Minimum* Attainable Heat Rate*	Heat Rate Points***
Crist 4	10499	10979	10184	-10.00
Crist 6	10546	10649	10230	-1.16
Crist 7	10196	10255	9890	0.00
Smith 1	10054	10206	9752	-3.39
Smith 2	10050	10309	9749	-8.14
Daniel 1	10191	9991	9885	5.41
Daniel 2	9906	9850	9609	0.00

* *From page 5, Schedule 3 of Exhibit to J. R. Douglass's September 20, 2001 GPIF testimony in Docket 010001-EI.*

** Refer to pages 9 through 15 of this Schedule for calculation.

*** If [(2) - 75] <= (3) <= [(2) + 75] then points = 0

$$\text{If } [\,(2) - (3) - 75\,] > 0 \text{ then points} = \frac{(2) - (3) - 75}{(2) - (4) - 75} * 10$$

$$\text{If } [\,(2) - (3) + 75\,] < 0 \text{ then points} = \frac{(2) - (3) + 75}{(2) - (4) - 75} * 10$$

IV. CALCULATION OF COMPANY GPIF POINTS AND REWARD/PENALTY

Calculation of Heat Rate Points

GPIF Points and Reward or Penalty

for January 2002 - December 2002

Unit	Availability Points	Availability* Weighting Factor	Heat Rate Points	Heat Rate* Weighting Factor
Crist 4	10.00	0.003	-10.00	0.029
Crist 6	4.76	0.031	-1.16	0.094
Crist 7	10.00	0.162	0.00	0.197
Smith 1	10.00	0.011	-3.39	0.080
Smith 2	-10.00	0.015	-8.14	0.087
Daniel 1	10.00	0.060	5.41	0.100
Daniel 2	10.00	0.050	0.00	0.081

Company GPIF Points = + 10.00 * 0.003 - 10.00 * 0.029
+ 4.76 * 0.031 - 1.16 * 0.094
+ 10.00 * 0.162 + 0.00 * 0.197
+ 10.00 * 0.011 - 3.39 * 0.080
- 10.00 * 0.015 - 8.14 * 0.087
+ 10.00 * 0.060 + 5.41 * 0.100
+ 10.00 * 0.050 + 0.00 * 0.081
= 2.02

Company reward/penalty = 2.02 points * $213822 per point
= $431,920

* *From page 5, Schedule 3 of Exhibit to J. R. Douglass's September 20, 2001 GPIF testimony in Docket 010001-EI.*

V. GPIF MINIMUM FILING REQUIREMENTS FOR THE JANUARY 2002 - DECEMBER 2002 PERIOD

CONTENTS	SCHEDULE 5 PAGE
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Generating Performance Incentive Factor

Actual Reward/Penalty Table

Gulf Power Company

Period of: January 2002 - December 2002

Generating Performance Incentive Factor Points	Fuel Saving/Loss ($000)	Generating Performance Incentive Factor ($000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10	6301	2138
+ 9	5671	1924
+ 8	5041	1711
+ 7	4411	1497
+ 6	3781	1283
+ 5	3151	1069
+ 4	2520	855
+ 3	1890	641
+ 2	1260	428
+ 1	630	214
0	0	0
- 1	-749	-214
- 2	-1498	-428
- 3	-2247	-641
- 4	-2996	-855
- 5	-3746	-1069
- 6	-4495	-1283
- 7	-5244	-1497
- 8	-5993	-1711
- 9	-6742	-1924
- 10	-7491	-2138
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Actual

Gulf Power Company

Period of: January 2002 - December 2002

Line 1	Beginning of Period Balance of Common Equity	$504,893,700
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '02	$546,969,667
Line 3	Month of Feb '02	$533,449,634
Line 4	Month of Mar '02	$537,235,449
Line 5	Month of Apr '02	$537,978,036
Line 6	Month of May '02	$524,491,955
Line 7	Month of Jun '02	$535,129,350
Line 8	Month of Jul '02	$530,687,174
Line 9	Month of Aug '02	$542,699,632
Line 10	Month of Sep '02	$552,874,447
Line 11	Month of Oct '02	$543,923,668
Line 12	Month of Nov '02	$544,553,467
Line 13	Month of Dec '02	$549,298,482
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$537,244,974
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	60.7202%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$2,211,968
Line 18	Jurisdictional Sales (KWH)	10,771,897,000
Line 19	Total Territorial Sales (KWH)	11,143,426,000
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	96.6659%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$2,138,220

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Calculation of System Actual GPIF Points

Gulf Power Company

Period of: January 2002 - December 2002

Plant & Unit	Performance Indicator (EAF or ANOHR)	Weighting Factor	Unit Points	Weighted Unit Points
Crist 4	EAF1	0.3%	10.00	0.030
Crist 4	ANOHR1	2.9%	-10.00	-0.290
Crist 6	EAF2	3.1%	4.76	0.148
Crist 6	ANOHR2	9.4%	-1.16	-0.109
Crist 7	EAF3	16.2%	10.00	1.620
Crist 7	ANOHR3	19.7%	0.00	0.000
Smith 1	EAF4	1.1%	10.00	0.110
Smith 1	ANOHR4	8.0%	-3.39	-0.271
Smith 2	EAF5	1.5%	-10.00	-0.150
Smith 2	ANOHR5	8.7%	-8.14	-0.708
Daniel 1	EAF6	6.0%	10.00	0.600
Daniel 1	ANOHR6	10.0%	5.41	0.541
Daniel 2	EAF7	5.0%	10.00	0.500
Daniel 2	ANOHR7	8.1%	0.00	0.000
Gulf Power GPIF Total		100.0%		2.02

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2002 - December 2002

Crist 4

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	17	91.70	+ 10	182	10,184
+ 9	15	91.62	+ 9	164	10,208
+ 8	14	91.54	+ 8	146	10,232
+ 7	12	91.46	+ 7	127	10,256
+ 6	10	91.38	+ 6	109	10,280
+ 5	9	91.30	+ 5	91	10,304
+ 4	7	91.22	+ 4	73	10,328
+ 3	5	91.14	+ 3	55	10,352
+ 2	3	91.06	+ 2	36	10,376
+ 1	2	90.98	+ 1	18	10,400
				0	10,424
0	0	90.90	0	0	10,499
				0	10,574
- 1	(4)	90.77	- 1	(18)	10,598
- 2	(8)	90.64	- 2	(36)	10,622
- 3	(13)	90.51	- 3	(55)	10,646
- 4	(17)	90.38	- 4	(73)	10,670
- 5	(21)	90.25	- 5	(91)	10,694
- 6	(25)	90.12	- 6	(109)	10,718
- 7	(29)	89.99	- 7	(127)	10,742
- 8	(34)	89.86	- 8	(146)	10,766
- 9	(38)	89.73	- 9	(164)	10,790
- 10	(42)	89.60	- 10	(182)	10,814
Weighting Factor:		0.003	Weighting Factor:		0.029

Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2002 - December 2002

Crist 6

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	197	79.40	+ 10	594	10,230
+ 9	177	79.19	+ 9	535	10,254
+ 8	158	78.98	+ 8	475	10,278
+ 7	138	78.77	+ 7	416	10,302
+ 6	118	78.56	+ 6	356	10,326
+ 5	99	78.35	+ 5	297	10,351
+ 4	79	78.14	+ 4	238	10,375
+ 3	59	77.93	+ 3	178	10,399
+ 2	39	77.72	+ 2	119	10,423
+ 1	20	77.51	+ 1	59	10,447
				0	10,471
0	0	77.30	0	0	10,546
				0	10,621
- 1	(30)	76.99	- 1	(59)	10,645
- 2	(61)	76.68	- 2	(119)	10,669
- 3	(91)	76.37	- 3	(178)	10,693
- 4	(121)	76.06	- 4	(238)	10,717
- 5	(152)	75.75	- 5	(297)	10,742
- 6	(182)	75.44	- 6	(356)	10,766
- 7	(212)	75.13	- 7	(416)	10,790
- 8	(242)	74.82	- 8	(475)	10,814
- 9	(273)	74.51	- 9	(535)	10,838
- 10	(303)	74.20	- 10	(594)	10,862
Weighting Factor:		0.031	Weighting Factor:		0.094

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2002 - December 2002

Crist 7

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	1,020	82.70	+ 10	1,242	9,890
+ 9	918	82.40	+ 9	1,118	9,913
+ 8	816	82.10	+ 8	994	9,936
+ 7	714	81.80	+ 7	869	9,959
+ 6	612	81.50	+ 6	745	9,982
+ 5	510	81.20	+ 5	621	10,006
+ 4	408	80.90	+ 4	497	10,029
+ 3	306	80.60	+ 3	373	10,052
+ 2	204	80.30	+ 2	248	10,075
+ 1	102	80.00	+ 1	124	10,098
				0	10,121
0	0	79.70	0	0	10,196
				0	10,271
- 1	(151)	79.24	- 1	(124)	10,294
- 2	(302)	78.78	- 2	(248)	10,317
- 3	(453)	78.32	- 3	(373)	10,340
- 4	(604)	77.86	- 4	(497)	10,363
- 5	(755)	77.40	- 5	(621)	10,387
- 6	(905)	76.94	- 6	(745)	10,410
- 7	(1,056)	76.48	- 7	(869)	10,433
- 8	(1,207)	76.02	- 8	(994)	10,456
- 9	(1,358)	75.56	- 9	(1,118)	10,479
- 10	(1,509)	75.10	- 10	(1,242)	10,502
Weighting Factor:		0.162	Weighting Factor:		0.197

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2002 - December 2002

Smith 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	67	91.40	+ 10	505	9,752
+ 9	60	91.33	+ 9	455	9,775
+ 8	54	91.26	+ 8	404	9,797
+ 7	47	91.19	+ 7	354	9,820
+ 6	40	91.12	+ 6	303	9,843
+ 5	34	91.05	+ 5	253	9,866
+ 4	27	90.98	+ 4	202	9,888
+ 3	20	90.91	+ 3	152	9,911
+ 2	13	90.84	+ 2	101	9,934
+ 1	7	90.77	+ 1	51	9,956
				0	9,979
0	0	90.70	0	0	10,054
				0	10,129
- 1	(12)	90.59	- 1	(51)	10,152
- 2	(23)	90.48	- 2	(101)	10,174
- 3	(35)	90.37	- 3	(152)	10,197
- 4	(46)	90.26	- 4	(202)	10,220
- 5	(58)	90.15	- 5	(253)	10,243
- 6	(70)	90.04	- 6	(303)	10,265
- 7	(81)	89.93	- 7	(354)	10,288
- 8	(93)	89.82	- 8	(404)	10,311
- 9	(104)	89.71	- 9	(455)	10,333
- 10	(116)	89.60	- 10	(505)	10,356
Weighting Factor:		0.011	Weighting Factor:		0.080

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2002 - December 2002

Smith 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	94	87.40	+ 10	548	9,749
+ 9	85	87.32	+ 9	493	9,772
+ 8	75	87.24	+ 8	438	9,794
+ 7	66	87.16	+ 7	384	9,817
+ 6	56	87.08	+ 6	329	9,839
+ 5	47	87.00	+ 5	274	9,862
+ 4	38	86.92	+ 4	219	9,885
+ 3	28	86.84	+ 3	164	9,907
+ 2	19	86.76	+ 2	110	9,930
+ 1	9	86.68	+ 1	55	9,952
				0	9,975
0	0	86.60	0	0	10,050
				0	10,125
- 1	(16)	86.47	- 1	(55)	10,148
- 2	(32)	86.34	- 2	(110)	10,170
- 3	(47)	86.21	- 3	(164)	10,193
- 4	(63)	86.08	- 4	(219)	10,216
- 5	(79)	85.95	- 5	(274)	10,239
- 6	(95)	85.82	- 6	(329)	10,261
- 7	(111)	85.69	- 7	(384)	10,284
- 8	(126)	85.56	- 8	(438)	10,307
- 9	(142)	85.43	- 9	(493)	10,329
- 10	(158)	85.30	- 10	(548)	10,352
Weighting Factor:		0.015	Weighting Factor:		0.087

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2002 - December 2002

Daniel 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	375	90.90	+ 10	633	9,885
+ 9	338	90.61	+ 9	570	9,908
+ 8	300	90.32	+ 8	506	9,931
+ 7	263	90.03	+ 7	443	9,954
+ 6	225	89.74	+ 6	380	9,977
+ 5	188	89.45	+ 5	317	10,001
+ 4	150	89.16	+ 4	253	10,024
+ 3	113	88.87	+ 3	190	10,047
+ 2	75	88.58	+ 2	127	10,070
+ 1	38	88.29	+ 1	63	10,093
				0	10,116
0	0	88.00	0	0	10,191
				0	10,266
- 1	(64)	87.57	- 1	(63)	10,289
- 2	(127)	87.14	- 2	(127)	10,312
- 3	(191)	86.71	- 3	(190)	10,335
- 4	(254)	86.28	- 4	(253)	10,358
- 5	(318)	85.85	- 5	(317)	10,382
- 6	(381)	85.42	- 6	(380)	10,405
- 7	(445)	84.99	- 7	(443)	10,428
- 8	(508)	84.56	- 8	(506)	10,451
- 9	(572)	84.13	- 9	(570)	10,474
- 10	(635)	83.70	- 10	(633)	10,497
Weighting Factor:		0.060	Weighting Factor:		0.100

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2002 - December 2002

Daniel 2

Equivalent Availability Points	Fuel *Savings*/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	315	73.00	+ 10	512	9,609
+ 9	284	72.77	+ 9	461	9,631
+ 8	252	72.54	+ 8	410	9,653
+ 7	221	72.31	+ 7	358	9,676
+ 6	189	72.08	+ 6	307	9,698
+ 5	158	71.85	+ 5	256	9,720
+ 4	126	71.62	+ 4	205	9,742
+ 3	95	71.39	+ 3	154	9,764
+ 2	63	71.16	+ 2	102	9,787
+ 1	32	70.93	+ 1	51	9,809
				0	9,831
0	0	70.70	0	0	9,906
				0	9,981
- 1	(51)	70.36	- 1	(51)	10,003
- 2	(102)	70.02	- 2	(102)	10,025
- 3	(154)	69.68	- 3	(154)	10,048
- 4	(205)	69.34	- 4	(205)	10,070
- 5	(256)	69.00	- 5	(256)	10,092
- 6	(307)	68.66	- 6	(307)	10,114
- 7	(358)	68.32	- 7	(358)	10,136
- 8	(410)	67.98	- 8	(410)	10,159
- 9	(461)	67.64	- 9	(461)	10,181
- 10	(512)	67.30	- 10	(512)	10,203
Weighting Factor:	0.050		Weighting Factor:		0.081

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GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2002 - December 2002

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)	EAF Adjusted Actual %	Actual Fuel Savings/ Loss ($000)
Crist 4	0.3	90.9	91.7	89.6	17.0	-42.0	93.1	$17
Crist 6	3.1	77.3	79.4	74.2	197.0	-303.0	78.3	$94
Crist 7	16.2	79.7	82.7	75.1	1020.0	-1509.0	85.8	$1,020
Smith 1	1.1	90.7	91.4	89.6	67.0	-116.0	92.0	$67
Smith 2	1.5	86.6	87.4	85.3	94.0	-158.0	58.2	($158)
Daniel 1	6.0	88.0	90.9	83.7	375.0	-635.0	92.4	$375
Daniel 2	5.0	70.7	73.0	67.3	315.0	-512.0	73.9	$315
Total:	33.2							

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Max BTU/KWH	ANOHR Range Min BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)	ANOHR Adjusted Actual BTU/KWH	Actual Fuel Savings/ Loss ($000)
Crist 4	2.9	10,499	85.9	10,814	10,184	$182	($182)	10,979	($182)
Crist 6	9.4	10,546	83.0	10,862	10,230	$594	($594)	10,649	($69)
Crist 7	19.7	10,196	97.8	10,502	9,890	$1,242	($1,242)	10,255	$0
Smith 1	8.0	10,054	95.6	10,356	9,752	$505	($505)	10,206	($171)
Smith 2	8.7	10,050	95.0	10,352	9,749	$548	($548)	10,309	($446)
Daniel 1	10.0	10,191	89.3	10,497	9,885	$633	($633)	9,991	$342
Daniel 2	8.1	9,906	91.2	10,203	9,609	$512	($512)	9,850	$0
Total:	66.8								

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Actual Unit Performance Data

Gulf Power Company

Period of: January 2002 - December 2002

Plant & Unit	Actual EAF %	Adjustments* to EAF %	Adjusted Actual %
Crist 4	93.6	-0.5	93.1
Crist 6	78.6	-0.3	78.3
Crist 7	77.8	8.0	85.8
Smith 1	88.3	3.7	92.0
Smith 2	55.8	2.4	58.2
Daniel 1	92.6	-0.2	92.4
Daniel 2	70.6	3.3	73.9

Plant & Unit	Actual ANOHR BTU/KWH	Adjustments** to ANOHR BTU/KWH	ANOHR Adjusted Actual BTU/KWH
Crist 4	11,351	-372	10,979
Crist 6	10,887	-238	10,649
Crist 7	10,388	-133	10,255
Smith 1	10,244	-38	10,206
Smith 2	10,409	-100	10,309
Daniel 1	10,095	-104	9,991
Daniel 2	10,036	-186	9,850

* Refer to pages 3 through 9, Schedule 2.

** Refer to pages 9 through 15, Schedule 3.

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	CRIST 4	Jan '02	Feb '02	Mar '02	Apr '02	May '02	Jun '02	
1.	EAF (%)	100.0	96.0	99.9	100.0	100.0	100.0	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	150.2	539.6	744.0	719.0	587.6	720.0	
4.	RSH	593.8	105.8	0.0	0.0	156.4	0.0	
5.	UH	0.0	26.6	0.0	0.0	0.0	0.0	
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
7.	FOH	0.0	10.2	0.0	0.0	0.0	0.0	
8.	MOH	0.0	16.4	0.0	0.0	0.0	0.0	
9.	PFOH	0.0	0.0	1.5	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	0.0	58.0	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	
14.	Oper MBtu	103318	285699	435488	439461	376975	420193	
15.	Net Gen (MWH)	8533	24841	38451	39093	33273	35945	
16.	ANOHR (Btu/KWH)	12108	11501	11326	11241	11330	11690	
17.	NOF %	72.8	59.0	66.3	69.7	72.6	64.0	
18.	NPC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	
19.	ANOHR Equation	10^6 / AKW * [449.21 - 12.61 * JAN + 16.96 * JUN + 24.56 * JUL + 27.59 * AUG] -3640 + 0.10501 * LSRF / AKW						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	CRIST 4	Jul '02	Aug '02	Sep '02	Oct '02	Nov '02	Dec '02	Total
1.	EAF (%)	100.0	98.9	98.9	100.0	73.2	56.3	93.6
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	744.0	744.0	711.8	745.0	527.2	418.6	7351.0
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	856.0
5.	UH	0.0	0.0	8.2	0.0	192.8	325.4	553.0
6.	POH	0.0	0.0	0.0	0.0	192.8	316.4	509.2
7.	FOH	0.0	0.0	8.2	0.0	0.0	9.0	27.4
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	16.4
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	1.5
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	58.0
11.	PMOH	0.0	32.0	0.0	0.0	0.0	0.0	32.0
12.	LR pm (MW)	0.0	20.7	0.0	0.0	0.0	0.0	20.7
13.	NSC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	78.0
14.	Oper MBtu	443221	435296	468668	469178	277091	237701	4392289
15.	Net Gen (MWH)	37756	38338	41999	42369	26308	20047	386953
16.	ANOHR (Btu/KWH)	11739	11354	11159	11074	10533	11857	11351
17.	NOF %	65.1	66.1	75.6	72.9	64.0	61.4	67.5
18.	NPC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	78.0
19.	ANOHR Equation	10^6 / AKW * [449.21 - 12.61 * JAN + 16.96 * JUN + 24.56 * JUL + 27.59 * AUG] -3640 + 0.10501 * LSRF / AKW						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	CRIST 6	Jan '02	Feb '02	Mar '02	Apr '02	May '02	Jun '02	
1.	EAF (%)	98.8	28.5	0.0	70.9	82.9	92.4	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	735.3	191.7	0.0	550.7	617.1	665.0	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	8.7	480.3	744.0	168.3	126.9	55.0	
6.	POH	0.0	480.3	744.0	144.0	0.0	0.0	
7.	FOH	8.7	0.0	0.0	24.3	0.8	0.0	
8.	MOH	0.0	0.0	0.0	0.0	126.1	55.0	
9.	PFOH	0.0	2.5	0.0	3.9	0.6	0.0	
10.	LR pf (MW)	0.0	38.0	0.0	189.7	292.0	0.0	
11.	PMOH	0.0	0.0	0.0	99.5	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	117.0	0.0	0.0	
13.	NSC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	
14.	Oper MBtu	1399806	354765	0	1131432	1217508	1305932	
15.	Net Gen (MWH)	123099	31507	0	104009	113976	117887	
16.	ANOHR (Btu/KWH)	11371	11260	0	10878	10682	11078	
17.	NOF %	55.4	54.4	0.0	62.5	61.2	58.7	
18.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	
19.	ANOHR Equation	10^6 / AKW * [187.63 - 85.12 * APR + 32.17 * JUN] + 9,810						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	CRIST 6	Jul '02	Aug '02	Sep '02	Oct '02	Nov '02	Dec '02	Total
1.	EAF (%)	85.9	92.5	99.4	100.0	91.7	96.2	78.6
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	639.7	688.1	720.0	745.0	659.9	715.5	6928.0
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	104.3	55.9	0.0	0.0	60.1	28.5	1832.0
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1368.3
7.	FOH	40.0	4.0	0.0	0.0	0.0	28.5	106.3
8.	MOH	64.3	51.9	0.0	0.0	60.1	0.0	357.4
9.	PFOH	1.7	0.0	0.0	1.3	0.0	0.0	10.0
10.	LR pf (MW)	48.0	0.0	0.0	67.0	0.0	0.0	117.9
11.	PMOH	0.0	0.0	7.6	0.0	0.0	0.0	107.1
12.	LR pm (MW)	0.0	0.0	174.0	0.0	0.0	0.0	121.0
13.	NSC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	302.0
14.	Oper MBtu	1352093	1438819	1664347	1797394	1241446	1365772	14269314
15.	Net Gen (MWH)	124159	133128	155547	167644	111886	127813	1310655
16.	ANOHR (Btu/KWH)	10890	10808	10700	10721	11096	10686	10887
17.	NOF %	64.3	64.1	71.5	74.5	56.1	59.2	62.6
18.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	302.0
19.	ANOHR Equation	10^6 / AKW * [187.63 - 85.12 * APR + 32.17 * JUN] + 9,810						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	CRIST 7	Jan '02	Feb '02	Mar '02	Apr '02	May '02	Jun '02	
1.	EAF (%)	100.0	100.0	43.2	0.0	52.4	93.6	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	744.0	672.0	321.4	0.0	462.2	676.4	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	0.0	422.6	719.0	281.8	43.6	
6.	POH	0.0	0.0	384.2	719.0	170.9	0.0	
7.	FOH	0.0	0.0	38.4	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	0.0	110.9	43.6	
9.	PFOH	0.0	0.0	0.0	0.0	0.0	1.8	
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	249.0	
11.	PMOH	0.0	0.0	0.0	0.0	172.8	14.7	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	199.0	40.0	
13.	NSC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	
14.	Oper MBtu	2217797	1997229	1160156	0	1386561	2548391	
15.	Net Gen (MWH)	207969	185501	123254	0	131263	242637	
16.	ANOHR (Btu/KWH)	10664	10767	9413	0	10563	10503	
17.	NOF %	58.6	57.9	80.4	0.0	59.5	75.2	
18.	NPC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	

19.	ANOHR Equation	10^6 / AKW * [204.45 - 44.16 * MAY + 83.05 * JUL + 67.20 * AUG + 91.16 * SEP + 58.82 * OCT] + 9,704

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	CRIST 7	Jul '02	Aug '02	Sep '02	Oct '02	Nov '02	Dec '02	Total
1.	EAF (%)	99.1	100.0	93.5	79.8	72.1	100.0	77.8
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	737.6	744.0	674.2	594.7	520.0	744.0	6890.5
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	6.4	0.0	45.8	150.3	200.0	0.0	1869.5
6.	POH	0.0	0.0	0.0	150.3	200.0	0.0	1624.4
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	38.4
8.	MOH	6.4	0.0	45.8	0.0	0.0	0.0	206.7
9.	PFOH	1.2	0.0	16.0	0.0	4.7	0.0	23.7
10.	LR pf (MW)	32.0	0.0	27.0	0.0	76.0	0.0	53.8
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	187.5
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	186.5
13.	NSC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	477.0
14.	Oper MBtu	3008386	3068888	2883845	2546998	2056174	3081389	25955814
15.	Net Gen (MWH)	286808	294099	277023	253714	195099	301341	2498708
16.	ANOHR (Btu/KWH)	10489	10435	10410	10039	10539	10226	10388
17.	NOF %	81.5	82.9	86.1	89.4	78.7	84.9	76.0
18.	NPC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	477.0
19.	ANOHR Equation	10^6 / AKW * [204.45 - 44.16 * MAY + 83.05 * JUL + 67.20 * AUG + 91.16 * SEP + 58.82 * OCT] + 9,704						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	SMITH 1	Jan '02	Feb '02	Mar '02	Apr '02	May '02	Jun '02	
1.	EAF (%)	99.7	99.7	81.1	14.6	95.0	100.0	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	687.2	669.7	603.5	118.7	744.0	720.0	
4.	RSH	56.8	0.0	0.0	0.0	0.0	0.0	
5.	UH	0.0	2.3	140.5	600.3	0.0	0.0	
6.	POH	0.0	0.0	114.0	600.3	0.0	0.0	
7.	FOH	0.0	2.3	26.5	0.0	0.0	0.0	
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	
9.	PFOH	3.6	0.0	1.2	4.8	0.0	0.0	
10.	LR pf (MW)	95.5	0.0	37.0	52.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	37.0	117.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	52.0	52.0	0.0	
13.	NSC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	
14.	Oper MBtu	848504	861182	872390	128734	890475	988861	
15.	Net Gen (MWH)	84506	85005	85465	12054	86392	96517	
16.	ANOHR (Btu/KWH)	10041	10131	10208	10680	10307	10245	
17.	NOF %	75.9	78.4	87.4	62.7	71.7	82.7	
18.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	
19.	ANOHR Equation	10^6 / AKW * [43.96 - 17.87 * FEB - 12.85 * MAY - 18.43 * NOV] + 9,793						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	SMITH 1	Jul '02	Aug '02	Sep '02	Oct '02	Nov '02	Dec '02	Total
1.	EAF (%)	100.0	100.0	100.0	77.6	91.9	100.0	88.3
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	744.0	744.0	720.0	578.1	661.6	744.0	7734.8
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	56.8
5.	UH	0.0	0.0	0.0	166.9	58.4	0.0	968.4
6.	POH	0.0	0.0	0.0	149.4	58.4	0.0	922.1
7.	FOH	0.0	0.0	0.0	17.5	0.0	0.0	46.3
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9.	PFOH	0.0	0.0	0.0	0.0	0.0	0.0	9.6
10.	LR pf (MW)	0.0	0.0	0.0	0.0	0.0	0.0	66.4
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	154.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	52.0
13.	NSC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	162.0
14.	Oper MBtu	1076408	1063449	1067090	879870	897086	1031025	10605074
15.	Net Gen (MWH)	104404	104245	104643	85939	86099	99945	1035214
16.	ANOHR (Btu/KWH)	10310	10201	10197	10238	10419	10316	10244
17.	NOF %	86.6	86.5	89.7	91.8	80.3	82.9	82.6
18.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	162.0
19.	ANOHR Equation	10^6 / AKW * [43.96 - 17.87 * FEB - 12.85 * MAY - 18.43 * NOV] + 9,793						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	SMITH 2	Jan '02	Feb '02	Mar '02	Apr '02	May '02	Jun '02	
1.	EAF (%)	100.0	99.9	3.5	4.3	82.0	25.4	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	589.6	646.3	26.2	26.8	610.1	183.1	
4.	RSH	154.4	25.7	0.0	4.0	0.0	0.0	
5.	UH	0.0	0.0	717.8	688.2	133.9	536.9	
6.	POH	0.0	0.0	717.8	323.9	0.0	0.0	
7.	FOH	0.0	0.0	0.0	159.3	133.9	345.4	
8.	MOH	0.0	0.0	0.0	205.0	0.0	191.5	
9.	PFOH	0.0	0.5	0.0	0.0	0.0	0.0	
10.	LR pf (MW)	0.0	184.0	0.0	0.0	0.0	0.0	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	189.0	189.0	189.0	189.0	189.0	189.0	
14.	Oper MBtu	752512	804290	43341	16067	811269	227825	
15.	Net Gen (MWH)	76365	80475	4237	1238	80027	22122	
16.	ANOHR (Btu/KWH)	9854	9994	10229	12978	10137	10299	
17.	NOF %	68.5	65.9	85.6	24.4	69.4	63.9	
18.	NPC (MW)	189.0	189.0	189.0	189.0	189.0	189.0	

19.	ANOHR Equation	10^6 / AKW * [410.85 - 30.87 * JAN - 38.46 * FEB - 38.20 * MAR - 18.64 * APR] + 4,743 + 0.01678 * LSRF / AKW

Issued by: T. A. Fanning

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Docket No.: 030001-EI
Order No.:

ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	SMITH 2	Jul '02	Aug '02	Sep '02	Oct '02	Nov '02	Dec '02	Total
1.	EAF (%)	55.9	68.3	34.9	59.2	68.8	68.9	55.8
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	553.7	744.0	371.3	675.3	720.0	744.0	5890.4
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	184.1
5.	UH	190.3	0.0	348.7	69.7	0.0	0.0	2685.5
6.	POH	0.0	0.0	317.9	0.0	0.0	0.0	1359.6
7.	FOH	131.4	0.0	0.0	33.5	0.0	0.0	803.5
8.	MOH	58.9	0.0	30.8	36.2	0.0	0.0	522.4
9.	PFOH	512.5	744.0	352.0	675.3	720.0	742.1	3746.4
10.	LR pf (MW)	50.9	60.0	64.3	65.6	59.0	59.0	59.8
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13.	NSC (MW)	189.0	189.0	189.0	189.0	189.0	189.0	189.0
14.	Oper MBtu	762393	977037	484763	873513	920824	958987	7632821
15.	Net Gen (MWH)	71223	91351	45974	82849	86679	90720	733260
16.	ANOHR (Btu/KWH)	10704	10695	10544	10543	10623	10571	10409
17.	NOF %	68.1	65.0	65.5	64.9	63.7	64.5	65.9
18.	NPC (MW)	189.0	189.0	189.0	189.0	189.0	189.0	189.0
19.	ANOHR Equation	10^6 / AKW * [410.85 - 30.87 * JAN - 38.46 * FEB - 38.20 * MAR - 18.64 * APR] + 4,743 + 0.01678 * LSRF / AKW						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	DANIEL 1	Jan '02	Feb '02	Mar '02	Apr '02	May '02	Jun '02	
1.	EAF (%)	80.4	92.1	98.9	60.2	93.0	97.7	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	550.7	619.5	744.0	450.3	697.8	720.0	
4.	RSH	48.3	0.0	0.0	0.0	0.0	0.0	
5.	UH	145.0	52.5	0.0	268.7	46.2	0.0	
6.	POH	145.0	50.8	0.0	0.0	0.0	0.0	
7.	FOH	0.0	1.7	0.0	140.5	46.2	0.0	
8.	MOH	0.0	0.0	0.0	128.2	0.0	0.0	
9.	PFOH	1.5	0.5	27.3	38.0	13.5	39.0	
10.	LR pf (MW)	258.0	308.5	149.1	218.6	206.7	209.0	
11.	PMOH	0.0	0.0	0.0	3.7	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	146.0	0.0	0.0	
13.	NSC (MW)	501.0	501.0	501.0	501.0	501.0	501.0	
14.	Oper MBtu	1811340	1987385	3173495	1615230	2644301	2737324	
15.	Net Gen (MWH)	174076	193346	318152	158358	259465	267077	
16.	ANOHR (Btu/KWH)	10405	10279	9975	10200	10191	10249	
17.	NOF %	63.1	62.3	85.4	70.2	74.2	74.0	
18.	NPC (MW)	501.0	501.0	501.0	501.0	501.0	501.0	
19.	ANOHR Equation	10^6 / AKW * [-429.41 - 91.37 * FEB - 136.56 * JUN + 105.89 * JUL] + 14,936 - 0.00805 * LSRF / AKW						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	DANIEL 1	Jul '02	Aug '02	Sep '02	Oct '02	Nov '02	Dec '02	Total
1.	EAF (%)	95.8	99.7	99.1	96.7	97.8	99.3	92.6
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	712.9	744.0	720.0	728.1	720.0	744.0	8151.3
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	48.3
5.	UH	31.1	0.0	0.0	16.9	0.0	0.0	560.4
6.	POH	0.0	0.0	0.0	0.0	0.0	0.0	195.8
7.	FOH	0.0	0.0	0.0	0.0	0.0	0.0	188.4
8.	MOH	31.1	0.0	0.0	16.9	0.0	0.0	176.2
9.	PFOH	1.4	15.1	86.2	20.5	68.6	356.6	668.2
10.	LR pf (MW)	48.7	70.0	36.9	182.5	87.2	7.8	60.9
11.	PMOH	0.0	0.0	0.0	0.0	30.6	0.0	34.3
12.	LR pm (MW)	0.0	0.0	0.0	0.0	63.5	0.0	72.4
13.	NSC (MW)	501.0	501.0	501.0	501.0	501.0	501.0	501.0
14.	Oper MBtu	2691591	2952511	3176048	3303173	2902821	3136081	32131301
15.	Net Gen (MWH)	266391	291923	315244	330609	293645	314531	3182817
16.	ANOHR (Btu/KWH)	10104	10114	10075	9991	9885	9971	10095
17.	NOF %	74.6	78.3	87.4	90.6	81.4	84.4	77.9
18.	NPC (MW)	501.0	501.0	501.0	501.0	501.0	501.0	501.0
19.	ANOHR Equation	10^6 / AKW * [-429.41 - 91.37 * FEB - 136.56 * JUN + 105.89 * JUL] + 14,936 - 0.00805 * LSRF / AKW						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	DANIEL 2	Jan '02	Feb '02	Mar '02	Apr '02	May '02	Jun '02	
1.	EAF (%)	51.6	0.0	0.0	53.1	89.9	98.0	
2.	PH	744.0	672.0	744.0	719.0	744.0	720.0	
3.	SH	386.9	0.0	0.0	393.6	675.4	716.2	
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
5.	UH	357.1	672.0	744.0	325.4	68.6	3.8	
6.	POH	312.8	672.0	744.0	311.6	0.0	0.0	
7.	FOH	44.3	0.0	0.0	13.8	28.8	3.8	
8.	MOH	0.0	0.0	0.0	0.0	39.8	0.0	
9.	PFOH	16.3	0.0	0.0	64.6	21.3	26.2	
10.	LR pf (MW)	86.7	0.0	0.0	94.6	151.7	214.6	
11.	PMOH	0.0	0.0	0.0	0.0	0.0	0.0	
12.	LR pm (MW)	0.0	0.0	0.0	0.0	0.0	0.0	
13.	NSC (MW)	510.0	510.0	510.0	514.0	514.0	514.0	
14.	Oper MBtu	1770260	0	0	1581548	2602626	2794556	
15.	Net Gen (MWH)	187779	0	0	148343	254171	273477	
16.	ANOHR (Btu/KWH)	9427	0	0	10661	10240	10219	
17.	NOF %	95.2	0.0	0.0	73.3	73.2	74.3	
18.	NPC (MW)	510.0	510.0	510.0	514.0	514.0	514.0	
19.	ANOHR Equation	10^6 / AKW * [-42.23 + 77.21 * MAY + 79.18 * JUL + 123.19 * AUG - 68.28 * NOV] + 13,010 - 0.00640 * LSRF / AKW						

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ACTUAL UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2002 - December 2002

	DANIEL 2	Jul '02	Aug '02	Sep '02	Oct '02	Nov '02	Dec '02	Total
1.	EAF (%)	88.1	99.5	98.1	76.5	89.1	98.7	70.6
2.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8760.0
3.	SH	657.9	744.0	720.0	586.6	715.6	744.0	6340.2
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	86.1	0.0	0.0	158.4	4.4	0.0	2419.8
6.	POH	0.0	0.0	0.0	153.3	0.0	0.0	2193.7
7.	FOH	16.0	0.0	0.0	5.1	4.4	0.0	116.2
8.	MOH	70.1	0.0	0.0	0.0	0.0	0.0	109.9
9.	PFOH	5.3	15.3	87.8	101.3	767.0	9.6	1114.7
10.	LR pf (MW)	144.0	115.4	79.8	85.4	49.8	311.9	68.0
11.	PMOH	39.3	0.0	0.0	0.0	0.0	9.6	48.9
12.	LR pm (MW)	15.3	0.0	0.0	0.0	0.0	188.6	49.3
13.	NSC (MW)	514.0	514.0	514.0	514.0	514.0	514.0	513.0
14.	Oper MBtu	2521702	2980646	3202242	2560394	2814688	3048965	25877627
15.	Net Gen (MWH)	248149	294998	313415	256674	289257	312148	2578411
16.	ANOHR (Btu/KWH)	10162	10104	10217	9975	9731	9768	10036
17.	NOF %	73.4	77.1	84.7	85.1	78.6	81.6	79.3
18.	NPC (MW)	514.0	514.0	514.0	514.0	514.0	514.0	513.0
19.	ANOHR Equation	10^6 / AKW * [-42.23 + 77.21 * MAY + 79.18 * JUL + 123.19 * AUG - 68.28 * NOV] + 13,010 - 0.00640 * LSRF / AKW						

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Planned Outage Schedules (Actual)

Period of: January 2002 - December 2002

Critical path bar charts of actual work activity performed during major planned outages are not shown here since corresponding bar charts of forecast work activity were not provided earlier in conformance with agreement with Staff to avoid the premature production of charts prior to their normal course of development. Forecast and actual critical path bar charts are developed for each planned outage and, per agreement with Staff, these charts will be provided on request.

Florida Public Service Commission
Docket No. 030001-EI
Gulf Power Company
Witness: L. S. Noack
Exhibit No.___(LSN-2)

EXHIBIT TO THE TESTIMONY OF

L. S. NOACK

IN FPSC DOCKET 030001-EI

I. DETERMINATION OF HEAT RATE TARGETS

Target Heat Rate Equations

Crist 4 ANOHR = 10^6 / AKW * [617.42 + 9.96 * MAR - 23.05 * NOV]

- 8329 + 0.13863 * LSRF / AKW

Crist 5 ANOHR = 10^6 / AKW * [-136.85 - 13.15 * OCT - 21.65 * NOV]

+ 18,611 - 0.08694 * LSRF / AKW

Crist 6 ANOHR = 10^6 / AKW * [1069.69 + 44.52 * MAR - 33.07 * MAY + 30.91 * AUG]

+ 844 + 0.02012 * LSRF / AKW

Crist 7 ANOHR = 10^6 / AKW * [349.83 - 96.07 * MAR + 61.52 * JUN + 115.03 * JUL + 78.38 * AUG + 90.36 * SEP + 64.01 * NOV]

+ 9,387

Smith 1 ANOHR = 10^6 / AKW * [111.12 - 22.83 * JAN - 27.46 * FEB + 17.98 * APR]

+ 9,412

Smith 2 ANOHR = 10^6 / AKW * [139.59 - 38.77 * JAN - 43.18 * FEB - 42.50 * MAR - 16.17 * MAY + 27.46 * JUL + 19.26 * AUG]

+ 9,289

Daniel 1 ANOHR = 10^6 / AKW * [-528.45 - 59.78 * MAY + 139.64 * JUL + 75.47 * AUG]

+ 15,490 - 0.00906 * LSRF / AKW

Daniel 2 ANOHR = 10^6 / AKW * [571.00 - 118.56 * JAN - 87.31 * FEB - 88.00 * MAR - 88.36 * NOV]

+ 8,698

Where:

ANOHR = Average Net Operating Heat Rate, BTU/KWH
AKW = Average Kilowatt Load, KW
LSRF = Load Square Range Factor, KW^2
BTU/LB = Coal Burned Average Heat Content, BTU/LB
JAN = January, 0 if not January, 1 if January
FEB = February, 0 if not February, 1 if February
MAR = March, 0 if not March, 1 if March
APR = April, 0 if not April, 1 if April
MAY = May, 0 if not May, 1 if May
JUN = June, 0 if not June, 1 if June
JUL = July, 0 if not July, 1 if July
AUG = August, 0 if not August, 1 if August
SEP = September, 0 if not September, 1 if September
OCT = October, 0 if not October, 1 if October
NOV = November, 0 if not November, 1 if November

WEEKLY UNIT OPERATING

DATA USED TO DEVELOP

TARGET HEAT RATE EQUATIONS

Data Base for CRIST 4 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10841	168	55.3	3270	0	0	0	0	0	0	1	0	0	0	0	0	2000
11096	168	64.3	4313	0	0	0	0	0	0	1	0	0	0	0	0	2000
11273	168	61.1	3941	0	0	0	0	0	0	1	0	0	0	0	0	2000
11174	168	52.8	3007	0	0	0	0	0	0	1	0	0	0	0	0	2000
11103	168	51.6	2831	0	0	0	0	0	0	0	1	0	0	0	0	2000
11101	168	56.2	3424	0	0	0	0	0	0	0	1	0	0	0	0	2000
11126	168	55.5	3331	0	0	0	0	0	0	0	1	0	0	0	0	2000
11059	168	57.5	3525	0	0	0	0	0	0	0	1	0	0	0	0	2000
11074	168	59.2	3741	0	0	0	0	0	0	0	1	0	0	0	0	2000
11020	168	53.0	3035	0	0	0	0	0	0	0	0	1	0	0	0	2000
10827	168	57.1	3474	0	0	0	0	0	0	0	0	1	0	0	0	2000
10732	168	54.4	3197	0	0	0	0	0	0	0	0	1	0	0	0	2000
12271	45	55.4	3614	0	0	0	0	0	0	0	0	0	0	1	1	2000
10462	168	70.5	5046	0	0	0	0	0	0	0	0	0	0	0	0	2000
10639	168	56.6	3361	0	0	0	0	0	0	0	0	0	0	0	0	2000
10265	168	64.4	4352	0	0	0	0	0	0	0	0	0	0	0	0	2000
*12730	24	57.0	3462	0	0	0	0	0	0	0	0	0	0	0	0	2000
10440	168	66.0	4500	1	0	0	0	0	0	0	0	0	0	0	0	2001
10440	143	64.2	4307	1	0	0	0	0	0	0	0	0	0	0	1	2001
10405	82	51.0	2738	1	0	0	0	0	0	0	0	0	0	0	0	2001
10730	118	51.9	2835	1	0	0	0	0	0	0	0	0	0	0	1	2001
10882	90	50.1	2626	0	1	0	0	0	0	0	0	0	0	0	1	2001
10339	168	61.7	4061	0	1	0	0	0	0	0	0	0	0	0	0	2001
10348	168	69.0	4893	0	1	0	0	0	0	0	0	0	0	0	0	2001
10338	168	73.6	5473	0	1	0	0	0	0	0	0	0	0	0	0	2001
10416	168	73.0	5408	0	0	1	0	0	0	0	0	0	0	0	0	2001
10285	168	73.3	5436	0	0	1	0	0	0	0	0	0	0	0	0	2001
10347	168	67.0	4650	0	0	1	0	0	0	0	0	0	0	0	0	2001
10372	168	68.9	4879	0	0	1	0	0	0	0	0	0	0	0	0	2001
10279	167	66.9	4574	0	0	1	0	0	0	0	0	0	0	0	0	2001
9943	168	70.1	5051	0	0	0	1	0	0	0	0	0	0	0	0	2001
9956	168	73.2	5441	0	0	0	1	0	0	0	0	0	0	0	0	2001
9966	168	76.5	5861	0	0	0	1	0	0	0	0	0	0	0	0	2001
10022	168	63.1	4175	0	0	0	1	0	0	0	0	0	0	0	0	2001
10174	168	67.7	4763	0	0	0	0	1	0	0	0	0	0	0	0	2001
10260	168	64.7	4373	0	0	0	0	1	0	0	0	0	0	0	0	2001
10413	168	57.4	3515	0	0	0	0	1	0	0	0	0	0	0	0	2001
10362	168	59.5	3710	0	0	0	0	1	0	0	0	0	0	0	0	2001
10603	168	56.1	3324	0	0	0	0	1	0	0	0	0	0	0	0	2001
10743	168	57.5	3547	0	0	0	0	0	1	0	0	0	0	0	0	2001
10565	168	64.4	4379	0	0	0	0	0	1	0	0	0	0	0	0	2001
10494	168	61.8	4079	0	0	0	0	0	1	0	0	0	0	0	0	2001
10721	144	56.6	3437	0	0	0	0	0	1	0	0	0	0	0	0	2001
10471	168	51.2	2751	0	0	0	0	0	0	1	0	0	0	0	0	2001
10392	168	58.3	3603	0	0	0	0	0	0	1	0	0	0	0	0	2001
10585	168	58.8	3681	0	0	0	0	0	0	1	0	0	0	0	0	2001
10579	168	58.1	3591	0	0	0	0	0	0	1	0	0	0	0	0	2001

Data Base for CRIST 4 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	PEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10251	168	65.7	4503	0	0	0	0	0	0	0	1	0	0	0	0	2001
10724	168	64.6	4351	0	0	0	0	0	0	0	1	0	0	0	0	2001
10625	168	65.3	4461	0	0	0	0	0	0	0	1	0	0	0	0	2001
10838	168	62.0	4093	0	0	0	0	0	0	0	1	0	0	0	0	2001
10965	168	59.2	3738	0	0	0	0	0	0	0	1	0	0	0	0	2001
10865	168	55.2	3274	0	0	0	0	0	0	0	0	1	0	0	0	2001
10726	168	54.6	3205	0	0	0	0	0	0	0	0	1	0	0	0	2001
10715	168	52.9	2984	0	0	0	0	0	0	0	0	1	0	0	0	2001
10812	167	53.2	3041	0	0	0	0	0	0	0	0	1	0	0	0	2001
* 9345	39	66.5	4682	0	0	0	0	0	0	0	0	0	1	0	1	2001
12170	104	53.5	3084	1	0	0	0	0	0	0	0	0	0	0	1	2002
*12101	47	63.3	4275	1	0	0	0	0	0	0	0	0	0	0	0	2002
12171	144	43.3	1982	0	1	0	0	0	0	0	0	0	0	0	1	2002
11446	158	45.9	2142	0	1	0	0	0	0	0	0	0	0	0	0	2002
11184	168	46.5	2217	0	1	0	0	0	0	0	0	0	0	0	0	2002
11293	168	52.0	2850	0	0	1	0	0	0	0	0	0	0	0	0	2002
11386	168	50.5	2669	0	0	1	0	0	0	0	0	0	0	0	0	2002
11355	168	48.6	2425	0	0	1	0	0	0	0	0	0	0	0	0	2002
11337	168	53.6	3027	0	0	1	0	0	0	0	0	0	0	0	0	2002
11192	168	52.8	2927	0	0	1	0	0	0	0	0	0	0	0	0	2002
11122	167	52.4	2903	0	0	0	1	0	0	0	0	0	0	0	0	2002
11422	168	49.9	2625	0	0	0	1	0	0	0	0	0	0	0	0	2002
11155	168	59.4	3755	0	0	0	1	0	0	0	0	0	0	0	0	2002
11282	168	55.6	3299	0	0	0	1	0	0	0	0	0	0	0	0	2002
11264	168	58.2	3633	0	0	0	0	1	0	0	0	0	0	0	0	2002
11296	168	60.8	3949	0	0	0	0	1	0	0	0	0	0	0	0	2002
11369	94	55.3	3305	0	0	0	0	1	0	0	0	0	0	0	0	2002
11392	87	56.6	3440	0	0	0	0	1	0	0	0	0	0	0	1	2002
11443	168	49.9	2662	0	0	0	0	1	0	0	0	0	0	0	0	2002
11730	168	48.1	2451	0	0	0	0	0	1	0	0	0	0	0	0	2002
11832	168	49.0	2557	0	0	0	0	0	1	0	0	0	0	0	0	2002
11737	168	49.1	2560	0	0	0	0	0	1	0	0	0	0	0	0	2002
11631	144	52.4	2934	0	0	0	0	0	1	0	0	0	0	0	0	2002
11757	168	49.2	2548	0	0	0	0	0	0	1	0	0	0	0	0	2002
11715	168	50.7	2663	0	0	0	0	0	0	1	0	0	0	0	0	2002
11769	168	53.5	3054	0	0	0	0	0	0	1	0	0	0	0	0	2002
11825	168	48.2	2443	0	0	0	0	0	0	1	0	0	0	0	0	2002
11303	168	55.4	3269	0	0	0	0	0	0	0	1	0	0	0	0	2002
11154	168	48.5	2462	0	0	0	0	0	0	0	1	0	0	0	0	2002
11341	168	51.6	2817	0	0	0	0	0	0	0	1	0	0	0	0	2002
11361	168	54.5	3159	0	0	0	0	0	0	0	1	0	0	0	0	2002
11734	168	48.1	2441	0	0	0	0	0	0	0	1	0	0	0	0	2002
11326	168	53.8	3104	0	0	0	0	0	0	0	0	1	0	0	0	2002
11052	168	62.1	4095	0	0	0	0	0	0	0	0	1	0	0	0	2002
11159	160	64.3	4379	0	0	0	0	0	0	0	0	1	0	0	0	2002
11082	168	57.2	3439	0	0	0	0	0	0	0	0	1	0	0	0	2002
11045	168	62.4	4098	0	0	0	0	0	0	0	0	0	1	0	0	2002

Data Base for CRIST 4 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11075	168	57.3	3436	0	0	0	0	0	0	0	0	0	1	0	0	2002
11218	168	49.0	2451	0	0	0	0	0	0	0	0	0	1	0	0	2002
10914	169	58.2	3554	0	0	0	0	0	0	0	0	0	1	0	0	2002
10974	168	56.5	3368	0	0	0	0	0	0	0	0	0	1	0	0	2002
10699	168	52.2	2854	0	0	0	0	0	0	0	0	0	0	1	0	2002
10330	168	47.1	2243	0	0	0	0	0	0	0	0	0	0	1	0	2002
10464	119	48.6	2400	0	0	0	0	0	0	0	0	0	0	1	0	2002
12817	44	39.2	1657	0	0	0	0	0	0	0	0	0	0	0	1	2002
11789	168	52.5	2890	0	0	0	0	0	0	0	0	0	0	0	0	2002
11835	160	45.6	2132	0	0	0	0	0	0	0	0	0	0	0	0	2002
11803	24	46.2	2133	0	0	0	0	0	0	0	0	0	0	0	0	2002
11010	168	58.0	3543	1	0	0	0	0	0	0	0	0	0	0	0	2003
10839	168	59.0	3685	1	0	0	0	0	0	0	0	0	0	0	0	2003
10855	168	68.0	4781	1	0	0	0	0	0	0	0	0	0	0	0	2003
10777	168	64.1	4286	1	0	0	0	0	0	0	0	0	0	0	0	2003
10800	168	62.0	4014	0	1	0	0	0	0	0	0	0	0	0	0	2003
10991	168	57.1	3420	0	1	0	0	0	0	0	0	0	0	0	0	2003
11023	168	55.6	3222	0	1	0	0	0	0	0	0	0	0	0	0	2003
10820	168	62.4	4043	0	1	0	0	0	0	0	0	0	0	0	0	2003
10772	168	70.2	5041	0	0	1	0	0	0	0	0	0	0	0	0	2003
10807	168	69.3	4940	0	0	1	0	0	0	0	0	0	0	0	0	2003
10905	168	68.7	4869	0	0	1	0	0	0	0	0	0	0	0	0	2003
10812	168	71.3	5206	0	0	1	0	0	0	0	0	0	0	0	0	2003
10798	168	72.4	5315	0	0	1	0	0	0	0	0	0	0	0	0	2003
10752	167	70.1	5029	0	0	0	1	0	0	0	0	0	0	0	0	2003
10689	168	71.2	5187	0	0	0	1	0	0	0	0	0	0	0	0	2003
10696	168	69.3	4942	0	0	0	1	0	0	0	0	0	0	0	0	2003
10730	168	69.6	4996	0	0	0	1	0	0	0	0	0	0	0	0	2003
10412	168	68.6	4871	0	0	0	0	1	0	0	0	0	0	0	0	2003
10495	168	63.4	4214	0	0	0	0	1	0	0	0	0	0	0	0	2003
10594	168	63.4	4196	0	0	0	0	1	0	0	0	0	0	0	0	2003
10497	168	60.8	3893	0	0	0	0	1	0	0	0	0	0	0	0	2003
10450	168	62.8	4133	0	0	0	0	1	0	0	0	0	0	0	0	2003
10428	168	63.0	4133	0	0	0	0	0	1	0	0	0	0	0	0	2003
10466	168	62.9	4145	0	0	0	0	0	1	0	0	0	0	0	0	2003
10546	168	61.6	4037	0	0	0	0	0	1	0	0	0	0	0	0	2003
10810	144	65.7	4496	0	0	0	0	0	1	0	0	0	0	0	0	2003

Data Base for CRIST 4 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for CRIST 5 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10502	168	64.9	4413	0	0	0	0	0	0	1	0	0	0	0	0	2000
10772	168	72.0	5255	0	0	0	0	0	0	1	0	0	0	0	0	2000
10863	168	71.2	5159	0	0	0	0	0	0	1	0	0	0	0	0	2000
10764	168	63.9	4301	0	0	0	0	0	0	1	0	0	0	0	0	2000
10637	168	66.4	4568	0	0	0	0	0	0	0	1	0	0	0	0	2000
10647	168	68.2	4785	0	0	0	0	0	0	0	1	0	0	0	0	2000
10683	168	66.6	4599	0	0	0	0	0	0	0	1	0	0	0	0	2000
10697	168	67.7	4712	0	0	0	0	0	0	0	1	0	0	0	0	2000
10785	168	70.1	4998	0	0	0	0	0	0	0	1	0	0	0	0	2000
10679	168	64.3	4297	0	0	0	0	0	0	0	0	1	0	0	0	2000
10562	168	66.2	4558	0	0	0	0	0	0	0	0	1	0	0	0	2000
10399	168	65.9	4516	0	0	0	0	0	0	0	0	1	0	0	0	2000
10354	168	66.8	4597	0	0	0	0	0	0	0	0	1	0	0	0	2000
10033	168	64.8	4334	0	0	0	0	0	0	0	0	0	1	0	0	2000
10375	168	64.5	4331	0	0	0	0	0	0	0	0	0	1	0	0	2000
9817	168	71.6	5240	0	0	0	0	0	0	0	0	0	1	0	0	2000
10377	168	68.5	4869	0	0	0	0	0	0	0	0	0	1	0	0	2000
10304	169	68.0	4799	0	0	0	0	0	0	0	0	0	1	0	0	2000
10251	168	67.2	4679	0	0	0	0	0	0	0	0	0	0	1	0	2000
10298	168	73.6	5492	0	0	0	0	0	0	0	0	0	0	1	0	2000
10199	168	75.5	5760	0	0	0	0	0	0	0	0	0	0	1	0	2000
10119	168	70.8	5092	0	0	0	0	0	0	0	0	0	0	1	0	2000
* 8947	1	33.0	1089	0	0	0	0	0	0	0	0	0	0	0	0	2000
*11621	9	40.6	1767	0	0	0	0	0	0	0	0	0	0	0	1	2000
10296	168	71.9	5288	0	0	0	0	0	0	0	0	0	0	0	0	2000
10340	168	60.3	3771	0	0	0	0	0	0	0	0	0	0	0	0	2000
10187	24	77.5	6000	0	0	0	0	0	0	0	0	0	0	0	0	2000
10256	168	67.9	4773	1	0	0	0	0	0	0	0	0	0	0	0	2001
10096	132	66.8	4617	1	0	0	0	0	0	0	0	0	0	0	0	2001
10446	120	51.6	2788	1	0	0	0	0	0	0	0	0	0	0	1	2001
10265	69	71.0	5255	0	1	0	0	0	0	0	0	0	0	0	1	2001
10135	168	70.7	5143	0	1	0	0	0	0	0	0	0	0	0	0	2001
10011	168	73.5	5468	0	1	0	0	0	0	0	0	0	0	0	0	2001
10101	168	72.0	5302	0	0	1	0	0	0	0	0	0	0	0	0	2001
10198	168	71.6	5242	0	0	1	0	0	0	0	0	0	0	0	0	2001
10171	168	65.9	4511	0	0	1	0	0	0	0	0	0	0	0	0	2001
10176	168	69.3	4933	0	0	1	0	0	0	0	0	0	0	0	0	2001
10170	167	66.8	4575	0	0	1	0	0	0	0	0	0	0	0	0	2001
9873	168	69.6	4993	0	0	0	1	0	0	0	0	0	0	0	0	2001
9883	168	72.0	5288	0	0	0	1	0	0	0	0	0	0	0	0	2001
9933	168	74.9	5674	0	0	0	1	0	0	0	0	0	0	0	0	2001
10003	168	63.4	4218	0	0	0	1	0	0	0	0	0	0	0	0	2001
10034	168	67.9	4785	0	0	0	0	1	0	0	0	0	0	0	0	2001
10096	168	64.5	4355	0	0	0	0	1	0	0	0	0	0	0	0	2001
10205	143	57.5	3526	0	0	0	0	1	0	0	0	0	0	0	0	2001
10579	136	54.4	3174	0	0	0	0	1	0	0	0	0	0	0	1	2001
10473	168	57.1	3509	0	0	0	0	0	1	0	0	0	0	0	0	2001

Data Base for CRIST 5 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11095	95	57.3	3543	0	0	0	0	0	1	0	0	0	0	0	1	2001
10235	115	61.3	4048	0	0	0	0	0	1	0	0	0	0	0	0	2001
10690	140	56.1	3407	0	0	0	0	0	1	0	0	0	0	0	1	2001
10473	168	50.9	2719	0	0	0	0	0	0	1	0	0	0	0	0	2001
10313	168	58.3	3616	0	0	0	0	0	0	1	0	0	0	0	0	2001
10406	168	59.1	3720	0	0	0	0	0	0	1	0	0	0	0	0	2001
10210	168	58.3	3618	0	0	0	0	0	0	1	0	0	0	0	0	2001
10150	168	65.8	4537	0	0	0	0	0	0	0	1	0	0	0	0	2001
10601	168	64.4	4342	0	0	0	0	0	0	0	1	0	0	0	0	2001
10553	168	65.7	4519	0	0	0	0	0	0	0	1	0	0	0	0	2001
10518	168	61.8	4081	0	0	0	0	0	0	0	1	0	0	0	0	2001
10832	168	60.2	3837	0	0	0	0	0	0	0	1	0	0	0	0	2001
10618	168	56.9	3481	0	0	0	0	0	0	0	0	1	0	0	0	2001
10622	166	56.2	3391	0	0	0	0	0	0	0	0	1	0	0	0	2001
10443	168	55.2	3252	0	0	0	0	0	0	0	0	1	0	0	0	2001
10617	168	54.6	3203	0	0	0	0	0	0	0	0	1	0	0	0	2001
10426	168	51.8	2856	0	0	0	0	0	0	0	0	0	1	0	0	2001
10409	168	54.9	3192	0	0	0	0	0	0	0	0	0	1	0	0	2001
10420	46	53.7	3107	0	0	0	0	0	0	0	0	0	1	0	0	2001
10505	38	58.9	3877	0	0	0	0	0	0	0	0	0	1	0	1	2001
*13359	24	34.6	1586	0	1	0	0	0	0	0	0	0	0	0	1	2002
11055	168	53.1	3064	0	1	0	0	0	0	0	0	0	0	0	0	2002
11005	23	48.0	2442	0	1	0	0	0	0	0	0	0	0	0	0	2002
11614	118	50.3	2785	0	0	1	0	0	0	0	0	0	0	0	2	2002
11250	168	52.0	2838	0	0	1	0	0	0	0	0	0	0	0	0	2002
11202	168	51.2	2696	0	0	1	0	0	0	0	0	0	0	0	0	2002
11332	166	55.5	3283	0	0	1	0	0	0	0	0	0	0	0	0	2002
11163	168	55.8	3259	0	0	1	0	0	0	0	0	0	0	0	0	2002
10918	167	56.9	3386	0	0	0	1	0	0	0	0	0	0	0	0	2002
10829	168	58.5	3586	0	0	0	1	0	0	0	0	0	0	0	0	2002
10888	168	61.4	3969	0	0	0	1	0	0	0	0	0	0	0	0	2002
10941	168	59.0	3657	0	0	0	1	0	0	0	0	0	0	0	0	2002
11090	168	59.1	3672	0	0	0	0	1	0	0	0	0	0	0	0	2002
11050	168	63.2	4206	0	0	0	0	1	0	0	0	0	0	0	0	2002
11057	96	57.5	3536	0	0	0	0	1	0	0	0	0	0	0	0	2002
11497	85	55.2	3294	0	0	0	0	1	0	0	0	0	0	0	1	2002
11231	168	52.6	2915	0	0	0	0	1	0	0	0	0	0	0	0	2002
11511	168	51.6	2785	0	0	0	0	0	1	0	0	0	0	0	0	2002
11536	168	53.5	3043	0	0	0	0	0	1	0	0	0	0	0	0	2002
11589	168	52.4	2910	0	0	0	0	0	1	0	0	0	0	0	0	2002
11541	144	54.9	3220	0	0	0	0	0	1	0	0	0	0	0	0	2002
11611	168	51.0	2720	0	0	0	0	0	0	1	0	0	0	0	0	2002
11506	168	54.2	3062	0	0	0	0	0	0	1	0	0	0	0	0	2002
11601	168	56.5	3396	0	0	0	0	0	0	1	0	0	0	0	0	2002
11651	168	51.0	2724	0	0	0	0	0	0	1	0	0	0	0	0	2002
11144	168	58.2	3611	0	0	0	0	0	0	0	1	0	0	0	0	2002
11037	168	52.0	2825	0	0	0	0	0	0	0	1	0	0	0	0	2002

Data Base for CRIST 5 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11189	168	55.5	3255	0	0	0	0	0	0	0	1	0	0	0	0	2002
11142	168	57.1	3473	0	0	0	0	0	0	0	1	0	0	0	0	2002
11301	168	53.3	3028	0	0	0	0	0	0	0	1	0	0	0	0	2002
11112	147	58.1	3608	0	0	0	0	0	0	0	0	1	0	0	0	2002
11191	168	57.8	3516	0	0	0	0	0	0	0	0	1	0	0	0	2002
11074	168	66.4	4609	0	0	0	0	0	0	0	0	1	0	0	0	2002
11135	168	57.3	3474	0	0	0	0	0	0	0	0	1	0	0	0	2002
11058	168	63.4	4221	0	0	0	0	0	0	0	0	0	1	0	0	2002
11120	168	58.0	3513	0	0	0	0	0	0	0	0	0	1	0	0	2002
11341	168	48.0	2324	0	0	0	0	0	0	0	0	0	1	0	0	2002
11106	169	58.9	3649	0	0	0	0	0	0	0	0	0	1	0	0	2002
11518	168	52.6	2887	0	0	0	0	0	0	0	0	0	1	0	0	2002
10867	168	52.4	2880	0	0	0	0	0	0	0	0	0	0	1	0	2002
10573	168	47.4	2273	0	0	0	0	0	0	0	0	0	0	1	0	2002
10469	120	49.4	2458	0	0	0	0	0	0	0	0	0	0	1	0	2002
*14672	28	41.5	1829	0	0	0	0	0	0	0	0	0	0	0	1	2002
12320	168	47.0	2252	0	0	0	0	0	0	0	0	0	0	0	0	2002
12309	168	45.1	2092	0	0	0	0	0	0	0	0	0	0	0	0	2002
12325	24	42.6	1816	0	0	0	0	0	0	0	0	0	0	0	0	2002
11110	168	54.4	3097	1	0	0	0	0	0	0	0	0	0	0	0	2003
11039	168	56.9	3457	1	0	0	0	0	0	0	0	0	0	0	0	2003
10852	168	67.1	4663	1	0	0	0	0	0	0	0	0	0	0	0	2003
10906	168	63.0	4167	1	0	0	0	0	0	0	0	0	0	0	0	2003
10985	168	62.4	4070	0	1	0	0	0	0	0	0	0	0	0	0	2003
11243	168	55.8	3282	0	1	0	0	0	0	0	0	0	0	0	0	2003
11209	168	54.3	3055	0	1	0	0	0	0	0	0	0	0	0	0	2003
11148	168	58.2	3530	0	1	0	0	0	0	0	0	0	0	0	0	2003
10947	168	69.8	4983	0	0	1	0	0	0	0	0	0	0	0	0	2003
10858	168	68.2	4785	0	0	1	0	0	0	0	0	0	0	0	0	2003
10926	168	65.9	4485	0	0	1	0	0	0	0	0	0	0	0	0	2003
10799	168	69.5	4974	0	0	1	0	0	0	0	0	0	0	0	0	2003
10800	168	71.8	5247	0	0	1	0	0	0	0	0	0	0	0	0	2003
10877	167	67.6	4706	0	0	0	1	0	0	0	0	0	0	0	0	2003
10850	168	68.7	4832	0	0	0	1	0	0	0	0	0	0	0	0	2003
10877	168	69.1	4921	0	0	0	1	0	0	0	0	0	0	0	0	2003
10956	168	67.7	4740	0	0	0	1	0	0	0	0	0	0	0	0	2003
10350	168	67.4	4713	0	0	0	0	1	0	0	0	0	0	0	0	2003
10446	168	62.8	4129	0	0	0	0	1	0	0	0	0	0	0	0	2003
10372	168	61.3	3978	0	0	0	0	1	0	0	0	0	0	0	0	2003
11754	97	56.9	3453	0	0	0	0	1	0	0	0	0	0	0	1	2003
10754	138	55.8	3322	0	0	0	0	1	0	0	0	0	0	0	1	2003
10657	168	60.3	3825	0	0	0	0	0	1	0	0	0	0	0	0	2003
10472	168	62.6	4104	0	0	0	0	0	1	0	0	0	0	0	0	2003
10567	168	60.7	3939	0	0	0	0	0	1	0	0	0	0	0	0	2003
10401	144	65.0	4431	0	0	0	0	0	1	0	0	0	0	0	0	2003

Data Base for CRIST 5 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10485	168	211.0	51070	0	0	0	0	0	0	1	0	0	0	0	0	2000
10565	168	280.8	15208	0	0	0	0	0	0	1	0	0	0	0	0	2000
10611	168	252.8	3624	0	0	0	0	0	0	1	0	0	0	0	0	2000
10668	168	235.8	61723	0	0	0	0	0	0	1	0	0	0	0	0	2000
10623	168	227.5	57701	0	0	0	0	0	0	0	1	0	0	0	0	2000
10538	168	250.0	2051	0	0	0	0	0	0	0	1	0	0	0	0	2000
10679	168	233.9	61200	0	0	0	0	0	0	0	1	0	0	0	0	2000
10605	168	248.8	1943	0	0	0	0	0	0	0	1	0	0	0	0	2000
10697	168	249.4	2022	0	0	0	0	0	0	0	1	0	0	0	0	2000
10747	168	214.3	51845	0	0	0	0	0	0	0	0	1	0	0	0	2000
10997	131	235.8	61505	0	0	0	0	0	0	0	0	1	0	0	1	2000
11444	74	146.0	26635	0	0	0	0	0	0	0	0	1	0	0	1	2000
10880	168	199.4	45140	0	0	0	0	0	0	0	0	1	0	0	0	2000
9891	168	208.2	49192	0	0	0	0	0	0	0	0	0	1	0	0	2000
11127	168	192.7	41069	0	0	0	0	0	0	0	0	0	1	0	0	2000
11039	140	204.9	49527	0	0	0	0	0	0	0	0	0	1	0	1	2000
10803	168	248.9	1752	0	0	0	0	0	0	0	0	0	1	0	0	2000
11136	143	231.4	60640	0	0	0	0	0	0	0	0	0	1	0	1	2000
11000	168	255.8	4710	0	0	0	0	0	0	0	0	0	0	1	0	2000
10520	21	283.3	16815	0	0	0	0	0	0	0	0	0	0	1	0	2000
11290	106	172.4	32972	0	0	0	0	0	0	0	0	0	0	0	1	2000
10669	145	265.2	9296	0	0	0	0	0	0	0	0	0	0	0	0	2000
10294	168	282.4	16106	0	0	0	0	0	0	0	0	0	0	0	0	2000
10950	86	200.2	47802	0	0	0	0	0	0	0	0	0	0	0	1	2000
10404	24	283.7	15342	0	0	0	0	0	0	0	0	0	0	0	0	2000
10421	168	279.7	14308	1	0	0	0	0	0	0	0	0	0	0	0	2001
10375	147	278.6	14905	1	0	0	0	0	0	0	0	0	0	0	0	2001
11365	133	182.4	39770	1	0	0	0	0	0	0	0	0	0	0	1	2001
10839	168	193.7	44148	1	0	0	0	0	0	0	0	0	0	0	0	2001
10980	99	208.3	50570	0	1	0	0	0	0	0	0	0	0	0	1	2001
10561	168	280.5	14378	0	1	0	0	0	0	0	0	0	0	0	0	2001
10612	168	275.6	13630	0	1	0	0	0	0	0	0	0	0	0	0	2001
10496	119	288.6	19299	0	1	0	0	0	0	0	0	0	0	0	0	2001
10985	144	262.7	7859	0	0	1	0	0	0	0	0	0	0	0	1	2001
10870	168	286.8	18155	0	0	1	0	0	0	0	0	0	0	0	0	2001
11177	168	256.3	3420	0	0	1	0	0	0	0	0	0	0	0	0	2001
10687	168	243.7	65011	0	0	1	0	0	0	0	0	0	0	0	0	2001
10719	122	276.4	13578	0	0	1	0	0	0	0	0	0	0	0	0	2001
13272	88	128.8	22929	0	0	0	0	1	0	0	0	0	0	0	1	2001
10764	159	224.2	56291	0	0	0	0	1	0	0	0	0	0	0	0	2001
11574	72	131.0	17426	0	0	0	0	1	0	0	0	0	0	0	1	2001
11961	83	128.3	16682	0	0	0	0	1	0	0	0	0	0	0	1	2001
11061	168	192.5	43304	0	0	0	0	0	1	0	0	0	0	0	0	2001
11006	168	225.5	57031	0	0	0	0	0	1	0	0	0	0	0	0	2001
11046	168	229.4	59143	0	0	0	0	0	1	0	0	0	0	0	0	2001
11036	144	201.4	46708	0	0	0	0	0	1	0	0	0	0	0	0	2001
11034	168	179.7	36387	0	0	0	0	0	0	1	0	0	0	0	0	2001

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10941	168	216.2	52184	0	0	0	0	0	0	1	0	0	0	0	0	2001
11082	168	214.7	51899	0	0	0	0	0	0	1	0	0	0	0	0	2001
11046	168	208.1	48669	0	0	0	0	0	0	1	0	0	0	0	0	2001
10780	168	239.4	62416	0	0	0	0	0	0	0	1	0	0	0	0	2001
10382	168	233.6	59282	0	0	0	0	0	0	0	1	0	0	0	0	2001
11369	168	243.9	64531	0	0	0	0	0	0	0	1	0	0	0	0	2001
11347	168	228.1	58131	0	0	0	0	0	0	0	1	0	0	0	0	2001
11260	168	222.3	55007	0	0	0	0	0	0	0	1	0	0	0	0	2001
10900	168	199.6	45497	0	0	0	0	0	0	0	0	1	0	0	0	2001
10434	168	191.9	42096	0	0	0	0	0	0	0	0	1	0	0	0	2001
*12358	168	186.0	39395	0	0	0	0	0	0	0	0	1	0	0	0	2001
11146	146	158.7	28544	0	0	0	0	0	0	0	0	1	0	0	0	2001
11167	168	160.7	28258	0	0	0	0	0	0	0	0	0	1	0	0	2001
11212	168	166.9	31106	0	0	0	0	0	0	0	0	0	1	0	0	2001
11276	168	152.1	25988	0	0	0	0	0	0	0	0	0	1	0	0	2001
10702	168	209.7	50015	0	0	0	0	0	0	0	0	0	1	0	0	2001
11684	169	145.6	22617	0	0	0	0	0	0	0	0	0	1	0	0	2001
11878	168	130.3	17165	0	0	0	0	0	0	0	0	0	0	1	0	2001
10602	168	166.9	31381	0	0	0	0	0	0	0	0	0	0	1	0	2001
11680	168	133.9	18904	0	0	0	0	0	0	0	0	0	0	1	0	2001
11186	168	162.9	30917	0	0	0	0	0	0	0	0	0	0	1	0	2001
11264	168	135.3	18786	0	0	0	0	0	0	0	0	0	0	0	0	2001
11077	168	148.6	24595	0	0	0	0	0	0	0	0	0	0	0	0	2001
11493	168	147.4	24482	0	0	0	0	0	0	0	0	0	0	0	0	2001
11180	168	142.3	22065	0	0	0	0	0	0	0	0	0	0	0	0	2001
11230	24	127.9	16364	0	0	0	0	0	0	0	0	0	0	0	0	2001
11108	168	202.5	46070	1	0	0	0	0	0	0	0	0	0	0	0	2002
11306	168	168.3	32082	1	0	0	0	0	0	0	0	0	0	0	0	2002
11335	168	159.4	28927	1	0	0	0	0	0	0	0	0	0	0	0	2002
11937	168	133.1	18333	1	0	0	0	0	0	0	0	0	0	0	0	2002
11419	159	163.3	30770	0	1	0	0	0	0	0	0	0	0	0	0	2002
11044	96	179.4	36812	0	1	0	0	0	0	0	0	0	0	0	0	2002
23013	16	67.1	6230	0	0	0	1	0	0	0	0	0	0	0	1	2002
11428	145	179.1	40163	0	0	0	1	0	0	0	0	0	0	0	0	2002
10561	168	236.2	60970	0	0	0	1	0	0	0	0	0	0	0	0	2002
10540	168	201.9	46346	0	0	0	1	0	0	0	0	0	0	0	0	2002
10491	99	204.5	47661	0	0	0	0	1	0	0	0	0	0	0	0	2002
10896	105	198.8	46019	0	0	0	0	1	0	0	0	0	0	0	1	2002
10622	168	191.1	41090	0	0	0	0	1	0	0	0	0	0	0	0	2002
10731	152	188.8	41134	0	0	0	0	1	0	0	0	0	0	0	0	2002
11072	168	163.6	30277	0	0	0	0	1	0	0	0	0	0	0	0	2002
11149	168	166.2	30550	0	0	0	0	0	1	0	0	0	0	0	0	2002
11228	168	164.5	30075	0	0	0	0	0	1	0	0	0	0	0	0	2002
10958	168	197.9	43593	0	0	0	0	0	1	0	0	0	0	0	0	2002
11157	89	191.3	43113	0	0	0	0	0	1	0	0	0	0	0	1	2002
10981	168	183.7	39026	0	0	0	0	0	0	1	0	0	0	0	0	2002
11059	168	193.0	42028	0	0	0	0	0	0	1	0	0	0	0	0	2002

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11058	141	196.5	44137	0	0	0	0	0	0	1	0	0	0	0	1	2002
10693	115	211.7	50374	0	0	0	0	0	0	1	0	0	0	0	1	2002
11345	93	178.0	38388	0	0	0	0	0	0	0	1	0	0	0	2	2002
11081	167	180.3	36714	0	0	0	0	0	0	0	1	0	0	0	0	2002
10790	167	198.9	45056	0	0	0	0	0	0	0	1	0	0	0	0	2002
10589	168	214.5	52158	0	0	0	0	0	0	0	1	0	0	0	0	2002
10845	167	180.8	37617	0	0	0	0	0	0	0	1	0	0	0	0	2002
10828	168	209.9	50386	0	0	0	0	0	0	0	0	1	0	0	0	2002
10871	168	206.5	48946	0	0	0	0	0	0	0	0	1	0	0	0	2002
10550	168	243.5	63877	0	0	0	0	0	0	0	0	1	0	0	0	2002
10553	168	209.0	49696	0	0	0	0	0	0	0	0	1	0	0	0	2002
10749	168	234.5	60594	0	0	0	0	0	0	0	0	0	1	0	0	2002
10554	168	240.8	62956	0	0	0	0	0	0	0	0	0	1	0	0	2002
10763	168	171.4	32738	0	0	0	0	0	0	0	0	0	1	0	0	2002
10624	169	242.2	63916	0	0	0	0	0	0	0	0	0	1	0	0	2002
11021	168	218.5	52972	0	0	0	0	0	0	0	0	0	1	0	0	2002
11060	168	194.3	42200	0	0	0	0	0	0	0	0	0	0	1	0	2002
11172	108	165.2	30616	0	0	0	0	0	0	0	0	0	0	1	1	2002
11063	168	167.1	30892	0	0	0	0	0	0	0	0	0	0	1	0	2002
11230	168	145.6	23047	0	0	0	0	0	0	0	0	0	0	1	0	2002
10305	140	215.4	52152	0	0	0	0	0	0	0	0	0	0	0	1	2002
10781	168	201.7	45536	0	0	0	0	0	0	0	0	0	0	0	0	2002
11064	168	162.5	29734	0	0	0	0	0	0	0	0	0	0	0	0	2002
10698	168	154.9	26662	0	0	0	0	0	0	0	0	0	0	0	0	2002
11131	24	128.6	16689	0	0	0	0	0	0	0	0	0	0	0	0	2002
10566	121	209.0	50146	1	0	0	0	0	0	0	0	0	0	0	1	2003
10210	168	281.3	15091	1	0	0	0	0	0	0	0	0	0	0	0	2003
10192	168	267.7	9406	1	0	0	0	0	0	0	0	0	0	0	0	2003
10177	168	291.3	20169	1	0	0	0	0	0	0	0	0	0	0	0	2003
10259	168	284.6	16944	0	1	0	0	0	0	0	0	0	0	0	0	2003
10349	168	264.4	8137	0	1	0	0	0	0	0	0	0	0	0	0	2003
10311	168	265.4	8161	0	1	0	0	0	0	0	0	0	0	0	0	2003
10294	168	285.9	16524	0	1	0	0	0	0	0	0	0	0	0	0	2003
10326	168	274.3	10732	0	0	1	0	0	0	0	0	0	0	0	0	2003
10282	168	267.3	8836	0	0	1	0	0	0	0	0	0	0	0	0	2003
10497	160	270.3	10431	0	0	1	0	0	0	0	0	0	0	0	0	2003
10639	131	257.9	4439	0	0	1	0	0	0	0	0	0	0	0	1	2003
10242	167	264.7	6412	0	0	1	0	0	0	0	0	0	0	0	0	2003
* 9379	75	196.4	39895	0	0	0	1	0	0	0	0	0	0	0	0	2003
11769	81	173.7	37047	0	0	0	1	0	0	0	0	0	0	0	1	2003
• 9075	168	252.3	2118	0	0	0	0	1	0	0	0	0	0	0	0	2003
9757	168	235.0	60567	0	0	0	0	1	0	0	0	0	0	0	0	2003
9993	168	234.8	60513	0	0	0	0	1	0	0	0	0	0	0	0	2003
11358	168	223.6	56523	0	0	0	0	1	0	0	0	0	0	0	0	2003
*11785	168	230.3	58755	0	0	0	0	1	0	0	0	0	0	0	0	2003
10407	168	231.3	59099	0	0	0	0	0	1	0	0	0	0	0	0	2003
10178	168	243.0	64410	0	0	0	0	0	1	0	0	0	0	0	0	2003

Data Base for CRIST 6 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10300	168	227.9	58544	0	0	0	0	0	1	0	0	0	0	0	0	2003
10333	144	249.2	1605	0	0	0	0	0	1	0	0	0	0	0	0	2003

Data Base for CRIST 6 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10354	168	385.4	29837	0	0	0	0	0	0	1	0	0	0	0	0	2000
10709	129	444.0	7806	0	0	0	0	0	0	1	0	0	0	0	1	2000
10662	145	453.3	13602	0	0	0	0	0	0	1	0	0	0	0	0	2000
10541	168	417.3	53347	0	0	0	0	0	0	1	0	0	0	0	0	2000
10368	168	423.4	55245	0	0	0	0	0	0	0	1	0	0	0	0	2000
10336	134	424.1	56216	0	0	0	0	0	0	0	1	0	0	0	1	2000
10414	168	425.9	57782	0	0	0	0	0	0	0	1	0	0	0	0	2000
10373	168	448.3	7636	0	0	0	0	0	0	0	1	0	0	0	0	2000
10483	168	438.3	65261	0	0	0	0	0	0	0	1	0	0	0	0	2000
10412	168	421.9	54666	0	0	0	0	0	0	0	0	1	0	0	0	2000
10789	168	432.6	60523	0	0	0	0	0	0	0	0	1	0	0	0	2000
10360	164	399.2	39589	0	0	0	0	0	0	0	0	1	0	0	0	2000
10398	168	409.3	45590	0	0	0	0	0	0	0	0	1	0	0	0	2000
9522	168	386.9	31831	0	0	0	0	0	0	0	0	0	1	0	0	2000
10801	155	378.7	25697	0	0	0	0	0	0	0	0	0	1	0	0	2000
10721	161	305.7	42809	0	0	0	0	0	0	0	0	0	1	0	0	2000
10610	118	407.1	46399	0	0	0	0	0	0	0	0	0	1	0	1	2000
10525	169	410.2	48065	0	0	0	0	0	0	0	0	0	1	0	0	2000
10531	119	384.8	28794	0	0	0	0	0	0	0	0	0	0	1	0	2000
10357	161	441.5	4501	0	0	0	0	0	0	0	0	0	0	1	1	2000
10407	168	455.3	14647	0	0	0	0	0	0	0	0	0	0	1	0	2000
10452	149	435.5	1050	0	0	0	0	0	0	0	0	0	0	1	0	2000
10025	168	477.9	31815	0	0	0	0	0	0	0	0	0	0	0	0	2000
10114	139	440.3	4058	0	0	0	0	0	0	0	0	0	0	0	1	2000
10107	168	439.1	2882	0	0	0	0	0	0	0	0	0	0	0	0	2000
10292	168	347.8	1329	0	0	0	0	0	0	0	0	0	0	0	0	2000
10149	24	475.6	29574	0	0	0	0	0	0	0	0	0	0	0	0	2000
10373	104	434.1	2291	1	0	0	0	0	0	0	0	0	0	0	1	2001
10170	168	420.5	54657	1	0	0	0	0	0	0	0	0	0	0	0	2001
10279	168	337.3	58535	1	0	0	0	0	0	0	0	0	0	0	0	2001
10897	129	313.4	41749	1	0	0	0	0	0	0	0	0	0	0	1	2001
10455	157	359.4	8987	0	1	0	0	0	0	0	0	0	0	0	0	2001
10618	37	281.9	23817	0	1	0	0	0	0	0	0	0	0	0	1	2001
10246	165	433.5	64953	0	0	1	0	0	0	0	0	0	0	0	1	2001
10591	168	377.9	17738	0	0	0	1	0	0	0	0	0	0	0	0	2001
10236	143	394.7	33673	0	0	0	1	0	0	0	0	0	0	0	1	2001
10182	168	458.7	17277	0	0	0	1	0	0	0	0	0	0	0	0	2001
10526	122	401.4	42940	0	0	0	1	0	0	0	0	0	0	0	1	2001
10155	89	444.4	7400	0	0	0	0	1	0	0	0	0	0	0	1	2001
10580	168	412.6	49950	0	0	0	0	1	0	0	0	0	0	0	0	2001
10151	139	380.7	28732	0	0	0	0	1	0	0	0	0	0	0	1	2001
10058	168	418.4	53067	0	0	0	0	1	0	0	0	0	0	0	0	2001
10273	168	384.1	29664	0	0	0	0	1	0	0	0	0	0	0	0	2001
10301	168	394.5	36344	0	0	0	0	0	1	0	0	0	0	0	0	2001
10334	168	419.8	54449	0	0	0	0	0	1	0	0	0	0	0	0	2001
10301	168	410.2	47815	0	0	0	0	0	1	0	0	0	0	0	0	2001
10293	144	404.2	42880	0	0	0	0	0	1	0	0	0	0	0	0	2001

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10560	168	378.6	25324	0	0	0	0	0	0	1	0	0	0	0	0	2001
10538	168	426.8	56438	0	0	0	0	0	0	1	0	0	0	0	0	2001
10567	155	424.2	56464	0	0	0	0	0	0	1	0	0	0	0	0	2001
10403	138	427.2	57724	0	0	0	0	0	0	1	0	0	0	0	1	2001
10483	168	424.5	56882	0	0	0	0	0	0	0	1	0	0	0	0	2001
10327	168	428.0	60101	0	0	0	0	0	0	0	1	0	0	0	0	2001
10742	77	376.3	26784	0	0	0	0	0	0	0	1	0	0	0	1	2001
10726	132	335.5	60291	0	0	0	0	0	0	0	0	0	1	0	1	2001
10793	133	276.4	18411	0	0	0	0	0	0	0	0	0	1	0	0	2001
10651	152	291.3	33337	0	0	0	0	0	0	0	0	0	1	0	1	2001
10500	156	290.9	28777	0	0	0	0	0	0	0	0	0	1	0	0	2001
10606	168	292.3	29313	0	0	0	0	0	0	0	0	0	0	1	0	2001
10153	168	351.0	6496	0	0	0	0	0	0	0	0	0	0	1	0	2001
10907	167	253.2	5658	0	0	0	0	0	0	0	0	0	0	1	0	2001
10789	168	297.3	35249	0	0	0	0	0	0	0	0	0	0	1	0	2001
10737	168	245.8	63840	0	0	0	0	0	0	0	0	0	0	0	0	2001
10511	168	269.0	14477	0	0	0	0	0	0	0	0	0	0	0	0	2001
10728	168	245.1	64858	0	0	0	0	0	0	0	0	0	0	0	0	2001
10591	168	275.3	19663	0	0	0	0	0	0	0	0	0	0	0	0	2001
10234	24	381.0	18773	0	0	0	0	0	0	0	0	0	0	0	0	2001
10314	168	378.7	24041	1	0	0	0	0	0	0	0	0	0	0	0	2002
10654	168	295.2	34461	1	0	0	0	0	0	0	0	0	0	0	0	2002
10666	168	267.6	16590	1	0	0	0	0	0	0	0	0	0	0	0	2002
11168	168	207.6	43385	1	0	0	0	0	0	0	0	0	0	0	0	2002
11091	168	219.0	50598	0	1	0	0	0	0	0	0	0	0	0	0	2002
10690	168	301.9	38965	0	1	0	0	0	0	0	0	0	0	0	0	2002
10837	168	256.2	7724	0	1	0	0	0	0	0	0	0	0	0	0	2002
10703	168	272.4	16244	0	1	0	0	0	0	0	0	0	0	0	0	2002
9861	168	361.2	12556	0	0	1	0	0	0	0	0	0	0	0	0	2002
9411	130	393.9	37892	0	0	1	0	0	0	0	0	0	0	0	1	2002
9501	96	369.2	19940	0	0	1	0	0	0	0	0	0	0	0	0	2002
11124	129	274.2	20002	0	0	0	0	1	0	0	0	0	0	0	1	2002
10431	156	271.9	9174	0	0	0	0	1	0	0	0	0	0	0	0	2002
10157	93	295.6	22086	0	0	0	0	1	0	0	0	0	0	0	0	2002
10606	157	334.6	60611	0	0	0	0	1	0	0	0	0	0	0	1	2002
10494	168	350.8	6705	0	0	0	0	0	1	0	0	0	0	0	0	2002
10460	168	344.6	2074	0	0	0	0	0	1	0	0	0	0	0	0	2002
10519	124	372.9	22137	0	0	0	0	0	1	0	0	0	0	0	1	2002
10545	144	368.1	18450	0	0	0	0	0	1	0	0	0	0	0	0	2002
10577	168	367.6	18013	0	0	0	0	0	0	1	0	0	0	0	0	2002
10465	168	388.2	32189	0	0	0	0	0	0	1	0	0	0	0	0	2002
10482	164	411.8	48265	0	0	0	0	0	0	1	0	0	0	0	0	2002
10485	168	379.4	25374	0	0	0	0	0	0	1	0	0	0	0	0	2002
10389	168	396.8	37802	0	0	0	0	0	0	0	1	0	0	0	0	2002
10451	168	393.9	34795	0	0	0	0	0	0	0	1	0	0	0	0	2002
10384	168	402.2	40811	0	0	0	0	0	0	0	1	0	0	0	0	2002
10481	168	399.1	38218	0	0	0	0	0	0	0	1	0	0	0	0	2002

Data Base for CRIST 7 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10446	168	381.4	26812	0	0	0	0	0	0	0	1	0	0	0	0	2002
10416	168	397.4	37232	0	0	0	0	0	0	0	0	1	0	0	0	2002
10343	168	411.2	45910	0	0	0	0	0	0	0	0	1	0	0	0	2002
10405	123	425.2	57890	0	0	0	0	0	0	0	0	1	0	0	1	2002
10507	168	414.3	48171	0	0	0	0	0	0	0	0	1	0	0	0	2002
10094	168	449.2	7663	0	0	0	0	0	0	0	0	0	1	0	0	2002
10088	168	440.3	1090	0	0	0	0	0	0	0	0	0	1	0	0	2002
10040	168	388.4	29897	0	0	0	0	0	0	0	0	0	1	0	0	2002
9955	115	430.0	60394	0	0	0	0	0	0	0	0	0	1	0	0	2002
11162	40	313.3	44711	0	0	0	0	0	0	0	0	0	0	1	1	2002
10579	168	364.5	11672	0	0	0	0	0	0	0	0	0	0	1	0	2002
10476	168	404.8	41263	0	0	0	0	0	0	0	0	0	0	1	0	2002
10403	168	375.9	19933	0	0	0	0	0	0	0	0	0	0	1	0	2002
10094	168	454.3	12461	0	0	0	0	0	0	0	0	0	0	0	0	2002
10143	168	421.0	53094	0	0	0	0	0	0	0	0	0	0	0	0	2002
10354	168	378.2	22136	0	0	0	0	0	0	0	0	0	0	0	0	2002
10334	168	383.7	26281	0	0	0	0	0	0	0	0	0	0	0	0	2002
10373	24	360.2	8220	0	0	0	0	0	0	0	0	0	0	0	0	2002
10195	168	415.9	49969	1	0	0	0	0	0	0	0	0	0	0	0	2003
10092	168	439.9	2003	1	0	0	0	0	0	0	0	0	0	0	0	2003
10027	168	448.9	9080	1	0	0	0	0	0	0	0	0	0	0	0	2003
10125	168	393.4	34461	1	0	0	0	0	0	0	0	0	0	0	0	2003
10260	168	405.0	41190	0	1	0	0	0	0	0	0	0	0	0	0	2003
10365	168	423.0	53736	0	1	0	0	0	0	0	0	0	0	0	0	2003
9942	168	413.5	47996	0	1	0	0	0	0	0	0	0	0	0	0	2003
10315	168	433.0	62817	0	1	0	0	0	0	0	0	0	0	0	0	2003
10368	72	456.4	16069	0	0	1	0	0	0	0	0	0	0	0	0	2003
11640	64	242.4	60292	0	0	1	0	0	0	0	0	0	0	0	1	2003
10358	167	405.8	41420	0	0	0	1	0	0	0	0	0	0	0	0	2003
10019	168	422.2	54676	0	0	0	1	0	0	0	0	0	0	0	0	2003
10334	138	408.0	44851	0	0	0	1	0	0	0	0	0	0	0	1	2003
10201	168	424.4	55148	0	0	0	1	0	0	0	0	0	0	0	0	2003
10332	168	412.5	50190	0	0	0	0	1	0	0	0	0	0	0	0	2003
10332	168	403.2	43092	0	0	0	0	1	0	0	0	0	0	0	0	2003
10369	168	411.6	47518	0	0	0	0	1	0	0	0	0	0	0	0	2003
10405	168	386.1	32339	0	0	0	0	1	0	0	0	0	0	0	0	2003
10313	168	406.1	43854	0	0	0	0	1	0	0	0	0	0	0	0	2003
10492	168	408.9	45376	0	0	0	0	0	1	0	0	0	0	0	0	2003
10437	168	420.2	53343	0	0	0	0	0	1	0	0	0	0	0	0	2003
10638	168	385.7	32935	0	0	0	0	0	1	0	0	0	0	0	0	2003
10498	144	426.2	58068	0	0	0	0	0	1	0	0	0	0	0	0	2003

Data Base for CRIST 7 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10488	144	127.0	17979	0	0	0	0	0	0	1	0	0	0	0	1	2000
10084	168	157.0	24787	0	0	0	0	0	0	1	0	0	0	0	0	2000
10065	168	155.8	24454	0	0	0	0	0	0	1	0	0	0	0	0	2000
10051	168	135.1	19578	0	0	0	0	0	0	1	0	0	0	0	0	2000
10044	168	140.1	20658	0	0	0	0	0	0	0	1	0	0	0	0	2000
10198	168	149.4	22784	0	0	0	0	0	0	0	1	0	0	0	0	2000
9980	168	144.7	21837	0	0	0	0	0	0	0	1	0	0	0	0	2000
9976	168	143.7	21421	0	0	0	0	0	0	0	1	0	0	0	0	2000
10015	168	147.9	22474	0	0	0	0	0	0	0	1	0	0	0	0	2000
10040	168	137.7	20122	0	0	0	0	0	0	0	0	1	0	0	0	2000
10169	168	143.0	21326	0	0	0	0	0	0	0	0	1	0	0	0	2000
10058	168	131.3	18662	0	0	0	0	0	0	0	0	1	0	0	0	2000
9979	168	135.1	19504	0	0	0	0	0	0	0	0	1	0	0	0	2000
10211	168	123.3	16508	0	0	0	0	0	0	0	0	0	1	0	0	2000
10171	168	139.6	20554	0	0	0	0	0	0	0	0	0	1	0	0	2000
10280	168	146.6	22480	0	0	0	0	0	0	0	0	0	1	0	0	2000
10202	168	138.2	20503	0	0	0	0	0	0	0	0	0	1	0	0	2000
10149	167	131.9	19136	0	0	0	0	0	0	0	0	0	1	0	0	2000
9894	153	148.9	22856	0	0	0	0	0	0	0	0	0	0	1	1	2000
9841	168	153.1	24033	0	0	0	0	0	0	0	0	0	0	1	0	2000
10130	168	148.6	22606	0	0	0	0	0	0	0	0	0	0	1	0	2000
9878	168	160.0	25639	0	0	0	0	0	0	0	0	0	0	0	0	2000
9920	168	136.1	19624	0	0	0	0	0	0	0	0	0	0	0	0	2000
10133	168	141.8	21218	0	0	0	0	0	0	0	0	0	0	0	0	2000
9977	168	153.3	23895	0	0	0	0	0	0	0	0	0	0	0	0	2000
10077	24	162.6	26435	0	0	0	0	0	0	0	0	0	0	0	0	2000
9887	168	157.5	24988	1	0	0	0	0	0	0	0	0	0	0	0	2001
9893	168	146.0	22120	1	0	0	0	0	0	0	0	0	0	0	0	2001
10024	168	112.2	13972	1	0	0	0	0	0	0	0	0	0	0	0	2001
10218	168	109.0	12976	1	0	0	0	0	0	0	0	0	0	0	0	2001
10032	168	103.0	11523	0	1	0	0	0	0	0	0	0	0	0	0	2001
10118	168	131.7	18687	0	1	0	0	0	0	0	0	0	0	0	0	2001
9795	168	152.5	23758	0	1	0	0	0	0	0	0	0	0	0	0	2001
9850	168	158.8	25318	0	1	0	0	0	0	0	0	0	0	0	0	2001
9866	168	156.7	24710	0	0	1	0	0	0	0	0	0	0	0	0	2001
9730	168	160.3	25748	0	0	1	0	0	0	0	0	0	0	0	0	2001
10064	168	154.7	24212	0	0	1	0	0	0	0	0	0	0	0	0	2001
10494	168	157.2	25050	0	0	1	0	0	0	0	0	0	0	0	0	2001
10087	167	162.7	26459	0	0	1	0	0	0	0	0	0	0	0	0	2001
10116	168	157.7	25093	0	0	0	1	0	0	0	0	0	0	0	0	2001
10018	168	158.2	25306	0	0	0	1	0	0	0	0	0	0	0	0	2001
9958	118	159.8	25786	0	0	0	1	0	0	0	0	0	0	0	0	2001
10339	75	141.4	21164	0	0	0	0	1	0	0	0	0	0	0	1	2001
10050	168	134.4	19566	0	0	0	0	1	0	0	0	0	0	0	0	2001
10083	168	143.1	21620	0	0	0	0	1	0	0	0	0	0	0	0	2001
10325	168	135.0	19676	0	0	0	0	1	0	0	0	0	0	0	0	2001
10253	168	147.0	22151	0	0	0	0	0	1	0	0	0	0	0	0	2001

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10325	168	150.7	23060	0	0	0	0	0	1	0	0	0	0	0	0	2001
10086	168	146.7	22062	0	0	0	0	0	1	0	0	0	0	0	0	2001
10035	144	144.9	21675	0	0	0	0	0	1	0	0	0	0	0	0	2001
10113	168	142.3	20828	0	0	0	0	0	0	1	0	0	0	0	0	2001
10378	168	151.8	23364	0	0	0	0	0	0	1	0	0	0	0	0	2001
10167	168	148.8	22610	0	0	0	0	0	0	1	0	0	0	0	0	2001
10134	168	161.6	26174	0	0	0	0	0	0	1	0	0	0	0	0	2001
10155	168	159.9	25585	0	0	0	0	0	0	0	1	0	0	0	0	2001
10302	168	157.3	24789	0	0	0	0	0	0	0	1	0	0	0	0	2001
10230	168	152.8	23707	0	0	0	0	0	0	0	1	0	0	0	0	2001
10274	168	148.5	22460	0	0	0	0	0	0	0	1	0	0	0	0	2001
10131	168	149.5	22934	0	0	0	0	0	0	0	1	0	0	0	0	2001
10140	168	144.6	21330	0	0	0	0	0	0	0	0	1	0	0	0	2001
9948	168	143.5	20980	0	0	0	0	0	0	0	0	1	0	0	0	2001
10076	168	138.9	20135	0	0	0	0	0	0	0	0	1	0	0	0	2001
10331	168	145.3	21456	0	0	0	0	0	0	0	0	1	0	0	0	2001
10244	160	143.6	21158	0	0	0	0	0	0	0	0	0	1	0	0	2001
10358	91	151.1	23357	0	0	0	0	0	0	0	0	0	1	0	1	2001
10206	168	140.6	20494	0	0	0	0	0	0	0	0	0	1	0	0	2001
10282	142	129.9	17952	0	0	0	0	0	0	0	0	0	1	0	1	2001
10116	168	124.8	16968	0	0	0	0	0	0	0	0	0	0	1	0	2001
10211	168	120.5	15363	0	0	0	0	0	0	0	0	0	0	1	0	2001
10233	168	118.6	15274	0	0	0	0	0	0	0	0	0	0	1	0	2001
10232	168	113.0	13153	0	0	0	0	0	0	0	0	0	0	1	0	2001
10310	168	104.8	11379	0	0	0	0	0	0	0	0	0	0	0	0	2001
10200	168	107.5	12147	0	0	0	0	0	0	0	0	0	0	0	0	2001
10168	168	113.7	13477	0	0	0	0	0	0	0	0	0	0	0	0	2001
10299	168	107.6	12069	0	0	0	0	0	0	0	0	0	0	0	0	2001
10191	24	102.1	10851	0	0	0	0	0	0	0	0	0	0	0	0	2001
10030	168	136.0	19496	1	0	0	0	0	0	0	0	0	0	0	0	2002
9888	168	126.0	16469	1	0	0	0	0	0	0	0	0	0	0	0	2002
9919	168	118.3	14431	1	0	0	0	0	0	0	0	0	0	0	0	2002
10393	111	111.1	12561	1	0	0	0	0	0	0	0	0	0	0	1	2002
10252	168	116.5	13672	0	1	0	0	0	0	0	0	0	0	0	0	2002
10101	168	126.6	16327	0	1	0	0	0	0	0	0	0	0	0	0	2002
10079	168	123.9	15654	0	1	0	0	0	0	0	0	0	0	0	0	2002
10141	166	129.4	17179	0	1	0	0	0	0	0	0	0	0	0	0	2002
10210	168	141.5	20440	0	0	1	0	0	0	0	0	0	0	0	0	2002
10391	168	147.6	22150	0	0	1	0	0	0	0	0	0	0	0	0	2002
10114	168	140.7	20238	0	0	1	0	0	0	0	0	0	0	0	0	2002
10114	168	137.1	19239	0	0	1	0	0	0	0	0	0	0	0	0	2002
9920	4	99.5	10395	0	0	1	0	0	0	0	0	0	0	0	0	2002
10726	95	108.3	13091	0	0	0	1	0	0	0	0	0	0	0	1	2002
10488	168	93.2	9151	0	0	0	0	1	0	0	0	0	0	0	0	2002
10248	168	126.9	17102	0	0	0	0	1	0	0	0	0	0	0	0	2002
10435	168	117.4	15392	0	0	0	0	1	0	0	0	0	0	0	0	2002
10224	168	121.7	16435	0	0	0	0	1	0	0	0	0	0	0	0	2002

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10197	168	117.7	15534	0	0	0	0	1	0	0	0	0	0	0	0	2002
10169	168	133.5	18662	0	0	0	0	0	1	0	0	0	0	0	0	2002
10286	168	132.8	18519	0	0	0	0	0	1	0	0	0	0	0	0	2002
10234	168	136.9	19484	0	0	0	0	0	1	0	0	0	0	0	0	2002
10320	144	139.1	20030	0	0	0	0	0	1	0	0	0	0	0	0	2002
10485	168	136.5	19362	0	0	0	0	0	0	1	0	0	0	0	0	2002
10378	168	140.6	20422	0	0	0	0	0	0	1	0	0	0	0	0	2002
10183	168	145.7	21765	0	0	0	0	0	0	1	0	0	0	0	0	2002
10215	168	138.2	19782	0	0	0	0	0	0	1	0	0	0	0	0	2002
10321	168	138.0	19683	0	0	0	0	0	0	0	1	0	0	0	0	2002
10272	168	137.1	19720	0	0	0	0	0	0	0	1	0	0	0	0	2002
10225	168	143.5	21171	0	0	0	0	0	0	0	1	0	0	0	0	2002
10146	168	143.8	21239	0	0	0	0	0	0	0	1	0	0	0	0	2002
10073	168	136.4	19178	0	0	0	0	0	0	0	1	0	0	0	0	2002
10251	168	145.6	21886	0	0	0	0	0	0	0	0	1	0	0	0	2002
10249	168	146.6	22022	0	0	0	0	0	0	0	0	1	0	0	0	2002
10068	168	150.4	22943	0	0	0	0	0	0	0	0	1	0	0	0	2002
10210	168	141.2	20822	0	0	0	0	0	0	0	0	1	0	0	0	2002
10151	168	154.3	24070	0	0	0	0	0	0	0	0	0	1	0	0	2002
10277	168	154.3	23998	0	0	0	0	0	0	0	0	0	1	0	0	2002
10281	151	136.6	19816	0	0	0	0	0	0	0	0	0	1	0	0	2002
10281	116	146.6	22107	0	0	0	0	0	0	0	0	0	1	0	0	2002
11783	14	79.2	7743	0	0	0	0	0	0	0	0	0	1	0	1	2002
10473	168	127.7	17780	0	0	0	0	0	0	0	0	0	0	1	0	2002
10496	168	124.1	15935	0	0	0	0	0	0	0	0	0	0	1	0	2002
10452	168	138.5	19777	0	0	0	0	0	0	0	0	0	0	1	0	2002
10205	168	136.7	19277	0	0	0	0	0	0	0	0	0	0	1	0	2002
10181	168	148.6	22429	0	0	0	0	0	0	0	0	0	0	0	0	2002
10236	168	141.1	20565	0	0	0	0	0	0	0	0	0	0	0	0	2002
10124	168	134.6	19144	0	0	0	0	0	0	0	0	0	0	0	0	2002
10717	168	119.9	15616	0	0	0	0	0	0	0	0	0	0	0	0	2002
10640	24	113.8	13946	0	0	0	0	0	0	0	0	0	0	0	0	2002
10717	168	124.4	17108	1	0	0	0	0	0	0	0	0	0	0	0	2003
10193	168	133.6	18777	1	0	0	0	0	0	0	0	0	0	0	0	2003
10121	168	143.1	21448	1	0	0	0	0	0	0	0	0	0	0	0	2003
10044	168	135.6	19412	1	0	0	0	0	0	0	0	0	0	0	0	2003
10101	168	121.3	15992	0	1	0	0	0	0	0	0	0	0	0	0	2003
10271	168	122.2	16108	0	1	0	0	0	0	0	0	0	0	0	0	2003
10044	168	122.1	16169	0	1	0	0	0	0	0	0	0	0	0	0	2003
10178	128	129.3	18120	0	1	0	0	0	0	0	0	0	0	0	1	2003
10361	168	152.1	23496	0	0	1	0	0	0	0	0	0	0	0	0	2003
10440	168	141.5	20982	0	0	1	0	0	0	0	0	0	0	0	0	2003
10573	168	138.4	20415	0	0	1	0	0	0	0	0	0	0	0	0	2003
10843	168	134.7	19386	0	0	1	0	0	0	0	0	0	0	0	0	2003
10414	168	141.9	21395	0	0	1	0	0	0	0	0	0	0	0	0	2003
10511	167	145.7	21928	0	0	0	1	0	0	0	0	0	0	0	0	2003
10807	168	136.5	20039	0	0	0	1	0	0	0	0	0	0	0	0	2003

Data Base for SMITH 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10360	71	133.9	19622	0	0	0	1	0	0	0	0	0	0	0	0	2003
10860	85	115.8	15111	0	0	0	0	1	0	0	0	0	0	0	1	2003
10512	168	122.1	16885	0	0	0	0	1	0	0	0	0	0	0	0	2003
10391	168	124.5	17250	0	0	0	0	1	0	0	0	0	0	0	0	2003
10475	168	129.3	18281	0	0	0	0	0	1	0	0	0	0	0	0	2003
10422	168	131.0	18761	0	0	0	0	0	1	0	0	0	0	0	0	2003
10588	168	119.8	16640	0	0	0	0	0	1	0	0	0	0	0	0	2003
10406	144	137.0	20224	0	0	0	0	0	1	0	0	0	0	0	0	2003

Data Base for SMITH 1 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10344	168	154.4	26091	0	0	0	0	0	0	1	0	0	0	0	0	2000
10268	168	182.7	33641	0	0	0	0	0	0	1	0	0	0	0	0	2000
10207	168	179.6	32561	0	0	0	0	0	0	1	0	0	0	0	0	2000
10291	168	152.7	25443	0	0	0	0	0	0	1	0	0	0	0	0	2000
10286	168	160.1	27329	0	0	0	0	0	0	0	1	0	0	0	0	2000
10337	168	172.1	30359	0	0	0	0	0	0	0	1	0	0	0	0	2000
10265	168	164.9	28619	0	0	0	0	0	0	0	1	0	0	0	0	2000
10236	168	164.2	28229	0	0	0	0	0	0	0	1	0	0	0	0	2000
10240	168	170.7	30046	0	0	0	0	0	0	0	1	0	0	0	0	2000
10327	168	155.9	26274	0	0	0	0	0	0	0	0	1	0	0	0	2000
10273	159	161.4	27879	0	0	0	0	0	0	0	0	1	0	0	0	2000
10299	168	148.8	24487	0	0	0	0	0	0	0	0	1	0	0	0	2000
10193	168	148.6	24297	0	0	0	0	0	0	0	0	1	0	0	0	2000
10352	168	138.2	21356	0	0	0	0	0	0	0	0	0	1	0	0	2000
10345	46	144.3	23091	0	0	0	0	0	0	0	0	0	1	0	0	2000
10408	161	153.2	26067	0	0	0	0	0	0	0	0	0	1	0	1	2000
10435	169	147.7	24530	0	0	0	0	0	0	0	0	0	1	0	0	2000
10233	168	157.6	27061	0	0	0	0	0	0	0	0	0	0	1	0	2000
10129	168	174.5	31493	0	0	0	0	0	0	0	0	0	0	1	0	2000
10148	168	177.3	32400	0	0	0	0	0	0	0	0	0	0	1	0	2000
10353	151	165.4	28720	0	0	0	0	0	0	0	0	0	0	1	0	2000
10033	166	181.2	33381	0	0	0	0	0	0	0	0	0	0	0	0	2000
10311	143	138.0	21194	0	0	0	0	0	0	0	0	0	0	0	1	2000
10214	168	156.2	26632	0	0	0	0	0	0	0	0	0	0	0	0	2000
10144	168	176.9	32034	0	0	0	0	0	0	0	0	0	0	0	0	2000
10226	24	189.9	36054	0	0	0	0	0	0	0	0	0	0	0	0	2000
10095	168	183.3	33830	1	0	0	0	0	0	0	0	0	0	0	0	2001
10093	168	172.2	30541	1	0	0	0	0	0	0	0	0	0	0	0	2001
10249	168	124.6	17746	1	0	0	0	0	0	0	0	0	0	0	0	2001
10290	168	120.6	16199	1	0	0	0	0	0	0	0	0	0	0	0	2001
10133	168	113.9	14471	0	1	0	0	0	0	0	0	0	0	0	0	2001
9904	168	148.4	24306	0	1	0	0	0	0	0	0	0	0	0	0	2001
9958	144	170.5	30450	0	1	0	0	0	0	0	0	0	0	0	1	2001
9906	168	185.1	34423	0	1	0	0	0	0	0	0	0	0	0	0	2001
9923	146	178.6	32686	0	0	1	0	0	0	0	0	0	0	0	0	2001
9758	168	186.4	34791	0	0	1	0	0	0	0	0	0	0	0	0	2001
9836	118	176.7	31832	0	0	1	0	0	0	0	0	0	0	0	0	2001
10365	42	168.0	29964	0	0	0	1	0	0	0	0	0	0	0	1	2001
9783	168	187.6	35293	0	0	0	1	0	0	0	0	0	0	0	0	2001
9839	168	182.9	34103	0	0	0	1	0	0	0	0	0	0	0	0	2001
10017	168	179.9	33126	0	0	0	1	0	0	0	0	0	0	0	0	2001
10095	168	181.9	33502	0	0	0	0	1	0	0	0	0	0	0	0	2001
9891	168	163.6	28730	0	0	0	0	1	0	0	0	0	0	0	0	2001
9786	147	151.0	25413	0	0	0	0	1	0	0	0	0	0	0	0	2001
10140	142	157.6	27252	0	0	0	0	1	0	0	0	0	0	0	1	2001
10264	168	164.7	28740	0	0	0	0	1	0	0	0	0	0	0	0	2001
9929	168	166.2	28499	0	0	0	0	0	1	0	0	0	0	0	0	2001

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10127	168	172.0	30223	0	0	0	0	0	1	0	0	0	0	0	0	2001
10058	168	165.7	28860	0	0	0	0	0	1	0	0	0	0	0	0	2001
10062	117	162.5	27836	0	0	0	0	0	1	0	0	0	0	0	0	2001
10057	168	158.8	26498	0	0	0	0	0	0	1	0	0	0	0	0	2001
10375	168	175.4	31205	0	0	0	0	0	0	1	0	0	0	0	0	2001
10201	168	170.9	29831	0	0	0	0	0	0	1	0	0	0	0	0	2001
10199	168	169.2	29474	0	0	0	0	0	0	1	0	0	0	0	0	2001
10055	168	169.0	29507	0	0	0	0	0	0	0	1	0	0	0	0	2001
10272	168	174.0	30479	0	0	0	0	0	0	0	1	0	0	0	0	2001
10248	168	143.5	23373	0	0	0	0	0	0	0	1	0	0	0	0	2001
10156	168	162.4	27843	0	0	0	0	0	0	0	1	0	0	0	0	2001
10065	168	163.5	28315	0	0	0	0	0	0	0	1	0	0	0	0	2001
10263	168	142.8	22878	0	0	0	0	0	0	0	0	1	0	0	0	2001
10184	168	139.0	22098	0	0	0	0	0	0	0	0	1	0	0	0	2001
10200	151	136.0	20976	0	0	0	0	0	0	0	0	1	0	0	0	2001
*10441	1	12.0	144	0	0	0	0	0	0	0	0	1	0	0	0	2001
10265	49	165.2	29203	0	0	0	0	0	0	0	0	0	1	0	1	2001
10159	168	169.3	29887	0	0	0	0	0	0	0	0	0	1	0	0	2001
10211	168	172.2	30372	0	0	0	0	0	0	0	0	0	1	0	0	2001
10025	168	162.3	27754	0	0	0	0	0	0	0	0	0	1	0	0	2001
9887	169	155.2	25575	0	0	0	0	0	0	0	0	0	1	0	0	2001
10372	140	141.1	22372	0	0	0	0	0	0	0	0	0	0	1	1	2001
9982	168	152.9	25525	0	0	0	0	0	0	0	0	0	0	1	0	2001
10175	132	118.5	15701	0	0	0	0	0	0	0	0	0	0	1	1	2001
10046	168	122.7	15757	0	0	0	0	0	0	0	0	0	0	1	0	2001
9978	168	116.7	14023	0	0	0	0	0	0	0	0	0	0	0	0	2001
10123	168	118.8	15161	0	0	0	0	0	0	0	0	0	0	0	0	2001
10069	59	108.5	13076	0	0	0	0	0	0	0	0	0	0	0	0	2001
10113	94	121.4	16438	0	0	0	0	0	0	0	0	0	0	0	1	2001
11133	24	105.3	11732	0	0	0	0	0	0	0	0	0	0	0	0	2001
9866	168	144.7	21926	1	0	0	0	0	0	0	0	0	0	0	0	2002
9876	168	132.5	18353	1	0	0	0	0	0	0	0	0	0	0	0	2002
9882	168	119.9	14880	1	0	0	0	0	0	0	0	0	0	0	0	2002
9717	86	112.3	12732	1	0	0	0	0	0	0	0	0	0	0	0	2002
10523	70	106.1	12027	0	1	0	0	0	0	0	0	0	0	0	1	2002
9992	168	124.4	15887	0	1	0	0	0	0	0	0	0	0	0	0	2002
9935	168	120.7	14861	0	1	0	0	0	0	0	0	0	0	0	0	2002
9955	168	127.5	16840	0	1	0	0	0	0	0	0	0	0	0	0	2002
9898	98	149.9	23504	0	0	1	0	0	0	0	0	0	0	0	0	2002
13940	27	45.9	2190	0	0	0	1	0	0	0	0	0	0	0	1	2002
10815	41	110.7	14466	0	0	0	0	1	0	0	0	0	0	0	1	2002
10007	161	141.2	22301	0	0	0	0	1	0	0	0	0	0	0	0	2002
10238	144	125.8	18286	0	0	0	0	1	0	0	0	0	0	0	1	2002
10120	168	131.8	20130	0	0	0	0	1	0	0	0	0	0	0	0	2002
10169	168	128.7	19309	0	0	0	0	1	0	0	0	0	0	0	0	2002
10636	64	113.7	14445	0	0	0	0	0	1	0	0	0	0	0	2	2002
10886	34	120.8	17626	0	0	0	0	0	1	0	0	0	0	0	1	2002

Data Base for SMITH 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10483	13	124.5	16352	0	0	0	0	0	1	0	0	0	0	0	0	2002
10766	77	137.6	19856	0	0	0	0	0	0	1	0	0	0	0	2	2002
10756	110	133.1	18124	0	0	0	0	0	0	1	0	0	0	0	1	2002
10784	128	132.0	17722	0	0	0	0	0	0	1	0	0	0	0	1	2002
10755	168	121.8	14851	0	0	0	0	0	0	1	0	0	0	0	0	2002
10744	168	119.6	14327	0	0	0	0	0	0	0	1	0	0	0	0	2002
10815	168	122.6	15027	0	0	0	0	0	0	0	1	0	0	0	0	2002
10768	168	122.0	14924	0	0	0	0	0	0	0	1	0	0	0	0	2002
10648	168	123.8	15331	0	0	0	0	0	0	0	1	0	0	0	0	2002
10478	164	125.5	16006	0	0	0	0	0	0	0	1	0	0	0	0	2002
10794	23	111.0	13129	0	0	0	0	0	0	0	0	1	0	0	1	2002
10638	138	122.9	15365	0	0	0	0	0	0	0	0	1	0	0	1	2002
10623	168	124.3	15473	0	0	0	0	0	0	0	0	1	0	0	0	2002
10439	168	124.7	15544	0	0	0	0	0	0	0	0	0	1	0	0	2002
10491	168	123.5	15269	0	0	0	0	0	0	0	0	0	1	0	0	2002
10612	132	121.7	15025	0	0	0	0	0	0	0	0	0	1	0	1	2002
10714	136	122.1	15067	0	0	0	0	0	0	0	0	0	1	0	1	2002
10695	168	119.1	14184	0	0	0	0	0	0	0	0	0	1	0	0	2002
10662	168	120.3	14475	0	0	0	0	0	0	0	0	0	0	1	0	2002
10625	168	120.1	14436	0	0	0	0	0	0	0	0	0	0	1	0	2002
10588	168	120.7	14610	0	0	0	0	0	0	0	0	0	0	1	0	2002
10569	168	121.5	14787	0	0	0	0	0	0	0	0	0	0	1	0	2002
10494	168	123.5	15254	0	0	0	0	0	0	0	0	0	0	0	0	2002
10485	168	122.9	15114	0	0	0	0	0	0	0	0	0	0	0	0	2002
10600	168	119.8	14506	0	0	0	0	0	0	0	0	0	0	0	0	2002
10704	168	121.6	14796	0	0	0	0	0	0	0	0	0	0	0	0	2002
10665	24	122.2	14936	0	0	0	0	0	0	0	0	0	0	0	0	2002
*14731	2	31.5	1175	1	0	0	0	0	0	0	0	0	0	0	0	2003
11076	68	91.6	9413	0	0	0	1	0	0	0	0	0	0	0	1	2003
10172	168	128.5	19067	0	0	0	1	0	0	0	0	0	0	0	0	2003
10124	168	152.7	25535	0	0	0	1	0	0	0	0	0	0	0	0	2003
10240	114	150.4	24717	0	0	0	0	1	0	0	0	0	0	0	1	2003
10244	168	144.9	23479	0	0	0	0	1	0	0	0	0	0	0	0	2003
10271	168	142.7	22894	0	0	0	0	1	0	0	0	0	0	0	0	2003
10330	168	132.6	20471	0	0	0	0	1	0	0	0	0	0	0	0	2003
10158	168	139.6	22195	0	0	0	0	1	0	0	0	0	0	0	0	2003
10206	161	143.9	22955	0	0	0	0	0	1	0	0	0	0	0	0	2003
10255	168	147.1	24013	0	0	0	0	0	1	0	0	0	0	0	0	2003
10319	168	133.8	21329	0	0	0	0	0	1	0	0	0	0	0	0	2003
10123	144	152.9	25583	0	0	0	0	0	1	0	0	0	0	0	0	2003

Data Base for SMITH 2 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for DANIEL 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
11089	168	497.2	52373	0	0	0	0	0	0	1	0	0	0	0	0	2000
10889	71	471.7	35127	0	0	0	0	0	0	1	0	0	0	0	1	2000
10655	168	472.4	36019	0	0	0	0	0	0	1	0	0	0	0	0	2000
10597	168	406.6	59116	0	0	0	0	0	0	1	0	0	0	0	0	2000
10358	150	465.8	28794	0	0	0	0	0	0	0	1	0	0	0	0	2000
10137	168	501.3	54885	0	0	0	0	0	0	0	1	0	0	0	0	2000
10372	167	466.2	31150	0	0	0	0	0	0	0	1	0	0	0	0	2000
10294	167	462.6	27431	0	0	0	0	0	0	0	1	0	0	0	0	2000
10272	121	469.3	32424	0	0	0	0	0	0	0	1	0	0	0	1	2000
10142	168	475.6	38231	0	0	0	0	0	0	0	0	1	0	0	0	2000
10004	168	491.6	46405	0	0	0	0	0	0	0	0	1	0	0	0	2000
10037	136	487.5	47356	0	0	0	0	0	0	0	0	1	0	0	1	2000
10010	168	482.6	42707	0	0	0	0	0	0	0	0	1	0	0	0	2000
10067	168	460.1	27650	0	0	0	0	0	0	0	0	0	1	0	0	2000
10103	168	482.1	43593	0	0	0	0	0	0	0	0	0	1	0	0	2000
9919	168	463.2	28003	0	0	0	0	0	0	0	0	0	1	0	0	2000
9937	168	470.2	32498	0	0	0	0	0	0	0	0	0	1	0	0	2000
9854	169	473.6	37604	0	0	0	0	0	0	0	0	0	1	0	0	2000
9960	168	488.3	46339	0	0	0	0	0	0	0	0	0	0	1	0	2000
9912	168	498.9	53929	0	0	0	0	0	0	0	0	0	0	1	0	2000
9910	168	480.6	37063	0	0	0	0	0	0	0	0	0	0	1	0	2000
11327	168	442.6	1816	0	0	0	0	0	0	0	0	0	0	1	0	2000
9417	168	479.6	35078	0	0	0	0	0	0	0	0	0	0	0	0	2000
10658	168	422.7	48045	0	0	0	0	0	0	0	0	0	0	0	0	2000
10222	168	407.2	42023	0	0	0	0	0	0	0	0	0	0	0	0	2000
10975	168	417.9	45312	0	0	0	0	0	0	0	0	0	0	0	0	2000
11374	24	425.3	49837	0	0	0	0	0	0	0	0	0	0	0	0	2000
9962	168	479.4	36727	1	0	0	0	0	0	0	0	0	0	0	0	2001
10416	168	429.6	55290	1	0	0	0	0	0	0	0	0	0	0	0	2001
10180	96	417.8	57434	1	0	0	0	0	0	0	0	0	0	0	0	2001
10620	69	428.7	468	0	0	1	0	0	0	0	0	0	0	0	1	2001
10176	138	474.0	33707	0	0	1	0	0	0	0	0	0	0	0	1	2001
10086	168	435.8	2427	0	0	1	0	0	0	0	0	0	0	0	0	2001
10054	168	463.7	25592	0	0	1	0	0	0	0	0	0	0	0	0	2001
10428	167	309.3	49744	0	0	1	0	0	0	0	0	0	0	0	0	2001
9879	168	407.7	54000	0	0	0	1	0	0	0	0	0	0	0	0	2001
10008	168	387.8	42553	0	0	0	1	0	0	0	0	0	0	0	0	2001
9942	168	413.9	57117	0	0	0	1	0	0	0	0	0	0	0	0	2001
10147	168	336.1	3674	0	0	0	1	0	0	0	0	0	0	0	0	2001
9920	168	337.1	3178	0	0	0	0	1	0	0	0	0	0	0	0	2001
10175	168	330.3	1056	0	0	0	0	1	0	0	0	0	0	0	0	2001
10477	168	278.4	34345	0	0	0	0	1	0	0	0	0	0	0	0	2001
10706	168	279.8	27721	0	0	0	0	1	0	0	0	0	0	0	0	2001
10512	168	315.7	53213	0	0	0	0	1	0	0	0	0	0	0	0	2001
10147	168	372.8	28388	0	0	0	0	0	1	0	0	0	0	0	0	2001
9911	168	423.7	62662	0	0	0	0	0	1	0	0	0	0	0	0	2001
9960	168	388.0	40274	0	0	0	0	0	1	0	0	0	0	0	0	2001

Data Base for DANIEL 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
9992	144	360.9	18129	0	0	0	0	0	1	0	0	0	0	0	0	2001
10573	168	282.1	32423	0	0	0	0	0	0	1	0	0	0	0	0	2001
10626	168	248.5	15445	0	0	0	0	0	0	1	0	0	0	0	0	2001
10515	168	260.0	23897	0	0	0	0	0	0	1	0	0	0	0	0	2001
10525	168	265.6	27735	0	0	0	0	0	0	1	0	0	0	0	0	2001
10395	168	268.3	24484	0	0	0	0	0	0	0	1	0	0	0	0	2001
10628	168	324.9	59850	0	0	0	0	0	0	0	1	0	0	0	0	2001
10607	168	364.3	21198	0	0	0	0	0	0	0	1	0	0	0	0	2001
10611	168	348.7	12451	0	0	0	0	0	0	0	1	0	0	0	0	2001
11005	168	294.1	43426	0	0	0	0	0	0	0	1	0	0	0	0	2001
11152	168	276.4	28832	0	0	0	0	0	0	0	0	1	0	0	0	2001
10684	168	328.3	62058	0	0	0	0	0	0	0	0	1	0	0	0	2001
10507	168	369.6	25571	0	0	0	0	0	0	0	0	1	0	0	0	2001
10121	168	447.3	10891	0	0	0	0	0	0	0	0	1	0	0	0	2001
9772	168	443.4	10765	0	0	0	0	0	0	0	0	0	1	0	0	2001
9716	168	476.3	33613	0	0	0	0	0	0	0	0	0	1	0	0	2001
9923	168	466.6	26371	0	0	0	0	0	0	0	0	0	1	0	0	2001
9818	148	475.8	35092	0	0	0	0	0	0	0	0	0	1	0	0	2001
9817	169	441.2	11572	0	0	0	0	0	0	0	0	0	1	0	0	2001
10666	168	390.6	41263	0	0	0	0	0	0	0	0	0	0	1	0	2001
9872	168	451.1	14652	0	0	0	0	0	0	0	0	0	0	1	0	2001
10153	168	356.4	17956	0	0	0	0	0	0	0	0	0	0	1	0	2001
10064	168	373.6	30909	0	0	0	0	0	0	0	0	0	0	1	0	2001
10215	168	361.1	22603	0	0	0	0	0	0	0	0	0	0	0	0	2001
10209	168	366.0	23905	0	0	0	0	0	0	0	0	0	0	0	0	2001
10400	168	311.3	50949	0	0	0	0	0	0	0	0	0	0	0	0	2001
10706	168	278.3	30626	0	0	0	0	0	0	0	0	0	0	0	0	2001
11037	24	261.7	21546	0	0	0	0	0	0	0	0	0	0	0	0	2001
10182	168	375.1	25018	1	0	0	0	0	0	0	0	0	0	0	0	2002
10229	168	371.7	21187	1	0	0	0	0	0	0	0	0	0	0	0	2002
10798	168	237.7	42	1	0	0	0	0	0	0	0	0	0	0	0	2002
11491	47	184.6	40196	1	0	0	0	0	0	0	0	0	0	0	0	2002
11237	43	292.6	43148	0	1	0	0	0	0	0	0	0	0	0	1	2002
9778	168	327.4	60779	0	1	0	0	0	0	0	0	0	0	0	0	2002
10534	168	231.0	62792	0	1	0	0	0	0	0	0	0	0	0	0	2002
10418	168	348.4	5842	0	1	0	0	0	0	0	0	0	0	0	0	2002
10116	168	393.6	38371	0	0	1	0	0	0	0	0	0	0	0	0	2002
9924	168	448.9	13753	0	0	1	0	0	0	0	0	0	0	0	0	2002
9945	168	423.1	64139	0	0	1	0	0	0	0	0	0	0	0	0	2002
10029	168	431.0	2591	0	0	1	0	0	0	0	0	0	0	0	0	2002
9992	149	419.6	60760	0	0	1	0	0	0	0	0	0	0	0	0	2002
10934	56	276.9	28064	0	0	0	1	0	0	0	0	0	0	0	1	2002
10080	168	375.3	30653	0	0	0	1	0	0	0	0	0	0	0	0	2002
10161	115	357.1	18925	0	0	0	1	0	0	0	0	0	0	0	0	2002
10281	79	379.2	34717	0	0	0	1	0	0	0	0	0	0	0	1	2002
10094	168	403.0	50497	0	0	0	0	1	0	0	0	0	0	0	0	2002
10242	168	386.5	36504	0	0	0	0	1	0	0	0	0	0	0	0	2002

Data Base for DANIEL 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10310	168	351.8	13111	0	0	0	0	1	0	0	0	0	0	0	0	2002
10122	145	366.4	29820	0	0	0	0	1	0	0	0	0	0	0	0	2002
10256	143	349.3	14987	0	0	0	0	1	0	0	0	0	0	0	1	2002
10213	168	377.6	32391	0	0	0	0	0	1	0	0	0	0	0	0	2002
10322	168	365.3	24171	0	0	0	0	0	1	0	0	0	0	0	0	2002
10131	168	380.8	36120	0	0	0	0	0	1	0	0	0	0	0	0	2002
10380	144	352.2	14138	0	0	0	0	0	1	0	0	0	0	0	0	2002
10243	168	350.0	12325	0	0	0	0	0	0	1	0	0	0	0	0	2002
10091	168	384.0	36777	0	0	0	0	0	0	1	0	0	0	0	0	2002
9973	168	403.4	47136	0	0	0	0	0	0	1	0	0	0	0	0	2002
10164	137	350.2	15054	0	0	0	0	0	0	1	0	0	0	0	1	2002
10070	168	362.8	22966	0	0	0	0	0	0	0	1	0	0	0	0	2002
9826	168	390.4	35868	0	0	0	0	0	0	0	1	0	0	0	0	2002
10195	168	412.5	52312	0	0	0	0	0	0	0	1	0	0	0	0	2002
10228	168	404.6	45644	0	0	0	0	0	0	0	1	0	0	0	0	2002
10233	168	384.8	35812	0	0	0	0	0	0	0	1	0	0	0	0	2002
10020	168	412.0	53376	0	0	0	0	0	0	0	0	1	0	0	0	2002
9983	168	450.6	13979	0	0	0	0	0	0	0	0	1	0	0	0	2002
9913	168	482.5	37714	0	0	0	0	0	0	0	0	1	0	0	0	2002
10381	168	416.3	51307	0	0	0	0	0	0	0	0	1	0	0	0	2002
10101	168	468.5	26490	0	0	0	0	0	0	0	0	0	1	0	0	2002
9934	166	458.5	22951	0	0	0	0	0	0	0	0	0	1	0	0	2002
10047	150	402.2	46877	0	0	0	0	0	0	0	0	0	1	0	0	2002
9821	169	480.0	36406	0	0	0	0	0	0	0	0	0	1	0	0	2002
10210	168	410.2	47483	0	0	0	0	0	0	0	0	0	1	0	0	2002
9860	168	421.7	59169	0	0	0	0	0	0	0	0	0	0	1	0	2002
9907	168	402.7	45328	0	0	0	0	0	0	0	0	0	0	1	0	2002
9760	168	447.4	11327	0	0	0	0	0	0	0	0	0	0	1	0	2002
9934	168	389.1	33713	0	0	0	0	0	0	0	0	0	0	1	0	2002
9901	168	477.1	33951	0	0	0	0	0	0	0	0	0	0	0	0	2002
9868	168	438.1	4372	0	0	0	0	0	0	0	0	0	0	0	0	2002
10081	168	393.0	37818	0	0	0	0	0	0	0	0	0	0	0	0	2002
10004	168	400.5	44691	0	0	0	0	0	0	0	0	0	0	0	0	2002
10352	24	393.1	35916	0	0	0	0	0	0	0	0	0	0	0	0	2002
* 8608	99	401.3	48311	1	0	0	0	0	0	0	0	0	0	0	0	2003
10713	112	414.8	61040	0	0	1	0	0	0	0	0	0	0	0	2	2003
9765	167	473.6	33730	0	0	0	1	0	0	0	0	0	0	0	0	2003
9908	168	465.4	29493	0	0	0	1	0	0	0	0	0	0	0	0	2003
9690	168	454.6	21396	0	0	0	1	0	0	0	0	0	0	0	0	2003
9698	168	443.3	12659	0	0	0	1	0	0	0	0	0	0	0	0	2003
9661	124	437.6	10927	0	0	0	0	1	0	0	0	0	0	0	1	2003
9528	168	428.6	2918	0	0	0	0	1	0	0	0	0	0	0	0	2003
9556	168	410.6	57330	0	0	0	0	1	0	0	0	0	0	0	0	2003
9742	168	395.2	48242	0	0	0	0	1	0	0	0	0	0	0	0	2003
9690	168	400.9	45094	0	0	0	0	1	0	0	0	0	0	0	0	2003
9998	168	425.8	558	0	0	0	0	0	1	0	0	0	0	0	0	2003
9938	167	443.1	13389	0	0	0	0	0	1	0	0	0	0	0	0	2003

Data Base for DANIEL 1 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
9768	168	408.7	56475	0	0	0	0	0	1	0	0	0	0	0	0	2003
9969	101	454.8	22500	0	0	0	0	0	1	0	0	0	0	0	1	2003

Data Base for DANIEL 1 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
•	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10774	168	368.4	28982	0	0	0	0	0	0	1	0	0	0	0	0	2000
10337	168	470.4	29745	0	0	0	0	0	0	1	0	0	0	0	0	2000
10591	101	372.3	29627	0	0	0	0	0	0	1	0	0	0	0	1	2000
10333	168	333.1	4008	0	0	0	0	0	0	1	0	0	0	0	0	2000
10367	168	383.9	35525	0	0	0	0	0	0	0	1	0	0	0	0	2000
10268	168	412.3	52753	0	0	0	0	0	0	0	1	0	0	0	0	2000
10319	168	405.8	52147	0	0	0	0	0	0	0	1	0	0	0	0	2000
10351	168	424.3	63503	0	0	0	0	0	0	0	1	0	0	0	0	2000
10246	168	451.8	16172	0	0	0	0	0	0	0	1	0	0	0	0	2000
10004	168	396.9	45858	0	0	0	0	0	0	0	0	1	0	0	0	2000
10098	168	382.8	34021	0	0	0	0	0	0	0	0	1	0	0	0	2000
9897	146	373.3	30430	0	0	0	0	0	0	0	0	1	0	0	0	2000
*11997	31	354.7	18614	0	0	0	0	0	0	0	0	0	1	0	1	2000
9792	169	405.4	55285	0	0	0	0	0	0	0	0	0	1	0	0	2000
9653	168	394.9	46968	0	0	0	0	0	0	0	0	0	0	1	0	2000
9634	168	423.4	64160	0	0	0	0	0	0	0	0	0	0	1	0	2000
9681	168	472.9	34118	0	0	0	0	0	0	0	0	0	0	1	0	2000
9679	168	444.9	14439	0	0	0	0	0	0	0	0	0	0	1	0	2000
9858	168	507.0	60458	0	0	0	0	0	0	0	0	0	0	0	0	2000
9326	168	498.9	54553	0	0	0	0	0	0	0	0	0	0	0	0	2000
9835	168	488.4	45274	0	0	0	0	0	0	0	0	0	0	0	0	2000
9945	168	446.4	21276	0	0	0	0	0	0	0	0	0	0	0	0	2000
9230	24	511.0	64514	0	0	0	0	0	0	0	0	0	0	0	0	2000
9667	168	504.2	58746	1	0	0	0	0	0	0	0	0	0	0	0	2001
9584	168	484.4	43398	1	0	0	0	0	0	0	0	0	0	0	0	2001
10154	168	412.0	54289	1	0	0	0	0	0	0	0	0	0	0	0	2001
9922	168	457.3	18662	1	0	0	0	0	0	0	0	0	0	0	0	2001
10171	168	430.4	64453	0	1	0	0	0	0	0	0	0	0	0	0	2001
10218	168	290.4	35743	0	1	0	0	0	0	0	0	0	0	0	0	2001
9958	168	370.0	28222	0	1	0	0	0	0	0	0	0	0	0	0	2001
9771	168	501.5	55221	0	1	0	0	0	0	0	0	0	0	0	0	2001
9860	168	494.5	49242	0	0	1	0	0	0	0	0	0	0	0	0	2001
9951	168	503.4	57060	0	0	1	0	0	0	0	0	0	0	0	0	2001
9862	168	478.0	34809	0	0	1	0	0	0	0	0	0	0	0	0	2001
9782	168	474.5	34884	0	0	1	0	0	0	0	0	0	0	0	0	2001
10118	167	358.1	14508	0	0	1	0	0	0	0	0	0	0	0	0	2001
9880	168	485.4	44053	0	0	0	1	0	0	0	0	0	0	0	0	2001
9909	165	487.9	46353	0	0	0	1	0	0	0	0	0	0	0	0	2001
9752	83	477.5	39176	0	0	0	1	0	0	0	0	0	0	0	1	2001
9675	119	499.6	56318	0	0	0	1	0	0	0	0	0	0	0	0	2001
10735	100	337.2	4161	0	0	0	0	1	0	0	0	0	0	0	1	2001
10620	138	359.8	26279	0	0	0	0	1	0	0	0	0	0	0	1	2001
10466	168	361.4	27590	0	0	0	0	1	0	0	0	0	0	0	0	2001
10620	168	308.8	58946	0	0	0	0	1	0	0	0	0	0	0	0	2001
10310	168	366.4	30914	0	0	0	0	0	1	0	0	0	0	0	0	2001
10154	168	419.2	539	0	0	0	0	0	1	0	0	0	0	0	0	2001
10123	168	410.3	59692	0	0	0	0	0	1	0	0	0	0	0	0	2001

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10120	144	377.2	38663	0	0	0	0	0	1	0	0	0	0	0	0	2001
11079	164	253.2	25541	0	0	0	0	0	0	1	0	0	0	0	0	2001
10434	168	309.1	60181	0	0	0	0	0	0	1	0	0	0	0	0	2001
10552	168	308.2	57091	0	0	0	0	0	0	1	0	0	0	0	0	2001
10439	168	339.1	8418	0	0	0	0	0	0	1	0	0	0	0	0	2001
10225	168	329.8	1405	0	0	0	0	0	0	0	1	0	0	0	0	2001
10455	168	382.2	33459	0	0	0	0	0	0	0	1	0	0	0	0	2001
10358	168	384.8	36588	0	0	0	0	0	0	0	1	0	0	0	0	2001
10397	168	357.6	20193	0	0	0	0	0	0	0	1	0	0	0	0	2001
10702	168	304.0	50137	0	0	0	0	0	0	0	1	0	0	0	0	2001
10737	168	290.8	36039	0	0	0	0	0	0	0	0	1	0	0	0	2001
10314	168	346.9	9632	0	0	0	0	0	0	0	0	1	0	0	0	2001
10184	168	388.8	42316	0	0	0	0	0	0	0	0	1	0	0	0	2001
9974	168	445.2	12532	0	0	0	0	0	0	0	0	1	0	0	0	2001
10015	144	409.1	52841	0	0	0	0	0	0	0	0	0	1	0	1	2001
9727	168	485.0	42862	0	0	0	0	0	0	0	0	0	1	0	0	2001
9897	168	486.3	44147	0	0	0	0	0	0	0	0	0	1	0	0	2001
9853	168	479.1	39032	0	0	0	0	0	0	0	0	0	1	0	0	2001
9941	169	459.0	27122	0	0	0	0	0	0	0	0	0	1	0	0	2001
10062	168	428.4	6319	0	0	0	0	0	0	0	0	0	0	1	0	2001
9869	168	508.7	62133	0	0	0	0	0	0	0	0	0	0	1	0	2001
9944	97	501.2	57404	0	0	0	0	0	0	0	0	0	0	1	0	2001
10137	103	476.6	36852	0	0	0	0	0	0	0	0	0	0	1	1	2001
9991	168	492.6	46440	0	0	0	0	0	0	0	0	0	0	0	0	2001
10071	168	460.6	25255	0	0	0	0	0	0	0	0	0	0	0	0	2001
9815	146	493.0	48508	0	0	0	0	0	0	0	0	0	0	0	0	2001
10167	87	471.0	37357	0	0	0	0	0	0	0	0	0	0	0	1	2001
9956	24	509.6	63111	0	0	0	0	0	0	0	0	0	0	0	0	2001
9342	168	507.9	61328	1	0	0	0	0	0	0	0	0	0	0	0	2002
9578	123	465.4	30083	1	0	0	0	0	0	0	0	0	0	0	1	2002
9451	95	475.9	36492	1	0	0	0	0	0	0	0	0	0	0	0	2002
*14436	46	188.2	51440	0	0	0	1	0	0	0	0	0	0	0	1	2002
10514	151	392.5	37160	0	0	0	1	0	0	0	0	0	0	0	0	2002
10389	168	428.1	1577	0	0	0	1	0	0	0	0	0	0	0	0	2002
10568	100	356.8	21145	0	0	0	0	1	0	0	0	0	0	0	1	2002
10235	169	416.3	58174	0	0	0	0	1	0	0	0	0	0	0	0	2002
10110	168	351.7	12783	0	0	0	0	1	0	0	0	0	0	0	0	2002
10202	168	378.9	34204	0	0	0	0	1	0	0	0	0	0	0	0	2002
10270	167	378.6	32518	0	0	0	0	1	0	0	0	0	0	0	0	2002
10266	168	388.2	40055	0	0	0	0	0	1	0	0	0	0	0	0	2002
10152	168	376.0	32370	0	0	0	0	0	1	0	0	0	0	0	0	2002
10193	164	383.6	40772	0	0	0	0	0	1	0	0	0	0	0	0	2002
10271	144	369.9	29397	0	0	0	0	0	1	0	0	0	0	0	0	2002
10332	168	356.4	19478	0	0	0	0	0	0	1	0	0	0	0	0	2002
10182	119	379.7	31147	0	0	0	0	0	0	1	0	0	0	0	0	2002
10222	129	391.9	43558	0	0	0	0	0	0	1	0	0	0	0	1	2002
9962	168	384.7	38646	0	0	0	0	0	0	1	0	0	0	0	0	2002

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
10265	168	373.5	30987	0	0	0	0	0	0	0	1	0	0	0	0	2002
10247	168	389.9	38057	0	0	0	0	0	0	0	1	0	0	0	0	2002
10123	168	413.2	53650	0	0	0	0	0	0	0	1	0	0	0	0	2002
10069	168	412.7	53111	0	0	0	0	0	0	0	1	0	0	0	0	2002
9552	168	382.3	35781	0	0	0	0	0	0	0	1	0	0	0	0	2002
10070	168	403.6	46885	0	0	0	0	0	0	0	0	1	0	0	0	2002
10289	168	457.4	20667	0	0	0	0	0	0	0	0	1	0	0	0	2002
10126	168	481.2	38302	0	0	0	0	0	0	0	0	1	0	0	0	2002
10640	168	412.7	51073	0	0	0	0	0	0	0	0	1	0	0	0	2002
10434	145	464.3	25892	0	0	0	0	0	0	0	0	0	1	0	0	2002
* 7393	36	347.5	6440	0	0	0	0	0	0	0	0	0	1	0	1	2002
9891	162	409.6	51410	0	0	0	0	0	0	0	0	0	1	0	0	2002
9966	169	449.8	13788	0	0	0	0	0	0	0	0	0	1	0	0	2002
10192	168	435.8	2777	0	0	0	0	0	0	0	0	0	1	0	0	2002
9955	162	414.0	57070	0	0	0	0	0	0	0	0	0	0	1	0	2002
9864	168	387.6	32513	0	0	0	0	0	0	0	0	0	0	1	0	2002
9470	168	439.6	5494	0	0	0	0	0	0	0	0	0	0	1	0	2002
9576	168	383.3	30334	0	0	0	0	0	0	0	0	0	0	1	0	2002
9717	168	463.5	22902	0	0	0	0	0	0	0	0	0	0	0	0	2002
9681	168	438.3	5936	0	0	0	0	0	0	0	0	0	0	0	0	2002
9751	168	389.5	37657	0	0	0	0	0	0	0	0	0	0	0	0	2002
9877	168	403.5	50500	0	0	0	0	0	0	0	0	0	0	0	0	2002
10059	24	406.9	48358	0	0	0	0	0	0	0	0	0	0	0	0	2002
9693	168	457.8	25725	1	0	0	0	0	0	0	0	0	0	0	0	2003
9613	168	492.5	50773	1	0	0	0	0	0	0	0	0	0	0	0	2003
9645	168	484.8	45324	1	0	0	0	0	0	0	0	0	0	0	0	2003
9787	168	419.8	62019	1	0	0	0	0	0	0	0	0	0	0	0	2003
9721	168	462.7	26646	0	1	0	0	0	0	0	0	0	0	0	0	2003
9983	157	431.4	4883	0	1	0	0	0	0	0	0	0	0	0	0	2003
9406	66	392.1	35805	0	1	0	0	0	0	0	0	0	0	0	0	2003
9668	119	421.1	2121	0	0	1	0	0	0	0	0	0	0	0	1	2003
9482	168	495.2	51263	0	0	1	0	0	0	0	0	0	0	0	0	2003
9525	168	495.8	50290	0	0	1	0	0	0	0	0	0	0	0	0	2003
9538	168	494.8	49468	0	0	1	0	0	0	0	0	0	0	0	0	2003
9569	168	507.1	60660	0	0	1	0	0	0	0	0	0	0	0	0	2003
10002	154	467.3	31665	0	0	0	1	0	0	0	0	0	0	0	0	2003
9894	168	458.1	26446	0	0	0	1	0	0	0	0	0	0	0	0	2003
9771	168	452.0	20389	0	0	0	1	0	0	0	0	0	0	0	0	2003
9791	168	445.7	14676	0	0	0	1	0	0	0	0	0	0	0	0	2003
9624	161	446.0	16821	0	0	0	0	1	0	0	0	0	0	0	0	2003
9696	168	442.0	11635	0	0	0	0	1	0	0	0	0	0	0	0	2003
9843	168	377.3	32875	0	0	0	0	1	0	0	0	0	0	0	0	2003
9917	168	370.9	25527	0	0	0	0	1	0	0	0	0	0	0	0	2003
9632	168	431.2	5317	0	0	0	0	1	0	0	0	0	0	0	0	2003
10048	168	423.6	60355	0	0	0	0	0	1	0	0	0	0	0	0	2003
10031	150	445.1	16412	0	0	0	0	0	1	0	0	0	0	0	0	2003
9873	168	419.1	63287	0	0	0	0	0	1	0	0	0	0	0	0	2003

Data Base for DANIEL 2 Target Heat Rate Equation

HR	HOUR	AMW	LSRF	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	NS	YEAR
9853	144	471.1	30204	0	0	0	0	0	1	0	0	0	0	0	0	2003

Data Base for DANIEL 2 Target Heat Rate Equation

HR	Average net operating heat rate based on unadjusted measured fuel consumption, before adjustment for unit start ups after shutdown for 24 hours or more, in BTU/KWH.
HOUR	Number of hours the unit was synchronized during the week.
AMW	Average load on the unit, in MW.
LSRF	Load square range factor, in MW^2.
JAN to NOV	The number 1 indicates the month of the observation. All 0's indicate December.
NS	Number of unit start ups during the week after being shut down for 24 hours or more.
YEAR	The year of the observation.
*	Indicates data points removed from the analysis of the target heat rate equation because they were out of the 90% confidence interval.

Calculation of
Target Average Net Operating Heat Rates
for January 2004 - December 2004

Unit	Month	(1) Forecast AKW • 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKW * 10^3 Generation	(5) Weighted ANOHR Target
CRIST 4	Jan '04	74.1	5,549	10,385	54,649	
	Feb '04	74.3	5,575	10,382	51,271	
	Mar '04	74.2	5,562	10,518	51,230	
	Apr '04	72.6	5,358	10,407	51,662	
	May '04	66.4	4,583	10,538	48,901	
	Jun '04	74.3	5,575	10,382	52,969	
	Jul '04	76.5	5,858	10,357	56,396	
	Aug '04	76.6	5,871	10,356	56,463	
	Sep '04	75.8	5,767	10,364	54,069	
	Oct '04	70.9	5,143	10,436	52,358	
	Nov '04	72.0	5,282	10,096	47,950	
	Dec '04	71.6	5,231	10,423	52,735	10,388
CRIST 5	Jan '04	74.6	5,611	10,238	54,373	
	Feb '04	74.7	5,623	10,234	50,959	
	Mar '04	75.0	5,661	10,224	51,176	
	Apr '04	72.8	5,383	10,303	51,234	
	May '04	66.6	4,610	10,538	48,584	
	Jun '04	75.0	5,661	10,224	52,874	
	Jul '04	77.6	5,993	10,133	56,548	
	Aug '04	78.0	6,044	10,120	56,836	
	Sep '04	76.1	5,801	10,185	53,675	
	Oct '04	70.8	5,132	10,190	51,709	
	Nov '04	72.2	5,308	10,025	47,539	
	Dec '04	70.4	5,082	10,391	51,304	10,232
CRIST 6	Jan '04	293.5	87,463	10,484	171,087	
	Feb '04	290.5	86,001	10,483	47,639	
	Mar '04	298.7	90,016	10,638	215,984	
	Apr '04	293.3	87,365	10,484	184,482	
	May '04	258.9	71,060	10,370	187,206	
	Jun '04	295.2	88,295	10,486	206,667	
	Jul '04	301.0	91,152	10,491	217,650	
	Aug '04	300.0	90,657	10,593	216,912	
	Sep '04	300.6	90,954	10,490	210,400	
	Oct '04	287.4	84,498	10,481	187,963	
	Nov '04	287.8	84,691	10,482	181,324	
	Dec '04	289.8	85,660	10,482	195,938	10,501

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on page 2 of Schedule 1.

Column (5) = $(\Sigma ((3)*(4)))/(\Sigma (4))$

Calculation of
Target Average Net Operating Heat Rates
for January 2004 - December 2004

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKW * 10^3 Generation	(5) Weighted ANOHR Target
CRIST 7	Jan '04	474.7	225,342	10,124	329,913	
	Feb '04	471.7	223,087	10,129	222,192	
	Mar '04	0.0	0	-	0	
	Apr '04	0.0	0	-	0	
	May '04	443.1	201,800	10,177	148,455	
	Jun '04	474.3	225,041	10,254	318,738	
	Jul '04	475.8	226,170	10,364	330,704	
	Aug '04	475.7	226,095	10,287	330,614	
	Sep '04	475.9	226,245	10,312	319,829	
	Oct '04	471.7	223,087	10,129	296,708	
	Nov '04	474.0	224,815	10,260	318,496	
	Dec '04	473.2	224,214	10,126	297,166	10,223
SMITH 1	Jan '04	158.2	25,196	9,970	116,282	
	Feb '04	157.5	25,009	9,943	74,810	
	Mar '04	158.7	25,329	10,112	37,760	
	Apr '04	153.7	24,003	10,252	101,889	
	May '04	135.9	19,434	10,230	99,887	
	Jun '04	157.4	24,982	10,118	112,063	
	Jul '04	161.4	26,053	10,100	118,597	
	Aug '04	160.6	25,838	10,104	118,074	
	Sep '04	161.0	25,945	10,102	114,626	
	Oct '04	151.9	23,530	10,144	111,776	
	Nov '04	153.2	23,871	10,137	109,054	
	Dec '04	153.8	24,029	10,134	113,014	10,114
SMITH 2	Jan '04	182.7	34,269	9,841	127,317	
	Feb '04	182.0	34,034	9,819	106,474	
	Mar '04	185.2	35,114	9,813	95,770	
	Apr '04	174.6	31,586	10,088	19,558	
	May '04	153.9	25,101	10,091	107,240	
	Jun '04	183.0	34,370	10,052	123,314	
	Jul '04	187.4	35,863	10,180	130,634	
	Aug '04	187.0	35,727	10,138	130,354	
	Sep '04	187.6	35,932	10,033	126,410	
	Oct '04	175.4	31,847	10,085	110,488	
	Nov '04	178.6	32,901	10,071	120,404	
	Dec '04	178.5	32,868	10,071	112,292	10,024

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on page 2 of Schedule 1.

Column (5) = $(\Sigma ((4) * (5))) / (\Sigma (5))$

Calculation of
Target Average Net Operating Heat Rates
for January 2004 - December 2004

Unit	Month	(1) Forecast AKW * 10^3	(2) Forecast LSRF * 10^6	(3) Forecast Monthly ANOHR	(4) Forecast AKW * 10^3 Generation	(5) Weighted ANOHR Target
DANIEL 1	Jan '04	469.6	227,041	9,984	171,418	
	Feb '04	485.5	238,947	9,943	310,238	
	Mar '04	492.1	243,937	9,925	348,385	
	Apr '04	467.9	225,777	9,989	287,752	
	May '04	402.8	178,796	10,008	285,175	
	Jun '04	485.5	238,947	9,943	332,564	
	Jul '04	502.5	251,857	10,175	355,747	
	Aug '04	500.4	250,252	10,054	354,248	
	Sep '04	500.6	250,405	9,902	342,927	
	Oct '04	460.4	220,226	10,008	63,530	
	Nov '04	0.0	0	-	0	
	Dec '04	453.5	215,150	10,026	72,559	9,994
DANIEL 2	Jan '04	474.0	231,586	9,653	96,218	
	Feb '04	488.9	242,899	9,687	77,248	
	Mar '04	502.1	253,094	9,660	316,342	
	Apr '04	484.6	239,613	9,876	326,646	
	May '04	415.5	189,166	10,072	290,004	
	Jun '04	496.8	248,981	9,847	335,342	
	Jul '04	511.4	260,375	9,815	356,924	
	Aug '04	508.9	258,410	9,820	355,181	
	Sep '04	510.4	259,588	9,817	344,512	
	Oct '04	477.4	234,149	9,894	333,685	
	Nov '04	480.7	236,647	9,702	302,855	
	Dec '04	486.8	241,292	9,871	339,757	9,828

NOTE: Column (3) monthly ANOHR's are determined using the values from columns (1) and (2) in the target ANOHR equation on page 2 of Schedule 1.

Column (5) = $(\Sigma ((4) * (5))) / (\Sigma (5))$

Summary of Target, Maximum, and Minimum
Average Net Operating Heat Rates
for January 2004 - December 2004

Unit	Target Heat Rate BTU/KWH (0 Points)	Minimum Attainable Heat Rate (+ 10 Points)	Maximum Attainable Heat Rate (- 10 Points)
CRIST 4	10,388	10,076	10,700
CRIST 5	10,232	9,925	10,539
CRIST 6	10,501	10,186	10,816
CRIST 7	10,223	9,916	10,530
SMITH 1	10,114	9,811	10,417
SMITH 2	10,024	9,723	10,325
DANIEL 1	9,994	9,694	10,294
DANIEL 2	9,828	9,533	10,123

II. DETERMINATION OF EQUIVALENT AVAILABILITY TARGETS

Calculation of
Target Equivalent Availabilities
for January 2004 - December 2004

Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR *	Planned Outage Hours for Jan '04 - Dec '04	Reserve Shutdown Hours for Jan '04 - Dec '04	Target Equivalent Availability **
Crist 4	0.0212	0	0	97.9
Crist 5	0.0323	0	0	96.8
Crist 6	0.0747	552	0	86.7
Crist 7	0.1066	1,896	0	70.1
Smith 1	0.0189	720	0	90.1
Smith 2	0.0980	720	0	82.8
Daniel 1	0.0743	2,184	0	69.6
Daniel 2	0.0783	1,056	0	81.1

* For Period July 1998 Through June 2003.

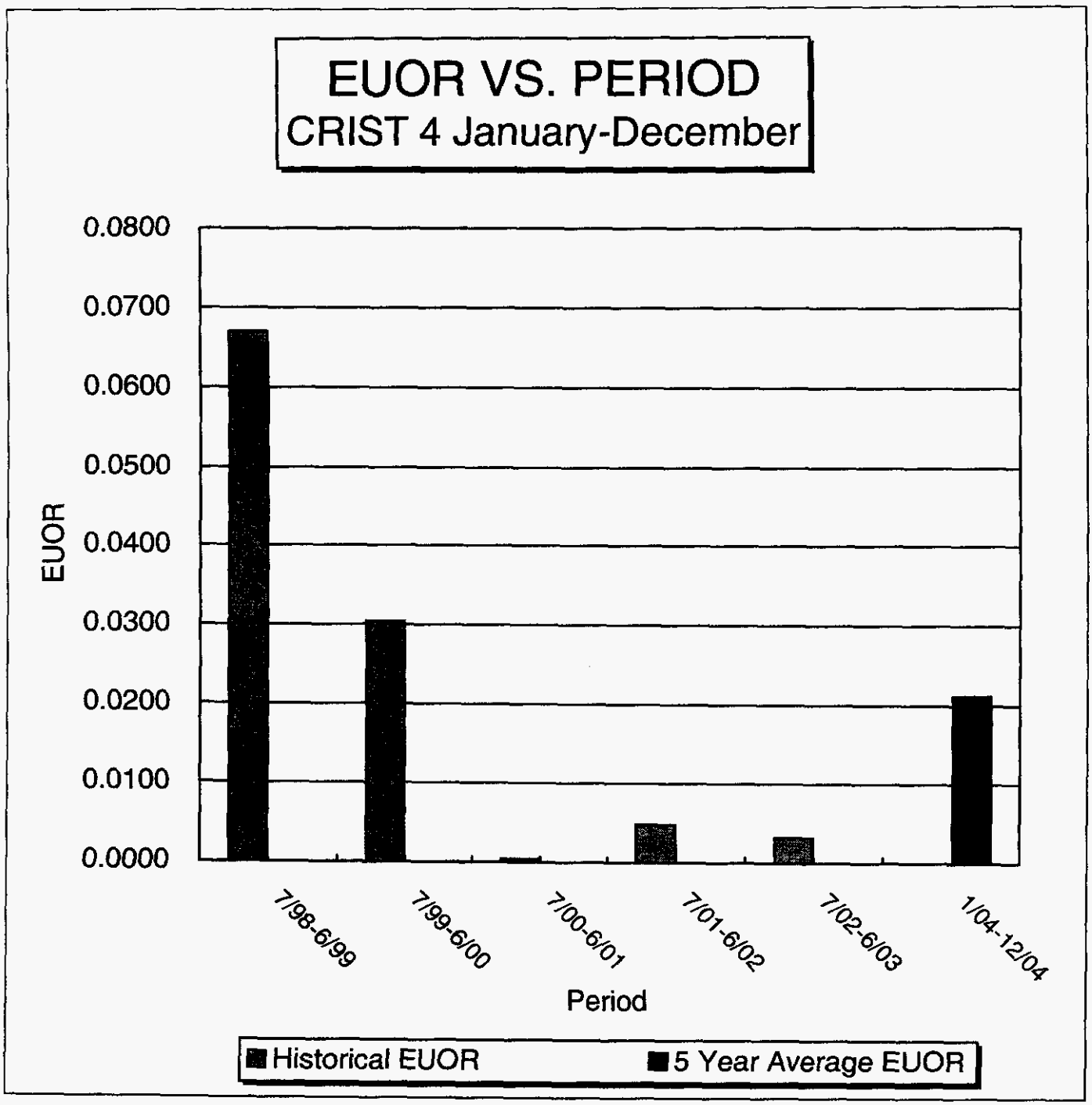
** EA = [1 - (POH + EUOR * (PH - POH - RSH)) / PH] * 100

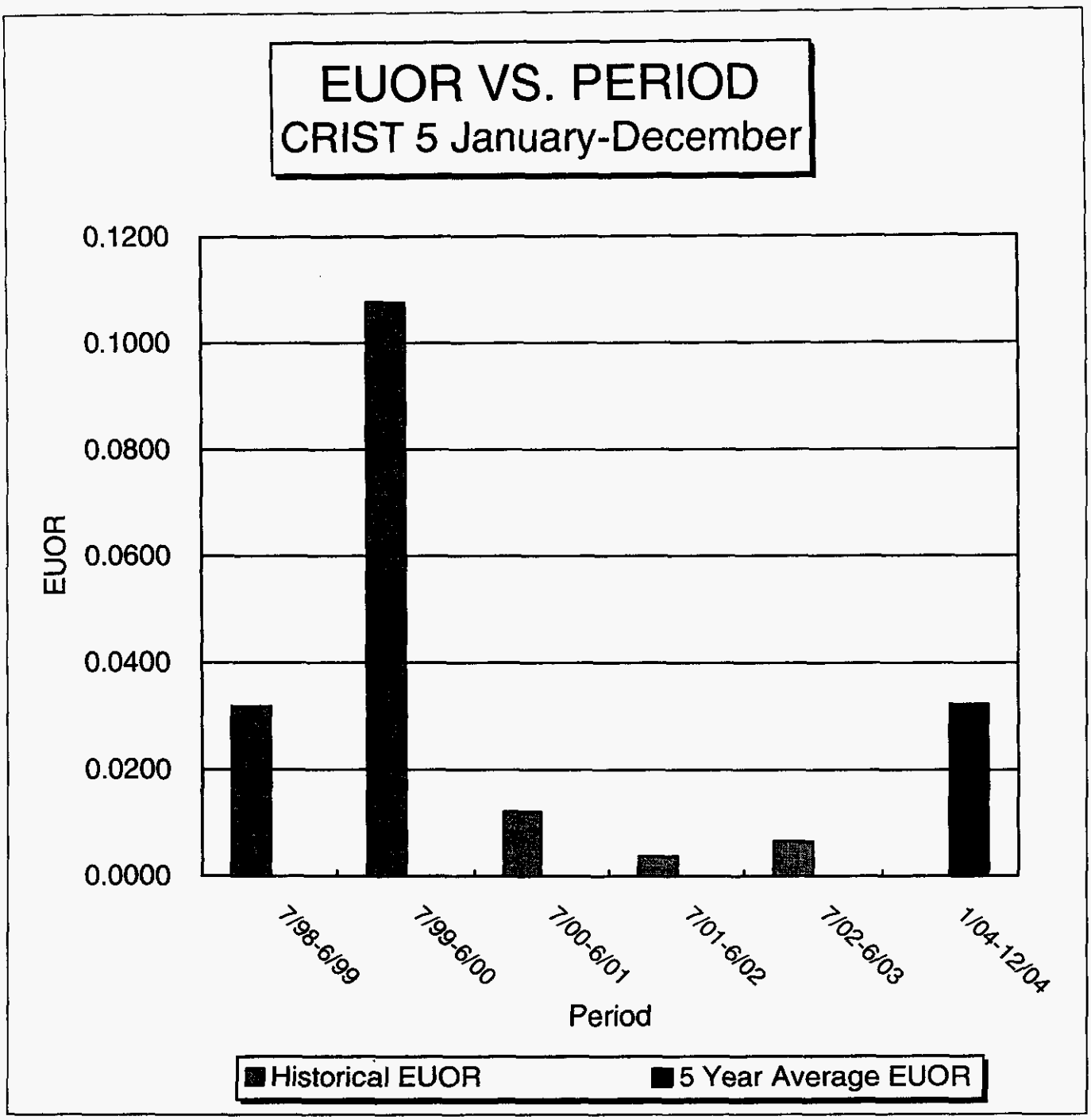
Calculation of Maximum and Minimum
Attainable Equivalent Availabilities
for January 2004 - December 2004

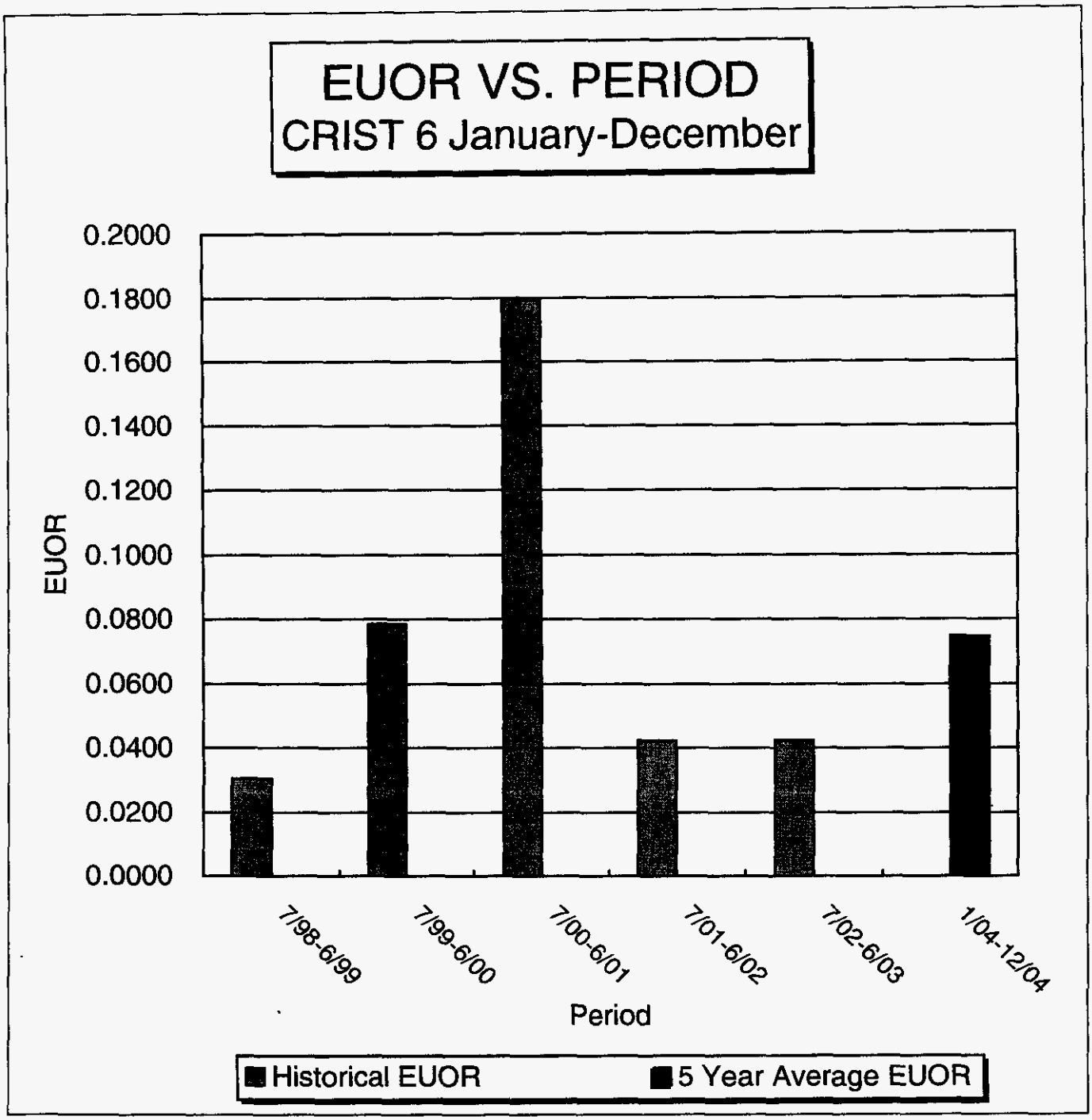
Unit	5 Year Historical Average of Equivalent Unplanned Outage Rate, EUOR (TARGET EUOR)	Minimum Attainable EUOR 70% of Target EUOR	Maximum Attainable Equivalent Availability	Maximum Attainable EUOR 145% of Target EUOR	Minimum Attainable Equivalent Availability
Crist 4	0.0212	0.0148	98.5	0.0307	96.9
Crist 5	0.0323	0.0226	97.7	0.0468	95.3
Crist 6	0.0747	0.0523	88.8	0.1083	83.6
Crist 7	0.1066	0.0746	72.6	0.1546	66.3
Smith 1	0.0189	0.0132	90.6	0.0274	89.3
Smith 2	0.0980	0.0686	85.5	0.1421	78.8
Daniel 1	0.0743	0.0520	71.2	0.1077	67.0
Daniel 2	0.0783	0.0548	83.2	0.1135	78.0

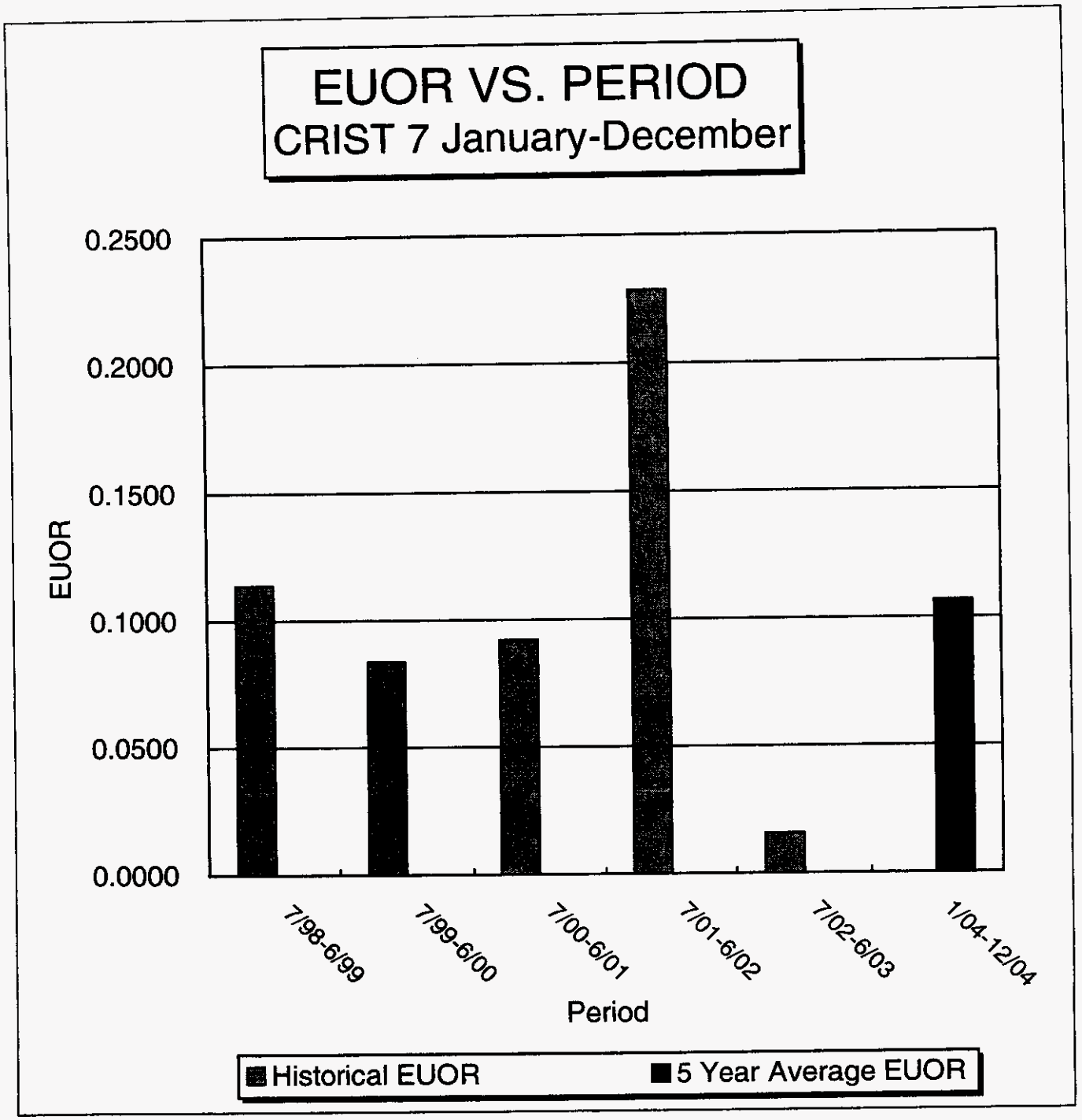
Summary of Target, Maximum, and Minimum
Equivalent Availabilities
for January 2004 - December 2004

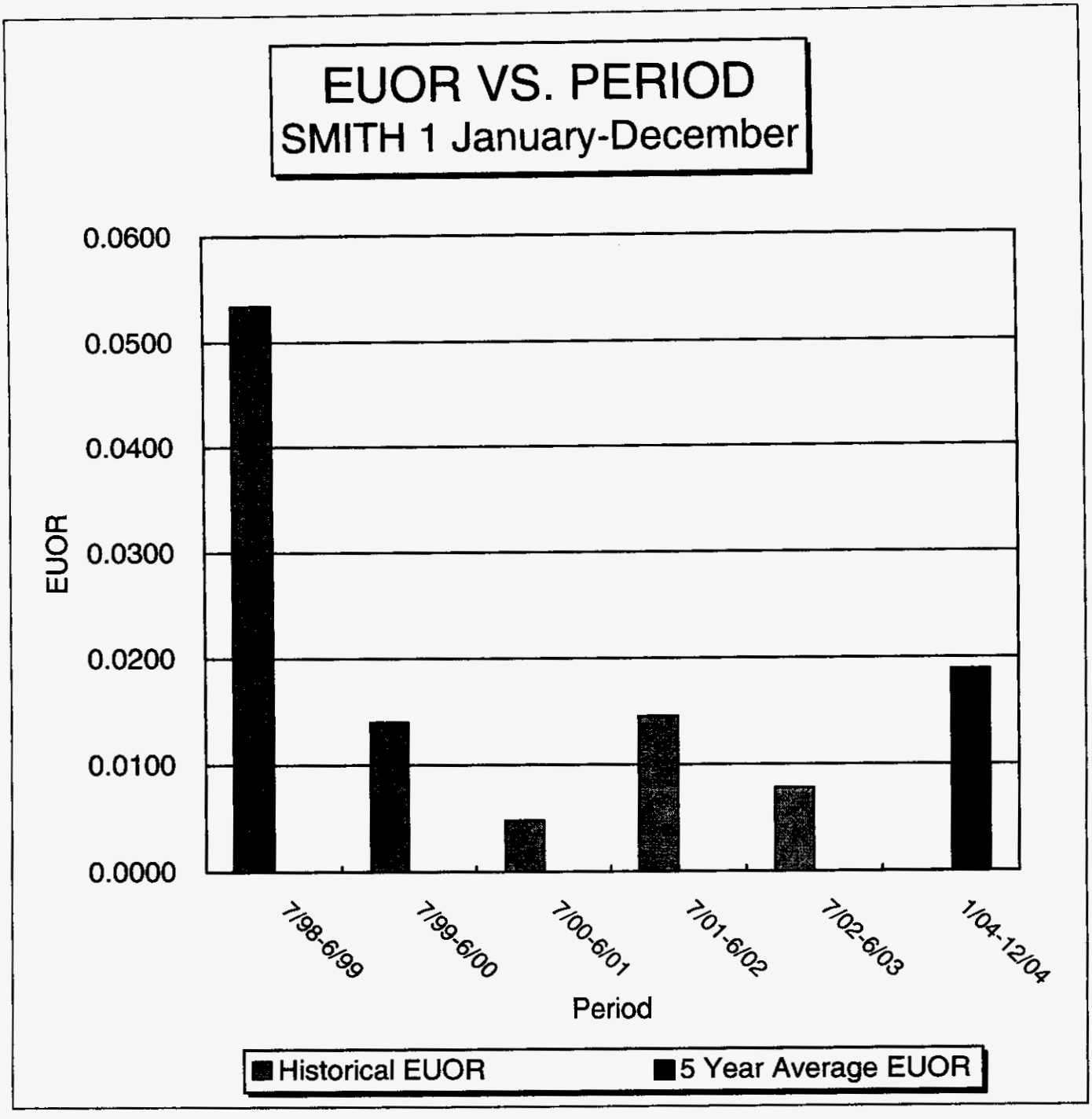
Unit	Target Equivalent Availability (0 Points)	Maximum Attainable Equivalent Availability (+10 Points)	Minimum Attainable Equivalent Availability (-10 Points)
Crist 4	97.9	98.5	96.9
Crist 5	96.8	97.7	95.3
Crist 6	86.7	88.8	83.6
Crist 7	70.1	72.6	66.3
Smith 1	90.1	90.6	89.3
Smith 2	82.8	85.5	78.8
Daniel 1	69.6	71.2	67.0
Daniel 2	81.1	83.2	78.0

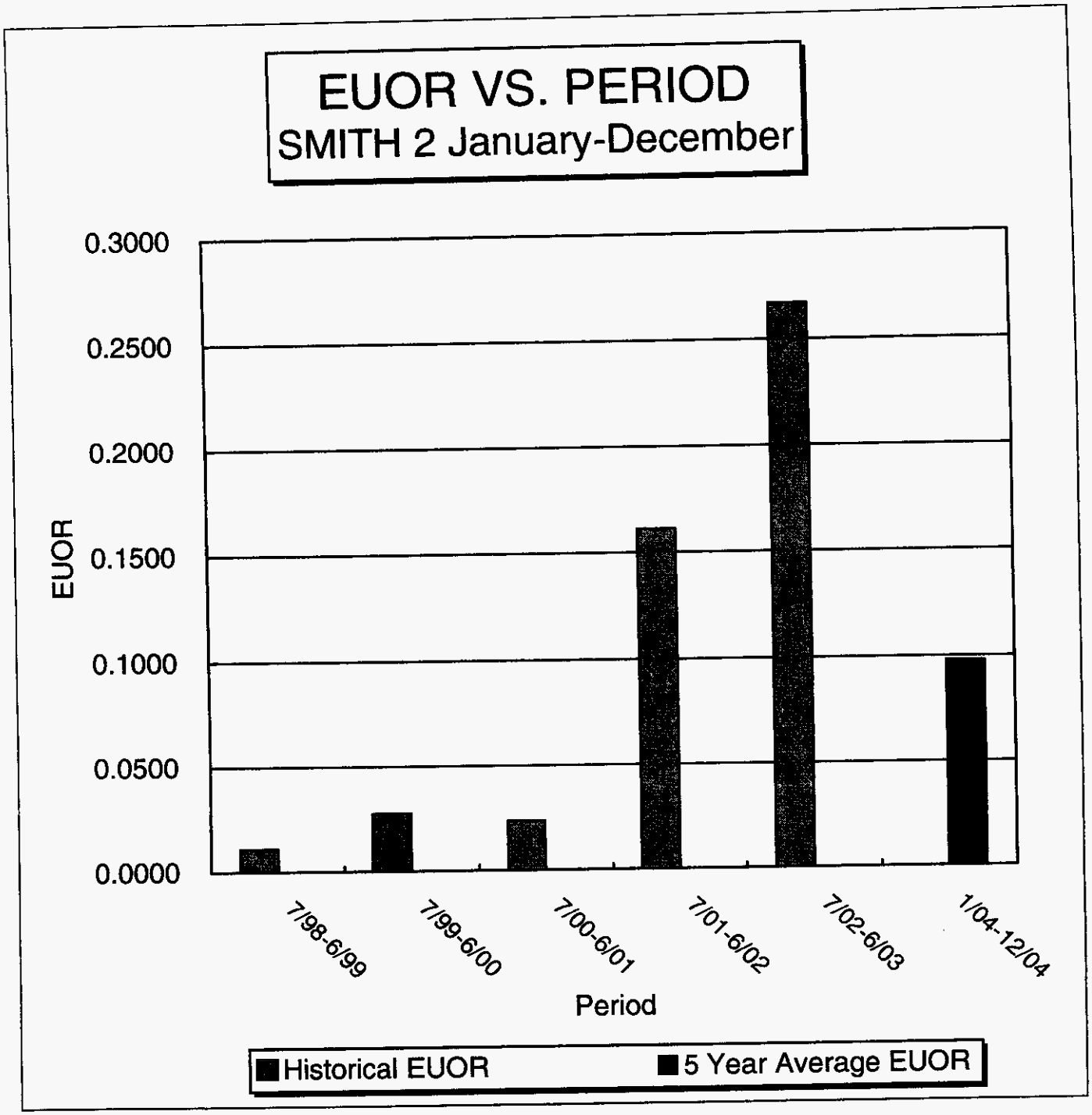

EUOR VS. PERIOD
CRIST 4 January-December
0.0800
0.0700
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
EUOR
7/98-6/99
7/99-6/00
7/00-6/01
7/01-6/02
7/02-6/03
1/04-12/04
Period
Historical EUOR
5 Year Average EUOR

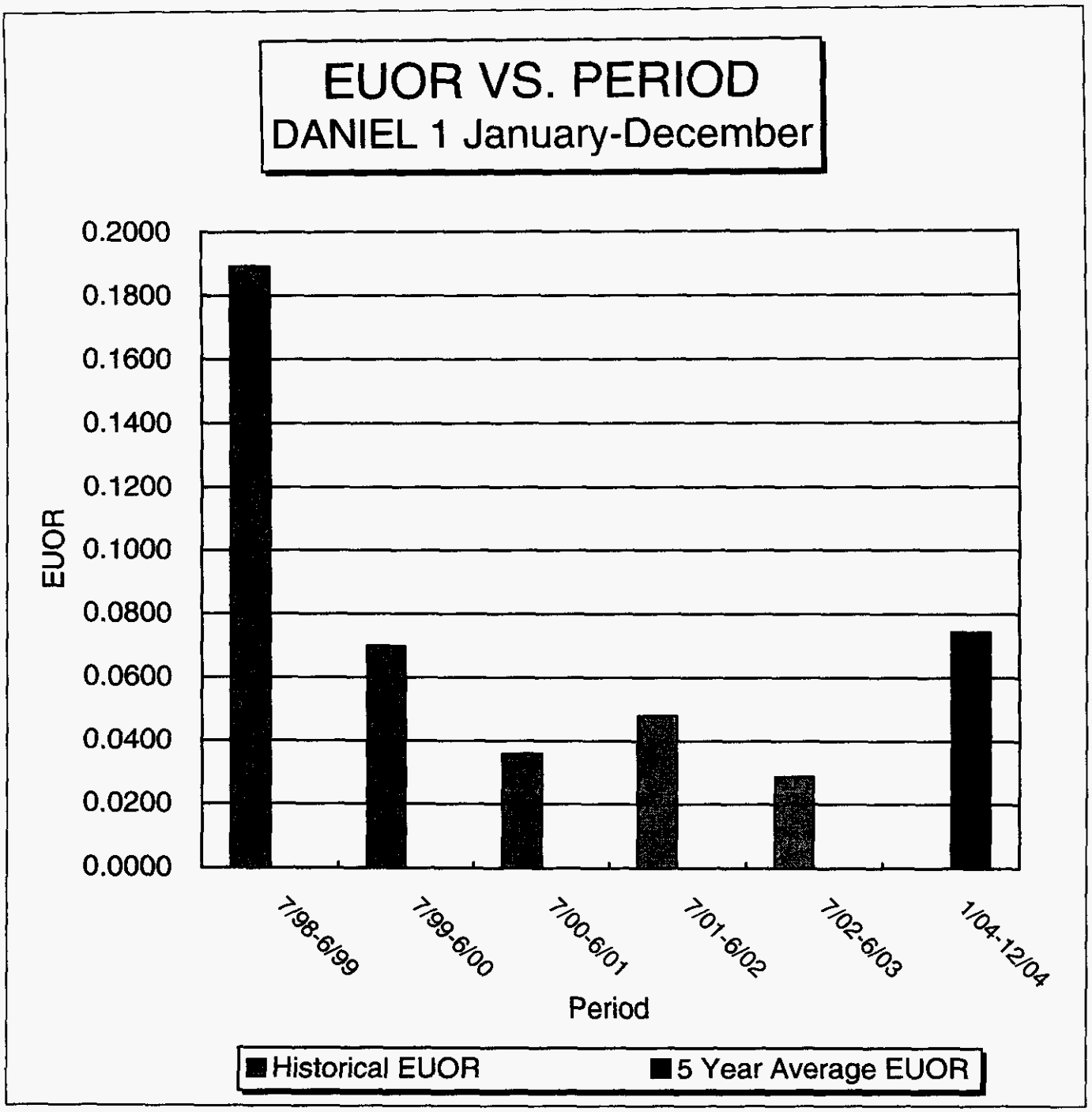

EUOR VS. PERIOD
CRIST 5 January-December
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
0.0000
EUOR
7/98-6/99
7/99-6/00
7/00-6/01
7/01-6/02
7/02-6/03
1/04-12/04
Period
Historical EUOR
5 Year Average EUOR

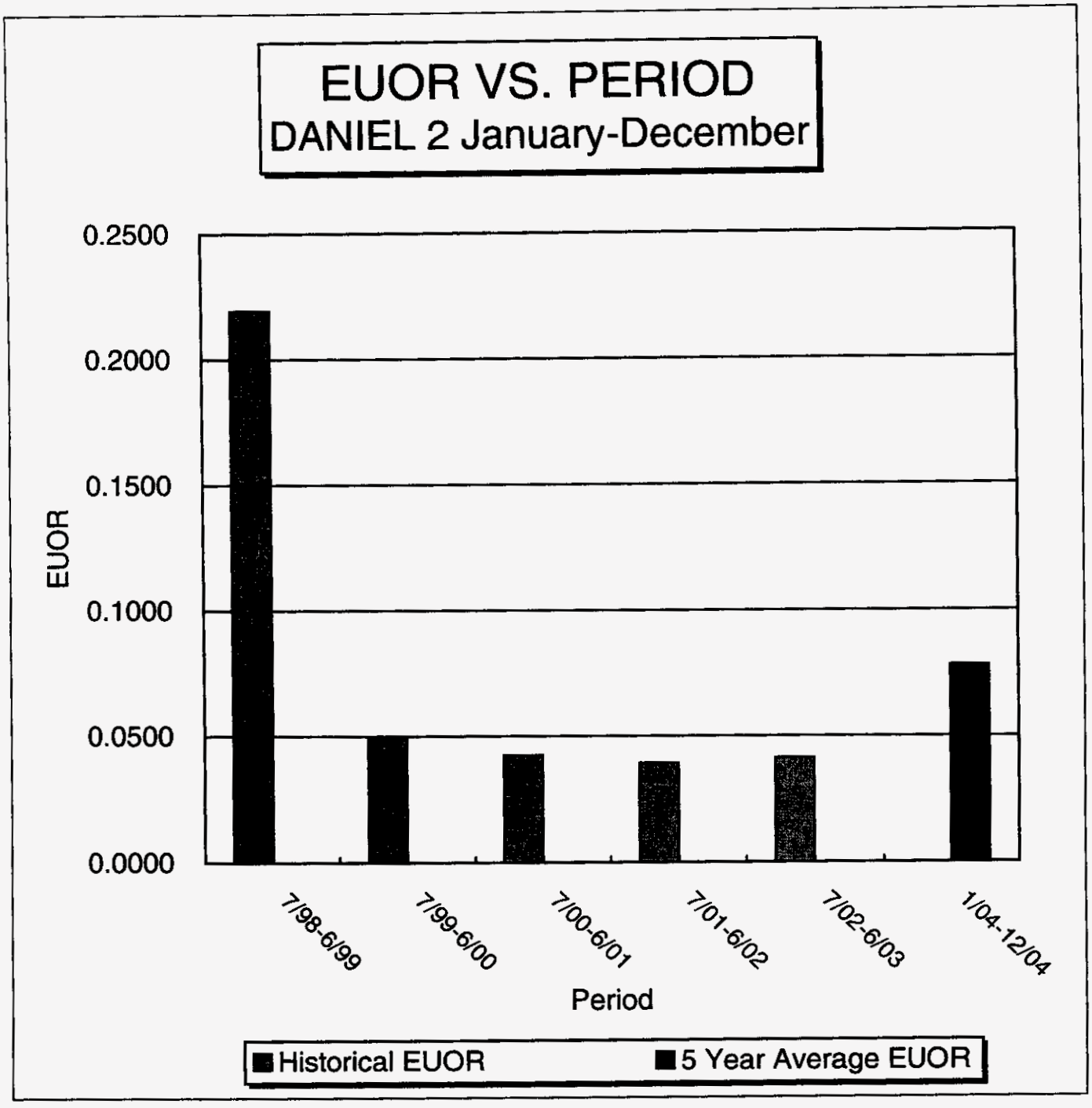

EUOR VS. PERIOD
CRIST 6 January-December
0.2000
0.1800
0.1600
0.1400
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
0.0000
EUOR
7/98-6/99
7/99-6/00
7/00-6/01
7/01-6/02
7/02-6/03
1/04-12/04
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
CRIST 7 January-December
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
EUOR
7/98-6/99
7/99-6/00
7/00-6/01
7/01-6/02
7/02-6/03
1/04-12/04
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
SMITH 1 January-December
0.0600
0.0500
0.0400
0.0300
0.0200
0.0100
0.0000
EUOR
7/98-6/99
7/99-6/00
7/00-6/01
7/01-6/02
7/02-6/03
1/04-12/04
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
SMITH 2 January-December
0.3000
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
EUOR
7/98-6/99
7/99-6/00
7/00-6/01
7/01-6/02
7/02-6/03
1/04-12/04
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
DANIEL 1 January-December
0.2000
0.1800
0.1600
0.1400
0.1200
0.1000
0.0800
0.0600
0.0400
0.0200
0.0000
EUOR
7/98-6/99
7/99-6/00
7/00-6/01
7/01-6/02
7/02-6/03
1/04-12/04
Period
Historical EUOR
5 Year Average EUOR


EUOR VS. PERIOD
DANIEL 2 January-December
0.2500
0.2000
0.1500
0.1000
0.0500
0.0000
EUOR
7/98-6/99
7/99-6/00
7/00-6/01
7/01-6/02
7/02-6/03
1/04-12/04
Period
Historical EUOR
5 Year Average EUOR

III. GPIF MINIMUM FILING REQUIREMENTS FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

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Generating Performance Incentive Factor

Estimated Reward/Penalty Table

Gulf Power Company

Period of: January 2004 - December 2004

Generating Performance Incentive Factor Points	Fuel Saving/Loss ($000)	Generating Performance Incentive Factor ($000)
	Maximum Attainable Fuel Savings	Maximum Incentive Dollars Allowed by Commission During Period (Reward)
+ 10	5678	2254
+ 9	5110	2029
+ 8	4542	1803
+ 7	3975	1578
+ 6	3407	1353
+ 5	2839	1127
+ 4	2271	902
+ 3	1703	676
+ 2	1136	451
+ 1	568	225
0	0	0
- 1	-638	-225
- 2	-1275	-451
- 3	-1913	-676
- 4	-2551	-902
- 5	-3189	-1127
- 6	-3826	-1353
- 7	-4464	-1578
- 8	-5102	-1803
- 9	-5739	-2029
- 10	-6377	-2254
	Minimum Attainable Fuel Loss	Maximum Incentive Dollars Allowed by Commission During Period (Penalty)

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Generating Performance Incentive Factor

Calculation of Maximum Allowed Incentive Dollars

Estimated

Gulf Power Company

Period of: January 2004 - December 2004

Line 1	Beginning of Period Balance of Common Equity	$563,241,000
	End of Month Balance of Common Equity:	
Line 2	Month of Jan '04	$585,548,000
Line 3	Month of Feb '04	$570,898,000
Line 4	Month of Mar '04	$574,339,000
Line 5	Month of Apr '04	$558,324,000
Line 6	Month of May '04	$563,502,000
Line 7	Month of Jun '04	$573,375,000
Line 8	Month of Jul '04	$566,597,000
Line 9	Month of Aug '04	$578,882,000
Line 10	Month of Sep '04	$586,577,000
Line 11	Month of Oct '04	$571,867,000
Line 12	Month of Nov '04	$572,361,000
Line 13	Month of Dec '04	$582,859,000
Line 14	Average Common Equity for the Period (sum of line 1 through line 13 divided by 13)	$572,951,538
Line 15	25 Basis Points	0.0025
Line 16	Revenue Expansion Factor	61.3808%
Line 17	Maximum Allowed Incentive Dollars (line 14 multiplied by line 15 divided by line 16 multiplied by 1.0)	$2,333,594
Line 18	Jurisdictional Sales (KWH)	10,605,379,000
Line 19	Total Territorial Sales (KWH)	10,978,892,000
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)	96.5979%
Line 21	Maximum Allowed Jurisdictional Incentive Dollars (line 17 multiplied by line 20)	$2,254,203

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GPIF Unit Performance Summary

Gulf Power Company

Period of: January 2004 - December 2004

Plant & Unit	Weighting Factor %	EAF Target %	EAF Range Max %	EAF Range Min %	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Crist 4	0.1%	97.9	98.5	96.9	$8	($9)
Crist 5	0.2%	96.8	97.7	95.3	$14	($19)
Crist 6	1.5%	86.7	88.8	83.6	$84	($147)
Crist 7	8.4%	70.1	72.6	66.3	$477	($634)
Smith 1	0.6%	90.1	90.6	89.3	$32	($32)
Smith 2	2.4%	82.8	85.5	78.8	$134	($227)
Daniel 1	5.3%	69.6	71.2	67.0	$299	($453)
Daniel 2	5.7%	81.1	83.2	78.0	$324	($550)

Plant & Unit	Weighting Factor %	ANOHR Target BTU/KWH	Target NOF	ANOHR Range Min BTU/KWH	ANOHR Range Max BTU/KWH	Max Fuel Savings ($000)	Max Fuel Loss ($000)
Crist 4	4.0%	10,388	93.9	10,076	10,700	$229	($229)
Crist 5	3.8%	10,232	92.1	9,925	10,539	$216	($216)
Crist 6	15.4%	10,501	96.5	10,186	10,816	$876	($876)
Crist 7	19.1%	10,223	99.1	9,916	10,530	$1,086	($1,086)
Smith 1	8.0%	10,114	95.7	9,811	10,417	$454	($454)
Smith 2	7.9%	10,024	95.2	9,723	10,325	$449	($449)
Daniel 1	7.5%	9,994	94.3	9,694	10,294	$428	($428)
Daniel 2	10.0%	9,828	94.7	9,533	10,123	$568	($568)

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2004 - December 2004

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Target			Actual Performance 1st Prior Period Jul '02 - Jun '03			Actual Performance 2nd Prior Period Jul '01 - Jun '02		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Crist 4	0.1%	0.6%	0.0000	0.0212	0.0212	0.0581	0.0030	0.0032	0.1009	0.0032	0.0048
Crist 5	0.2%	1.0%	0.0000	0.0323	0.0323	0.0598	0.0061	0.0065	0.1123	0.0024	0.0037
Crist 6	1.5%	6.1%	0.0628	0.0700	0.0747	0.0589	0.0399	0.0424	0.1562	0.0356	0.0423
Crist 7	8.4%	34.8%	0.2158	0.0836	0.1066	0.1199	0.0136	0.0155	0.1454	0.1952	0.2284
Smith 1	0.6%	2.3%	0.0820	0.0173	0.0189	0.1019	0.0070	0.0078	0.1105	0.0128	0.0145
Smith 2	2.4%	9.8%	0.0820	0.0901	0.0980	0.3159	0.1825	0.2668	0.1490	0.1303	0.1610
Daniel 1	5.3%	21.8%	0.2486	0.0559	0.0743	0.2250	0.0222	0.0287	0.0224	0.0466	0.0479
Daniel 2	5.7%	23.6%	0.1202	0.0689	0.0783	0.0526	0.0391	0.0413	0.2329	0.0291	0.0393
Weighted GPIF System Average:			0.1714	0.0715	0.0868	0.1409	0.0393	0.0503	0.1389	0.1001	0.1178

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Availability

Gulf Power Company

Period of: January 2004 - December 2004

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Actual Performance 3rd Prior Period Jul '00 - Jun '01			Actual Performance 4th Prior Period Jul '99 - Jun '00			Actual Performance 5th Prior Period Jul '98 - Jun '99		
			POF	EUOF	EUOR	POF	EUOF	EUOR	POF	EUOF	EUOR
Crist 4	0.1%	0.6%	0.1868	0.0003	0.0004	0.0974	0.0266	0.0304	0.0435	0.0512	0.0670
Crist 5	0.2%	1.0%	0.0372	0.0106	0.0121	0.2874	0.0745	0.1076	0.0193	0.0297	0.0318
Crist 6	1.5%	6.1%	0.1102	0.1580	0.1795	0.0988	0.0708	0.0786	0.0768	0.0281	0.0305
Crist 7	8.4%	34.8%	0.1224	0.0808	0.0920	0.1589	0.0703	0.0835	0.0888	0.1036	0.1137
Smith 1	0.6%	2.3%	0.0759	0.0044	0.0048	0.0589	0.0132	0.0140	0.2058	0.0424	0.0534
Smith 2	2.4%	9.8%	0.0920	0.0216	0.0237	0.0590	0.0260	0.0276	0.0583	0.0103	0.0110
Daniel 1	5.3%	21.8%	0.1153	0.0318	0.0359	0.1396	0.0601	0.0698	0.2959	0.1331	0.1891
Daniel 2	5.7%	23.6%	0.1167	0.0374	0.0424	0.0396	0.0473	0.0493	0.2633	0.1614	0.2191
Weighted GPIF System Average:			0.1142	0.0558	0.0634	0.1117	0.0568	0.0650	0.1732	0.1075	0.1374

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Comparison of GPIF Targets vs. Actual Performance of Prior Periods

Average Net Operating Heat Rate

Gulf Power Company

Period of: January 2004 - December 2004

Plant & Unit	Target Weighting Factor	Normalized Weighting Factor	Heat Rate Target	1st Prior Period Heat Rate Jul '02 - Jun '03	2nd Prior Period Heat Rate Jul '01 - Jun '02	3rd Prior Period Heat Rate Jul '00 - Jun '01
Crist 4	4.0%	5.3%	10,388	10,567	10,350	10,353
Crist 5	3.8%	5.0%	10,232	10,460	10,058	10,058
Crist 6	15.4%	20.3%	10,501	10,359	10,533	10,591
Crist 7	19.1%	25.2%	10,223	10,221	9,104	10,283
Smith 1	8.0%	10.5%	10,114	10,240	10,088	10,009
Smith 2	7.9%	10.4%	10,024	10,379	9,930	10,068
Daniel 1	7.5%	9.9%	9,994	9,838	9,973	10,086
Daniel 2	10.0%	13.2%	9,828	9,705	9,901	9,873
Weighted GPIF System Average:			10,182	10,192	9,890	10,213

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Example Calculation of Prior Season

Average Net Operating Heat Rate

Adjusted to Target Basis

Crist 6 Jul '01 - Jun '02

	Jul Jan	Aug Feb	Sep Mar	Oct Apr	Nov May	Dec Jun
1. Target Heat Rate*	10491.0 10484.0	10593.0 10483.0	10490.0 10638.0	10481.0 10484.0	10482.0 10370.0	10482.0 10486.0
2. Target Heat Rate at Actual Conditions**	10686.0 11094.0	10727.0 11106.0	10908.0 0.0	11025.0 11502.0	11347.0 11032.0	11482.0 10908.0
3. Adjustments to Actual Heat Rate (1-2)	-195.0 -610.0	-134.0 -623.0	-418.0 10638.0	-544.0 -1018.0	-865.0 -662.0	-1000.0 -422.0
4. Actual Heat Rate for Prior Period	10982.0 11371.0	11062.0 11260.0	11213.0 0.0	11064.0 10878.0	11337.0 10682.0	11257.0 11078.0
5. Adjusted actual Heat Rate (4+3)	10787.0 10761.0	10928.0 10637.0	10795.0 10638.0	10520.0 9860.0	10472.0 10020.0	10257.0 10656.0
6. Forecast Net MWH Generation*	217650.3 171086.7	216912.4 47638.6	210399.9 215983.7	187962.6 184482.0	181323.8 187205.9	195937.5 206666.9

7. Adjusted Actual Heat Rate for Jul '01 - Jun '02 = (Σ ((5) * (6)))/(Σ (6)) 10,533

* For the January 2004 - December 2004 time period.

** Based on the target heat rate equation from page 2 of Schedule 1 using actual rather than forecast variable values.

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Derivation of Weighting Factors

Gulf Power Company

Period of: January 2004 - December 2004

Plant & Unit	Unit Performance Indicator	Production Cost Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	Weighting Factor (% of Savings)
Crist 4	EA-1	$275,872	$275,864	$8	0.1%
Crist 4	ANOHR-1	$275,872	$275,643	$229	4.0%
Crist 5	EA-1	$275,872	$275,858	$14	0.2%
Crist 5	ANOHR-1	$275,872	$275,656	$216	3.8%
Crist 6	EA-1	$275,872	$275,788	$84	1.5%
Crist 6	ANOHR-1	$275,872	$274,996	$876	15.4%
Crist 7	EA-2	$275,872	$275,395	$477	8.4%
Crist 7	ANOHR-2	$275,872	$274,786	$1,086	19.1%
Smith 1	EA-3	$275,872	$275,840	$32	0.6%
Smith 1	ANOHR-3	$275,872	$275,418	$454	8.0%
Smith 2	EA-4	$275,872	$275,738	$134	2.4%
Smith 2	ANOHR-4	$275,872	$275,423	$449	7.9%
Daniel 1	EA-5	$275,872	$275,573	$299	5.3%
Daniel 1	ANOHR-5	$275,872	$275,444	$428	7.5%
Daniel 2	EA-6	$275,872	$275,548	$324	5.7%
Daniel 2	ANOHR-6	$275,872	$275,304	$568	10.0%

(1) Fuel Adjustment Base Case - All unit performance indicators at target.

(2) All other unit performance indicators at target.

(3) Expressed in replacement energy costs. Also includes variable operating and maintenance expense savings associated with availability improvements.

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2004 - December 2004

Crist 4

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	8	98.50	+ 10	229	10,076
+ 9	7	98.44	+ 9	206	10,100
+ 8	6	98.38	+ 8	183	10,123
+ 7	6	98.32	+ 7	160	10,147
+ 6	5	98.26	+ 6	137	10,171
+ 5	4	98.20	+ 5	115	10,195
+ 4	3	98.14	+ 4	92	10,218
+ 3	2	98.08	+ 3	69	10,242
+ 2	2	98.02	+ 2	46	10,266
+ 1	1	97.96	+ 1	23	10,289
				0	10,313
0	0	97.90	0	0	10,388
				0	10,463
- 1	(1)	97.80	- 1	(23)	10,487
- 2	(2)	97.70	- 2	(46)	10,510
- 3	(3)	97.60	- 3	(69)	10,534
- 4	(4)	97.50	- 4	(92)	10,558
- 5	(5)	97.40	- 5	(115)	10,582
- 6	(5)	97.30	- 6	(137)	10,605
- 7	(6)	97.20	- 7	(160)	10,629
- 8	(7)	97.10	- 8	(183)	10,653
- 9	(8)	97.00	- 9	(206)	10,676
- 10	(9)	96.90	- 10	(229)	10,700
Weighting Factor:		0.001	Weighting Factor:		0.040

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2004 - December 2004

Crist 5

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	14	97.70	+ 10	216	9,925
+ 9	13	97.61	+ 9	194	9,948
+ 8	11	97.52	+ 8	173	9,971
+ 7	10	97.43	+ 7	151	9,995
+ 6	8	97.34	+ 6	130	10,018
+ 5	7	97.25	+ 5	108	10,041
+ 4	6	97.16	+ 4	86	10,064
+ 3	4	97.07	+ 3	65	10,087
+ 2	3	96.98	+ 2	43	10,111
+ 1	1	96.89	+ 1	22	10,134
				0	10,157
0	0	96.80	0	0	10,232
				0	10,307
- 1	(2)	96.65	- 1	(22)	10,330
- 2	(4)	96.50	- 2	(43)	10,353
- 3	(6)	96.35	- 3	(65)	10,377
- 4	(8)	96.20	- 4	(86)	10,400
- 5	(10)	96.05	- 5	(108)	10,423
- 6	(11)	95.90	- 6	(130)	10,446
- 7	(13)	95.75	- 7	(151)	10,469
- 8	(15)	95.60	- 8	(173)	10,493
- 9	(17)	95.45	- 9	(194)	10,516
- 10	(19)	95.30	- 10	(216)	10,539
Weighting Factor:		0.002	Weighting Factor:		0.038

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2004 - December 2004

Crist 6

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	84	88.80	+ 10	876	10,186
+ 9	76	88.59	+ 9	788	10,210
+ 8	67	88.38	+ 8	701	10,234
+ 7	59	88.17	+ 7	613	10,258
+ 6	50	87.96	+ 6	526	10,282
+ 5	42	87.75	+ 5	438	10,306
+ 4	34	87.54	+ 4	350	10,330
+ 3	25	87.33	+ 3	263	10,354
+ 2	17	87.12	+ 2	175	10,378
+ 1	8	86.91	+ 1	88	10,402
				0	10,426
0	0	86.70	0	0	10,501
				0	10,576
- 1	(15)	86.39	- 1	(88)	10,600
- 2	(29)	86.08	- 2	(175)	10,624
- 3	(44)	85.77	- 3	(263)	10,648
- 4	(59)	85.46	- 4	(350)	10,672
- 5	(74)	85.15	- 5	(438)	10,696
- 6	(88)	84.84	- 6	(526)	10,720
- 7	(103)	84.53	- 7	(613)	10,744
- 8	(118)	84.22	- 8	(701)	10,768
- 9	(132)	83.91	- 9	(788)	10,792
- 10	(147)	83.60	- 10	(876)	10,816
Weighting Factor:		0.015	Weighting Factor:		0.154

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2004 - December 2004

Crist 7

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	477	72.60	+ 10	1,086	9,916
+ 9	429	72.35	+ 9	977	9,939
+ 8	382	72.10	+ 8	869	9,962
+ 7	334	71.85	+ 7	760	9,986
+ 6	286	71.60	+ 6	652	10,009
+ 5	239	71.35	+ 5	543	10,032
+ 4	191	71.10	+ 4	434	10,055
+ 3	143	70.85	+ 3	326	10,078
+ 2	95	70.60	+ 2	217	10,102
+ 1	48	70.35	+ 1	109	10,125
				0	10,148
0	0	70.10	0	0	10,223
				0	10,298
- 1	(63)	69.72	- 1	(109)	10,321
- 2	(127)	69.34	- 2	(217)	10,344
- 3	(190)	68.96	- 3	(326)	10,368
- 4	(254)	68.58	- 4	(434)	10,391
- 5	(317)	68.20	- 5	(543)	10,414
- 6	(380)	67.82	- 6	(652)	10,437
- 7	(444)	67.44	- 7	(760)	10,460
- 8	(507)	67.06	- 8	(869)	10,484
- 9	(571)	66.68	- 9	(977)	10,507
- 10	(634)	66.30	- 10	(1,086)	10,530
Weighting Factor:		0.084	Weighting Factor:		0.191

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2004 - December 2004

Smith 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	32	90.60	+ 10	454	9,811
+ 9	29	90.55	+ 9	409	9,834
+ 8	26	90.50	+ 8	363	9,857
+ 7	22	90.45	+ 7	318	9,879
+ 6	19	90.40	+ 6	272	9,902
+ 5	16	90.35	+ 5	227	9,925
+ 4	13	90.30	+ 4	182	9,948
+ 3	10	90.25	+ 3	136	9,971
+ 2	6	90.20	+ 2	91	9,993
+ 1	3	90.15	+ 1	45	10,016
				0	10,039
0	0	90.10	0	0	10,114
				0	10,189
- 1	(3)	90.02	- 1	(45)	10,212
- 2	(6)	89.94	- 2	(91)	10,235
- 3	(10)	89.86	- 3	(136)	10,257
- 4	(13)	89.78	- 4	(182)	10,280
- 5	(16)	89.70	- 5	(227)	10,303
- 6	(19)	89.62	- 6	(272)	10,326
- 7	(22)	89.54	- 7	(318)	10,349
- 8	(26)	89.46	- 8	(363)	10,371
- 9	(29)	89.38	- 9	(409)	10,394
- 10	(32)	89.30	- 10	(454)	10,417
Weighting Factor:		0.006	Weighting Factor:		0.080

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2004 - December 2004

Smith 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	134	85.50	+ 10	449	9,723
+ 9	121	85.23	+ 9	404	9,746
+ 8	107	84.96	+ 8	359	9,768
+ 7	94	84.69	+ 7	314	9,791
+ 6	80	84.42	+ 6	269	9,813
+ 5	67	84.15	+ 5	225	9,836
+ 4	54	83.88	+ 4	180	9,859
+ 3	40	83.61	+ 3	135	9,881
+ 2	27	83.34	+ 2	90	9,904
+ 1	13	83.07	+ 1	45	9,926
				0	9,949
0	0	82.80	0	0	10,024
				0	10,099
- 1	(23)	82.40	- 1	(45)	10,122
- 2	(45)	82.00	- 2	(90)	10,144
- 3	(68)	81.60	- 3	(135)	10,167
- 4	(91)	81.20	- 4	(180)	10,189
- 5	(114)	80.80	- 5	(225)	10,212
- 6	(136)	80.40	- 6	(269)	10,235
- 7	(159)	80.00	- 7	(314)	10,257
- 8	(182)	79.60	- 8	(359)	10,280
- 9	(204)	79.20	- 9	(404)	10,302
- 10	(227)	78.80	- 10	(449)	10,325
Weighting Factor:		0.024	Weighting Factor:		0.079

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2004 - December 2004

Daniel 1

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	299	71.20	+ 10	428	9,694
+ 9	269	71.04	+ 9	385	9,717
+ 8	239	70.88	+ 8	342	9,739
+ 7	209	70.72	+ 7	300	9,762
+ 6	179	70.56	+ 6	257	9,784
+ 5	150	70.40	+ 5	214	9,807
+ 4	120	70.24	+ 4	171	9,829
+ 3	90	70.08	+ 3	128	9,852
+ 2	60	69.92	+ 2	86	9,874
+ 1	30	69.76	+ 1	43	9,897
				0	9,919
0	0	69.60	0	0	9,994
				0	10,069
- 1	(45)	69.34	- 1	(43)	10,092
- 2	(91)	69.08	- 2	(86)	10,114
- 3	(136)	68.82	- 3	(128)	10,137
- 4	(181)	68.56	- 4	(171)	10,159
- 5	(227)	68.30	- 5	(214)	10,182
- 6	(272)	68.04	- 6	(257)	10,204
- 7	(317)	67.78	- 7	(300)	10,227
- 8	(362)	67.52	- 8	(342)	10,249
- 9	(408)	67.26	- 9	(385)	10,272
- 10	(453)	67.00	- 10	(428)	10,294
Weighting Factor:		0.053	Weighting Factor:		0.075

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Generating Performance Incentive Points Table

Gulf Power Company

Period of: January 2004 - December 2004

Daniel 2

Equivalent Availability Points	Fuel Savings/ Loss ($000)	Adjusted Actual Equivalent Availability	Average Heat Rate Points	Fuel Savings/ Loss ($000)	Adjusted Actual Heat Rate
+ 10	324	83.20	+ 10	568	9,533
+ 9	292	82.99	+ 9	511	9,555
+ 8	259	82.78	+ 8	454	9,577
+ 7	227	82.57	+ 7	398	9,599
+ 6	194	82.36	+ 6	341	9,621
+ 5	162	82.15	+ 5	284	9,643
+ 4	130	81.94	+ 4	227	9,665
+ 3	97	81.73	+ 3	170	9,687
+ 2	65	81.52	+ 2	114	9,709
+ 1	32	81.31	+ 1	57	9,731
				0	9,753
0	0	81.10	0	0	9,828
				0	9,903
- 1	(55)	80.79	- 1	(57)	9,925
- 2	(110)	80.48	- 2	(114)	9,947
- 3	(165)	80.17	- 3	(170)	9,969
- 4	(220)	79.86	- 4	(227)	9,991
- 5	(275)	79.55	- 5	(284)	10,013
- 6	(330)	79.24	- 6	(341)	10,035
- 7	(385)	78.93	- 7	(398)	10,057
- 8	(440)	78.62	- 8	(454)	10,079
- 9	(495)	78.31	- 9	(511)	10,101
- 10	(550)	78.00	- 10	(568)	10,123
Weighting Factor:		0.057	Weighting Factor:		0.100

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ESTIMATED UNIT PERFORMANCE DATA

ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2004 - December 2004

	CRIST 4	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	
1.	EAF (%)	99.1	98.7	92.3	99.0	99.1	99.0	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	0.9	1.3	7.7	1.0	0.9	1.0	
4.	EUOR (%)	0.9	1.3	7.7	1.0	0.9	1.0	
5.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
6.	SH	737.0	690.0	690.0	712.0	737.0	713.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	7.0	6.0	54.0	7.0	7.0	7.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	7.0	9.0	9.0	7.0	7.0	7.0	
11.	MOH & EMOH	0.0	0.0	48.0	0.0	0.0	0.0	
12.	Oper MBtu	567525.0	532290.0	538839.0	537643.0	515319.0	549925.0	
13.	Net Gen (MWH)	54648.5	51270.5	51230.2	51661.7	48901.0	52969.1	
14.	ANOHR (Btu/KWH)	10385.0	10382.0	10518.0	10407.0	10538.0	10382.0	
15.	NOF %	95.1	95.3	95.2	93.0	85.1	95.2	
16.	NPC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	

19.	ANOHR Equation	10^6 / AKW * [617.42 + 9.96 * MAR - 23.05 * NOV] - 8329 + 0.13863 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2004 - December 2004

	CRIST 4	Jul '04	Aug '04	Sep '04	Oct '04	Nov '04	Dec '04	Total
1.	EAF (%)	99.1	99.1	99.0	98.7	92.5	99.1	97.9
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	EUOF (%)	0.9	0.9	1.0	1.3	7.5	0.9	2.1
4.	EUOR (%)	0.9	0.9	1.0	1.3	7.5	0.9	2.1
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
6.	SH	737.0	737.0	713.0	738.0	666.0	737.0	8607.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	7.0	7.0	7.0	7.0	54.0	7.0	177.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.	FOH & EFOH	7.0	7.0	7.0	10.0	6.0	7.0	90.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	48.0	0.0	96.0
12.	Oper MBtu	584093.0	584727.0	560374.0	546410.0	484107.0	549655.0	6550907.0
13.	Net Gen (MWH)	56396.0	56462.6	54069.3	52358.2	47950.4	52734.8	630652.3
14.	ANOHR (Btu/KWH)	10357.0	10356.0	10364.0	10436.0	10096.0	10423.0	10388.0
15.	NOF %	98.1	98.2	97.2	91.0	92.3	91.7	93.9
16.	NPC (MW)	78.0	78.0	78.0	78.0	78.0	78.0	78.0

19.	ANOHR Equation	10^6 / AKW * [617.42 + 9.96 * MAR - 23.05 * NOV] - 8329 + 0.13863 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2004 - December 2004

	CRIST 5	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	
1.	EAF (%)	98.0	97.6	91.3	97.9	98.0	97.9	
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	2.0	2.4	8.7	2.1	2.0	2.1	
4.	EUOR (%)	2.0	2.4	8.7	2.1	2.0	2.1	
5.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
6.	SH	729.0	682.0	682.0	704.0	729.0	705.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	15.0	14.0	62.0	15.0	15.0	15.0	
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	15.0	17.0	17.0	15.0	15.0	15.0	
11.	MOH & EMOH	0.0	0.0	48.0	0.0	0.0	0.0	
12.	Oper MBtu	556669.0	521515.0	523218.0	527860.0	511982.0	540587.0	
13.	Net Gen (MWH)	54372.8	50959.1	51175.5	51233.6	48584.4	52874.3	
14.	ANOHR (Btu/KWH)	10238.0	10234.0	10224.0	10303.0	10538.0	10224.0	
15.	NOF %	93.2	93.4	93.8	91.0	83.3	93.7	
16.	NPC (MW)	80.0	80.0	80.0	80.0	80.0	80.0	

19.	ANOHR Equation	10^6 / AKW * [-136.85 - 13.15 * OCT - 21.65 * NOV] + 18.611 - 0.08694 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2004 - December 2004

	CRIST 5	Jul '04	Aug '04	Sep '04	Oct '04	Nov '04	Dec '04	Total
1.	EAF (%)	98.0	98.0	97.9	97.6	91.4	97.7	96.8
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3.	EUOF (%)	2.0	2.0	2.1	2.4	8.6	2.3	3.2
4.	EUOR (%)	2.0	2.0	2.1	2.4	8.6	2.3	3.2
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
6.	SH	729.0	729.0	705.0	730.0	658.0	729.0	8511.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	15.0	15.0	15.0	15.0	62.0	15.0	273.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10.	FOH & EFOH	15.0	15.0	15.0	18.0	14.0	17.0	188.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	48.0	0.0	96.0
12.	Oper MBtu	572999.0	575183.0	546676.0	526916.0	476578.0	533101.0	6413284.0
13.	Net Gen (MWH)	56547.8	56836.3	53674.6	51709.1	47539.0	51304.1	626810.6
14.	ANOHR (Btu/KWH)	10133.0	10120.0	10185.0	10190.0	10025.0	10391.0	10232.0
15.	NOF %	97.0	97.5	95.2	88.5	90.3	88.0	92.1
16.	NPC (MW)	80.0	80.0	80.0	80.0	80.0	80.0	80.0

19.	ANOHR Equation	10^6 / AKW * [-136.85 - 13.15 * OCT - 21.65 * NOV] + 18,611 - 0.08694 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2004 - December 2004

	CRIST 6	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	
1.	EAF (%)	78.4	23.6	96.8	87.2	97.2	97.2	
2.	POF (%)	3.2	75.9	0.0	0.0	0.0	0.0	
3.	EUOF (%)	18.4	0.5	3.2	12.8	2.8	2.8	
4.	EUOR (%)	19.0	2.4	3.2	12.8	2.8	2.8	
5.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
6.	SH	583.0	164.0	723.0	629.0	723.0	700.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	161.0	532.0	21.0	90.0	21.0	20.0	
9.	POH	24.0	528.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	17.0	4.0	24.0	20.0	21.0	20.0	
11.	MOH & EMOH	120.0	0.0	0.0	72.0	0.0	0.0	
12.	Oper MBtu	1793673.0	499395.0	2297635.0	1934109.0	1941325.0	2167109.0	
13.	Net Gen (MWH)	171086.7	47638.6	215983.7	184482.0	187205.9	206666.9	
14.	ANOHR (Btu/KWH)	10484.0	10483.0	10638.0	10484.0	10370.0	10486.0	
15.	NOF %	97.2	96.2	98.9	97.1	85.7	97.8	
16.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	

19.	ANOHR Equation	10^6 / AKW * [1069.69 + 44.52 * MAR - 33.07 * MAY + 30.91 * AUG] + 844 + 0.02012 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2004 - December 2004

	CRIST 6	Jul '04	Aug '04	Sep '04	Oct '04	Nov '04	Dec '04	Total
1.	EAF (%)	97.2	97.2	96.8	87.8	87.1	90.9	86.7
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	6.3
3.	EUOF (%)	2.8	2.8	3.2	12.2	12.9	9.1	7.0
4.	EUOR (%)	2.8	2.8	3.2	12.2	12.9	9.1	7.5
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
6.	SH	723.0	723.0	700.0	654.0	630.0	676.0	7628.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	21.0	21.0	20.0	91.0	90.0	68.0	1156.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	552.0
10.	FOH & EFOH	21.0	21.0	23.0	19.0	21.0	20.0	231.0
11.	MOH & EMOH	0.0	0.0	0.0	72.0	72.0	48.0	384.0
12.	Oper MBtu	2283369.0	2297753.0	2207095.0	1970036.0	1900636.0	2053817.0	23345952.0
13.	Net Gen (MWH)	217650.3	216912.4	210399.9	187962.6	181323.8	195937.5	2223250.3
14.	ANOHR (Btu/KWH)	10491.0	10593.0	10490.0	10481.0	10482.0	10482.0	10501.0
15.	NOF %	99.7	99.3	99.5	95.2	95.3	96.0	96.5
16.	NPC (MW)	302.0	302.0	302.0	302.0	302.0	302.0	302.0

19.	ANOHR Equation	10^6 / AKW * [1069.69 + 44.52 * MAR - 33.07 * MAY + 30.91 * AUG] + 844 + 0.02012 * LSRF / AKW

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GULF POWER COMPANY

PERIOD OF: January 2004 - December 2004

	CRIST 7	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	
1.	EAF (%)	93.0	67.4	0.0	0.0	45.0	93.3	
2.	POF (%)	0.0	6.9	100.0	100.0	51.7	0.0	
3.	EUOF (%)	7.0	25.7	0.0	0.0	3.3	6.7	
4.	EUOR (%)	7.0	27.6	0.0	0.0	6.7	6.7	
5.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
6.	SH	695.0	471.0	0.0	0.0	335.0	672.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	49.0	225.0	744.0	719.0	409.0	48.0	
9.	POH	0.0	48.0	744.0	719.0	385.0	0.0	
10.	FOH & EFOH	52.0	35.0	0.0	0.0	24.0	48.0	
11.	MOH & EMOH	0.0	144.0	0.0	0.0	0.0	0.0	
12.	Oper MBtu	3340043.0	2250580.0	0.0	0.0	1510822.0	3268337.0	
13.	Net Gen (MWH)	329913.4	222191.7	0.0	0.0	148454.6	318737.8	
14.	ANOHR (Btu/KWH)	10124.0	10129.0	-	-	10177.0	10254.0	
15.	NOF %	99.5	98.9	0.0	0.0	92.9	99.4	
16.	NPC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	

19.	ANOHR Equation	10^6 / AKW * [349.83 - 96.07 * MAR + 61.52 * JUN + 115.03 * JUL + 78.38 * AUG + 90.36 * SEP + 64.01 * NOV] + 9,387

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GULF POWER COMPANY

PERIOD OF: January 2004 - December 2004

	CRIST 7	Jul '04	Aug '04	Sep '04	Oct '04	Nov '04	Dec '04	Total
1.	EAF (%)	93.4	93.4	93.3	84.0	93.1	84.4	70.1
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	21.6
3.	EUOF (%)	6.6	6.6	6.7	16.0	6.9	15.6	8.3
4.	EUOR (%)	6.6	6.6	6.7	16.0	6.9	15.6	10.7
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
6.	SH	695.0	695.0	672.0	629.0	672.0	628.0	6164.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	49.0	49.0	48.0	116.0	48.0	116.0	2620.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1896.0
10.	FOH & EFOH	49.0	49.0	48.0	47.0	50.0	44.0	446.0
11.	MOH & EMOH	0.0	0.0	0.0	72.0	0.0	72.0	288.0
12.	Oper MBtu	3427414.0	3401024.0	3298075.0	3005352.0	3267772.0	3009101.0	29778520.0
13.	Net Gen (MWH)	330703.8	330613.8	319828.8	296707.7	318496.3	297165.8	2912813.7
14.	ANOHR (Btu/KWH)	10364.0	10287.0	10312.0	10129.0	10260.0	10126.0	10223.0
15.	NOF %	99.8	99.7	99.8	98.9	99.4	99.2	99.1
16.	NPC (MW)	477.0	477.0	477.0	477.0	477.0	477.0	477.0

19.	ANOHR Equation	10^6 / AKW * [349.83 - 96.07 * MAR + 61.52 * JUN + 115.03 * JUL + 78.38 * AUG + 90.36 * SEP + 64.01 * NOV] + 9,387

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2004 - December 2004

	SMITH 1	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	
1.	EAF (%)	98.5	67.8	32.0	92.2	98.8	98.9	
2.	POF (%)	0.0	31.0	67.7	0.0	0.0	0.0	
3.	EUOF (%)	1.5	1.2	0.3	7.8	1.2	1.1	
4.	EUOR (%)	1.5	1.7	0.8	7.8	1.2	1.1	
5.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
6.	SH	735.0	475.0	238.0	663.0	735.0	712.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	9.0	221.0	506.0	56.0	9.0	8.0	
9.	POH	0.0	216.0	504.0	0.0	0.0	0.0	
10.	FOH & EFOH	11.0	8.0	2.0	8.0	9.0	8.0	
11.	MOH & EMOH	0.0	0.0	0.0	48.0	0.0	0.0	
12.	Oper MBtu	1159333.0	743840.0	381829.0	1044563.0	1021843.0	1133851.0	
13.	Net Gen (MWH)	116282.1	74810.4	37760.0	101888.7	99886.9	112062.8	
14.	ANOHR (Btu/KWH)	9970.0	9943.0	10112.0	10252.0	10230.0	10118.0	
15.	NOF %	97.7	97.2	97.9	94.9	83.9	97.2	
16.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	

19.	ANOHR Equation	10^6 / AKW * [111.12 - 22.83 * JAN - 27.46 * FEB + 17.98 * APR] + 9,412

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2004 - December 2004

	SMITH 1	Jul '04	Aug '04	Sep '04	Oct '04	Nov '04	Dec '04	Total
1.	EAF (%)	98.8	98.8	98.5	98.8	98.5	98.8	90.1
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	8.2
3.	EUOF (%)	1.2	1.2	1.5	1.2	1.5	1.2	1.7
4.	EUOR (%)	1.2	1.2	1.5	1.2	1.5	1.2	1.9
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
6.	SH	735.0	735.0	712.0	736.0	712.0	735.0	7923.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	9.0	9.0	8.0	9.0	8.0	9.0	861.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	720.0
10.	FOH & EFOH	9.0	9.0	11.0	9.0	11.0	9.0	104.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	0.0	0.0	48.0
12.	Oper MBtu	1197830.0	1193018.0	1157951.0	1133856.0	1105477.0	1145279.0	12418670.0
13.	Net Gen (MWH)	118597.0	118073.8	114625.9	111776.0	109053.7	113013.5	1227830.8
14.	ANOHR (Btu/KWH)	10100.0	10104.0	10102.0	10144.0	10137.0	10134.0	10114.0
15.	NOF %	99.6	99.2	99.4	93.7	94.5	94.9	95.7
16.	NPC (MW)	162.0	162.0	162.0	162.0	162.0	162.0	162.0

19.	ANOHR Equation	10^6 / AKW * [111.12 - 22.83 * JAN - 27.46 * FEB + 17.98 * APR] + 9,412

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2004 - December 2004

	SMITH 2	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	
1.	EAF (%)	93.7	83.8	69.5	15.6	93.3	93.6	
2.	POF (%)	0.0	0.0	16.1	83.4	0.0	0.0	
3.	EUOF (%)	6.3	16.2	14.4	1.0	6.7	6.4	
4.	EUOR (%)	6.3	16.2	17.1	5.9	6.7	6.4	
5.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
6.	SH	697.0	585.0	517.0	112.0	697.0	674.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	47.0	111.0	227.0	607.0	47.0	46.0	
9.	POH	0.0	0.0	120.0	600.0	0.0	0.0	
10.	FOH & EFOH	47.0	41.0	35.0	7.0	50.0	46.0	
11.	MOH & EMOH	0.0	72.0	72.0	0.0	0.0	0.0	
12.	Oper MBtu	1252926.0	1045472.0	939795.0	197300.0	1082162.0	1239550.0	
13.	Net Gen (MWH)	127316.9	106474.4	95770.4	19557.9	107240.3	123313.8	
14.	ANOHR (Btu/KWH)	9841.0	9819.0	9813.0	10088.0	10091.0	10052.0	
15.	NOF %	96.6	96.3	98.0	92.4	81.4	96.8	
16.	NPC (MW)	189.0	189.0	189.0	189.0	189.0	189.0	

19.	ANOHR Equation	10^6 / AKW * [139.59 - 38.77 * JAN - 43.18 * FEB - 42.50 * MAR - 16.17 * MAY + 27.46 * JUL + 19.26 * AUG] + 9,289

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2004 - December 2004

	SMITH 2	Jul '04	Aug '04	Sep '04	Oct '04	Nov '04	Dec '04	Total
1.	EAF (%)	93.7	93.7	93.2	84.6	93.3	84.5	82.8
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	8.2
3.	EUOF (%)	6.3	6.3	6.8	15.4	6.7	15.5	9.0
4.	EUOR (%)	6.3	6.3	6.8	15.4	6.7	15.5	9.8
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
6.	SH	697.0	697.0	674.0	630.0	674.0	629.0	7283.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	47.0	47.0	46.0	115.0	46.0	115.0	1501.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	720.0
10.	FOH & EFOH	47.0	47.0	49.0	43.0	48.0	43.0	503.0
11.	MOH & EMOH	0.0	0.0	0.0	72.0	0.0	72.0	288.0
12.	Oper MBtu	1329849.0	1321533.0	1268272.0	1114266.0	1212589.0	1130891.0	13134605.0
13.	Net Gen (MWH)	130633.5	130354.4	126410.0	110487.5	120404.0	112291.8	1310254.9
14.	ANOHR (Btu/KWH)	10180.0	10138.0	10033.0	10085.0	10071.0	10071.0	10024.0
15.	NOF %	99.2	99.0	99.2	92.8	94.5	94.5	95.2
16.	NPC (MW)	189.0	189.0	189.0	189.0	189.0	189.0	189.0

19.	*ANOHR Equation*	10^6 / AKW * [139.59 - 38.77 * JAN - 43.18 * FEB - 42.50 * MAR - 16.17 * MAY + 27.46 * JUL + 19.26 * AUG] + 9,289

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2004 - December 2004

	DANIEL 1	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	
1.	EAF (%)	48.8	91.5	94.8	85.5	94.8	95.1	
2.	POF (%)	45.2	0.0	0.0	0.0	0.0	0.0	
3.	EUOF (%)	6.0	8.5	5.2	14.5	5.2	4.9	
4.	EUOR (%)	11.0	8.5	5.2	14.5	5.2	4.9	
5.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
6.	SH	365.0	639.0	708.0	615.0	708.0	685.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	379.0	57.0	36.0	104.0	36.0	35.0	
9.	POH	336.0	0.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	21.0	35.0	39.0	32.0	39.0	35.0	
11.	MOH & EMOH	24.0	24.0	0.0	72.0	0.0	0.0	
12.	Oper MBtu	1711433.0	3084692.0	3457717.0	2874351.0	2854035.0	3306686.0	
13.	Net Gen (MWH)	171417.6	310237.6	348384.6	287751.6	285175.4	332564.2	
14.	ANOHR (Btu/KWH)	9984.0	9943.0	9925.0	9989.0	10008.0	9943.0	
15.	NOF %	92.6	95.8	97.1	92.3	79.4	95.8	
16.	NPC (MW)	507.0	507.0	507.0	507.0	507.0	507.0	

19.	ANOHR Equation	10^6 / AKW * [-528.45 - 59.78 * MAY + 139.64 * JUL + 75.47 * AUG] + 15,490 - 0.00906 * LSRF / AKW

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2004 - December 2004

	DANIEL 1	Jul '04	Aug '04	Sep '04	Oct '04	Nov '04	Dec '04	Total
1.	EAF (%)	95.2	95.2	95.1	18.5	0.0	21.5	69.6
2.	POF (%)	0.0	0.0	0.0	74.1	100.0	77.4	24.9
3.	EUOF (%)	4.8	4.8	4.9	7.4	0.0	1.1	5.5
4.	EUOR (%)	4.8	4.8	4.9	28.5	0.0	4.8	7.4
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
6.	SH	708.0	708.0	685.0	138.0	0.0	160.0	6119.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	36.0	36.0	35.0	607.0	720.0	584.0	2665.0
9.	POH	0.0	0.0	0.0	552.0	720.0	576.0	2184.0
10.	FOH & EFOH	36.0	36.0	35.0	7.0	0.0	8.0	323.0
11.	MOH & EMOH	0.0	0.0	0.0	48.0	0.0	0.0	168.0
12.	Oper MBtu	3619726.0	3561609.0	3395661.0	635806.0	0.0	727477.0	29229193.0
13.	Net Gen (MWH)	355747.0	354248.0	342926.8	63529.8	0.0	72559.0	2924541.6
14.	ANOHR (Btu/KWH)	10175.0	10054.0	9902.0	10008.0	-	10026.0	9994.0
15.	NOF %	99.1	98.7	98.7	90.8	0.0	89.4	94.3
16.	NPC (MW)	507.0	507.0	507.0	507.0	507.0	507.0	507.0

19.	ANOHR Equation	10^6 / AKW * [-528.45 - 59.78 * MAY + 139.64 * JUL + 75.47 * AUG] + 15,490 - 0.00906 * LSRF / AKW

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2004 - December 2004

	DANIEL 2	Jan '04	Feb '04	Mar '04	Apr '04	May '04	Jun '04	
1.	EAF (%)	27.3	22.7	84.1	93.7	93.4	93.8	
2.	POF (%)	71.0	75.9	0.0	0.0	0.0	0.0	
3.	EUOF (%)	1.7	1.4	15.9	6.3	6.6	6.2	
4.	EUOR (%)	6.0	6.0	15.9	6.3	6.6	6.3	
5.	PH	744.0	696.0	744.0	719.0	744.0	720.0	
6.	SH	203.0	158.0	630.0	674.0	698.0	675.0	
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	
8.	UH	541.0	538.0	114.0	45.0	46.0	45.0	
9.	POH	528.0	528.0	0.0	0.0	0.0	0.0	
10.	FOH & EFOH	13.0	10.0	46.0	45.0	49.0	45.0	
11.	MOH & EMOH	0.0	0.0	72.0	0.0	0.0	0.0	
12.	Oper MBtu	928792.0	748299.0	3055868.0	3225952.0	2920922.0	3302115.0	
13.	Net Gen (MWH)	96218.0	77247.8	316342.4	326645.6	290004.2	335342.2	
14.	ANOHR (Btu/KWH)	9653.0	9687.0	9660.0	9876.0	10072.0	9847.0	
15.	NOF %	92.2	95.1	97.7	94.3	80.8	96.7	
16.	NPC (MW)	514.0	514.0	514.0	514.0	514.0	514.0	

19.	ANOHR Equation	10^6 / AKW * [571.00 - 118.56 * JAN - 87.31 * FEB - 88.00 * MAR - 88.36 * NOV] + 8,698

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ESTIMATED UNIT PERFORMANCE DATA

GULF POWER COMPANY

PERIOD OF: January 2004 - December 2004

	DANIEL 2	Jul '04	Aug '04	Sep '04	Oct '04	Nov '04	Dec '04	Total
1.	EAF (%)	93.8	93.8	93.8	93.8	87.1	93.4	81.1
2.	POF (%)	0.0	0.0	0.0	0.0	0.0	0.0	12.0
3.	EUOF (%)	6.2	6.2	6.2	6.2	12.9	6.6	6.9
4.	EUOR (%)	6.2	6.2	6.3	6.2	12.9	6.6	7.8
5.	PH	744.0	744.0	720.0	745.0	720.0	744.0	8784.0
6.	SH	698.0	698.0	675.0	699.0	630.0	698.0	7136.0
7.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8.	UH	46.0	46.0	45.0	46.0	90.0	46.0	1648.0
9.	POH	0.0	0.0	0.0	0.0	0.0	0.0	1056.0
10.	FOH & EFOH	46.0	46.0	45.0	46.0	45.0	49.0	485.0
11.	MOH & EMOH	0.0	0.0	0.0	0.0	48.0	0.0	120.0
12.	Oper MBtu	3503209.0	3487881.0	3382070.0	3301483.0	2938297.0	3353737.0	34148625.0
13.	Net Gen (MWH)	356924.0	355181.4	344511.6	333685.4	302854.8	339756.6	3474714.0
14.	ANOHR (Btu/KWH)	9815.0	9820.0	9817.0	9894.0	9702.0	9871.0	9828.0
15.	NOF %	99.5	99.0	99.3	92.9	93.5	94.7	94.7
16.	NPC (MW)	514.0	514.0	514.0	514.0	514.0	514.0	514.0

19.	ANOHR Equation	10^6 / AKW * [571.00 - 118.56 * JAN - 87.31 * FEB - 88.00 * MAR - 88.36 * NOV] + 8,698

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Planned Outage Schedules (Estimated)

Gulf Power Company

Period of: January 2004 - December 2004

Plant & Unit	Planned Outage Dates			Reason for Outage
Crist 6	01/31/04	-	02/22/04	General boiler maintenance and inspection.
Crist 7	02/28/04	-	05/16/04	Turbine and general boiler maintenance and inspection.
Smith 1	02/21/04	-	03/21/04	Turbine valve outage and boiler inspection.
Smith 2	03/27/04	-	04/25/04	General boiler maintenance and inspection.
Daniel 1	01/17/04	-	01/30/04	Semi-annual maintenance and inspection
Daniel 1	10/09/04	-	12/24/04	General boiler maintenance and inspection.
Daniel 2	01/10/04	-	02/22/04	General boiler maintenance and inspection.

Notes Regarding Estimated Planned Outage Schedules

Gulf Power Company

Period of: January 2004 - December 2004

It is important to understand that estimated dates for planned outages and their bar chart schedules are frequently changed in timing and work scope due to system conditions, findings of inspections, subcontractor requirements, material availability and so on.

Please note that in addition to the outages scheduled for the target period of January 2004 - December 2004, the outages shown below are currently planned and could be rescheduled for the target period.

Plant & Unit	Planned Outage Dates	Reason for Outage
None		

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GULF POWER COMPANY
PROJECTED PURCHASED POWER CONTRACT TRANSACTIONS
JANUARY 2004 - DECEMBER 2004

Contract		MW Purchase/(Sale)	Capacity ($) Costs/(Receipts)
Southern Company Intercompany Interchange (IIC)			
	January 2004	485.0	1,380,481
	February	364.6	415,231
	March	495.2	552,636
	April	103.6	55,910
	May	81.9	93,536
	June	272.3	1,736,350
	July	361.4	6,298,381
	August	327.5	5,700,300
	September	292.5	2,372,298
	October	354.3	203,080
	November	124.8	71,149
	December	258.5	148,135
	SUBTOTAL		19,027,487
Solutia			
	January 2004	19.0	62,202
	February	19.0	62,202
	March	19.0	62,202
	April	19.0	62,202
	May	19.0	62,202
	June	19.0	62,202
	July	19.0	62,202
	August	19.0	62,202
	September	19.0	62,202
	October	19.0	62,202
	November	19.0	62,202
	December	19.0	62,202
	SUBTOTAL		746,424

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 5
COMPANY/ Gulf Power
WITNESS: H.H.B-1
DATE: 11-12-03

GULF POWER COMPANY
PROJECTED PURCHASED POWER CONTRACT TRANSACTIONS
JANUARY 2004 - DECEMBER 2004

Contract	Capacity ($) Costs/(Receipts)
Non-Firm Capacity Sales	
January 2004	(12,056)
February	(12,056)
March	(12,056)
April	(12,056)
May	(12,056)
June	(12,056)
July	(12,056)
August	(12,056)
September	(12,056)
October	(3,500)
November	(3,500)
December	(3,500)
SUBTOTAL	(119,004)
TOTAL	**19,654,907**

Exhibit No. ____ (PRM-1)

Confidential Document (confidential information redacted)

Progress Energy Florida, Inc.
Risk Management Plan
Fuel Procurement and Wholesale Power Purchases

I. Objective

The objective of Progress Energy Florida, Inc.'s, (PEF) Risk Management plan is to provide the mechanisms to manage PEF's overall fuel costs and wholesale power purchases to provide reliable service to PEF's customers. As a result, this should ultimately reduce the number of mid-course corrections to the fuel factor portion of the customer's bill. The risk management plan allows for the use of various tools to reduce price volatility of natural gas and oil using approved products to hedge either financially and/or physically.

Progress Energy Carolinas, Inc., acts as agent for PEF. PEF has adopted Progress Ventures' risk management policies and practices.

II. Fossil Fuel and Purchased Power Future Needs

A. Fossil Fuel

1. Coal
   - PEF plans to burn approximately 6 million tons of coal per year in 2004 and in 2005

2. Residual Oil
   - PEF plans to burn approximately 9.5 million bbls. of #6 fuel oil per year in 2004 and 9.8 million bbls. in 2005

3. Distillate Oil
   - PEF plans to burn approximately 600,000 bbls. of #2 fuel oil per year in 2004 and 700,000 bbls. In 2005

4. Natural Gas
   - PEF plans to burn approximately 55,000,000 MMBtu in 2004 and approximately 58,500,000 MMBtu in 2005

B. Purchased Power - PEF plans to purchase approximately 0.6 million MWH/year and sell approximately 1.1 million MWH/year on the wholesale market in 2004 and 2005.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. Comp. Ex. 6
COMPANY/ Progress FL. Energy, Inc.
WITNESS: PRM-1 + PRM-2
DATE: 11-12-03

III. Risk Management Profile

A. Risk Identification * The primary risks PEF has identified with procurement of fossil fuels and purchased power are:

1. Coal

- Plant availability due to unscheduled outages
- Supply or transport problems due to labor disputes, weather, or other unforeseen delays
- Coal quality errors
- Financial strength of suppliers
- Changes in laws regulating mining, transportation or burning of coal
- Price volatility

2. Oil (Residual and Distillate)

- Differences between forecasted/scheduled requirements and actual requirements due to economic changes, overall power demand, weather changes, change in price relationships between competing fuels, plant availability (maintenance/unexpected shutdowns or startups), out-of-economic plant dispatch (e.g., due to transmission system constraints), power market changes, etc.
- Differences between forecasted/scheduled deliveries and actual deliveries due to supply or transport problems, loading and unloading delays, etc.
- Fuel quality problems such as blending errors, off-spec deliveries, changes in SO2 values, changes in plant fuel handling capability, etc.
- Changes in laws, regulations, plant permits, etc. that affect the amount, cost, testing requirements or quality of oil required
- Impact of regulatory, management, internal and external audit reviews
- General industry changes that impact overall availability/cost/quality of fuel oil
- Price volatility and fuel oil market related factors

3. Natural Gas

- Imbalance penalties with interstate pipelines as a result of over/under burns based on differences between forecasted /scheduled gas and actual requirements due to, but not limited to, changes in weather, plant availability, and alert day tolerances
- Deliveries by interstate pipelines and suppliers impacted by force majeure events, such as pipeline disruptions, production outages, hurricanes, etc.

- Natural gas storage level deviation from expected norms
- Crude oil prices
- Degree day deviations from expected monthly norms
- Defaults by suppliers (for example, bankruptcy)
- Price risk based on volatility in the natural gas industry caused by commodity funds (technical trading)
- Contractual disputes regarding payment and deliveries

4. Purchased Power

- Default risk – inability of the supplier to obtain adequate resources to deliver the power per contract or agreement
- Directional price risk – e.g., purchased power contracts in which the price of the purchased power is tied to an index
- Physical risk – inability of electrical grid to reliably support power transfer
- Credit risk – inability of contract counterparty to deliver per contract resulting in purchase of higher cost purchased power
- Basis risk – e.g., supplier(s) can experience adverse weather as compared with PEF's service territory

*Acts of terrorism are considered beyond PEF's control

B. Risk Quantification

- Quantification of various risks, including stop-loss limits and Value-at-Risk (VaR) calculations, are included in Progress Ventures Risk Management Guidelines Appendix 13.

C. Risk Management (Daily Management Activities)

1. Coal

- Review actual conditions and adjust delivery schedules as needed
- Maintain contacts with plants and suppliers
- Monitor market prices and spot market options
- Monitor suppliers financial strength
- Build flexibility on volume terms etc., into agreements
- Develop alternative supply sources whenever possible

2. Oil

- Monitor actual conditions and consumption levels vs. forecasted levels and update forecasts frequently as conditions change. Adjust delivery schedules as needed
- Monitor actual delivery status and maintain frequent contact with suppliers and receiving plants to anticipate problems and take corrective action
- Keep current on market prices and activity. Utilize contract price options, inventory, and spot market options as appropriate. PEF has used, and continues to use, negotiated fixed prices as a method of stabilizing prices. This is usually accomplished by fixing prices on all or part of individual ships or a series of shipments to be delivered over a period of time of one to three months.
- Continue to scrutinize a supplier's financial strength in order to assess ongoing creditworthiness.

3. Natural Gas

- Monitor plant gas burns vs. forecasted gas burns. If gas burn is projected to be out of tolerance on the pipeline, reschedule gas and re-allocate gas to different plants, or switching to alternative fuels, like oil
- Use fuel oil, where applicable, to maintain load
- Build additional optionality into seasonal/term contracts by specifying the use of a daily or a monthly market index (with the right to select either one), include take or release triggers on volumes to allow added flexibility, as well as the right to mutually agree to a fixed price
- Implement term contracts that allow swing volumes
- Evaluate fixing a percentage of the monthly natural gas requirements, in order to offset volatility for the ratepayers
- Evaluate zero cost collars for physical natural gas requirements in lieu of, or in conjunction with, fixed-price natural gas
- Evaluate the premium cost of purchasing a call option for a percentage of the utility's monthly natural gas requirements
- Use physical fuel oil inventory, where applicable, to dispatch at lowest fuel price. Logistics of physical fuel oil inventory levels must also be managed with this alternative
- Monitor natural gas trends to determine the direction of long-term market swings
- Re-market any excess gas supplies/capacity, separately or bundled, on a daily basis
- Continue to scrutinize a supplier's financial strength in order to assess ongoing creditworthiness

4. Purchased Power

    - PEF assesses each supplier's ability to deliver power based on historical reliability as a supplier (default risk) and credit ratings
    - PEF utilizes both fixed price contracts (next day purchases) and variable price contracts tied to a specific counterparty's incremental cost
    - PEF utilizes firm transmission paths where available for reliable purchased power

5. Portfolio Management

    - PEF will manage its risks associated with meeting its forecasted load requirements by maintaining a generation fleet with the capability of fuel switching, contracting for a diverse fuel supply and transportation portfolio, and the use of sales and purchases of energy to and from outside sources.

D. Acceptable Level of Risk

1. Oil and Coal - The amount of risk considered acceptable is based on past experiences with what has been successful and evaluating the risk profile of any problems or opportunities based on this experience.

2. Natural Gas - Decisions regarding acceptable risk are based on the circumstances at the time natural gas is purchased. The circumstances at the time may include scenarios involving all or a part of the following: force majeure events, fuel oil inventories, competitive fuel pricing, supply constraints, forward pricing trends etc. For example, if the utility views a strong directional market trend for natural gas based on industry reports, events in the marketplace, demand, national storage levels, etc., the utility would consider implementing the risk management tools identified for managing natural gas risk.

3. Purchased Power- Considerations for purchasing power on a long term and mid-term basis include, but are not limited to the following:
    - Price curves – directional price risk associated with fuel and power
    - Generator outages
    - Load forecast
    - Physical risk associated with transfer capability of transmission system
    - Credit worthiness of potential supplier(s)
    - Default risk of potential supplier(s)
    - Basis risk – e.g., supplier(s) can experience adverse weather as compared with PEF's service territory

E. Constraints to Implementing Financial Hedging Tools

1. Energy Trading and Risk Management Software System
   - Progress Ventures (Ventures) is in Phase 1 timeline of transitioning to the Zainet electronic software system. Anticipated completion of Phase 1 should occur by October 1st for PEF. Phase 2 of the software system will begin after the completion of Phase 1. Phase 2 contains the natural gas software system (Gas Management System) that will be used for financial and physical transactions to capture and report risk. Anticipated completion of Phase 2 is June 1, 2004.

2. Financial Trading Expertise
   - This process has been delayed until PEF is closer to implementing Phase 2 of the Zainet system. At that time, PEF will evaluate the skill set and staffing requirements in the front, middle, and back office to, (i) transact in the financial markets, and (ii) to monitor, control, bill and report financial transactions.

IV. Fuel Procurement and Wholesale Purchased Power Plans for 2004

1. Coal
   [redacted]

2. Oil
   - [redacted]

3. Natural Gas
   - [redacted]

4. Purchased Power
   - [redacted]
   - [redacted]

V. Guidelines

1. The Board of Directors has established a Risk Management Policy which directs the Risk Management Committee (RMC) to oversee Progress Energy's management of financial risks. The Risk Management Policy states the RMC shall regularly report on activities related to and carried out under the Policy to the Chief Executive Officer (CEO), the Board of Directors and the Finance Committee. The CEO is ultimately responsible for the company's management of risk.

2. The Risk Management Committee Guidelines identify the roles, responsibilities and decision making process of the RMC and its agents.

3. Progress Ventures Risk Management Guidelines provide a methodology to assess, report, and mitigate risk associated with trading and marketing activities and procurement. In addition, there is a product approval process to provide a structure to validate that all significant product risks have been identified and integrated into the risk control structure.

4. Progress Ventures Credit Risk Management Guidelines provide a methodology to evaluate, measure, mitigate, and report credit risk associated with Ventures trading, marketing, and procurement activities.

VI. Processes (Front Office)

PEF's Oil Process Analysis, PEF's Natural Gas Process Analysis, and Progress Fuels' Coal Purchasing Procedures provide the procedures utilized to implement PEF's risk management plan. To date, "Nucleus" is PEF's natural gas transaction software system utilized to track and verify natural gas transactions. Zainet (Phase 1) will become the system of record (anticipated to be October 1, 2003) to track and verify natural gas transactions. "FMS" (Fuel Management System) is the system used to track and verify coal and oil transactions.

VII. Risk Reporting (Middle Office)

Risk control generates reports and distributes to both trading and senior management on a daily basis. This is the primary mechanism to communicate group performance to management, the RMC, and the Board of Directors. The reports include all current positions and updates according to the markets. Market changes include pricing, correlation, volatility, et cetera. In addition, as conditions differ from day-to-day, gas scheduling updates deals with best-available information to correctly reflect how much gas is received and delivered at their respective delivery and receipt points.

A. Risk control manages all of the following activities:

1. Forward Curves - Forward curves provide prices for delivery of products at future dates. Forward curves provide the critical data necessary to calculate mark-to-market, value-at-risk, and stress testing. These curves are generated daily.

2. Market Pricing – Daily prices received from index providers are updated on a daily basis to settle or to mark all positions to the correct market price as of close of business.

3. Mark-to-Market (MTM) - MTM is a methodology utilized to value all physical and financial instruments, including those associated with assets. MTM measures unrealized gains and losses (forward positions) prior to contract settlement by calculating the difference between the transaction price and the forward curve.

4. Stress Testing - Stress testing is used to simulate extreme market conditions (e.g., hurricane), and the results are delivered in the daily reports.

VIII. Controls and Oversight

1. The Risk Management Committee (RMC) – The RMC oversees Progress Energy's management of financial risks.

Committee Members

- Chief Executive Officer - Progress Energy, Inc. (Optional)
- Chief Financial Officer - Progress Energy, Inc. (Chair)
- President – Progress Energy Service Company, LLC
- President – Energy Supply business unit
- President – Progress Ventures
- Executive Vice President – General Counsel – Progress Energy, Inc.
- Senior Vice President – Finance and Information Technology (*non-voting*) – Progress Energy, Inc.

Committee Members Responsibilities

- Identifies, assesses, and monitors corporate financial risks
- Approves:
  - (i) Risk guidelines for various company activities
  - (ii) New and existing trading, marketing, procurements and hedging products
  - (iii) Analytical methodologies, models and assumptions
  - (iv) Organization structure to ensure adequate segregation of duties
- Reviews:

(i) Aggregate market and credit capital for approval by the BOD
(ii) Summary positions and financial reports
(iii) Broad trading, marketing, hedging, and procurement strategies
(iv) General business conditions, market and credit risk exposures

- Presents to the CEO, BOD and Finance Committee:
  (i) Recommended aggregate market and credit limits and modifications for approval
  (ii) Summary positions and financial reports
  (iii) Summary of valuation methods, key controls, limit exceptions and violations
  (iv) Special studies as requested
- Creates sub-committees to provide greater attention to risk issues in various company activities

2. Trading, Marketing and Fuels Sub-Committee - The Trading, Marketing and Fuels Subcommittee's objective is to review market and credit risk exposure and business development and proposal opportunities associated with trading, marketing and procurement activities.

Sub-Committee Members

- President – Ventures
- VP – Regulated Commercial Operations
- VP – Ventures Finance
- Manager – Middle Office
- Manager - Risk Management
- Manager – Credit
- Trading and Marketing Managers

Sub-Committee Responsibilities - Reviews, at a minimum:

- Commodity market trends
- Trading, hedging, procurement and marketing strategies
- Aggregate commodity risk exposures
- Market and credit exposure versus defined limits
- New products and services for RMC approval
- Model and model assumptions
- Key operational controls
- Credit exposure versus defined limits
- Pricing methodologies
- Summary exception reports
- Conducts special studies requested by the RMC
- Approves liquidity limits

3. Auditing Department – Audit Services provides independent assurance and consulting services that ensure regulatory compliance, effective corporate governance, operational excellence, and appropriate risk management for all major activities including fuel procurement. Activities are audited based on relative priority rather than a fixed cycle. Within that framework, Audit Services' oversight of fuel procurement risk management activities is addressed from the following perspectives:
    - Compliance
    - Trading and procurement
    - Operational

SUMMARY OF THE SUCCESS OF RISK MANAGEMENT PLAN

Progress Energy Florida's (PEF) Risk Management Plan (Plan) was developed in mid-2002 to identify certain risks associated with fossil fuel and wholesale power requirements. The Plan also identified, among other things, the controls, oversight, risk reporting, and processes that PEF would follow to carry out its Plan. To that end, the following summarizes the various items listed above for 2002:

I. Risk Identification – Force Majeure Events

A. FGT Pipeline Leak - May 2 – PEF utilized #6 and #2 fuel oil to meet its projected load. PEF implemented voltage reduction and demand side management during the time.

B. FGT Compressor Station unscheduled outage – May 5-12 – PEF again utilized #6 and #2 fuel oil to meet its projected load. PEF also had to implement voltage reduction during this time.

C. Tropical Storm Isidore – September 24-27 – PEF relied on #6 and #2 fuel oil, as well as PEF went considerably short on Gulfstream (using line pack) to meet projected load. PEF repaid the gas to Gulfstream Natural Gas after the storm.

D. Hurricane Lili – October 1-4 – Once again, PEF utilized the same resources identified above for Tropical Storm Isidore.

II. Daily Management Activities

A. Fuel Oil – The difference between actual burns and forecast burns was 10 million barrels projected vs. an actual of 9.85 million barrels of #6 oil and 1.6 million barrels projected vs. an actual of 1.55 million barrels of #2 oil. Month-to-month variances were taken care of by working with suppliers to (i) either change delivery schedules as necessary, and/or (ii) not ordering #2 fuel oil truck loads to the plants.

B. Natural Gas – Month-end gas imbalances were either traded with third-party counterparties or cashed out by FGT. Due to PEF's Operational Balance Agreement with Gulfstream, PEF is allowed to carryover imbalances to the next month without penalty. The monthly imbalances were a result of balancing actual burns versus nominations with FGT that could not be mitigated due to alert day restrictions and/or end-of-month timing.

C. Coal – Two coal suppliers were temporarily suspended due to quality problems.

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D. PEF purchased daily transmission on an as available basis to support economy purchases. In addition, PEF purchased 200 MWs of monthly transmission for the period May through October to improve diversity and availability of economic purchase opportunities.

E. Daily dispatch continues on an economic basis for its ratepayers. This dispatch is updated twice daily for next-day projected load forecasts. This process may, on occasion, deviate from economic dispatch due to operational problems at plant sites or forces beyond our control.

F. One coal supplier filed bankruptcy, however, there was no interruption of service

III. Monitoring of Industry Events

A. PEF continues to monitor the War with Iraq and its short- and long-term affects in the market, as well as the events leading up to the war.

B. Weekly gas storage injection/withdrawal amounts published by EIA are being followed to determine short- and long-term affects to future gas prices. In addition, rig counts are also followed to monitor the increase/decrease of drilling activity for replacement reserves.

C. Defaults by suppliers based on bankruptcies or announcements to exit the market are monitored by our credit section, as well as the respective front office personnel. For 2002, we have seen marketing companies like Dynegy, Aquila, Reliant, and El Paso either exit the business totally or reduce staff to return to its core business of managing its existing generation portfolio. Liquidity in the natural gas and power markets have been reduced by these events where major marketing companies have elected to exit the business line of "market making" activities.

IV. Price Risk Mitigation

A. Natural Gas – A zero cost collar was entered into for 20,000 mmbtu/day of natural gas supply for the period December 2002 through and including February 2003 which was not exercised in 2002. PEF has one (1) long-term fixed price contract that resulted in additional cost to ratepayers of $2,098,791. The mark-to-market on this fixed price contract for its remaining term is valued at approximately $33 million favorable for the ratepayers.

B. Wholesale Power – Savings from wholesale sales & purchases for 2002 were as follows:
   1. Sales $5,628,586
   2. Purchases $7,013,273

C. Fuel Oil – For 2002, PEF elected to fix the price on 1,964,727 barrels of #6 fuel oil on various shipments resulting in an overall additional cost to the ratepayers of $1,533,222.

D. Total Value Created: **$9,009,846**

V. Process and Guidelines

A. The Mid Office – Risk Reporting is incorporating forward curves and market pricing to provide daily reporting of mark-to-market and stress testing to Senior Management.

B. Audit Services continues to provide the services outlines in the Plan for fuel and wholesale power purchases. Their audits in 2002 included various aspects related to compliance, trading and procurement, and operational perspectives for fuel procurement and wholesale power purchases. The audits completed in 2002 had no major findings.

C. PEF natural gas, fuel oil, and wholesale power processes/procedures continue to be refined as part of our overall effort to improve business practices.

D. The guidelines referenced in the Plan have been adhered to and no trading and/or credit violations occurred in 2002.

Progress Energy Florida, Inc.
Docket No. 030001-EI
Witness: Murphy
Exhibit No. PRM-2

PROGRESS ENERGY FLORIDA, INC.

Hedging information provided as part of the 2002 Fuel Clause Final True-up Filing as required by Order No. PSC-02-1484-FOF-EI, Issued October 30, 2002 in Docket No. 011605-EI

Hedging Instrument	Fuel Type	Total 2002 Volume Hedged*		Avg Period of Hedge	Total Cost of Hedge
Fixed Price Contact	Heavy Oil	1,964,727	bbls	daily	$0
Fixed Price Contact	Natural Gas	10,263,435	mmbtu	daily	$0
Zero Cost Collar	Natural Gas	620,000	mmbtu	daily	$0

* Physical Only

Progress Energy Florida
Docket No. 030001-EI
Witness: Jacob
Exhibit No. _____ (MFJ-1)

GPIF REWARD/PENALTY SCHEDULES

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GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ACTUAL

Progress Energy Florida
January 2002 - December 2002

	Generating Performance Incentive Points (GPIF)	Fuel Savings/Loss ($)	Generating Performance Incentive Factor ($)
	10	$50,391,526	$8,050,257
	9	$45,352,373	$7,245,231
	8	$40,313,220	$6,440,206
	7	$35,274,068	$5,635,180
	6	$30,234,915	$4,830,154
	5	$25,195,763	$4,025,129
	4	$20,156,610	$3,220,103
****	3.455	$17,409,388	$2,781,223
	3	$15,117,458	$2,415,077
	2	$10,078,305	$1,610,051
	1	$5,039,153	$805,026
	0	$0	$0
	-1	($6,352,053)	($805,026)
	-2	($12,704,105)	($1,610,051)
	-3	($19,056,158)	($2,415,077)
	-4	($25,408,210)	($3,220,103)
	-5	($31,760,263)	($4,025,129)
	-6	($38,112,315)	($4,830,154)
	-7	($44,464,368)	($5,635,180)
	-8	($50,816,420)	($6,440,206)
	-9	($57,168,473)	($7,245,231)
	-10	($63,520,526)	($8,050,257)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

Progress Energy Florida
January 2002 - December 2002

1	Beginning of period balance of common equity	2,031,644,452
2	END OF MONTH BALANCE OF COMMON EQUITY:	
	Month of JANUARY 2002	$2,066,548,114
3	Month of FEBRUARY 2002	$2,010,755,515
4	Month of MARCH 2002	$1,989,513,129
5	Month of APRIL 2002	$2,005,303,917
6	Month of MAY 2002	$1,976,442,219
7	Month of JUNE 2002	$2,006,541,822
8	Month of JULY 2002	$2,046,093,355
9	Month of AUGUST 2002	$2,019,135,149
10	Month of SEPTEMBER 2002	$2,036,729,285
11	Month of OCTOBER 2002	$2,050,241,392
12	Month of NOVEMBER 2002	$2,028,890,786
13	Month of DECEMBER 2002	$2,050,734,235
14	Average common equity for the period	$ 2,024,505,644
15	25 Basis Points	0.0025
16	Revenue Expansion Factor	61.3808%
17	Maximum allowed incentive dollars	$8,245,680
18	Jurisdictional Sales *	36,832,117 MWH
19	Total Sales *	37,725,274 MWH
20	Jurisdictional Separation Factor	97.63%
21	Maximum allowed jurisdictional incentive dollars	$8,050,257

* Net sales (Sales - Interruptible)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF SYSTEM ACTUAL GPIF POINTS

Progress Energy Florida
January 2002 - December 2002

Plant/Unit	Performance Indicator EAF or ANOHR	Weighting Factor %	Unit Points	Weighted Unit Points
Anclote 1	EAF	8.78	10.000	0.878
	ANOHR	4.46	-4.637	-0.207
Anclote 2	EAF	3.13	10.000	0.313
	ANOHR	3.91	0.000	0.000
Crystal River 1	EAF	3.51	10.000	0.351
	ANOHR	2.71	0.000	0.000
Crystal River 2	EAF	13.39	1.986	0.266
	ANOHR	3.51	0.000	0.000
Crystal River 3	EAF	7.81	10.000	0.781
	ANOHR	10.89	0.000	0.000
Crystal River 4	EAF	5.19	-0.688	-0.036
	ANOHR	5.36	0.000	0.000
Crystal River 5	EAF	5.62	10.000	0.562
	ANOHR	7.28	-0.774	-0.056
Bartow 3	EAF	2.67	6.784	0.181
	ANOHR	1.39	0.000	0.000
Tiger Bay	EAF	6.76	6.226	0.421
	ANOHR	3.62	0.000	0.000
GPIF System		100.00		3.455

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GENERATION PERFORMANCE INCENTIVE FACTOR
GPIF UNIT PERFORMANCE SUMMARY

Progress Energy Florida
January 2002 - December 2002

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	EAF Adjusted Actual (%)	Estimated Fuel Savings/ Loss ($000)
Anclote 1	8.78	91.71	95.57	84.05	$4,426	($3,269)	96.35	$4,426.0
Anclote 2	3.13	81.68	84.11	76.72	$1,579	($2,672)	84.33	$1,579.0
Crystal River 1	3.51	86.75	92.87	74.82	$1,770	($7,066)	92.92	$1,770.0
Crystal River 2	13.39	65.14	71.66	52.88	$6,745	($8,834)	66.43	$1,339.3
Crystal River 3	7.81	96.21	98.00	92.51	$3,938	($6,718)	98.64	$3,938.0
Crystal River 4	5.19	76.48	78.14	73.10	$2,615	($4,740)	76.25	($326.3)
Crystal River 5	5.62	94.52	97.09	89.30	$2,833	($6,760)	98.51	$2,833.0
Bartow 3	2.67	80.12	84.02	72.41	$1,344	($750)	82.76	$911.7
Tiger Bay	6.76	80.31	83.22	74.49	$3,404	($974)	82.12	$2,119.3
GPIF System	56.86				$28,654	($41,783)		$18,590.0

Plant/Unit	Weighting Factor (%)	ANOHR Target (BTU/KWH)	NOF	ANOHR RANGE Min. (Btu/kwh)	ANOHR RANGE Max. (Btu/kwh)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)	ANOHR Adjusted Actual (Btu/kwh)	Estimated Fuel Savings/ Loss ($000)
Anclote 1	4.46	10183	48.9	9833	10534	$2,249	($2,249)	10386	($1,043.0)
Anclote 2	3.91	10090	53.1	9783	10396	$1,970	($1,970)	10124	$0.0
Crystal River 1	2.71	9750	93.5	9529	9972	$1,365	($1,365)	9725	$0.0
Crystal River 2	3.51	9619	93.0	9323	9915	$1,771	($1,771)	9656	$0.0
Crystal River 3	10.89	10283	101.1	10096	10470	$5,486	($5,486)	10288	$0.0
Crystal River 4	5.36	9413	85.7	9187	9639	$2,704	($2,704)	9441	$0.0
Crystal River 5	7.28	9376	90.2	9137	9614	$3,668	($3,668)	9463	($283.9)
Bartow 3	1.39	10053	71.7	9832	10275	$701	($701)	10008	$0.0
Tiger Bay	3.62	8267	71.9	7782	8751	$1,823	($1,823)	8313	$0.0
GPIF System	43.14					$21,738	($21,738)		($1,326.9)

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GENERATION PERFORMANCE INCENTIVE FACTOR
ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida
January 2002 - December 2002

Plant/Unit	ACTUAL EAF %	ADJUSTMENTS (1) TO EAF %	ADJUSTED ACTUAL EAF %
Crystal River 1	92.92	0.00	92.92
Crystal River 2	83.61	-17.18	66.43
Crystal River 3	98.64	0.00	98.64
Crystal River 4	78.49	-2.24	76.25
Crystal River 5	87.20	11.31	98.51
Anclote 1	90.72	5.63	96.35
Anclote 2	97.10	-12.77	84.33
Bartow 3	87.62	-4.86	82.76
Tiger Bay	89.90	-7.78	82.12

Plant/Unit	ACTUAL ANOHR BTU/KWH	ADJUSTMENTS (2) TO ANOHR BTU/KWH	ADJUSTED ACTUAL ANOHR BTU/KWH
Crystal River 1	9799.7	-74.3	9725.4
Crystal River 2	9813.4	-157.3	9656.1
Crystal River 3	10290.7	-2.7	10288.0
Crystal River 4	9451.9	-10.4	9441.4
Crystal River 5	9487.1	-23.8	9463.3
Anclote 1	10306.9	79.0	10385.9
Anclote 2	10108.9	15.1	10124.1
Bartow 3	10048.2	-40.4	10007.8
Tiger Bay	7777.3	535.6	8312.9

(1) For documentation of adjustments to actual EAF, see sheet 6.
(2) For documentation of adjustments to actual ANOHR, see sheet 7.

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GENERATION PERFORMANCE INCENTIVE FACTOR
ADJUSTMENTS TO EAF ACTUAL

Progress Energy Florida
January 2002 - December 2002

EAF adjustments for Planned Outage Hours			AN1	AN2	CR1	CR2	CR3	CR4	CR5	BA3	TB
1	Actual POH	Hrs.	512.32	0.00	0.00	0.00	0.00	1546.10	1005.96	553.23	457.63
2	Target POH	Hrs.	0.00	1152.00	0.00	1800.00	0.00	1752.00	0.00	1008.00	1176.00
3	Adj. Factor (PH-POHT/PH-POHA)		1.06	0.87	1.00	0.79	1.00	0.97	1.13	0.94	0.91
4	Actual EUOH	Hrs.	300.94	254.23	620.59	1435.62	118.79	338.03	115.53	531.34	427.12
5	Adj. EUOH (3*4)	Hrs.	319.64	220.80	620.59	1140.63	118.79	328.39	130.52	501.89	390.16
6	Actual EAF	%	90.72	97.10	92.92	83.61	98.64	78.49	87.20	87.62	89.90
7	Adjusted EAF (using 2 & 5)	%	96.35	84.33	92.92	66.43	98.64	76.25	98.51	82.76	82.12
8	Difference (7-6)	%	5.63	-12.77	0.00	-17.18	0.00	-2.24	11.31	-4.86	-7.78
9	Total adj. to EAF	%	5.63	-12.77	0.00	-17.18	0.00	-2.24	11.31	-4.86	-7.78

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ADJUSTMENTS TO ANOHR ACTUAL

Progress Energy Florida
January 2002 - December 2002

ANOHR adjustments for Target NOF			CR1	CR2	CR3	CR4	CR5	AN1	AN2	BA3	TB
1	Target NOF	%	93.5	93.0	101.1	85.7	90.2	48.9	53.1	71.7	71.9
2	Target ANOHR	Btu/kwh	9750.2	9619.1	10283.1	9413.0	9375.7	10183.1	10089.8	10053.3	8266.8
3	Actual NOF	%	81.8	77.3	100.8	83.6	85.1	54.0	53.9	68.3	86.5
4	Calc. ANOHR (using 3)	Btu/kwh	9824.5	9776.4	10285.8	9423.4	9399.4	10104.1	10074.7	10093.6	7731.2
5	Total adj. to ANOHR (2-4)	Btu/kwh	-74.3	-157.3	-2.7	-10.4	-23.8	79.0	15.1	-40.4	535.6

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
January 2002 - December 2002
Unit: Anclote 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10.000	$4,426,000	96.35	10	$2,249,192	9832.5	
	10	$4,426,000	95.57	9	$2,024,273	9860.1	
	9	$3,983,400	95.18	8	$1,799,354	9887.7	
	8	$3,540,800	94.80	7	$1,574,435	9915.2	
	7	$3,098,200	94.41	6	$1,349,515	9942.8	
	6	$2,655,600	94.03	5	$1,124,596	9970.3	
	5	$2,213,000	93.64	4	$899,677	9997.9	
	4	$1,770,400	93.25	3	$674,758	10025.4	
	3	$1,327,800	92.87	2	$449,838	10053.0	
	2	$885,200	92.48	1	$224,919	10080.6	
	1	$442,600	92.10	0	$0	10108.1	
		$0	91.71	0	$0	10183.1	
	0	$0	91.71	0	$0	10258.1	
		$0	91.71	-1	($224,919)	10285.7	
	-1	($326,900)	90.95	-2	($449,838)	10313.2	
	-2	($653,800)	90.18	-3	($674,758)	10340.8	
	-3	($980,700)	89.41	-4	($899,677)	10368.4	
	-4	($1,307,600)	88.65	-4.637	($1,043,008)	10385.9	****
	-5	($1,634,500)	87.88	-5	($1,124,596)	10395.9	
	-6	($1,961,400)	87.12	-6	($1,349,515)	10423.5	
	-7	($2,288,300)	86.35	-7	($1,574,435)	10451.0	
	-8	($2,615,200)	85.58	-8	($1,799,354)	10478.6	
	-9	($2,942,100)	84.82	-9	($2,024,273)	10506.2	
	-10	($3,269,000)	84.05	-10	($2,249,192)	10533.7	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
8.78%	4.46%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
January 2002 - December 2002
Unit: Anclote 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10.000	$1,579,000	84.33	10	$1,969,775	9783.1	
	10	$1,579,000	84.11	9	$1,772,797	9806.3	
	9	$1,421,100	83.87	8	$1,575,820	9829.4	
	8	$1,263,200	83.62	7	$1,378,842	9852.6	
	7	$1,105,300	83.38	6	$1,181,865	9875.8	
	6	$947,400	83.14	5	$984,887	9898.9	
	5	$789,500	82.90	4	$787,910	9922.1	
	4	$631,600	82.65	3	$590,932	9945.3	
	3	$473,700	82.41	2	$393,955	9968.5	
	2	$315,800	82.17	1	$196,977	9991.6	
	1	$157,900	81.92	0	$0	10014.8	
		$0	81.68	0	$0	10089.8	
	0	$0	81.68	0.000	$0	10124.1	****
		$0	81.68	0	$0	10164.8	
	-1	($267,200)	81.18	-1	($196,977)	10188.0	
	-2	($534,400)	80.69	-2	($393,955)	10211.1	
	-3	($801,600)	80.19	-3	($590,932)	10234.3	
	-4	($1,068,800)	79.69	-4	($787,910)	10257.5	
	-5	($1,336,000)	79.20	-5	($984,887)	10280.6	
	-6	($1,603,200)	78.70	-6	($1,181,865)	10303.8	
	-7	($1,870,400)	78.21	-7	($1,378,842)	10327.0	
	-8	($2,137,600)	77.71	-8	($1,575,820)	10350.1	
	-9	($2,404,800)	77.21	-9	($1,772,797)	10373.3	
	-10	($2,672,000)	76.72	-10	($1,969,775)	10396.5	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.13%	3.91%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
January 2002 - December 2002
Unit: Bartow 3

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$1,344,000	84.02	10	$701,404	9831.5	
	9	$1,209,600	83.63	9	$631,263	9846.2	
	8	$1,075,200	83.24	8	$561,123	9860.9	
	7	$940,800	82.85	7	$490,983	9875.5	
****	6.784	$911,723	82.76	6	$420,842	9890.2	
	6	$806,400	82.46	5	$350,702	9904.9	
	5	$672,000	82.07	4	$280,561	9919.6	
	4	$537,600	81.68	3	$210,421	9934.2	
	3	$403,200	81.29	2	$140,281	9948.9	
	2	$268,800	80.90	1	$70,140	9963.6	
	1	$134,400	80.51	0	$0	9978.3	
		$0	80.12	0.000	$0	10007.8	****
	0	$0	80.12	0	$0	10053.3	
		$0	80.12	0	$0	10128.3	
	-1	($75,000)	79.35	-1	($70,140)	10142.9	
	-2	($150,000)	78.58	-2	($140,281)	10157.6	
	-3	($225,000)	77.81	-3	($210,421)	10172.3	
	-4	($300,000)	77.04	-4	($280,561)	10187.0	
	-5	($375,000)	76.27	-5	($350,702)	10201.6	
	-6	($450,000)	75.49	-6	($420,842)	10216.3	
	-7	($525,000)	74.72	-7	($490,983)	10231.0	
	-8	($600,000)	73.95	-8	($561,123)	10245.7	
	-9	($675,000)	73.18	-9	($631,263)	10260.3	
	-10	($750,000)	72.41	-10	($701,404)	10275.0	

Equivalent Availability *Weighting Factor:*	Heat Rate Weighting Factor:
2.67%	1.39%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
January 2002 - December 2002
Unit: Crystal River 1

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10.000	$1,770,000	92.92	10	$1,365,059	9528.7	
	10	$1,770,000	92.87	9	$1,228,553	9543.3	
	9	$1,593,000	92.26	8	$1,092,047	9558.0	
	8	$1,416,000	91.65	7	$955,541	9572.6	
	7	$1,239,000	91.04	6	$819,035	9587.3	
	6	$1,062,000	90.43	5	$682,530	9602.0	
	5	$885,000	89.81	4	$546,024	9616.6	
	4	$708,000	89.20	3	$409,518	9631.3	
	3	$531,000	88.59	2	$273,012	9645.9	
	2	$354,000	87.98	1	$136,506	9660.6	
	1	$177,000	87.37	0	$0	9675.2	
		$0	86.75	0.000	$0	9725.4	****
	0	$0	86.75	0	$0	9750.2	
		$0	86.75	0	$0	9825.2	
	-1	($706,600)	85.56	-1	($136,506)	9839.9	
	-2	($1,413,200)	84.37	-2	($273,012)	9854.6	
	-3	($2,119,800)	83.17	-3	($409,518)	9869.2	
	-4	($2,826,400)	81.98	-4	($546,024)	9883.9	
	-5	($3,533,000)	80.78	-5	($682,530)	9898.5	
	-6	($4,239,600)	79.59	-6	($819,035)	9913.2	
	-7	($4,946,200)	78.40	-7	($955,541)	9927.8	
	-8	($5,652,800)	77.20	-8	($1,092,047)	9942.5	
	-9	($6,359,400)	76.01	-9	($1,228,553)	9957.2	
	-10	($7,066,000)	74.82	-10	($1,365,059)	9971.8	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
3.51%	2.71%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
January 2002 - December 2002
Unit: Crystal River 2

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$6,745,000	71.66	10	$1,771,167	9323.1	
	9	$6,070,500	71.00	9	$1,594,051	9345.2	
	8	$5,396,000	70.35	8	$1,416,934	9367.3	
	7	$4,721,500	69.70	7	$1,239,817	9389.4	
	6	$4,047,000	69.05	6	$1,062,700	9411.5	
	5	$3,372,500	68.40	5	$885,584	9433.6	
	4	$2,698,000	67.74	4	$708,467	9455.7	
	3	$2,023,500	67.09	3	$531,350	9477.8	
	2	$1,349,000	66.44	2	$354,233	9499.9	
****	1.986	$1,339,262	66.43	1	$177,117	9522.0	
	1	$674,500	65.79	0	$0	9544.1	
		$0	65.14	0	$0	9619.1	
	0	$0	65.14	0.000	$0	9656.1	****
		$0	65.14	0	$0	9694.1	
	-1	($883,400)	63.91	-1	($177,117)	9716.2	
	-2	($1,766,800)	62.69	-2	($354,233)	9738.3	
	-3	($2,650,200)	61.46	-3	($531,350)	9760.4	
	-4	($3,533,600)	60.23	-4	($708,467)	9782.5	
	-5	($4,417,000)	59.01	-5	($885,584)	9804.6	
	-6	($5,300,400)	57.78	-6	($1,062,700)	9826.7	
	-7	($6,183,800)	56.56	-7	($1,239,817)	9848.8	
	-8	($7,067,200)	55.33	-8	($1,416,934)	9870.9	
	-9	($7,950,600)	54.11	-9	($1,594,051)	9893.0	
	-10	($8,834,000)	52.88	-10	($1,771,167)	9915.1	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
13.39%	3.51%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
January 2002 - December 2002
Unit: Crystal River 3

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10.000	$3,938,000	98.64	10	$5,485,663	10095.9	
	10	$3,938,000	98.00	9	$4,937,097	10107.1	
	9	$3,544,200	97.82	8	$4,388,531	10118.3	
	8	$3,150,400	97.64	7	$3,839,964	10129.5	
	7	$2,756,600	97.46	6	$3,291,398	10140.8	
	6	$2,362,800	97.28	5	$2,742,832	10152.0	
	5	$1,969,000	97.10	4	$2,194,265	10163.2	
	4	$1,575,200	96.92	3	$1,645,699	10174.4	
	3	$1,181,400	96.74	2	$1,097,133	10185.6	
	2	$787,600	96.56	1	$548,566	10196.8	
	1	$393,800	96.39	0	$0	10208.1	
		$0	96.21	0	$0	10283.1	
	0	$0	96.21	0.000	$0	10288.0	****
		$0	96.21	0	$0	10358.1	
	-1	($671,800)	95.84	-1	($548,566)	10369.3	
	-2	($1,343,600)	95.47	-2	($1,097,133)	10380.5	
	-3	($2,015,400)	95.10	-3	($1,645,699)	10391.7	
	-4	($2,687,200)	94.73	-4	($2,194,265)	10402.9	
	-5	($3,359,000)	94.36	-5	($2,742,832)	10414.1	
	-6	($4,030,800)	93.99	-6	($3,291,398)	10425.4	
	-7	($4,702,600)	93.62	-7	($3,839,964)	10436.6	
	-8	($5,374,400)	93.25	-8	($4,388,531)	10447.8	
	-9	($6,046,200)	92.88	-9	($4,937,097)	10459.0	
	-10	($6,718,000)	92.51	-10	($5,485,663)	10470.2	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
7.81%	10.89%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
January 2002 - December 2002
Unit: Crystal River 4

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$2,615,000	78.14	10	$2,703,503	9186.9	
	9	$2,353,500	77.97	9	$2,433,153	9202.0	
	8	$2,092,000	77.81	8	$2,162,802	9217.1	
	7	$1,830,500	77.64	7	$1,892,452	9232.2	
	6	$1,569,000	77.48	6	$1,622,102	9247.3	
	5	$1,307,500	77.31	5	$1,351,751	9262.4	
	4	$1,046,000	77.15	4	$1,081,401	9277.5	
	3	$784,500	76.98	3	$811,051	9292.7	
	2	$523,000	76.82	2	$540,701	9307.8	
	1	$261,500	76.65	1	$270,350	9322.9	
		$0	76.48	0	$0	9338.0	
	0	$0	76.48	0	$0	9413.0	
		$0	76.48	0.000	$0	9441.4	****
****	-0.688	($326,271)	76.25	0	$0	9488.0	
	-1	($474,000)	76.15	-1	($270,350)	9503.1	
	-2	($948,000)	75.81	-2	($540,701)	9518.2	
	-3	($1,422,000)	75.47	-3	($811,051)	9533.3	
	-4	($1,896,000)	75.13	-4	($1,081,401)	9548.5	
	-5	($2,370,000)	74.79	-5	($1,351,751)	9563.6	
	-6	($2,844,000)	74.45	-6	($1,622,102)	9578.7	
	-7	($3,318,000)	74.11	-7	($1,892,452)	9593.8	
	-8	($3,792,000)	73.77	-8	($2,162,802)	9608.9	
	-9	($4,266,000)	73.44	-9	($2,433,153)	9624.0	
	-10	($4,740,000)	73.10	-10	($2,703,503)	9639.1	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.19%	5.36%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
January 2002 - December 2002
Unit: Crystal River 5

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
****	10.000	$2,833,000	98.51	10	$3,668,376	9137.1	
	10	$2,833,000	97.09	9	$3,301,539	9153.5	
	9	$2,549,700	96.83	8	$2,934,701	9169.9	
	8	$2,266,400	96.58	7	$2,567,864	9186.2	
	7	$1,983,100	96.32	6	$2,201,026	9202.6	
	6	$1,699,800	96.06	5	$1,834,188	9218.9	
	5	$1,416,500	95.81	4	$1,467,351	9235.3	
	4	$1,133,200	95.55	3	$1,100,513	9251.6	
	3	$849,900	95.29	2	$733,675	9268.0	
	2	$566,600	95.04	1	$366,838	9284.3	
	1	$283,300	94.78	0	$0	9300.7	
		$0	94.52	0	$0	9375.7	
	0	$0	94.52	0	$0	9450.7	
		$0	94.52	-0.774	($283,925)	9463.3	****
	-1	($676,000)	94.00	-1	($366,838)	9467.0	
	-2	($1,352,000)	93.48	-2	($733,675)	9483.4	
	-3	($2,028,000)	92.95	-3	($1,100,513)	9499.7	
	-4	($2,704,000)	92.43	-4	($1,467,351)	9516.1	
	-5	($3,380,000)	91.91	-5	($1,834,188)	9532.5	
	-6	($4,056,000)	91.39	-6	($2,201,026)	9548.8	
	-7	($4,732,000)	90.86	-7	($2,567,864)	9565.2	
	-8	($5,408,000)	90.34	-8	($2,934,701)	9581.5	
	-9	($6,084,000)	89.82	-9	($3,301,539)	9597.9	
	-10	($6,760,000)	89.30	-10	($3,668,376)	9614.2	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.62%	7.28%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
January 2002 - December 2002
Unit: Tiger Bay

	Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)	
	10	$3,404,000	83.22	10	$1,823,386	7782.5	
	9	$3,063,600	82.93	9	$1,641,047	7823.4	
	8	$2,723,200	82.64	8	$1,458,708	7864.3	
	7	$2,382,800	82.35	7	$1,276,370	7905.3	
****	6.226	$2,119,336	82.12	6	$1,094,031	7946.2	
	6	$2,042,400	82.06	5	$911,693	7987.1	
	5	$1,702,000	81.76	4	$729,354	8028.1	
	4	$1,361,600	81.47	3	$547,016	8069.0	
	3	$1,021,200	81.18	2	$364,677	8109.9	
	2	$680,800	80.89	1	$182,339	8150.9	
	1	$340,400	80.60	0	$0	8191.8	
		$0	80.31	0	$0	8266.8	
	0	$0	80.31	0.000	$0	8312.9	****
		$0	80.31	0	$0	8341.8	
	-1	($97,400)	79.72	-1	($182,339)	8382.7	
	-2	($194,800)	79.14	-2	($364,677)	8423.7	
	-3	($292,200)	78.56	-3	($547,016)	8464.6	
	-4	($389,600)	77.98	-4	($729,354)	8505.5	
	-5	($487,000)	77.40	-5	($911,693)	8546.5	
	-6	($584,400)	76.82	-6	($1,094,031)	8587.4	
	-7	($681,800)	76.24	-7	($1,276,370)	8628.3	
	-8	($779,200)	75.66	-8	($1,458,708)	8669.3	
	-9	($876,600)	75.08	-9	($1,641,047)	8710.2	
	-10	($974,000)	74.49	-10	($1,823,386)	8751.1	

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
6.76%	3.62%

Issued by: Progress Energy Florida

Filed:
Suspended:
Effective:
Docket No.:
Order No.:

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Anclote 1	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-Dec Period
1. EAF	98.96	99.42	97.59	95.31	94.56	96.35	96.14	95.63	96.28	93.72	24.36	99.49	90.72
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
3. SH	244.6	130.4	744.0	719.0	743.5	720.0	744.0	743.2	720.0	745.0	200.4	744.0	7198.0
4. RSH	495.5	541.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1037.1
5. UH	3.9	0.0	0.0	0.0	0.5	0.0	0.0	0.8	0.0	0.0	519.7	0.0	525.0
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	512.3	0.0	512.3
7. FOH	3.9	0.0	0.0	0.0	0.0	0.0	0.0	0.8	0.0	0.0	7.4	0.0	12.1
8. MOH	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
9. PFOH	62.2	2.1	0.0	13.3	5.5	0.2	45.8	34.5	4.0	107.5	48.4	0.3	323.8
10. LR PF (MW) **	6.4	198.3	0.0	56.2	62.0	108.4	61.8	36.9	33.0	62.1	256.0	254.5	78.1
11. PMOH	10.1	10.0	56.2	105.7	123.1	82.3	72.3	91.2	83.1	104.5	0.0	11.4	749.9
12. LR PM (MW)	147.7	153.5	159.0	151.7	159.0	159.0	158.7	159.0	159.0	159.0	0.0	159.0	157.7
13. NSC (MW)	498	498	498	498	498	498	498	498	498	498	498	498	498
14. OPER MBTU	672363	298647	2074458	2067207	2189147	2000672	2108750	2155645	2314376	2425228	290698	1340085	19937277
15. NET GEN (MWH)	67611	25628	207568	207767	213455	195737	203951	204314	226209	237450	22553	122120	1934363
16. ANOHR (BTU/KWH)	9944.6	11653.2	9994.1	9949.6	10255.8	10221.2	10339.5	10550.6	10231.1	10213.6	12889.6	10973.5	10306.9
17. NOF (%)	55.50	39.47	56.02	58.03	57.65	54.59	55.05	55.21	63.09	64.00	22.60	32.96	53.96
18. NPC (MW)	498	498	498	498	498	498	498	498	498	498	498	498	498
ANOHR EQUATION:	ANOHR=	-15.471	x NOF +	10938.9									

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** January SH and RSH were revised after the January 2003 monthly data filing. This revision involved a shift of 0.6 hours between SH and RSH, which also impacts January NOF and annual SH and RSH. There was no impact to annual NOF.

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Anclote 2	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-Dec Period
1. EAF	98.95	99.34	91.34	97.55	94.16	96.25	97.91	97.05	97.66	97.21	99.39	98.65	97.10
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
3. SH	698.5	672.0	501.4	719.0	744.0	720.0	744.0	744.0	720.0	745.0	720.0	520.1	8248.0
4. RSH	45.5	0.0	192.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	223.9	461.8
5. UH	0.0	0.0	50.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.2
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8. MOH	0.0	0.0	50.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	50.2
9. PFOH	0.4	0.0	4.0	0.7	9.5	0.0	9.3	7.6	0.0	0.0	0.0	2.7	34.1
10. LR PF (MW)	484.7	0.0	229.1	251.9	71.7	0.0	91.5	285.1	0.0	0.0	0.0	251.8	165.9
11. PMOH	25.1	10.5	39.2	54.8	133.5	85.6	44.2	55.9	53.5	65.9	11.7	25.7	605.5
12. LR PM (MW)	145.0	207.8	156.0	156.0	156.0	156.0	155.5	155.8	156.0	156.0	185.4	167.4	157.4
13. NSC (MW)	495	495	495	495	495	495	495	495	495	495	495	495	495
14. OPER MBTU	1726553	1165516	1455542	2078806	2179060	1961400	2137088	2036123	2314749	2464877	1717443	1008517	22245675
15. NET GEN (MWH)	173090	114584	147324	210986	213512	195578	205548	198801	231159	247009	166156	96850	2200597
16. ANOHR (BTU/KWH)	9974.9	10171.7	9879.9	9852.8	10205.8	10028.7	10397.0	10242.0	10013.7	9978.9	10336.3	10413.2	10108.9
17. NOF (%)	50.06	34.45	59.36	59.28	57.98	54.88	55.81	53.98	64.86	66.98	46.62	37.62	53.90
18. NPC (MW)	495	495	495	495	495	495	495	495	495	495	495	495	495
ANOHR EQUATION:	ANOHR=	-18.331	x NOF +	11062.7									

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ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Bartow 3	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-Dec Period
1. EAF	98.00	87.13	21.38	95.21	87.57	92.68	97.34	85.91	97.18	95.97	97.10	96.92	87.62
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
3. SH	586.4	625.2	116.0	712.3	678.2	681.7	744.0	669.2	720.0	745.0	720.0	744.0	7742.0
4. RSH	157.6	0.0	45.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	202.9
5. UH	0.0	46.9	582.8	6.7	65.9	38.3	0.0	74.8	0.0	0.0	0.0	0.0	815.2
6. POH	0.0	13.5	539.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	553.2
7. FOH	0.0	33.4	43.0	3.3	0.0	38.3	0.0	74.8	0.0	0.0	0.0	0.0	192.7
8. MOH	0.0	0.0	0.0	3.4	65.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	69.2
9. PFOH	539.7	88.5	0.0	0.0	96.1	0.0	7.8	0.5	0.0	6.7	0.0	0.0	739.2
10. LR PF (MW)	1.3	46.9	0.0	0.0	14.0	0.0	14.0	153.8	0.0	34.0	0.0	0.0	9.0
11. PMOH	18.9	32.8	5.7	50.3	36.1	26.1	35.3	54.4	36.3	53.1	38.4	41.0	428.2
12. LR PM (MW)	121.9	119.8	78.8	112.8	113.3	112.7	111.3	111.3	114.1	111.1	110.7	113.9	112.8
13. NSC (MW)	204	204	204	204	204	204	204	204	204	204	204	204	204
14. OPER MBTU	761752	726495	147004	1068657	993741	1000269	1082981	999820	1110807	1173773	917706	853012	10836017
15. NET GEN (MWH)	75037	69508	14650	107163	99322	99840	107902	94164	111267	117242	94236	88075	1078406
16. ANOHR (BTU/KWH)	10151.7	10452.0	10034.4	9972.3	10005.2	10018.7	10036.7	10617.9	9983.3	10011.5	9738.4	9685.1	10048.2
17. NOF (%)	62.73	54.50	61.92	73.74	71.79	71.79	71.09	68.97	75.75	77.14	64.16	58.03	68.28
18. NPC (MW)	204	204	204	204	204	204	204	204	204	204	204	204	204
ANOHR EQUATION:	ANOHR=	-11.726	x NOF +	10894.3									

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ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 1	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-Dec Period
1. EAF	99.16	99.94	92.72	98.47	97.96	67.50	87.82	96.19	83.61	98.30	98.06	95.17	92.92
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
3. SH	744.0	672.0	691.1	719.0	744.0	498.0	669.0	744.0	628.5	745.0	720.0	744.0	8318.5
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	52.9	0.0	0.0	222.1	75.0	0.0	91.5	0.0	0.0	0.0	441.5
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	0.0	0.0	0.0	222.1	75.0	0.0	91.5	0.0	0.0	0.0	388.6
8. MOH	0.0	0.0	52.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	52.9
9. PFOH	14.0	0.0	8.3	3.8	36.0	1.5	53.6	54.3	26.6	0.9	23.8	0.0	222.8
10. LR PF (MW)	169.0	0.0	59.0	77.9	159.8	75.0	42.4	118.4	231.5	55.6	119.4	0.0	120.2
11. PMOH	0.0	6.7	0.0	87.9	0.0	39.2	36.2	24.7	23.4	39.1	11.0	111.9	380.1
12. LR PM (MW)	0.0	22.0	0.0	44.3	0.0	112.9	100.5	174.7	166.0	121.3	222.7	121.8	108.2
13. NSC (MW)	379	379	379	379	379	379	379	379	379	379	379	379	379
14. OPER MBTU	2031544	1887377	2157932	2247814	2301237	1511616	2041019	2304801	1948432	2536606	2145261	2164089	25277727
15. NET GEN (MWH)	208234	194135	224212	233824	234962	152038	204735	231041	195239	260494	219216	221302	2579432
16. ANOHR (BTU/KWH)	9756.1	9722.0	9624.5	9613.3	9794.1	9942.4	9969.1	9975.7	9979.7	9737.7	9786.1	9778.9	9799.7
17. NOF (%)	73.85	76.22	85.60	85.81	83.33	80.56	80.75	81.94	81.96	92.26	80.33	78.48	81.82
18. NPC (MW)	379	379	379	379	379	379	379	379	379	379	379	379	379
ANOHR EQUATION:	ANOHR=	-6.335	x NOF +	10342.9									

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ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 2	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-Dec Period
1. EAF	80.28	94.69	68.15	92.53	87.43	83.52	93.84	96.95	51.52	85.87	85.59	83.36	83.61
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
3. SH	674.5	672.0	557.6	719.0	667.2	618.1	741.4	744.0	393.1	745.0	720.0	744.0	7995.8
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	69.5	0.0	186.4	0.0	76.8	101.9	2.6	0.0	326.9	0.0	0.0	0.0	764.2
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	110.1	0.0	0.0	101.9	2.6	0.0	326.9	0.0	0.0	0.0	541.6
8. MOH	69.5	0.0	76.3	0.0	76.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	222.6
9. PFOH	179.1	262.0	93.8	122.3	45.3	13.4	73.5	42.2	34.6	731.0	775.9	22.9	2396.0
10. LR PF (MW)	78.4	50.7	167.7	170.8	105.0	133.0	195.9	171.3	208.2	61.0	59.9	67.0	80.1
11. PMOH	309.3	76.9	106.7	20.6	17.5	26.1	86.0	36.3	21.7	57.9	75.0	410.6	1244.5
12. LR PM (MW)	75.9	52.8	82.9	254.0	193.3	242.8	76.5	105.0	163.5	113.7	52.2	142.8	108.0
13. NSC (MW)	486	486	486	486	486	486	486	486	486	486	486	486	486
14. OPER MBTU	2237293	2419906	1875621	2676094	2689073	2356882	2808389	2942007	1531591	2856694	2518087	2568877	29480514
15. NET GEN (MWH)	231525	253827	189885	274596	275375	240122	283020	295124	150404	289458	257035	263741	3004112
16. ANOHR (BTU/KWH)	9663.3	9533.7	9877.7	9745.6	9765.1	9815.4	9922.9	9968.7	10183.2	9869.1	9796.7	9740.1	9813.4
17. NOF (%)	70.63	77.72	70.07	78.58	84.92	79.94	78.55	81.62	78.73	79.95	73.46	72.94	77.31
18. NPC (MW)	486	486	486	486	486	486	486	486	486	486	486	486	486

ANOHR EQUATION: ANOHR= -10.021 x NOF + 10551.1

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** December PFOH and LR PF (MW) were revised after the January 2003 monthly data filing. This revision also impacts December EAF and annual EAF, PFOH and LR PF (MW).

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 3	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-Dec Period
1. EAF	100.00	100.00	100.00	100.00	94.73	99.99	100.00	100.00	99.96	99.90	89.10	100.00	98.64
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
3. SH	744.0	672.0	744.0	719.0	717.4	720.0	744.0	744.0	720.0	745.0	679.0	744.0	8692.4
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	0.0	0.0	26.6	0.0	0.0	0.0	0.0	0.0	41.0	0.0	67.6
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	41.0	0.0	41.0
8. MOH	0.0	0.0	0.0	0.0	26.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	26.6
9. PFOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	10.5	50.2	0.0	60.7
10. LR PF (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	53.5	150.5	0.0	133.7
11. PMOH	0.0	0.0	0.0	0.0	38.3	6.0	0.0	0.0	7.2	0.0	171.9	0.0	223.4
12. LR PM (MW)	0.0	0.0	0.0	0.0	251.8	12.1	0.0	0.0	28.0	0.0	123.1	0.0	139.1
13. NSC (MW) **	765	765	765	765	765	765	765	765	765	765	765	765	765
14. OPER MBTU	5923217	5347366	5921051	5731382	5739545	5735772	5928931	5929199	5734669	5927420	5103738	5928018	68950308
15. NET GEN (MWH)	579868	524292	580019	558027	545308	555651	571233	571147	555341	577656	499133	582592	6700267
16. ANOHR (BTU/KWH)	10214.8	10199.2	10208.4	10270.8	10525.3	10322.6	10379.2	10381.2	10326.4	10261.2	10225.2	10175.2	10290.7
17. NOF (%)	101.88	101.99	101.91	101.45	99.36	100.88	100.36	100.35	100.82	101.36	96.09	102.36	100.76
18. NPC (MW)	765	765	765	765	765	765	765	765	765	765	765	765	765
ANOHR EQUATION:	ANOHR=	-8.146	x NOF +	11106.6									

Issued by: Progress Energy Florida

ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 4	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-Dec Period
1. EAF	97.92	99.50	26.13	0.00	36.73	96.75	93.39	99.54	99.83	93.64	99.90	99.92	78.49
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
3. SH	744.0	672.0	195.1	0.0	311.4	708.9	696.2	744.0	720.0	710.3	720.0	744.0	6965.9
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	548.9	719.0	432.6	11.1	47.8	0.0	0.0	34.7	0.0	0.0	1794.1
6. POH	0.0	0.0	548.9	719.0	278.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1546.1
7. FOH	0.0	0.0	0.0	0.0	105.5	11.1	47.8	0.0	0.0	34.7	0.0	0.0	199.1
8. MOH	0.0	0.0	0.0	0.0	48.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	48.9
9. PFOH	12.0	19.4	7.5	0.0	0.0	53.7	7.3	4.6	21.4	54.3	0.8	3.6	184.6
10. LR PF (MW)	589.4	124.7	70.0	0.0	0.0	165.1	132.2	92.1	40.7	147.1	78.1	118.0	160.4
11. PMOH	10.4	0.0	0.0	0.0	63.3	0.0	0.0	22.5	0.0	9.0	3.0	0.0	108.2
12. LR PM (MW)	388.1	0.0	0.0	0.0	434.0	0.0	0.0	92.0	0.0	132.2	149.0	0.0	325.5
13. NSC (MW)	720	720	720	720	720	720	720	720	720	720	720	720	720
14. OPER MBTU	3654646	3107193	1169282	0	1185949	4142774	4150764	4588858	4628464	4401150	4316659	4303088	39648825
15. NET GEN (MWH)	377504	322166	124243	0	112674	445675	445289	486551	495120	472657	455580	457342	4194801
16. ANOHR (BTU/KWH)	9681.1	9644.7	9411.3	0.0	10525.5	9295.5	9321.5	9431.4	9348.2	9311.5	9475.1	9408.9	9451.9
17. NOF (%)	70.47	66.59	88.45	0.00	50.25	87.32	88.83	90.83	95.51	92.42	87.88	85.38	83.64
18. NPC (MW)	720	720	720	720	720	720	720	720	720	720	720	720	720
ANOHR EQUATION:	ANOHR=	-5.064	x NOF +	9847.0									

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ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Crystal River 5	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-Dec Period
1. EAF	99.64	100.00	99.94	99.93	96.92	99.70	95.89	99.18	99.89	13.06	43.59	99.81	87.20
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
3. SH	744.0	672.0	744.0	719.0	742.8	720.0	717.2	744.0	720.0	97.3	313.8	744.0	7678.1
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	0.0	0.0	1.2	0.0	26.8	0.0	0.0	647.7	406.2	0.0	1081.9
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	647.7	358.2	0.0	1006.0
7. FOH	0.0	0.0	0.0	0.0	1.2	0.0	26.8	0.0	0.0	0.0	47.9	0.0	76.0
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PFOH	2.6	0.0	0.8	2.1	156.1	3.6	0.0	57.1	19.6	0.0	0.0	11.5	253.3
10. LR PF (MW)	411.5	0.0	420.6	166.1	87.0	431.6	0.0	76.7	30.1	0.0	0.0	88.8	90.3
11. PMOH	12.1	0.0	0.0	0.0	5.8	0.0	22.4	0.0	0.0	0.0	0.0	0.0	40.2
12. LR PM (MW)	71.0	0.0	0.0	0.0	336.1	0.0	120.2	0.0	0.0	0.0	0.0	0.0	136.8
13. NSC (MW)	717	717	717	717	717	717	717	717	717	717	717	717	717
14. OPER MBTU	3942224	3316053	4375731	4504238	4344707	4203579	4333360	4480222	4550885	574374	1497133	4346596	44469100
15. NET GEN (MWH)	409143	345746	466781	475181	451453	442899	459256	475083	481997	62027	153286	464470	4687322
16. ANOHR (BTU/KWH)	9635.3	9591.0	9374.3	9479.0	9623.8	9491.1	9435.6	9430.4	9441.7	9260.1	9766.9	9358.2	9487.1
17. NOF (%)	76.70	71.76	87.50	92.17	84.77	85.79	89.31	89.06	93.37	88.94	68.12	87.07	85.14
18. NPC (MW)	717	717	717	717	717	717	717	717	717	717	717	717	717
ANOHR EQUATION:	ANOHR=	-4.720	x NOF +	9801.3									

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ACTUAL UNIT PERFORMANCE DATA

Progress Energy Florida

Tiger Bay	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-Dec Period
1. EAF	95.39	100.00	38.49	92.98	100.00	98.74	96.24	99.50	98.28	61.18	100.00	100.00	89.90
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8760
3. SH	709.7	672.0	286.4	669.3	744.0	710.9	716.0	742.7	708.0	464.7	720.0	744.0	7887.7
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	34.3	0.0	457.6	49.7	0.0	9.1	28.0	1.3	12.0	280.3	0.0	0.0	872.3
6. POH	0.0	0.0	457.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	457.6
7. FOH	34.3	0.0	0.0	4.8	0.0	9.1	28.0	1.3	12.0	2.4	0.0	0.0	91.9
8. MOH	0.0	0.0	0.0	44.9	0.0	0.0	0.0	0.0	0.0	277.9	0.0	0.0	322.8
9. PFOH	0.0	0.0	0.0	0.9	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0	1.3
10. LR PF (MW)	0.0	0.0	0.0	199.0	0.0	0.0	0.0	0.0	182.3	0.0	0.0	0.0	193.0
11. PMOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.4	0.0	9.6	0.0	0.0	12.0
12. LR PM (MW)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	207.3	0.0	190.9	0.0	0.0	194.2
13. NSC (MW)	207	207	207	207	207	207	207	207	207	207	207	207	207
14. OPER MBTU	957345	857613	416591	964718	1028100	994984	973008	1077232	990339	654641	1038361	1034172	10987103
15. NET GEN (MWH)	124067	109266	50603	125115	135461	127566	128747	133894	128376	82584	134918	132109	1412706
16. ANOHR (BTU/KWH)	7716.4	7848.9	8232.5	7710.6	7589.6	7799.8	7557.5	8045.4	7714.4	7927.0	7696.2	7828.2	7777.3
17. NOF (%)	84.45	78.55	85.36	90.30	87.96	86.68	86.87	87.09	87.60	85.85	90.52	85.78	86.52
18. NPC (MW)	207	207	207	207	207	207	207	207	207	207	207	207	207
ANOHR EQUATION:	ANOHR=	-36.715	x NOF +	10907.9									

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PLANNED OUTAGE SCHEDULES
ACTUAL

Progress Energy Florida
January 2002 - December 2002

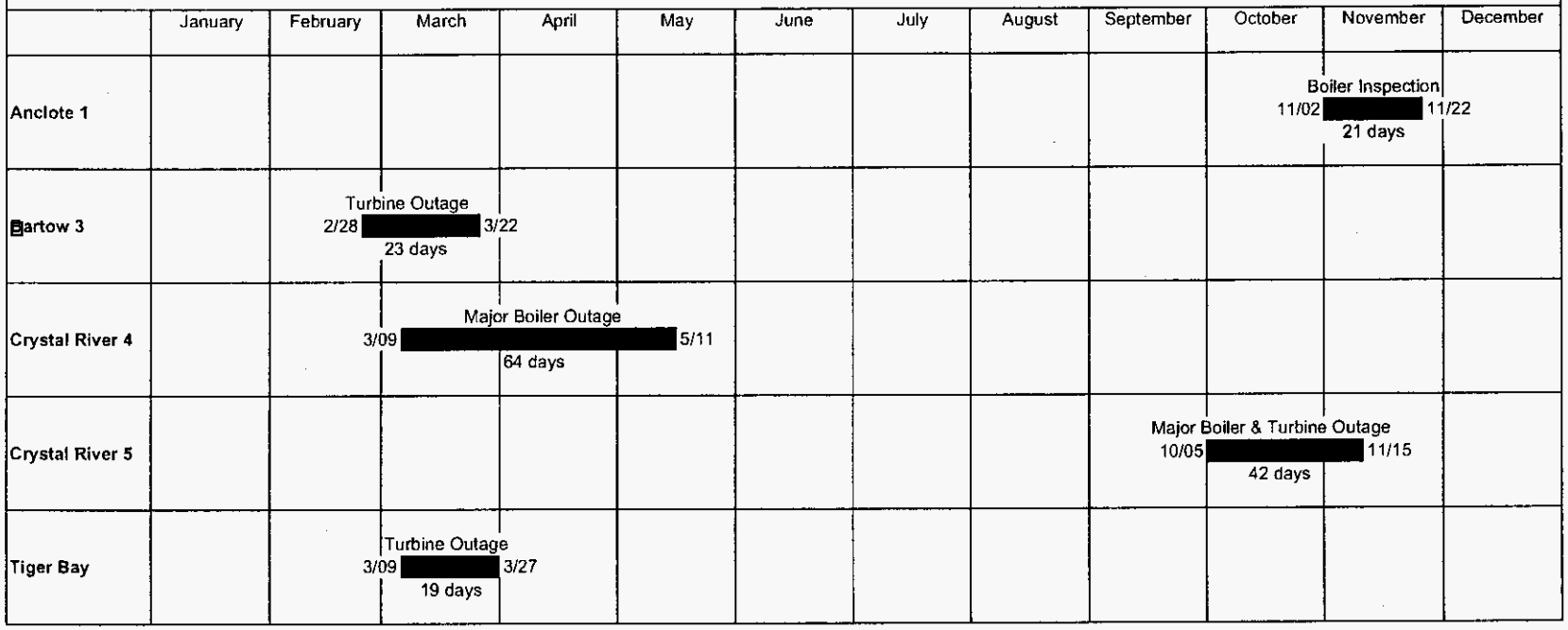
Plant/Unit	Planned Outage Dates	Reason for Outage
Anclote 1	11/02 (0001) - 11/22 (2400)	Boiler Inspection
Bartow 3	2/28 (0001) - 3/22 (2400)	Turbine Outage
Crystal River 4	3/09 (0001) - 5/11 (2400)	Major Boiler Outage
Crystal River 5	10/05 (0001) - 11/15 (2400)	Major Boiler & Turbine Outage
Tiger Bay	3/09 (0001) - 3/27 (2400)	Turbine Outage

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Planned Outage Schedule - Actual

Progress Energy Florida
January 2002 - December 2002



Progress Energy Florida
Docket No. 030001-EI
Witness: Jacob
Exhibit No. ____ (MFJ-3)

GPIF Targets and Ranges for January through December 2004

STANDARD FORM GPIF SCHEDULES

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GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE

ESTIMATED

Progress Energy Florida
Period of: January 2004 - December 2004

Generating Performance Incentive Points (GPIF)	Fuel Saving/Loss ($)	Generating Performance Incentive Factor ($)
10	$66,950,546	$8,552,779
9	$60,255,492	$7,697,501
8	$53,560,437	$6,842,223
7	$46,865,382	$5,986,945
6	$40,170,328	$5,131,667
5	$33,475,273	$4,276,389
4	$26,780,218	$3,421,112
3	$20,085,164	$2,565,834
2	$13,390,109	$1,710,556
1	$6,695,055	$855,278
0	$0	$0
-1	($8,663,355)	($855,278)
-2	($17,326,709)	($1,710,556)
-3	($25,990,064)	($2,565,834)
-4	($34,653,418)	($3,421,112)
-5	($43,316,773)	($4,276,389)
-6	($51,980,128)	($5,131,667)
-7	($60,643,482)	($5,986,945)
-8	($69,306,837)	($6,842,223)
-9	($77,970,192)	($7,697,501)
-10	($86,633,546)	($8,552,779)

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GENERATION PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ESTIMATED

Progress Energy Florida
Period of: January 2004 - December 2004

1	Beginning of period balance of common equity	$2,060,000,172	
	END OF MONTH BALANCE OF COMMON EQUITY:		
2	Month of JANUARY 2004	$2,089,820,128	
3	Month of FEBRUARY 2004	$2,082,120,299	
4	Month of MARCH 2004	$2,101,674,858	
5	Month of APRIL 2004	$2,114,653,607	
6	Month of MAY 2004	$2,117,660,265	
7	Month of JUNE 2004	$2,151,672,798	
8	Month of JULY 2004	$2,193,045,557	
9	Month of AUGUST 2004	$2,205,640,552	
10	Month of SEPTEMBER 2004	$2,238,354,573	
11	Month of OCTOBER 2004	$2,259,962,017	
12	Month of NOVEMBER 2004	$2,247,079,605	
13	Month of DECEMBER 2004	$2,263,983,706	
14	Average common equity for the period (Summation of LINE 1 through LINE 13 divided by 13)	$2,163,512,934	
15	25 Basis Points	0.0025	
16	Revenue Expansion Factor	61.3808%	
17	Maximum allowed incentive dollars (LINE 14 times LINE 15 divided by LINE 16)	$8,811,847	
18	Jurisdictional Sales	38,930,464	MWH
19	Total Sales	40,107,781	MWH
20	Jurisdictional Separation Factor (LINE 18 divided by LINE 19)	97.06%	
21	Maximum allowed jurisdictional incentive dollars (LINE 17 times LINE 20)	$8,552,779	

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GPIF TARGET AND RANGE SUMMARY

Progress Energy Florida
Period of: January 2004 - December 2004

Plant/Unit	Weighting Factor (%)	EAF Target (%)	EAF RANGE Max. (%)	EAF RANGE Min. (%)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
Anclote 1	2.64	94.43	97.06	89.02	1,766	(1,047)
Anclote 2	5.62	91.14	93.51	86.25	3,760	(3,196)
Crystal River 1	6.93	81.13	84.58	74.26	4,643	(4,558)
Crystal River 2	10.02	81.26	89.76	65.47	6,710	(24,309)
Crystal River 3	6.10	97.14	98.49	94.32	4,084	(5,380)
Crystal River 4	11.31	85.22	87.67	80.24	7,574	(9,951)
Crystal River 5	9.76	93.42	96.49	87.23	6,535	(6,682)
Hines 1	0.97	88.27	89.30	86.15	650	(519)
Tiger Bay	0.83	87.99	90.04	83.83	554	(317)
GPIF System	54.18				36,276	(55,959)

Plant/Unit	Weighting Factor (%)	ANOHR Target (BTU/KWH)	NOF	ANOHR RANGE Min. (BTU/KWH)	ANOHR RANGE Max. (BTU/KWH)	Max. Fuel Savings ($000)	Max. Fuel Loss ($000)
Anclote 1	6.20	10407	46.8	9897	10917	4,151	(4,151)
Anclote 2	3.56	10174	50.4	9891	10458	2,381	(2,381)
Crystal River 1	2.12	9731	90.2	9465	9998	1,419	(1,419)
Crystal River 2	4.04	9685	83.8	9276	10094	2,702	(2,702)
Crystal River 3	11.46	10310	100.0	10097	10524	7,675	(7,675)
Crystal River 4	3.54	9322	93.6	9125	9520	2,371	(2,371)
Crystal River 5	3.74	9389	91.6	9194	9584	2,502	(2,502)
Hines 1	8.37	7530	68.9	7077	7983	5,604	(5,604)
Tiger Bay	2.79	7964	71.5	7725	8202	1,870	(1,870)
GPIF System	45.82					30,675	(30,675)

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COMPARISON OF GPIF TARGETS VS. PRIOR PERIODS' ACTUAL PERFORMANCE AVAILABILITY

Progress Energy Florida
Period of: January 2004 - December 2004

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Target POF	Target EUOF	Target EUOR	Actual Performance 1st Prior Period Jan-Jun 2003 POF	Actual Performance 1st Prior Period Jan-Jun 2003 EUOF	Actual Performance 1st Prior Period Jan-Jun 2003 EUOR	Actual Performance 2nd Prior Period Jan-Dec 2002 POF	Actual Performance 2nd Prior Period Jan-Dec 2002 EUOF	Actual Performance 2nd Prior Period Jan-Dec 2002 EUOR
Anclote 1	2.64	4.87	0.00	5.57	6.11	0.00	6.74	7.74	5.85	3.44	4.17
Anclote 2	5.62	10.36	3.83	5.04	5.62	0.00	7.55	7.55	0.00	2.90	3.06
Crystal River 1	6.93	12.80	11.48	7.39	8.41	0.00	7.61	7.61	0.00	7.08	7.08
Crystal River 2	10.02	18.50	0.00	18.74	18.77	24.66	11.04	14.66	0.00	16.39	16.39
Crystal River 3	6.10	11.26	0.00	2.86	2.86	0.00	0.50	0.50	0.00	1.31	1.31
Crystal River 4	11.31	20.88	9.56	5.22	5.77	0.00	1.22	1.22	17.65	3.86	4.69
Crystal River 5	9.76	18.01	0.00	6.58	6.59	0.00	7.93	7.93	11.48	1.32	1.49
Hines 1	0.97	1.79	9.56	2.16	3.43	9.71	4.76	5.35	9.27	1.48	1.63
Tiger Bay	0.83	1.53	7.65	4.36	4.76	5.37	2.36	2.50	5.22	4.88	5.14
GPIF System Wghtd. Avg.	54.18	100.00	4.15	7.91	8.28	4.82	5.99	6.72	6.28	5.70	5.96

Plant/Unit	Actual Performance 3rd Prior Period Jan-Dec 2001 POF	Actual Performance 3rd Prior Period Jan-Dec 2001 EUOF	Actual Performance 3rd Prior Period Jan-Dec 2001 EUOR	Actual Performance 4th Prior Period Jan-Dec 2000 POF	Actual Performance 4th Prior Period Jan-Dec 2000 EUOF	Actual Performance 4th Prior Period Jan-Dec 2000 EUOR	Actual Performance 5th Prior Period Jan-Dec 1999 POF	Actual Performance 5th Prior Period Jan-Dec 1999 EUOF	Actual Performance 5th Prior Period Jan-Dec 1999 EUOR
Anclote 1	12.04	5.12	6.25	0.00	12.13	13.01	14.40	6.66	8.56
Anclote 2	0.00	7.31	7.87	12.55	3.60	4.43	0.00	7.88	8.25
Crystal River 1	9.38	7.97	8.84	0.00	10.94	10.94	14.15	12.39	15.27
Crystal River 2	15.35	8.41	9.93	0.00	37.25	37.25	0.00	7.35	7.52
Crystal River 3	7.27	4.54	4.89	0.00	3.23	3.23	11.55	2.86	3.23
Crystal River 4	0.00	6.24	6.24	9.73	6.22	6.89	0.00	4.09	4.22
Crystal River 5	10.25	6.43	7.17	0.00	7.05	7.05	15.82	4.14	4.93
Hines 1	15.62	1.87	2.60	10.36	5.01	5.90	10.92	7.20	8.32
Tiger Bay	9.33	3.78	4.17	12.17	3.86	4.49	10.09	6.00	7.50
GPIF System Wghtd. Avg.	7.71	6.65	7.34	3.70	12.34	12.63	7.01	6.23	7.02

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COMPARISON OF GPIF TARGETS VS. PRIOR PERIODS' ACTUAL PERFORMANCE
AVERAGE NET OPERATING HEAT RATE

Progress Energy Florida
Period of: January 2004 - December 2004

Plant/Unit	Target Wt. Factor	Norm. Wt. Factor	Average Heat Rate Target	1st Prior HR Jan 2002 - Dec 2002	2nd Prior HR Jan 2001 - Dec 2001	3rd Prior HR Jan 2000 - Dec 2000
Anclote 1	6.20	13.53	10407	10595	10297	10432
Anclote 2	3.56	7.76	10174	10169	10253	10199
Crystal River 1	2.12	4.63	9731	9701	9689	9708
Crystal River 2	4.04	8.81	9685	9672	9608	9606
Crystal River 3	11.46	25.02	10310	10318	10373	10257
Crystal River 4	3.54	7.73	9322	9350	9328	9230
Crystal River 5	3.74	8.16	9389	9448	9344	9303
Hines 1	8.37	18.27	7530	7473	7420	7405
Tiger Bay	2.79	6.10	7964	8023	7933	7896
GPIF System Weighted Avg.	45.82	100.00	9428	9453	9402	9371

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DERIVATION OF WEIGHTING FACTORS

Progress Energy Florida
Period of: January 2004 - December 2004

Unit Performance *Indicator*	Production Costing Simulation Fuel Cost ($000) At Target (1)	At Maximum Improvement (2)	Savings (3)	*Weighting Factor* (% of Savings)
Anclote 1 EA	1550147	1548381	1766	2.64
Anclote 1 HR	1550147	1545996	4151	6.20
Anclote 2 EA	1550147	1546387	3760	5.62
Anclote 2 HR	1550147	1547766	2381	3.56
Crystal River 1 EA	1550147	1545504	4643	6.93
Crystal River 1 HR	1550147	1548728	1419	2.12
Crystal River 2 EA	1550147	1543437	6710	10.02
Crystal River 2 HR	1550147	1547445	2702	4.04
Crystal River 3 EA	1550147	1546063	4084	6.10
Crystal River 3 HR	1550147	1542472	7675	11.46
Crystal River 4 EA	1550147	1542573	7574	11.31
Crystal River 4 HR	1550147	1547776	2371	3.54
Crystal River 5 EA	1550147	1543612	6535	9.76
Crystal River 5 HR	1550147	1547645	2502	3.74
Hines 1 EA	1550147	1549497	650	0.97
Hines 1 HR	1550147	1544543	5604	8.37
Tiger Bay EA	1550147	1549593	554	0.83
Tiger Bay HR	1550147	1548277	1870	2.79

1. Fuel Adjustment Base Case - all unit performance indicators at Target.
2. All other unit performance indicators at Target.
3. Expressed in replacement costs.

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INCENTIVE POINTS TABLES

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2004 - December 2004

Anclote 1

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$1,766,000	97.06	10	$4,150,710	9896.7
9	$1,589,400	96.79	9	$3,735,639	9940.2
8	$1,412,800	96.53	8	$3,320,568	9983.7
7	$1,236,200	96.27	7	$2,905,497	10027.2
6	$1,059,600	96.01	6	$2,490,426	10070.7
5	$883,000	95.74	5	$2,075,355	10114.3
4	$706,400	95.48	4	$1,660,284	10157.8
3	$529,800	95.22	3	$1,245,213	10201.3
2	$353,200	94.96	2	$830,142	10244.8
1	$176,600	94.69	1	$415,071	10288.3
					10331.8
0	$0	94.43	0	$0	10406.8
					10481.8
-1	($104,700)	93.89	-1	($415,071)	10525.3
-2	($209,400)	93.35	-2	($830,142)	10568.8
-3	($314,100)	92.81	-3	($1,245,213)	10612.3
-4	($418,800)	92.27	-4	($1,660,284)	10655.8
-5	($523,500)	91.73	-5	($2,075,355)	10699.3
-6	($628,200)	91.18	-6	($2,490,426)	10742.8
-7	($732,900)	90.64	-7	($2,905,497)	10786.3
-8	($837,600)	90.10	-8	($3,320,568)	10829.8
-9	($942,300)	89.56	-9	($3,735,639)	10873.3
-10	($1,047,000)	89.02	-10	($4,150,710)	10916.9

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
2.64%	6.20%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2004 - December 2004

Anclote 2

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$3,760,000	93.51	10	$2,381,230	9890.7
9	$3,384,000	93.27	9	$2,143,107	9911.6
8	$3,008,000	93.04	8	$1,904,984	9932.4
7	$2,632,000	92.80	7	$1,666,861	9953.3
6	$2,256,000	92.56	6	$1,428,738	9974.1
5	$1,880,000	92.32	5	$1,190,615	9995.0
4	$1,504,000	92.09	4	$952,492	10015.8
3	$1,128,000	91.85	3	$714,369	10036.7
2	$752,000	91.61	2	$476,246	10057.5
1	$376,000	91.37	1	$238,123	10078.4
					10099.2
0	$0	91.14	0	$0	10174.2
					10249.2
-1	($319,600)	90.65	-1	($238,123)	10270.1
-2	($639,200)	90.16	-2	($476,246)	10290.9
-3	($958,800)	89.67	-3	($714,369)	10311.8
-4	($1,278,400)	89.18	-4	($952,492)	10332.6
-5	($1,598,000)	88.69	-5	($1,190,615)	10353.5
-6	($1,917,600)	88.20	-6	($1,428,738)	10374.3
-7	($2,237,200)	87.71	-7	($1,666,861)	10395.2
-8	($2,556,800)	87.22	-8	($1,904,984)	10416.0
-9	($2,876,400)	86.73	-9	($2,143,107)	10436.9
-10	($3,196,000)	86.25	-10	($2,381,230)	10457.7

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
5.62%	3.56%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2004 - December 2004

Crystal River 1

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$4,643,000	84.58	10	$1,419,219	9464.9
9	$4,178,700	84.23	9	$1,277,297	9484.1
8	$3,714,400	83.89	8	$1,135,375	9503.2
7	$3,250,100	83.54	7	$993,453	9522.4
6	$2,785,800	83.20	6	$851,531	9541.5
5	$2,321,500	82.85	5	$709,609	9560.7
4	$1,857,200	82.51	4	$567,687	9579.8
3	$1,392,900	82.17	3	$425,766	9599.0
2	$928,600	81.82	2	$283,844	9618.1
1	$464,300	81.48	1	$141,922	9637.3
					9656.5
0	$0	81.13	0	$0	9731.5
					9806.5
-1	($455,800)	80.45	-1	($141,922)	9825.6
-2	($911,600)	79.76	-2	($283,844)	9844.8
-3	($1,367,400)	79.07	-3	($425,766)	9863.9
-4	($1,823,200)	78.38	-4	($567,687)	9883.1
-5	($2,279,000)	77.70	-5	($709,609)	9902.2
-6	($2,734,800)	77.01	-6	($851,531)	9921.4
-7	($3,190,600)	76.32	-7	($993,453)	9940.6
-8	($3,646,400)	75.64	-8	($1,135,375)	9959.7
-9	($4,102,200)	74.95	-9	($1,277,297)	9978.9
-10	($4,558,000)	74.26	-10	($1,419,219)	9998.0

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
6.93%	2.12%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2004 - December 2004

Crystal River 2

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$6,710,000	89.76	10	$2,702,019	9276.4
9	$6,039,000	88.91	9	$2,431,817	9309.8
8	$5,368,000	88.06	8	$2,161,615	9343.1
7	$4,697,000	87.21	7	$1,891,413	9376.5
6	$4,026,000	86.36	6	$1,621,211	9409.8
5	$3,355,000	85.51	5	$1,351,009	9443.2
4	$2,684,000	84.66	4	$1,080,807	9476.6
3	$2,013,000	83.81	3	$810,606	9509.9
2	$1,342,000	82.96	2	$540,404	9543.3
1	$671,000	82.11	1	$270,202	9576.7
					9610.0
0	$0	81.26	0	$0	9685.0
					9760.0
-1	($2,430,900)	79.68	-1	($270,202)	9793.4
-2	($4,861,800)	78.10	-2	($540,404)	9826.8
-3	($7,292,700)	76.52	-3	($810,606)	9860.1
-4	($9,723,600)	74.95	-4	($1,080,807)	9893.5
-5	($12,154,500)	73.37	-5	($1,351,009)	9926.9
-6	($14,585,400)	71.79	-6	($1,621,211)	9960.2
-7	($17,016,300)	70.21	-7	($1,891,413)	9993.6
-8	($19,447,200)	68.63	-8	($2,161,615)	10027.0
-9	($21,878,100)	67.05	-9	($2,431,817)	10060.3
-10	($24,309,000)	65.47	-10	($2,702,019)	10093.7

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
10.02%	4.04%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2004 - December 2004

Crystal River 3

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$4,084,000	98.49	10	$7,675,079	10096.6
9	$3,675,600	98.36	9	$6,907,571	10110.5
8	$3,267,200	98.22	8	$6,140,063	10124.3
7	$2,858,800	98.09	7	$5,372,555	10138.2
6	$2,450,400	97.95	6	$4,605,047	10152.1
5	$2,042,000	97.82	5	$3,837,540	10166.0
4	$1,633,600	97.68	4	$3,070,032	10179.8
3	$1,225,200	97.55	3	$2,302,524	10193.7
2	$816,800	97.41	2	$1,535,016	10207.6
1	$408,400	97.27	1	$767,508	10221.4
					10235.3
0	$0	97.14	0	$0	10310.3
					10385.3
-1	($538,000)	96.86	-1	($767,508)	10399.2
-2	($1,076,000)	96.58	-2	($1,535,016)	10413.1
-3	($1,614,000)	96.29	-3	($2,302,524)	10426.9
-4	($2,152,000)	96.01	-4	($3,070,032)	10440.8
-5	($2,690,000)	95.73	-5	($3,837,540)	10454.7
-6	($3,228,000)	95.45	-6	($4,605,047)	10468.5
-7	($3,766,000)	95.17	-7	($5,372,555)	10482.4
-8	($4,304,000)	94.88	-8	($6,140,063)	10496.3
-9	($4,842,000)	94.60	-9	($6,907,571)	10510.1
-10	($5,380,000)	94.32	-10	($7,675,079)	10524.0

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
6.10%	11.46%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2004 - December 2004

Crystal River 4

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$7,574,000	87.67	10	$2,370,572	9125.0
9	$6,816,600	87.42	9	$2,133,515	9137.3
8	$6,059,200	87.18	8	$1,896,458	9149.5
7	$5,301,800	86.93	7	$1,659,401	9161.7
6	$4,544,400	86.69	6	$1,422,343	9174.0
5	$3,787,000	86.44	5	$1,185,286	9186.2
4	$3,029,600	86.20	4	$948,229	9198.5
3	$2,272,200	85.96	3	$711,172	9210.7
2	$1,514,800	85.71	2	$474,114	9222.9
1	$757,400	85.47	1	$237,057	9235.2
					9247.4
0	$0	85.22	0	$0	9322.4
					9397.4
-1	($995,100)	84.72	-1	($237,057)	9409.6
-2	($1,990,200)	84.22	-2	($474,114)	9421.9
-3	($2,985,300)	83.73	-3	($711,172)	9434.1
-4	($3,980,400)	83.23	-4	($948,229)	9446.3
-5	($4,975,500)	82.73	-5	($1,185,286)	9458.6
-6	($5,970,600)	82.23	-6	($1,422,343)	9470.8
-7	($6,965,700)	81.73	-7	($1,659,401)	9483.0
-8	($7,960,800)	81.23	-8	($1,896,458)	9495.3
-9	($8,955,900)	80.73	-9	($2,133,515)	9507.5
-10	($9,951,000)	80.24	-10	($2,370,572)	9519.7

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
11.31%	3.54%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2004 - December 2004

Crystal River 5

Equivalent *Availability* (Points)	Fuel *Savings/Loss* ($)	Equivalent *Availability* (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$6,535,000	96.49	10	$2,502,137	9194.4
9	$5,881,500	96.18	9	$2,251,923	9206.4
8	$5,228,000	95.88	8	$2,001,710	9218.3
7	$4,574,500	95.57	7	$1,751,496	9230.3
6	$3,921,000	95.26	6	$1,501,282	9242.2
5	$3,267,500	94.95	5	$1,251,069	9254.2
4	$2,614,000	94.65	4	$1,000,855	9266.2
3	$1,960,500	94.34	3	$750,641	9278.1
2	$1,307,000	94.03	2	$500,427	9290.1
1	$653,500	93.72	1	$250,214	9302.0
					9314.0
0	$0	93.42	0	$0	9389.0
					9464.0
-1	($668,200)	92.80	-1	($250,214)	9475.9
-2	($1,336,400)	92.18	-2	($500,427)	9487.9
-3	($2,004,600)	91.56	-3	($750,641)	9499.8
-4	($2,672,800)	90.94	-4	($1,000,855)	9511.8
-5	($3,341,000)	90.32	-5	($1,251,069)	9523.7
-6	($4,009,200)	89.70	-6	($1,501,282)	9535.7
-7	($4,677,400)	89.09	-7	($1,751,496)	9547.6
-8	($5,345,600)	88.47	-8	($2,001,710)	9559.6
-9	($6,013,800)	87.85	-9	($2,251,923)	9571.5
-10	($6,682,000)	87.23	-10	($2,502,137)	9583.5

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
9.76%	3.74%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2004 - December 2004

Hines 1

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$650,000	89.30	10	$5,603,687	7076.7
9	$585,000	89.19	9	$5,043,319	7114.5
8	$520,000	89.09	8	$4,482,950	7152.3
7	$455,000	88.99	7	$3,922,581	7190.1
6	$390,000	88.89	6	$3,362,212	7227.9
5	$325,000	88.78	5	$2,801,844	7265.7
4	$260,000	88.68	4	$2,241,475	7303.5
3	$195,000	88.58	3	$1,681,106	7341.3
2	$130,000	88.48	2	$1,120,737	7379.2
1	$65,000	88.37	1	$560,369	7417.0
					7454.8
0	$0	88.27	0	$0	7529.8
					7604.8
-1	($51,900)	88.06	-1	($560,369)	7642.6
-2	($103,800)	87.85	-2	($1,120,737)	7680.4
-3	($155,700)	87.64	-3	($1,681,106)	7718.2
-4	($207,600)	87.42	-4	($2,241,475)	7756.0
-5	($259,500)	87.21	-5	($2,801,844)	7793.8
-6	($311,400)	87.00	-6	($3,362,212)	7831.6
-7	($363,300)	86.79	-7	($3,922,581)	7869.4
-8	($415,200)	86.57	-8	($4,482,950)	7907.2
-9	($467,100)	86.36	-9	($5,043,319)	7945.1
-10	($519,000)	86.15	-10	($5,603,687)	7982.9

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.97%	8.37%

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GENERATING PERFORMANCE INCENTIVE POINTS TABLE

Progress Energy Florida
Period of: January 2004 - December 2004

Tiger Bay

Equivalent Availability (Points)	Fuel Savings/Loss ($)	Equivalent Availability (%)	Average Heat Rate (Points)	Fuel Savings/Loss ($)	Average Heat Rate (BTU/KWH)
10	$554,000	90.04	10	$1,869,892	7725.1
9	$498,600	89.83	9	$1,682,903	7741.5
8	$443,200	89.63	8	$1,495,914	7757.8
7	$387,800	89.42	7	$1,308,925	7774.2
6	$332,400	89.22	6	$1,121,935	7790.6
5	$277,000	89.01	5	$934,946	7806.9
4	$221,600	88.81	4	$747,957	7823.3
3	$166,200	88.60	3	$560,968	7839.6
2	$110,800	88.40	2	$373,978	7856.0
1	$55,400	88.19	1	$186,989	7872.4
					7888.7
0	$0	87.99	0	$0	7963.7
					8038.7
-1	($31,700)	87.57	-1	($186,989)	8055.1
-2	($63,400)	87.16	-2	($373,978)	8071.5
-3	($95,100)	86.74	-3	($560,968)	8087.8
-4	($126,800)	86.33	-4	($747,957)	8104.2
-5	($158,500)	85.91	-5	($934,946)	8120.5
-6	($190,200)	85.50	-6	($1,121,935)	8136.9
-7	($221,900)	85.08	-7	($1,308,925)	8153.3
-8	($253,600)	84.66	-8	($1,495,914)	8169.6
-9	($285,300)	84.25	-9	($1,682,903)	8186.0
-10	($317,000)	83.83	-10	($1,869,892)	8202.3

Equivalent Availability Weighting Factor:	Heat Rate Weighting Factor:
0.83%	2.79%

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UNIT PERFORMANCE DATA

ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2004 - December 2004

PLANT/UNIT **Anclote 1**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	94.34	94.23	95.41	93.96	95.34	93.98	93.89	93.94	93.89	93.89	95.76	94.54	94.43
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	5.66	5.77	4.59	6.04	4.66	6.02	6.11	6.06	6.11	6.11	4.24	5.46	5.57
4. EUOR	6.11	6.11	6.11	6.11	6.11	6.11	6.11	6.11	6.11	6.11	6.11	6.11	6.11
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	677.9	646.4	550.0	699.5	557.8	697.5	732.0	726.1	708.4	731.0	490.9	654.3	7871.7
7. RSH	55.0	39.0	185.0	9.0	177.0	11.0	0.0	6.0	0.0	1.0	221.0	79.0	783.0
8. UH	11.1	10.6	9.0	11.5	9.2	11.5	12.0	11.9	11.6	12.0	8.1	10.7	129.3
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. FOH & PFOH	16.2	15.5	13.2	16.7	13.4	16.7	17.5	17.4	17.0	17.5	11.8	15.7	188.5
11. MOH & PMOH	25.9	24.7	21.0	26.7	21.3	26.6	28.0	27.7	27.1	27.9	18.8	25.0	300.7
12. Oper. Btu(MBtu)	1457438	1451283	1239021	1360244	1337774	1897161	2098061	2118998	1877810	1430283	1556874	1168612	19091410
13. Net Gen. (MWH)	137756.1	137945.2	117823.2	127066.6	128333.9	185740.7	207423.7	210239.0	183024.7	133699.9	157250.4	108212.3	1834515.7
14. ANOHR (Btu/KWH)	10580	10521	10516	10705	10424	10214	10115	10079	10260	10698	9901	10799	10407
15. NOF (%)	40.8	42.9	43.0	36.5	46.2	53.5	56.9	58.1	51.9	36.7	64.3	33.2	46.8
16. NSC (MW)	498	498	498	498	498	498	498	498	498	498	498	498	498
17. ANOHR Equation	ANOHR=	-28.890 x NOF +		11758.7									

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ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2004 - December 2004

PLANT/UNIT **Anclote 2**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	94.83	95.69	94.81	73.60	73.31	94.38	94.38	94.38	94.38	94.54	94.59	94.80	91.14
2. POF	0.00	0.00	0.00	23.33	22.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.83
3. EUOF	5.17	4.31	5.19	3.07	4.11	5.62	5.62	5.62	5.62	5.46	5.41	5.20	5.04
4. EUOR	5.62	5.62	5.62	5.62	5.62	5.62	5.62	5.62	5.62	5.62	5.62	5.62	5.62
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	658.8	513.4	661.7	378.5	524.0	693.5	716.6	716.6	693.5	695.4	667.5	662.7	7582.2
7. RSH	60.0	163.0	57.0	159.0	32.0	0.0	0.0	0.0	0.0	22.0	27.0	56.0	576.0
8. UH	25.2	19.6	25.3	182.5	188.0	26.5	27.4	27.4	26.5	26.6	25.5	25.3	625.8
9. POH	0.0	0.0	0.0	168.0	168.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	336.0
10. FOH & PFOH	1.6	1.2	1.6	0.9	1.3	1.7	1.7	1.7	1.7	1.7	1.6	1.6	18.2
11. MOH & PMOH	36.9	28.7	37.0	21.2	29.3	38.8	40.1	40.1	38.8	38.9	37.4	37.1	424.3
12. Oper. Btu(MBtu)	1365296	1187289	1573257	688148	1428861	2036831	2203553	2269553	2064418	1506958	1744422	1119675	19242645
13. Net Gen. (MWH)	132383.4	115924.1	153900.8	66247.8	141239.2	202634.8	220164.9	227418.1	205632.7	146516.1	171842.3	107407.7	1891311.9
14. ANOHR (Btu/KWH)	10313	10242	10223	10387	10117	10052	10009	9980	10039	10285	10151	10425	10174
15. NOF (%)	40.6	45.6	47.0	35.4	54.5	59.0	62.1	64.1	59.9	42.6	52.0	32.7	50.4
16. NSC (MW)	495	495	495	495	495	495	495	495	495	495	495	495	495
17. ANOHR Equation	ANOHR=	-14.183 x NOF +		10888.9									

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ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2004 - December 2004

PLANT/UNIT **Crystal River 1**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	91.59	91.59	14.77	43.38	91.61	91.59	91.59	91.59	91.59	91.59	91.59	91.60	81.13
2. POF	0.00	0.00	83.87	53.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.48
3. EUOF	8.41	8.41	1.36	3.28	8.39	8.41	8.41	8.41	8.41	8.41	8.41	8.40	7.39
4. EUOR	8.41	8.41	8.41	8.41	8.41	8.41	8.41	8.41	8.41	8.41	8.41	8.41	8.41
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	705.2	659.7	113.7	266.3	703.3	682.4	705.2	705.2	682.4	705.2	682.4	704.2	7315.1
7. RSH	0.0	0.0	0.0	55.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0	58.0
8. UH	38.8	36.3	630.3	398.7	38.7	37.6	38.8	38.8	37.6	38.8	37.6	38.8	1410.9
9. POH	0.0	0.0	624.0	384.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1008.0
10. FOH & PFOH	26.3	24.6	4.2	9.9	26.2	25.4	26.3	26.3	25.4	26.3	25.4	26.2	272.3
11. MOH & PMOH	36.3	34.0	5.9	13.7	36.2	35.2	36.3	36.3	35.2	36.3	35.2	36.3	377.0
12. Oper. Btu(MBtu)	2162991	2096684	395425	840927	2325815	2319010	2393680	2444552	2347930	2349984	2351380	2304175	24337556
13. Net Gen. (MWH)	220049.2	214211.9	40875.6	85845.8	238813.4	238970.7	246628.9	252594.7	242358.8	241535.5	242763.8	236266.3	2500914.6
14. ANOHR (Btu/KWH)	9830	9788	9674	9796	9739	9704	9706	9678	9688	9729	9686	9752	9731
15. NOF (%)	82.3	85.7	94.8	85.0	89.6	92.4	92.3	94.5	93.7	90.4	93.9	88.5	90.2
16. NSC (MW)	379	379	379	379	379	379	379	379	379	379	379	379	379
17. ANOHR Equation	ANOHR=	-12.467 x NOF +		10858.0									

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ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2004 - December 2004

PLANT/UNIT **Crystal River 2**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	81.40	81.31	81.23	81.28	81.23	81.23	81.23	81.23	81.23	81.33	81.23	81.23	81.26
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	18.60	18.69	18.77	18.72	18.77	18.77	18.77	18.77	18.77	18.67	18.77	18.77	18.74
4. EUOR	18.77	18.77	18.77	18.77	18.77	18.77	18.77	18.77	18.77	18.77	18.77	18.77	18.77
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	638.0	599.9	644.1	621.6	644.1	623.3	644.1	644.1	623.3	640.6	623.3	644.1	7590.7
7. RSH	7.0	3.0	0.0	2.0	0.0	0.0	0.0	0.0	0.0	4.0	0.0	0.0	16.0
8. UH	99.0	93.1	99.9	96.4	99.9	96.7	99.9	99.9	96.7	99.4	96.7	99.9	1177.3
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. FOH & PFOH	55.1	51.8	55.6	53.7	55.6	53.8	55.6	55.6	53.8	55.3	53.8	55.6	655.7
11. MOH & PMOH	83.2	78.3	84.0	81.1	84.0	81.3	84.0	84.0	81.3	83.6	81.3	84.0	990.2
12. Oper. Btu(MBtu)	2305680	2263288	2677195	2379227	2459507	2487086	2584259	2654530	2537734	2500557	2563411	2523091	29950250
13. Net Gen. (MWH)	233310.5	231201.4	280209.5	243864.5	251952.0	257519.1	267958.8	277194.9	264137.0	257502.1	267525.7	260050.0	3092425.5
14. ANOHR (Btu/KWH)	9882	9789	9554	9756	9762	9658	9644	9576	9608	9711	9582	9702	9685
15. NOF (%)	75.2	79.3	89.5	80.7	80.5	85.0	85.6	88.6	87.2	82.7	88.3	83.1	83.8
16. NSC (MW)	486	486	486	486	486	486	486	486	486	486	486	486	486
17. ANOHR Equation	ANOHR=	-22.992 x NOF +		11612.4									

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ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2004 - December 2004

PLANT/UNIT Crystal River 3	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	97.14	97.14	97.14	97.14	97.14	97.14	97.14	97.14	97.14	97.14	97.14	97.14	97.14
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86
4. EUOR	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.86
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	727.2	680.3	727.2	703.7	727.2	703.7	727.2	727.2	703.7	727.2	703.7	727.2	8585.6
7. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8. UH	16.8	15.7	16.8	16.3	16.8	16.3	16.8	16.8	16.3	16.8	16.3	16.8	198.4
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. FOH & PFOH	2.4	2.2	2.4	2.3	2.4	2.3	2.4	2.4	2.3	2.4	2.3	2.4	27.8
11. MOH & PMOH	18.9	17.7	18.9	18.3	18.9	18.3	18.9	18.9	18.3	18.9	18.3	18.9	223.5
12. Oper. Btu(MBtu)	5798742	5424186	5798742	5608171	5798742	5608171	5798742	5798742	5608171	5798742	5608171	5798742	68448062
13. Net Gen. (MWH)	562428.0	526097.0	562428.0	543926.1	562428.0	543926.1	562428.0	562428.0	543926.1	562428.0	543926.1	562428.0	6638797.4
14. ANOHR (Btu/KWH)	10310	10310	10310	10311	10310	10311	10310	10310	10311	10310	10311	10310	10310
15. NOF (%)	100.1	100.0	100.1	100.0	100.1	100.0	100.1	100.1	100.0	100.1	100.0	100.1	100.0
16. NSC (MW)	773	773	773	773	773	773	773	773	773	773	773	773	773
17. ANOHR Equation	ANOHR=	-5.213 x NOF +		10831.7									

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ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
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PLANT/UNIT **Crystal River 4**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	94.23	94.23	94.23	94.23	94.23	94.23	94.23	94.23	94.23	66.89	12.56	94.23	85.22
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.03	86.67	0.00	9.56
3. EUOF	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77	4.08	0.77	5.77	5.22
4. EUOR	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77	5.77
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	711.8	665.9	711.8	688.9	711.8	688.9	711.8	711.8	688.9	503.2	91.8	711.8	7598.5
7. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0	0.0	0.0	2.0
8. UH	32.2	30.1	32.2	31.1	32.2	31.1	32.2	32.2	31.1	238.8	628.2	32.2	1183.5
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	216.0	624.0	0.0	840.0
10. FOH & PFOH	30.5	28.5	30.5	29.5	30.5	29.5	30.5	30.5	29.5	21.5	3.9	30.5	325.2
11. MOH & PMOH	12.5	11.7	12.5	12.1	12.5	12.1	12.5	12.5	12.1	8.8	1.6	12.5	133.0
12. Oper. Btu(MBtu)	3986961	3940635	4657093	4241367	4417324	4442911	4627138	4658419	4508071	3051072	589599	4612565	47746529
13. Net Gen. (MWH)	422616.9	419995.2	501879.8	453946.9	473185.2	477999.2	498273.8	502039.6	485835.6	326009.8	63398.6	496521.7	5121702.3
14. ANOHR (Btu/KWH)	9434	9383	9279	9343	9335	9295	9286	9279	9279	9359	9300	9290	9322
15. NOF (%)	82.5	87.6	97.9	91.5	92.3	96.4	97.2	98.0	98.0	90.0	95.9	96.9	93.6
16. NSC (MW)	720	720	720	720	720	720	720	720	720	720	720	720	720
17. ANOHR Equation	ANOHR=	-10.002 x NOF +		10258.7									

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ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2004 - December 2004

PLANT/UNIT **Crystal River 5**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	93.41	93.41	93.41	93.47	93.41	93.41	93.41	93.41	93.41	93.41	93.41	93.41	93.42
2. POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
3. EUOF	6.59	6.59	6.59	6.53	6.59	6.59	6.59	6.59	6.59	6.59	6.59	6.59	6.58
4. EUOR	6.59	6.59	6.59	6.59	6.59	6.59	6.59	6.59	6.59	6.59	6.59	6.59	6.59
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	707.8	662.1	707.8	679.2	707.8	684.9	707.8	707.8	684.9	707.8	684.9	707.8	8350.6
7. RSH	0.0	0.0	0.0	6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	6.0
8. UH	36.2	33.9	36.2	34.8	36.2	35.1	36.2	36.2	35.1	36.2	35.1	36.2	427.4
9. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
10. FOH & PFOH	24.6	23.0	24.6	23.6	24.6	23.8	24.6	24.6	23.8	24.6	23.8	24.6	289.7
11. MOH & PMOH	24.5	22.9	24.5	23.5	24.5	23.7	24.5	24.5	23.7	24.5	23.7	24.5	288.7
12. Oper. Btu(MBtu)	3984308	3866473	4599637	4024971	4258972	4299493	4444798	4594304	4402440	4305770	4410870	4300304	51498851
13. Net Gen. (MWH)	422082.8	410458.3	491549.3	427652.5	452931.4	458440.2	473947.0	490941.6	470133.9	458212.8	471093.1	457595.6	5485038.5
14. ANOHR (Btu/KWH)	9440	9420	9357	9412	9403	9379	9378	9358	9364	9397	9363	9398	9389
15. NOF (%)	83.2	86.5	96.9	87.8	89.3	93.3	93.4	96.7	95.7	90.3	95.9	90.2	91.6
16. NSC (MW)	717	717	717	717	717	717	717	717	717	717	717	717	717
17. ANOHR Equation	ANOHR=	-6.006 x NOF +		9939.1									

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ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
Period of: January 2004 - December 2004

PLANT/UNIT Hlnes 1	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	98.42	98.01	53.71	98.41	97.86	96.90	96.82	96.57	96.57	97.15	29.59	98.87	88.27
2. POF	0.00	0.00	45.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.00	0.00	9.56
3. EUOF	1.58	1.99	1.13	1.59	2.14	3.10	3.18	3.43	3.43	2.85	0.41	1.13	2.16
4. EUOR	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43	3.43
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	338.2	399.5	241.3	330.3	457.8	642.7	681.3	735.7	712.0	610.1	85.0	241.3	5475.2
7. RSH	402.0	292.0	164.0	386.0	281.0	70.0	55.0	0.0	0.0	127.0	130.0	500.0	2407.0
8. UH	3.8	4.5	338.7	3.7	5.2	7.3	7.7	8.3	8.0	6.9	505.0	2.7	901.8
9. POH	0.0	0.0	336.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	504.0	0.0	840.0
10. FOH & PFOH	5.3	6.3	3.8	5.2	7.2	10.1	10.7	11.6	11.2	9.6	1.3	3.8	86.1
11. MOH & PMOH	6.4	7.6	4.6	6.3	8.7	12.2	12.9	14.0	13.5	11.6	1.6	4.6	104.1
12. Oper. Btu(MBtu)	830917	940404	487633	782554	1158989	1633047	1789276	1946527	1836479	1550539	169870	546225	13686140
13. Net Gen. (MWH)	109951.0	123375.1	62322.1	102796.5	154342.6	217647.6	240266.2	261839.6	245587.9	206662.8	21672.0	71139.3	1817602.7
14. ANOHR (Btu/KWH)	7557	7622	7824	7613	7509	7503	7447	7434	7478	7503	7838	7678	7530
15. NOF (%)	67.5	64.1	53.6	64.6	69.9	70.3	73.2	73.8	71.6	70.3	52.9	61.2	68.9
16. NSC (MW)	482	482	482	482	482	482	482	482	482	482	482	482	482
17. ANOHR Equation	ANOHR=	-19.277 x NOF +		8857.4									

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ESTIMATED UNIT PERFORMANCE DATA

Progress Energy Florida
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PLANT/UNIT **Tiger Bay**	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Year
1. EAF	95.24	95.52	95.44	50.79	95.24	95.24	95.24	95.24	95.24	52.23	95.24	95.24	87.99
2. POF	0.00	0.00	0.00	46.67	0.00	0.00	0.00	0.00	0.00	45.16	0.00	0.00	7.65
3. EUOF	4.76	4.48	4.56	2.54	4.76	4.76	4.76	4.76	4.76	2.61	4.76	4.76	4.36
4. EUOR	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76	4.76
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8784
6. SH	712.4	627.2	682.8	367.7	712.4	689.5	712.4	712.4	689.5	390.7	689.5	712.4	7699.0
7. RSH	0.0	41.0	31.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	72.0
8. UH	31.6	27.8	30.2	352.3	31.6	30.5	31.6	31.6	30.5	353.3	30.5	31.6	1013.0
9. POH	0.0	0.0	0.0	336.0	0.0	0.0	0.0	0.0	0.0	336.0	0.0	0.0	672.0
10. FOH & PFOH	20.4	18.0	19.6	10.5	20.4	19.8	20.4	20.4	19.8	11.2	19.8	20.4	220.7
11. MOH & PMOH	15.0	13.2	14.4	7.7	15.0	14.5	15.0	15.0	14.5	8.2	14.5	15.0	162.2
12. Oper. Btu(MBtu)	789812	688644	735504	405818	849610	858396	900613	928162	879316	461381	801796	768270	9074648
13. Net Gen. (MWH)	98307.5	85602.3	91195.6	50481.0	106873.8	108715.9	114349.5	118456.3	111812.0	57951.9	100479.8	95271.2	1139496.8
14. ANOHR (Btu/KWH)	8034	8045	8065	8039	7950	7896	7876	7835	7864	7961	7980	8064	7964
15. NOF (%)	66.7	65.9	64.5	66.3	72.5	76.2	77.5	80.3	78.3	71.7	70.4	64.6	71.5
16. NSC (MW)	207	207	207	207	207	207	207	207	207	207	207	207	207
17. ANOHR Equation	ANOHR=	-14.538 x NOF +		9003.2									

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PLANNED OUTAGE SCHEDULES

Progress Energy Florida
Period of: January 2004 - December 2004

Plant/Unit	Planned Outage Dates	Reason for Outage
Anclote 2	04/24 (0001) - 05/07 (2400)	Boiler inspection and repair
Crystal River 1	03/06 (0001) - 04/16 (2400)	Major boiler and turbine inspection
Crystal River 4	10/23 (0001) - 11/26 (2400)	Boiler inspection and repair
Hines 1	03/06 (0001) - 03/19 (2400)	Combustion inspection & BOP maint./inspect.
Hines 1	11/01 (0001) - 11/21 (2400)	Combustion inspection & BOP maint./inspect.
Tiger Bay	04/17 (0001) - 04/30 (2400)	Hot gas path inspection & BOP maint./inspect.
Tiger Bay	10/18 (0001) - 10/31 (2400)	BOP maint./inspections

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AVERAGE NET OPERATING HEAT RATE CURVES

PROGRESS ENERGY FLORIDA

ANCLOTE UNIT 1

ANOHR -28.890 * NOF + 11758.75

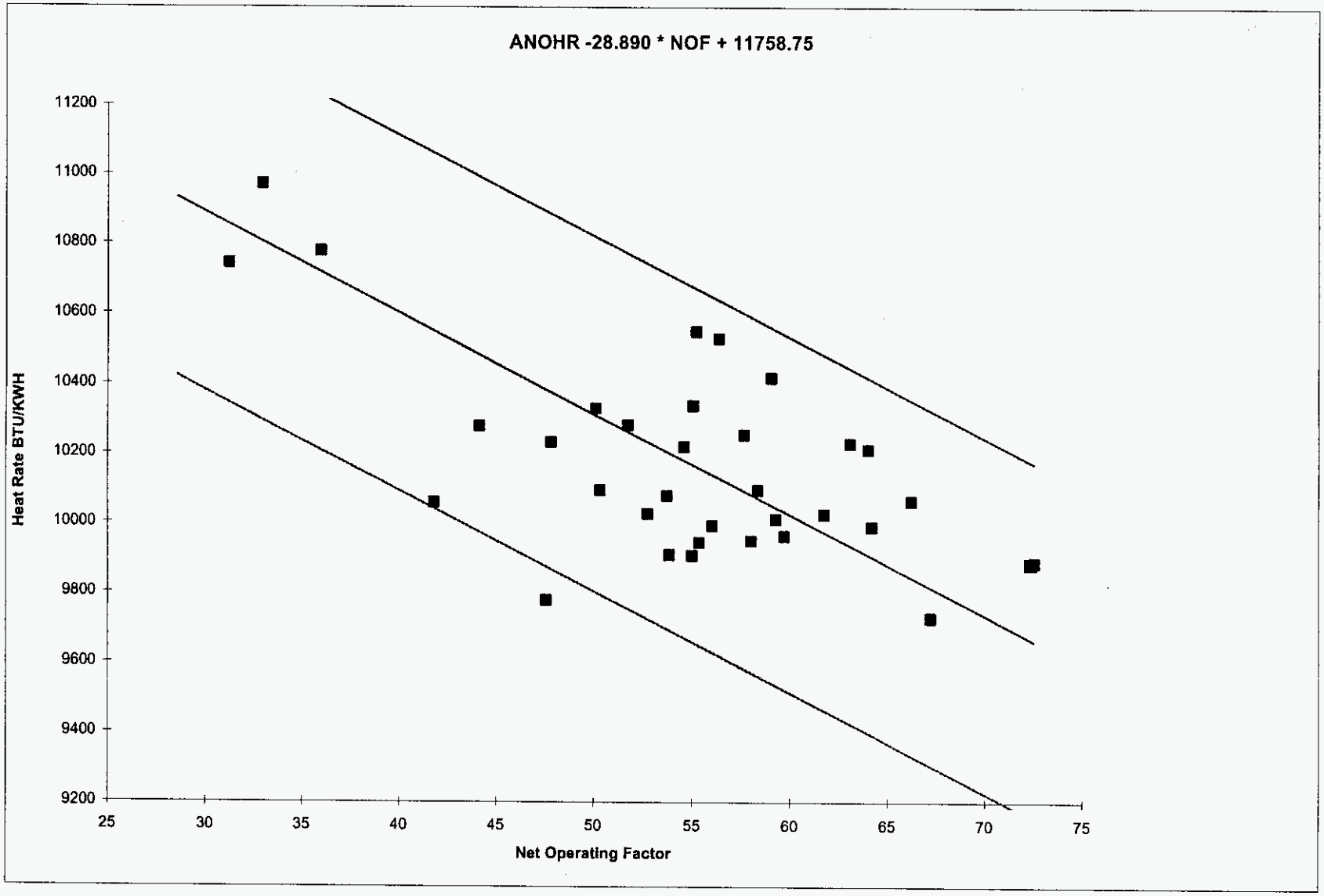
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-00	66.2	10064.0	9845.4	218.6	510.1
Aug-00	72.6	9889.0	9662.7	226.3	510.1
Sep-00	67.2	9729.0	9816.7	-87.7	510.1
Oct-00	50.1	10331.0	10310.8	20.2	510.1
Nov-00	50.3	10095.0	10304.8	-209.8	510.1
Dec-00	56.4	10531.0	10130.5	400.5	510.1
Jan-01	55.0	9907.0	10169.8	-262.8	510.1
Feb-01	41.8	10059.0	10551.5	-492.5	510.1
Mar-01	36.0	10779.0	10719.5	59.5	510.1
Apr-01	47.6	9779.0	10384.9	-605.9	510.1
May-01	61.8	10026.0	9974.7	51.3	510.1
Jun-01	53.7	10079.0	10206.3	-127.3	510.1
Jul-01	58.4	10095.0	10072.6	22.4	510.1
Aug-01	59.1	10419.0	10052.5	366.5	510.1
Sep-01	51.7	10283.0	10263.9	19.1	510.1
Oct-01	64.2	9990.0	9904.5	85.5	510.1
Nov-01	47.8	10234.0	10377.8	-143.8	510.1
Dec-01	53.8	9909.0	10203.3	-294.3	510.1
Jan-02	55.4	9945.0	10159.4	-214.4	510.1
Feb-02	39.5	11653.0	10618.4	1034.6	510.1
Mar-02	56.0	9994.0	10140.3	-146.3	510.1
Apr-02	58.0	9950.0	10082.4	-132.4	510.1
May-02	57.7	10256.0	10093.2	162.8	510.1
Jun-02	54.6	10221.0	10181.4	39.6	510.1
Jul-02	55.0	10339.5	10168.5	171.0	510.1
Aug-02	55.2	10550.6	10163.9	386.8	510.1
Sep-02	63.1	10231.1	9936.2	295.0	510.1
Oct-02	64.0	10213.6	9909.8	303.9	510.1
Dec-02	33.0	10973.5	10806.6	167.0	510.1
Jan-03	44.1	10280.7	10484.1	-203.4	510.1
Feb-03	31.2	10744.5	10856.6	-112.0	510.1
Mar-03	28.8	11406.7	10925.7	481.0	510.1
Apr-03	52.7	10027.6	10235.1	-207.5	510.1
May-03	59.7	9963.8	10033.6	-69.8	510.1
Jun-03	59.3	10012.1	10046.1	-34.1	510.1

Regression Output:

Constant	11758.75
Std Err of Y Est	314.5988298
R Squared	0.481470034
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-28.88962798
Std Err of Coef.	5.218999767

Anclote Unit 1



PROGRESS ENERGY FLORIDA

ANCLOTE UNIT 2

ANOHR -14.183 * NOF + 10888.94

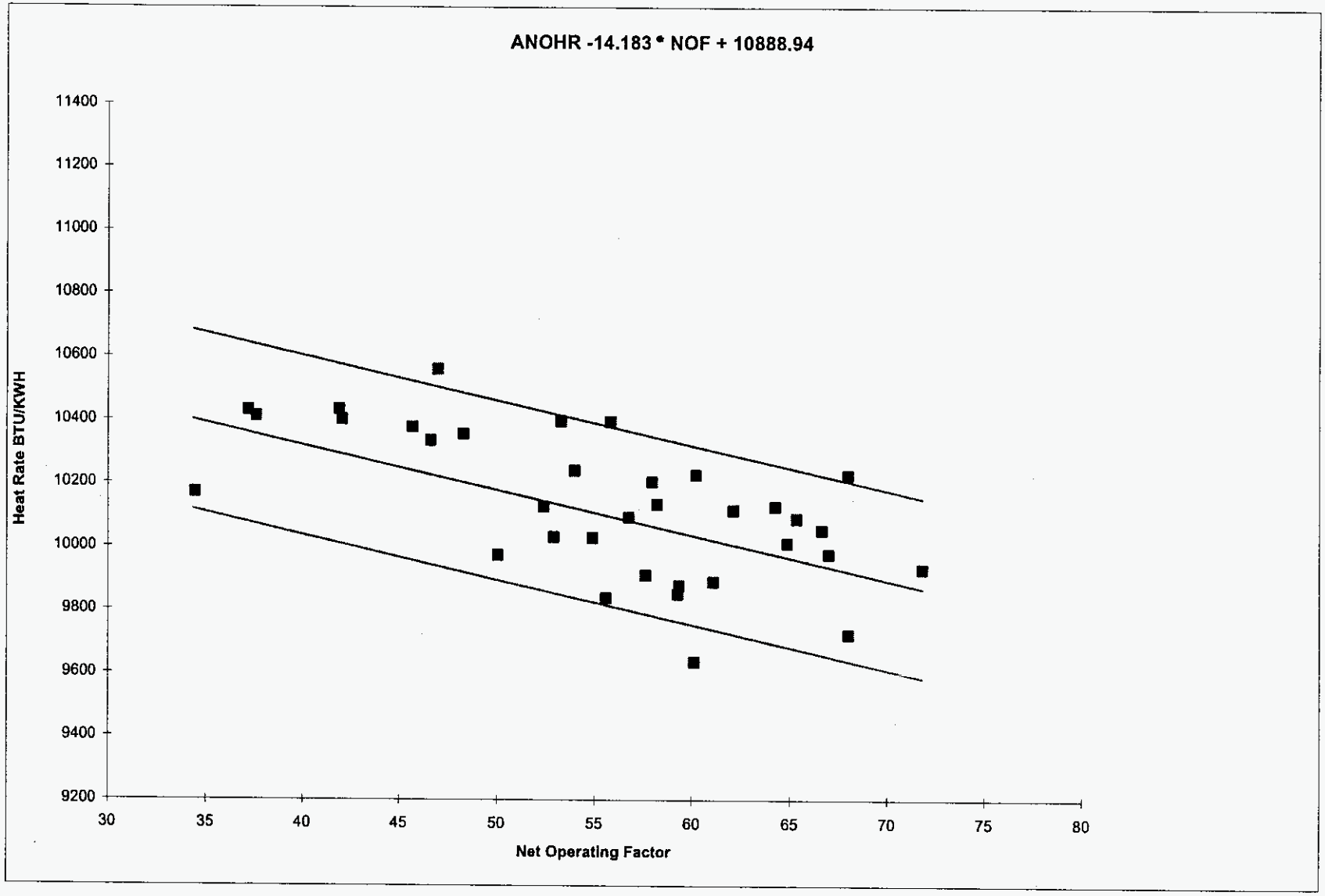
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-00	61.1	9892.0	10022.4	-130.4	283.5
Aug-00	68.0	9724.0	9924.6	-200.6	283.5
Sep-00	60.1	9638.0	10036.3	-398.3	283.5
Oct-00	48.3	10357.0	10203.9	153.1	283.5
Dec-00	66.6	10055.0	9944.1	110.9	283.5
Jan-01	56.8	10095.0	10083.9	11.1	283.5
Feb-01	52.9	10032.0	10138.5	-106.5	283.5
Mar-01	45.7	10379.0	10241.1	137.9	283.5
Apr-01	57.6	9913.0	10071.5	-158.5	283.5
May-01	71.8	9932.0	9870.1	61.9	283.5
Jun-01	58.2	10136.0	10063.2	72.8	283.5
Jul-01	65.3	10091.0	9962.1	128.9	283.5
Aug-01	68.0	10228.0	9924.9	303.1	283.5
Sep-01	53.3	10398.0	10133.0	265.0	283.5
Oct-01	64.3	10130.0	9977.7	152.3	283.5
Nov-01	47.0	10562.0	10222.5	339.5	283.5
Dec-01	55.6	9840.0	10100.4	-260.4	283.5
Jan-02	50.1	9975.0	10178.9	-203.9	283.5
Feb-02	34.4	10172.0	10400.4	-228.4	283.5
Mar-02	59.4	9880.0	10047.0	-167.0	283.5
Apr-02	59.3	9853.0	10048.2	-195.2	283.5
May-02	58.0	10206.0	10066.7	139.3	283.5
Jun-02	54.9	10029.0	10110.3	-81.3	283.5
Jul-02	55.8	10397.0	10097.4	299.7	283.5
Aug-02	54.0	10242.0	10123.3	118.7	283.5
Sep-02	64.9	10013.7	9969.0	44.6	283.5
Oct-02	67.0	9978.9	9939.0	39.9	283.5
Nov-02	46.6	10336.3	10227.7	108.6	283.5
Dec-02	37.6	10413.2	10355.4	57.8	283.5
Jan-03	42.0	10403.1	10292.7	110.4	283.5
Feb-03	37.2	10432.3	10361.4	70.9	283.5
Mar-03	41.9	10434.6	10294.7	139.9	283.5
Apr-03	52.4	10127.9	10145.8	-17.8	283.5
May-03	60.2	10228.4	10034.9	193.5	283.5
Jun-03	62.1	10117.7	10007.6	110.1	283.5

Regression Output:

Constant	10888.94
Std Err of Y Est	174.8654972
R Squared	0.380397892
No. of Observations	35
Degrees of Freedom	34
X Coefficient	-14.18292468
Std Err of Coef.	3.150984156

Anclote Unit 2



PROGRESS ENERGY FLORIDA

CRYSTAL RIVER UNIT 1

ANOHR -12.467 * NOF + 10856.05

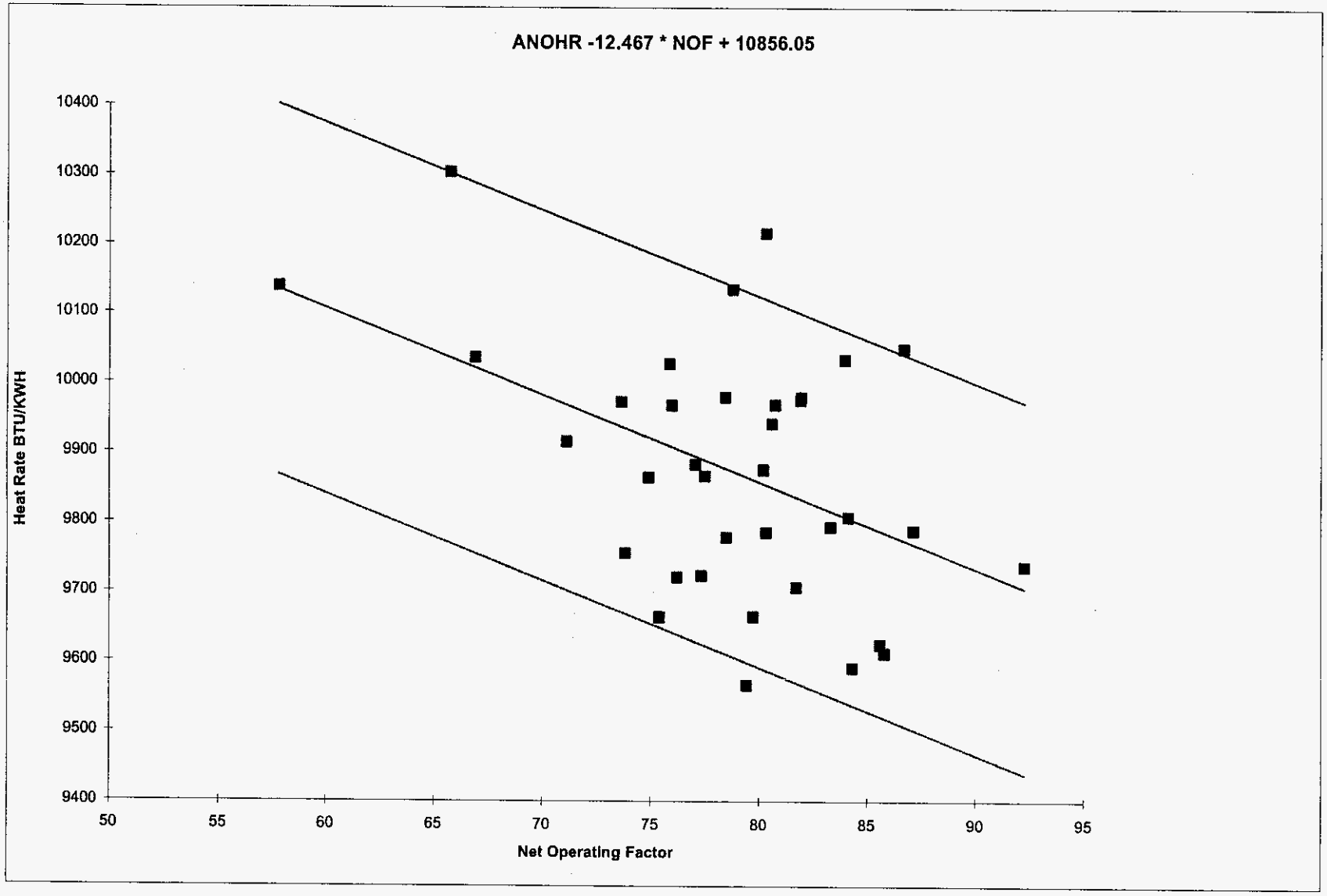
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-00	84.0	10034.0	9809.1	224.9	266.6
Aug-00	86.7	10050.0	9775.3	274.7	266.6
Sep-00	80.2	9876.0	9856.1	19.9	266.6
Oct-00	77.3	9724.0	9891.9	-167.9	266.6
Nov-00	79.7	9665.0	9862.0	-197.0	266.6
Dec-00	81.7	9707.0	9837.0	-130.0	266.6
Jan-01	79.4	9567.0	9865.7	-298.7	266.6
Feb-01	75.4	9664.0	9916.0	-252.0	266.6
Mar-01	77.5	9867.0	9889.8	-22.8	266.6
Apr-01	84.3	9592.0	9804.7	-212.7	266.6
May-01	87.1	9789.0	9769.8	19.2	266.6
Jun-01	76.0	9968.0	9908.8	59.2	266.6
Jul-01	78.4	9980.0	9878.1	101.9	266.6
Aug-01	75.9	10028.0	9910.3	117.7	266.6
Sep-01	73.7	9973.0	9937.6	35.4	266.6
Oct-01	77.1	9884.0	9895.4	-11.4	266.6
Nov-01	71.2	9916.0	9969.0	-53.0	266.6
Dec-01	57.9	10139.0	10134.6	4.4	266.6
Jan-02	73.8	9756.0	9935.4	-179.4	266.6
Feb-02	76.2	9722.0	9905.8	-183.8	266.6
Mar-02	85.6	9625.0	9788.9	-163.9	266.6
Apr-02	85.8	9613.0	9786.3	-173.3	266.6
May-02	83.3	9794.0	9817.2	-23.2	266.6
Jun-02	80.6	9942.0	9851.2	90.8	266.6
Jul-02	80.7	9969.1	9849.4	119.7	266.6
Aug-02	81.9	9975.7	9834.6	141.2	266.6
Sep-02	82.0	9979.7	9834.2	145.5	266.6
Oct-02	92.3	9737.7	9705.9	31.8	266.6
Nov-02	80.3	9786.1	9854.5	-68.5	266.6
Dec-02	78.5	9778.9	9877.6	-98.7	266.6
Jan-03	84.1	9808.0	9807.0	1.0	266.6
Feb-03	74.9	9865.3	9922.2	-56.9	266.6
Mar-03	66.9	10036.5	10022.0	14.5	266.6
Apr-03	80.3	10216.8	9854.9	361.9	266.6
May-03	78.8	10135.1	9873.8	261.3	266.6
Jun-03	65.8	10304.6	10036.3	268.3	266.6

Regression Output:

Constant	10856.05
Std Err of Y Est	164.3450323
R Squared	0.199681582
No. of Observations	36
Degrees of Freedom	35
X Coefficient	-12.46677912
Std Err of Coef.	4.280329548

Crystal River Unit 1



PROGRESS ENERGY FLORIDA

CRYSTAL RIVER UNIT 2

ANOHR -22.992 * NOF + 11612.36

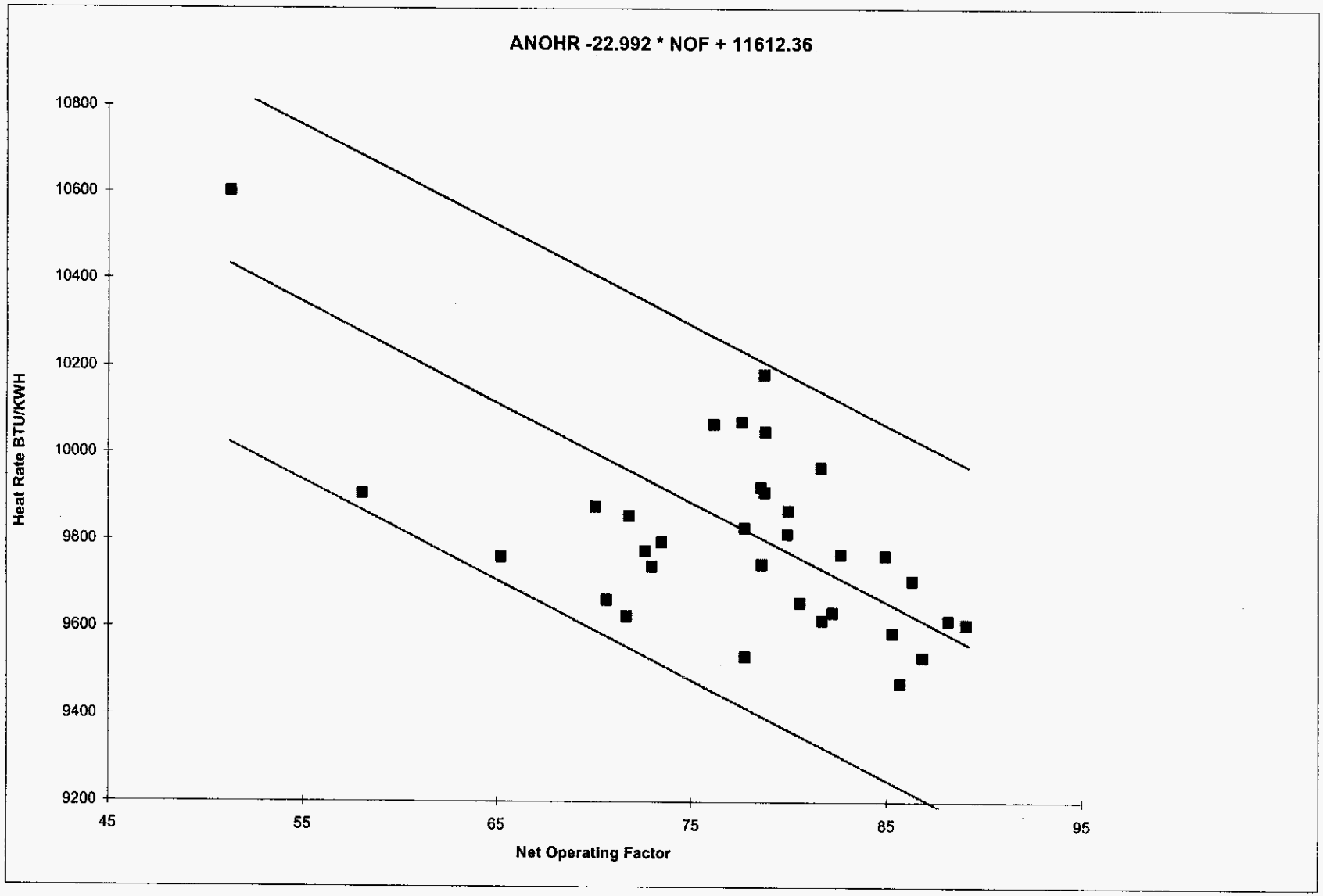
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Sep-00	72.6	9775.0	9943.0	-168.0	408.6
Oct-00	82.2	9634.0	9722.2	-88.2	408.6
Nov-00	85.3	9588.0	9651.3	-63.3	408.6
Dec-00	88.2	9616.0	9585.3	30.7	408.6
Jan-01	85.7	9473.0	9642.7	-169.7	408.6
Feb-01	81.7	9617.0	9734.4	-117.4	408.6
Mar-01	51.3	10603.0	10433.4	169.6	408.6
Apr-01	86.9	9533.0	9615.5	-82.5	408.6
May-01	86.3	9708.0	9627.9	80.1	408.6
Jun-01	77.7	9829.0	9825.6	3.4	408.6
Jul-01	78.7	9912.0	9802.1	109.9	408.6
Aug-01	78.8	10052.0	9801.1	250.9	408.6
Sep-01	71.8	9857.0	9961.9	-104.9	408.6
Oct-01	71.6	9626.0	9965.0	-339.0	408.6
Nov-01	58.0	9908.0	10277.9	-369.9	408.6
Dec-01	65.2	9762.0	10112.3	-350.3	408.6
Jan-02	70.6	9663.0	9988.4	-325.4	408.6
Feb-02	77.7	9534.0	9825.4	-291.4	408.6
Mar-02	70.1	9878.0	10001.3	-123.3	408.6
Apr-02	78.6	9746.0	9805.6	-59.6	408.6
May-02	84.9	9765.0	9659.9	105.1	408.6
Jun-02	79.9	9815.0	9775.3	39.7	408.6
Jul-02	78.5	9922.9	9806.4	116.5	408.6
Aug-02	81.6	9968.7	9735.8	232.9	408.6
Sep-02	78.7	10183.2	9802.2	381.0	408.6
Oct-02	79.9	9869.1	9774.3	94.8	408.6
Nov-02	73.5	9796.7	9923.5	-126.8	408.6
Dec-02	72.9	9740.1	9935.3	-195.2	408.6
Jan-03	89.1	9606.9	9564.0	43.0	408.6
Feb-03	80.5	9657.0	9760.4	-103.4	408.6
Mar-03	77.6	10074.4	9828.8	245.6	408.6
Apr-03	60.3	11137.6	10226.0	911.6	408.6
May-03	82.6	9768.4	9712.4	56.0	408.6
Jun-03	76.2	10068.8	9861.1	207.7	408.6

Regression Output:

Constant	11612.36
Std Err of Y Est	252.1536611
R Squared	0.388011747
No. of Observations	34
Degrees of Freedom	33
X Coefficient	-22.99169015
Std Err of Coef.	5.104403706

Crystal River Unit 2



PROGRESS ENERGY FLORIDA

CRYSTAL RIVER UNIT 3

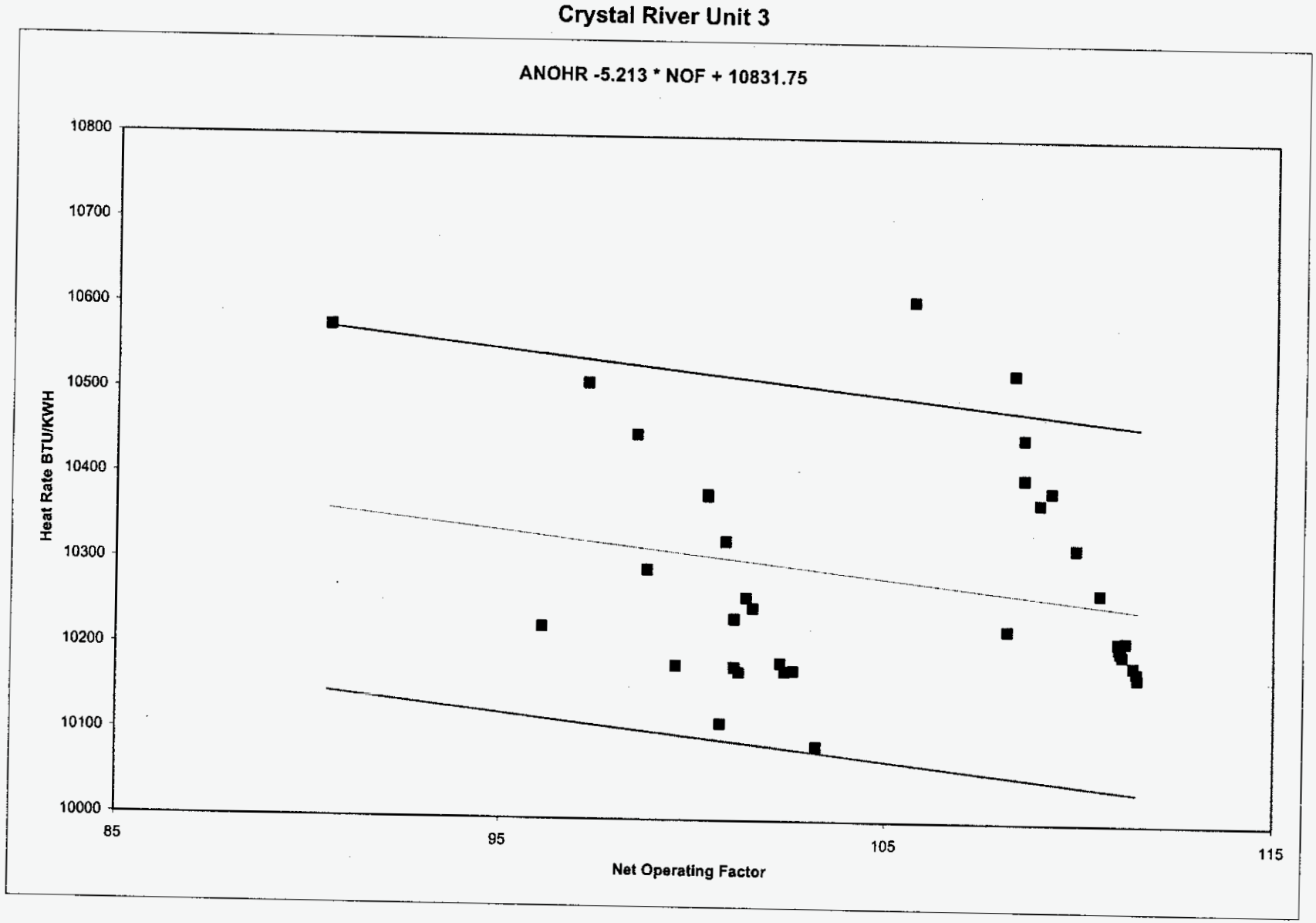
ANOHR -5.213 * NOF + 10831.75

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-00	98.5	10451.0	10318.2	132.8	213.7
Aug-00	97.2	10511.0	10324.9	186.1	213.7
Sep-00	98.8	10293.0	10316.7	-23.7	213.7
Oct-00	99.6	10181.0	10312.7	-131.7	213.7
Nov-00	101.2	10174.0	10304.3	-130.3	213.7
Dec-00	101.1	10180.0	10304.9	-124.9	213.7
Jan-01	111.4	10186.0	10251.0	-65.0	213.7
Feb-01	111.5	10172.0	10250.5	-78.5	213.7
Mar-01	111.5	10179.0	10250.6	-71.6	213.7
Apr-01	111.2	10215.0	10252.1	-37.1	213.7
May-01	105.6	10610.0	10281.1	328.9	213.7
Jun-01	108.5	10403.0	10266.0	137.0	213.7
Jul-01	109.2	10388.0	10262.3	125.7	213.7
Aug-01	108.5	10450.0	10266.1	183.9	213.7
Sep-01	108.9	10374.0	10263.8	110.2	213.7
Oct-01	90.5	10576.0	10359.8	216.2	213.7
Nov-01	111.1	10203.0	10252.8	-49.8	213.7
Dec-01	108.1	10226.0	10268.0	-42.0	213.7
Jan-02	111.0	10214.0	10253.1	-39.1	213.7
Feb-02	111.1	10199.0	10252.5	-53.5	213.7
Mar-02	111.0	10208.0	10253.0	-45.0	213.7
Apr-02	110.5	10270.0	10255.5	14.5	213.7
May-02	108.3	10525.0	10267.4	257.6	213.7
Jun-02	109.9	10322.0	10258.9	63.1	213.7
Jul-02	100.4	10379.2	10308.6	70.6	213.7
Aug-02	100.3	10381.2	10308.7	72.6	213.7
Sep-02	100.8	10326.4	10306.2	20.2	213.7
Oct-02	101.4	10261.2	10303.4	-42.2	213.7
Nov-02	96.1	10225.2	10330.9	-105.7	213.7
Dec-02	102.4	10175.2	10298.2	-122.9	213.7
Jan-03	102.3	10185.1	10298.7	-113.6	213.7
Feb-03	102.6	10176.2	10297.0	-120.8	213.7
Mar-03	103.2	10087.2	10293.8	-206.6	213.7
Apr-03	100.7	10113.1	10306.8	-193.6	213.7
May-03	101.1	10236.7	10304.9	-68.3	213.7
Jun-03	101.5	10249.1	10302.5	-53.4	213.7

Regression Output:

Constant	10831.75
Std Err of Y Est	131.7570682
R Squared	0.047050673
No. of Observations	36
Degrees of Freedom	35
X Coefficient	-5.21271223
Std Err of Coef.	4.023243115


Crystal River Unit 3
ANOHR -5.213 * NOF + 10831.75
Heat Rate BTU/KWH
10800
10700
10600
10500
10400
10300
10200
10100
10000
85
95
105
115
Net Operating Factor

PROGRESS ENERGY FLORIDA

CRYSTAL RIVER UNIT 4

ANOHR -10.002 * NOF + 10258.73

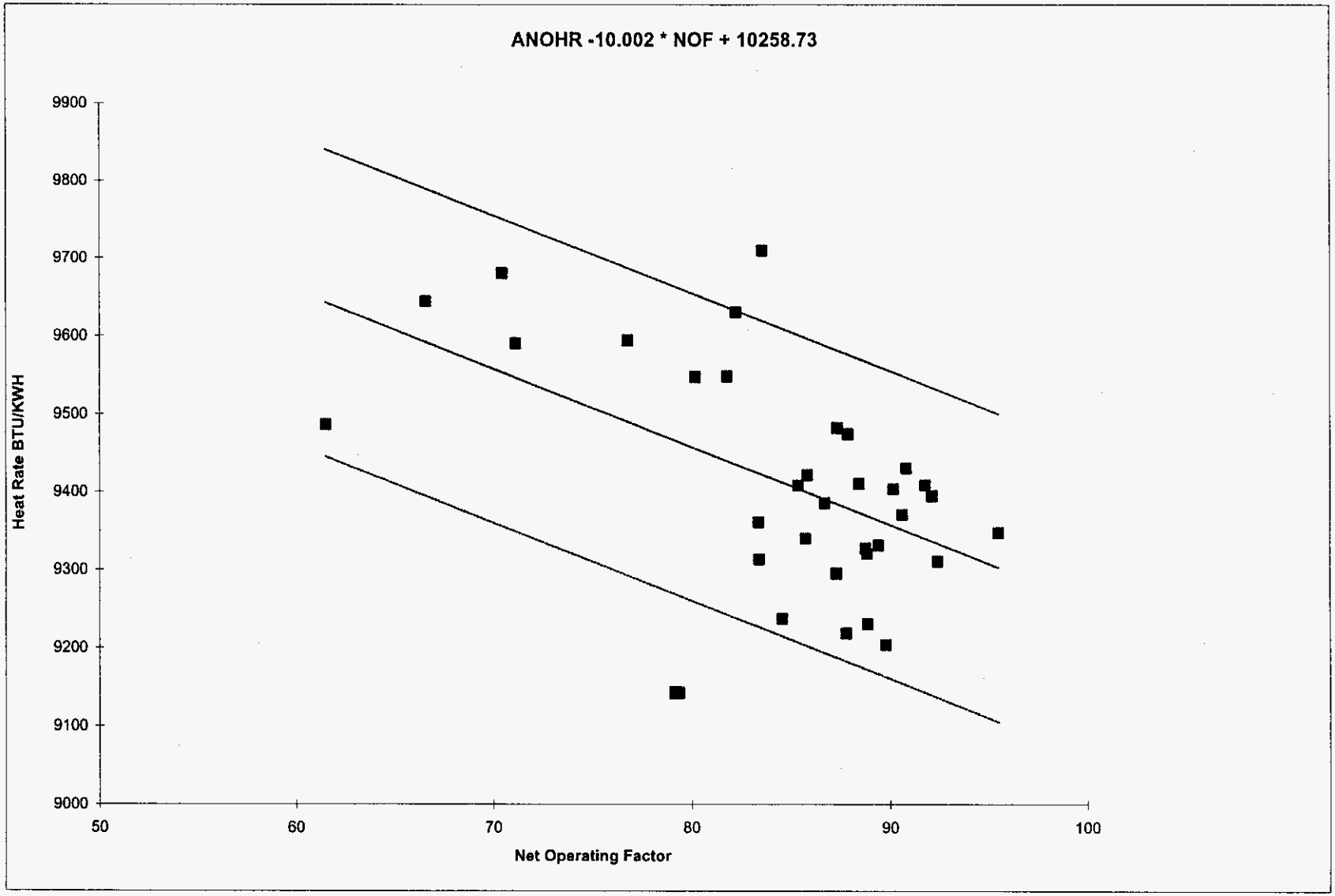
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-00	91.8	9409.0	9340.7	68.3	197.4
Aug-00	92.1	9395.0	9337.2	57.8	197.4
Sep-00	89.4	9332.0	9364.3	-32.3	197.4
Oct-00	85.7	9341.0	9401.2	-60.2	197.4
Nov-00	79.4	9143.0	9464.9	-321.9	197.4
Dec-00	87.8	9219.0	9380.6	-161.6	197.4
Jan-01	88.9	9231.0	9369.8	-138.8	197.4
Feb-01	84.6	9238.0	9413.0	-175.0	197.4
Mar-01	83.4	9314.0	9424.5	-110.5	197.4
Apr-01	88.8	9328.0	9371.0	-43.0	197.4
May-01	90.2	9404.0	9356.7	47.3	197.4
Jun-01	80.2	9548.0	9456.6	91.4	197.4
Jul-01	82.3	9631.0	9436.0	195.0	197.4
Aug-01	87.3	9483.0	9385.1	97.9	197.4
Sep-01	81.8	9549.0	9440.4	108.6	197.4
Oct-01	76.8	9595.0	9490.7	104.3	197.4
Nov-01	71.2	9591.0	9547.0	44.0	197.4
Dec-01	61.5	9487.0	9643.4	-156.4	197.4
Jan-02	70.5	9681.0	9553.9	127.1	197.4
Feb-02	66.6	9645.0	9592.8	52.2	197.4
Mar-02	88.4	9411.0	9374.1	36.9	197.4
Jun-02	87.3	9296.0	9385.6	-89.6	197.4
Jul-02	88.8	9321.5	9370.2	-48.7	197.4
Aug-02	90.8	9431.4	9350.3	81.1	197.4
Sep-02	95.5	9348.2	9303.5	44.7	197.4
Oct-02	92.4	9311.5	9334.4	-22.9	197.4
Nov-02	87.9	9475.1	9379.8	95.3	197.4
Dec-02	85.4	9408.9	9404.8	4.1	197.4
Jan-03	90.6	9371.4	9352.3	19.0	197.4
Feb-03	83.4	9361.7	9424.7	-63.0	197.4
Mar-03	85.8	9422.5	9400.1	22.4	197.4
Apr-03	86.7	9386.1	9391.4	-5.2	197.4
May-03	89.8	9204.6	9360.6	-156.1	197.4
Jun-03	83.6	9710.7	9422.9	287.8	197.4

Regression Output:

Constant	10258.73
Std Err of Y Est	121.7768781
R Squared	0.288090849
No. of Observations	34
Degrees of Freedom	33
X Coefficient	-10.00177108
Std Err of Coef.	2.779389914

Crystal River Unit 4



PROGRESS ENERGY FLORIDA

CRYSTAL RIVER UNIT 5

ANOHR -6.006 * NOF + 9939.13

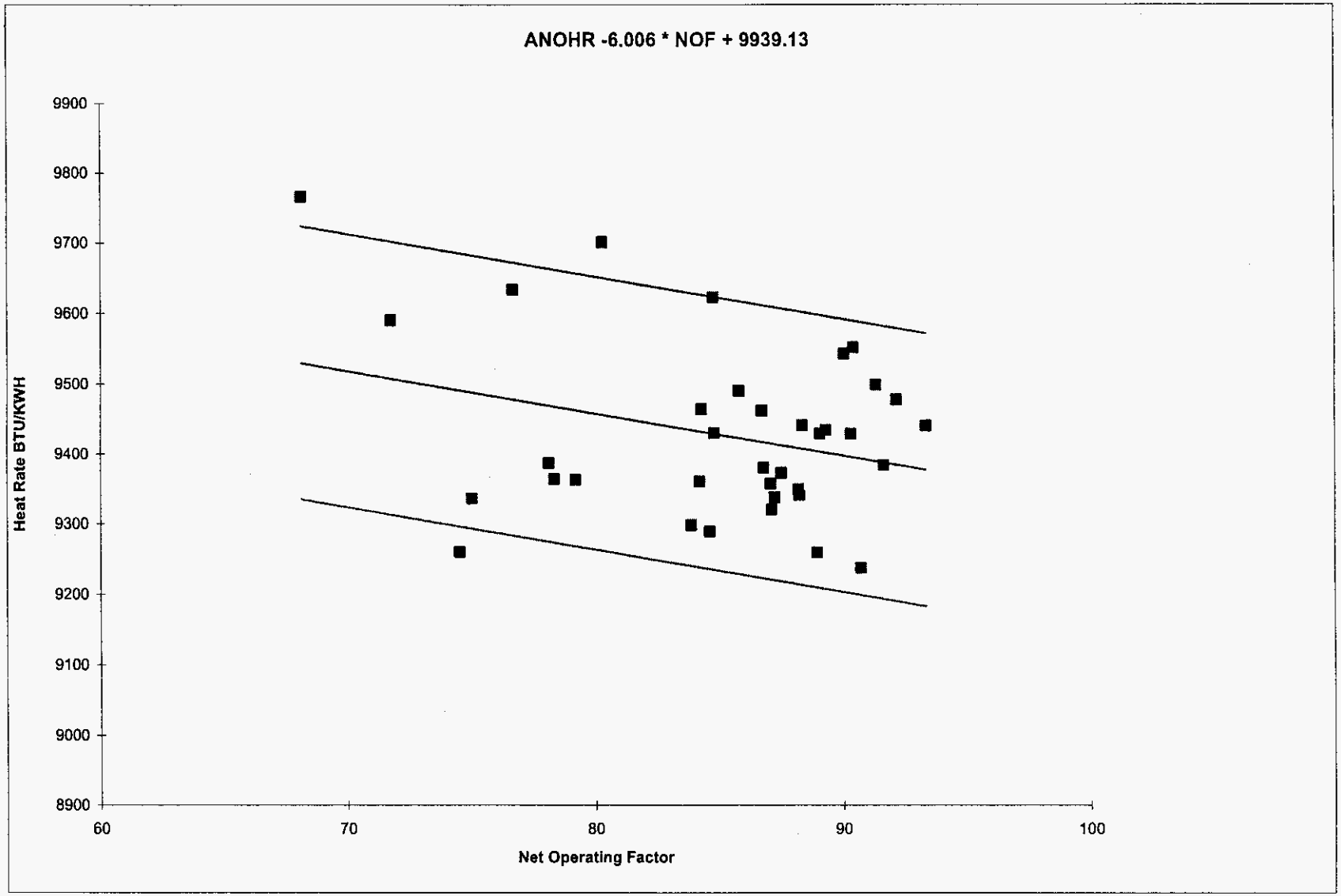
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-00	90.0	9544.0	9398.4	145.6	194.5
Aug-00	91.3	9500.0	9390.6	109.4	194.5
Sep-00	88.4	9442.0	9408.5	33.5	194.5
Oct-00	79.2	9364.0	9463.4	-99.4	194.5
Nov-00	84.6	9290.0	9431.0	-141.0	194.5
Dec-00	84.3	9465.0	9432.9	32.1	194.5
Jan-01	88.2	9342.0	9409.3	-67.3	194.5
Feb-01	86.8	9381.0	9417.9	-36.9	194.5
Mar-01	86.7	9463.0	9418.3	44.7	194.5
Apr-01	90.3	9430.0	9396.7	33.3	194.5
May-01	80.3	9702.0	9456.8	245.2	194.5
Jun-01	88.2	9350.0	9409.4	-59.4	194.5
Jul-01	84.8	9431.0	9429.9	1.1	194.5
Aug-01	84.2	9361.0	9433.4	-72.4	194.5
Sep-01	83.9	9299.0	9435.4	-136.4	194.5
Oct-01	90.7	9238.0	9394.3	-156.3	194.5
Nov-01	78.4	9365.0	9468.6	-103.6	194.5
Dec-01	74.5	9261.0	9491.5	-230.5	194.5
Jan-02	76.7	9635.0	9478.5	156.5	194.5
Feb-02	71.8	9591.0	9508.2	82.8	194.5
Mar-02	87.5	9374.0	9413.6	-39.6	194.5
Apr-02	92.2	9479.0	9385.6	93.4	194.5
May-02	84.8	9624.0	9430.1	193.9	194.5
Jun-02	85.8	9491.0	9423.9	67.1	194.5
Jul-02	89.3	9435.6	9402.8	32.8	194.5
Aug-02	89.1	9430.4	9404.3	26.1	194.5
Sep-02	93.4	9441.7	9378.4	63.3	194.5
Oct-02	88.9	9260.1	9405.0	-145.0	194.5
Nov-02	68.1	9766.9	9530.0	236.9	194.5
Dec-02	87.1	9358.2	9416.2	-58.0	194.5
Jan-03	91.7	9384.8	9388.7	-3.9	194.5
Feb-03	78.1	9387.7	9470.0	-82.3	194.5
Mar-03	87.2	9338.9	9415.3	-76.4	194.5
Apr-03	87.1	9321.4	9416.0	-94.6	194.5
May-03	75.0	9337.0	9488.5	-151.6	194.5
Jun-03	90.4	9552.9	9396.1	156.9	194.5

Regression Output:

Constant	9939.13
Std Err of Y Est	119.9350143
R Squared	0.088641906
No. of Observations	36
Degrees of Freedom	35
X Coefficient	-6.005500824
Std Err of Coef.	3.302438647

Crystal River Unit 5



PROGRESS ENERGY FLORIDA

HINES UNIT 1

ANOHR -19.277 * NOF + 8857.43

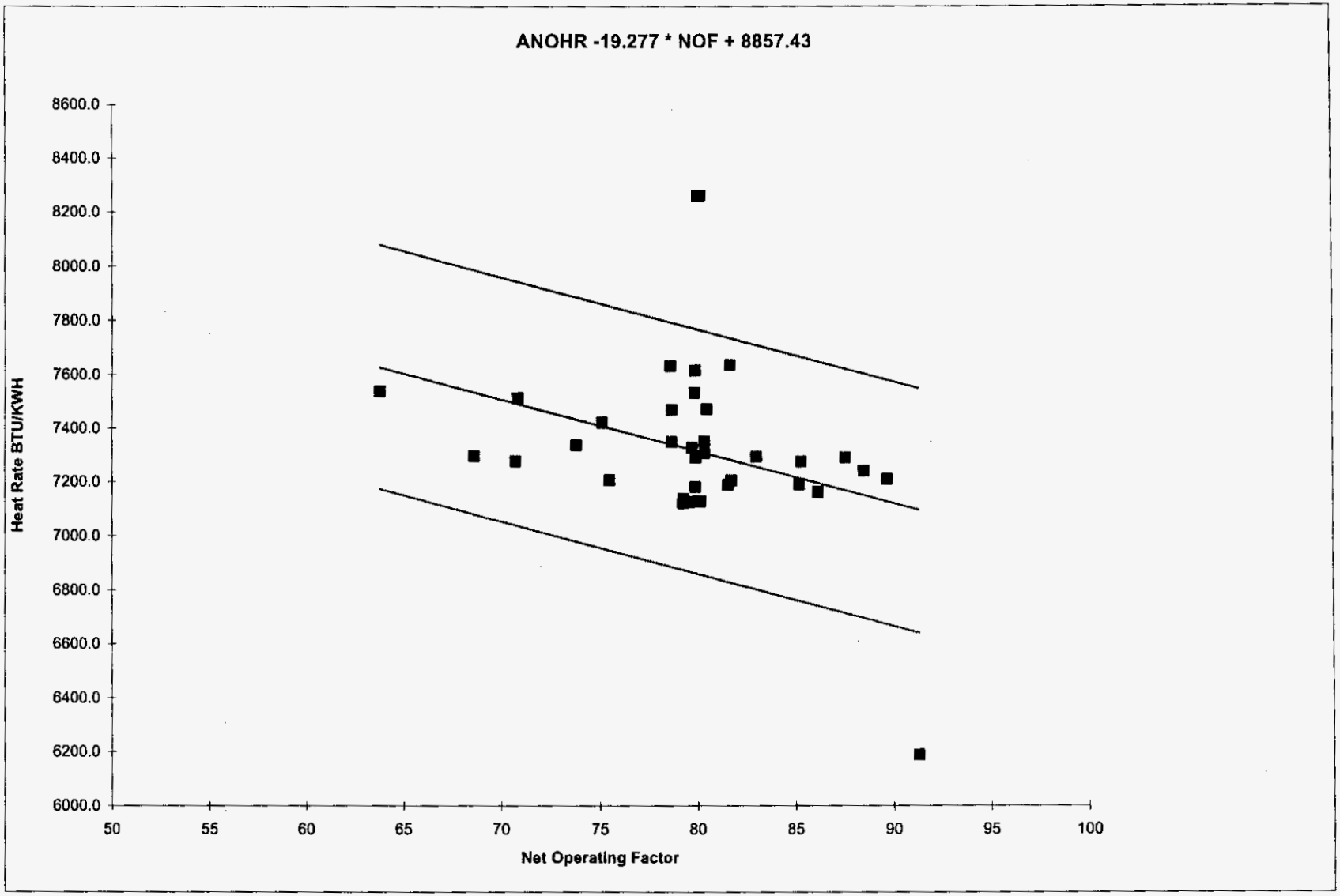
TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-00	79.9	7291.0	7316.5	-25.5	453.1
Aug-00	75.5	7208.0	7401.6	-193.6	453.1
Sep-00	91.3	6190.0	7097.6	-907.6	453.1
Oct-00	80.2	8263.0	7311.5	951.5	453.1
Nov-00	63.8	7539.0	7628.0	-89.0	453.1
Dec-00	79.7	7329.0	7320.2	8.8	453.1
Jan-01	79.3	7138.0	7328.8	-190.8	453.1
Mar-01	75.1	7423.0	7409.2	13.8	453.1
Apr-01	80.2	7128.0	7311.8	-183.8	453.1
May-01	81.7	7637.0	7282.6	354.4	453.1
Jun-01	79.9	7183.0	7317.3	-134.3	453.1
Jul-01	88.5	7242.0	7151.2	90.8	453.1
Aug-01	87.6	7291.0	7169.4	121.6	453.1
Sep-01	89.7	7211.0	7128.1	82.9	453.1
Oct-01	79.7	7127.0	7321.3	-194.3	453.1
Dec-01	85.2	7192.0	7214.9	-22.9	453.1
Jan-02	68.6	7297.0	7534.3	-237.3	453.1
Feb-02	83.0	7295.0	7257.0	38.0	453.1
Mar-02	86.2	7163.0	7196.3	-33.3	453.1
Apr-02	81.7	7206.0	7281.7	-75.7	453.1
May-02	80.4	7352.0	7308.1	43.9	453.1
Jun-02	80.5	7472.0	7305.7	166.3	453.1
Jul-02	79.9	7532.8	7317.7	215.1	453.1
Aug-02	79.9	7615.8	7317.0	298.8	453.1
Sep-02	80.4	7308.2	7307.9	0.3	453.1
Oct-02	85.3	7275.6	7212.9	62.7	453.1
Nov-02	81.6	7189.9	7285.0	-95.0	453.1
Dec-02	70.9	7512.9	7490.9	21.9	453.1
Jan-03	78.7	7470.4	7339.9	130.4	453.1
Feb-03	73.8	7337.2	7434.3	-97.1	453.1
Mar-03	79.3	7121.6	7329.3	-207.6	453.1
Apr-03	70.8	7278.7	7493.5	-214.8	453.1
May-03	78.6	7632.5	7341.4	291.1	453.1
Jun-03	78.7	7350.3	7340.3	10.0	453.1

Regression Output:

Constant	8857.43
Std Err of Y Est	279.5754694
R Squared	0.14171934
No. of Observations	34
Degrees of Freedom	33
X Coefficient	-19.2768108
Std Err of Coef.	8.386105063

Hines Unit 1


ANOHR -19.277 * NOF + 8857.43
Heat Rate BTU/KWH
8600.0
8400.0
8200.0
8000.0
7800.0
7600.0
7400.0
7200.0
7000.0
6800.0
6600.0
6400.0
6200.0
6000.0
50
55
60
65
70
75
80
85
90
95
100
Net Operating Factor

PROGRESS ENERGY FLORIDA

TIGER BAY

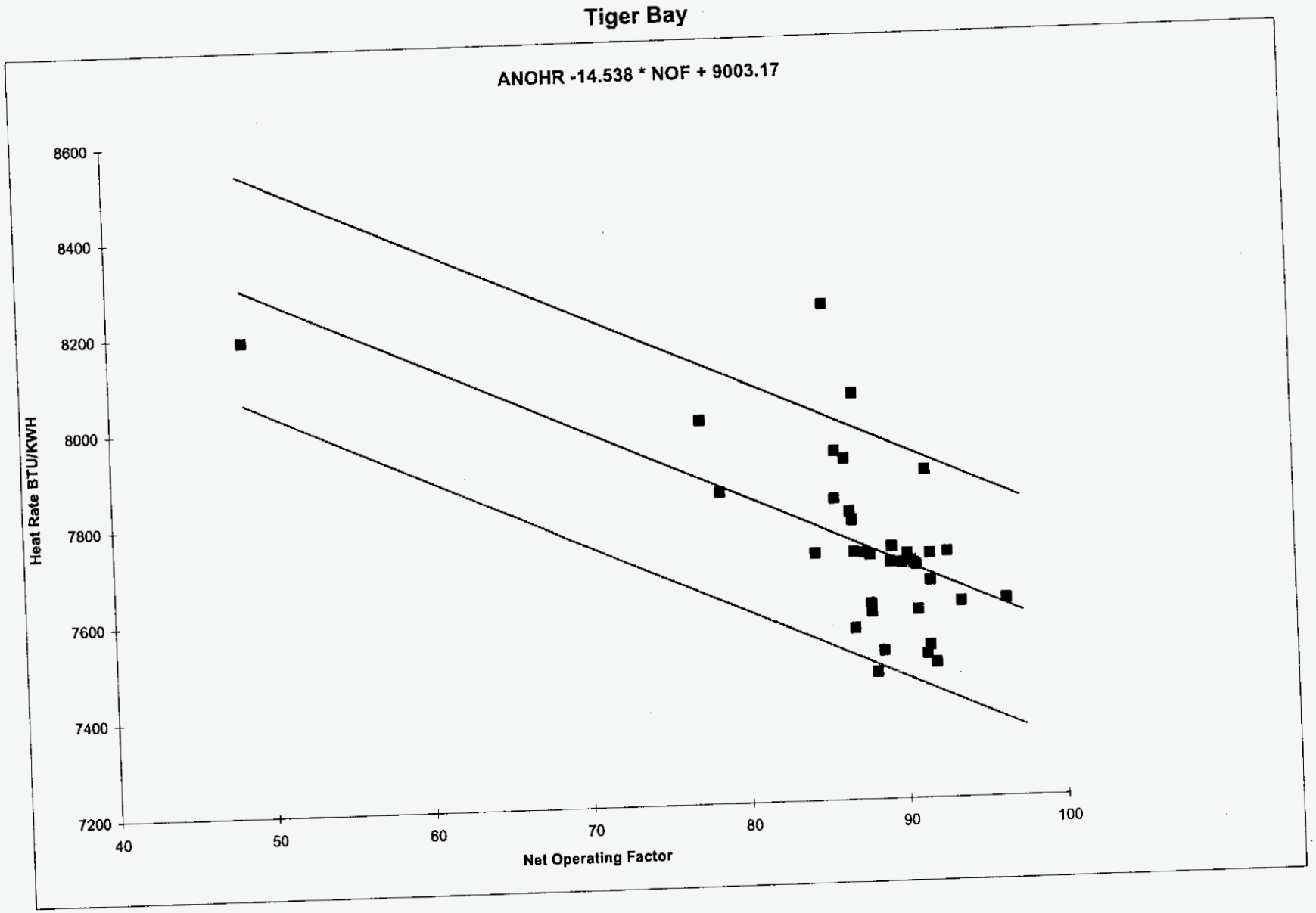
ANOHR -14.538 * NOF + 9003.17

TABLE OF RESIDUALS

DATE	OUTPUT FACTOR	ACT MONTHLY HEATRATE	PROJECTED HEATRATE	DIFFERENCE (ACT-PROJ)	HEAT RATE RANGE @90% CONFID
Jul-00	88.7	7509.0	7714.4	-205.4	238.6
Aug-00	89.9	7693.0	7695.7	-2.7	238.6
Sep-00	87.9	7608.0	7725.1	-117.1	238.6
Oct-00	88.2	7465.0	7721.2	-256.2	238.6
Nov-00	77.4	7999.0	7877.8	121.2	238.6
Dec-00	91.4	7500.0	7674.4	-174.4	238.6
Jan-01	91.6	7519.0	7671.7	-152.7	238.6
Feb-01	89.3	7726.0	7704.7	21.3	238.6
Mar-01	92.0	7482.0	7666.3	-184.3	238.6
Apr-01	91.6	7883.0	7671.9	211.1	238.6
May-01	90.9	7593.0	7681.8	-88.8	238.6
Jun-01	90.7	7690.0	7684.4	5.6	238.6
Jul-01	93.6	7609.0	7642.0	-33.0	238.6
Aug-01	91.7	7654.0	7669.9	-15.9	238.6
Sep-01	48.5	8189.0	8297.5	-108.5	238.6
Oct-01	96.5	7613.0	7600.9	12.1	238.6
Nov-01	86.9	7717.0	7739.6	-22.6	238.6
Dec-01	89.2	7694.0	7706.2	-12.2	238.6
Jan-02	84.4	7716.0	7775.5	-59.5	238.6
Feb-02	78.5	7849.0	7861.2	-12.2	238.6
Mar-02	85.4	8233.0	7762.2	470.8	238.6
Apr-02	90.3	7711.0	7690.4	20.6	238.6
May-02	88.0	7590.0	7724.5	-134.5	238.6
Jun-02	86.7	7800.0	7742.8	57.2	238.6
Jul-02	86.9	7557.5	7740.3	-182.8	238.6
Aug-02	87.1	8045.4	7737.1	308.3	238.6
Sep-02	87.6	7714.4	7729.8	-15.4	238.6
Oct-02	85.9	7927.0	7755.1	171.9	238.6
Nov-02	90.5	7696.2	7687.2	9.1	238.6
Dec-02	85.8	7828.2	7756.1	72.0	238.6
Jan-03	92.8	7713.0	7653.6	59.4	238.6
Feb-03	87.9	7709.7	7724.9	-15.3	238.6
Mar-03	86.8	7782.9	7740.8	42.0	238.6
Apr-03	86.5	7911.2	7746.4	164.8	238.6
May-03	90.9	7687.4	7682.2	5.1	238.6
Jun-03	91.7	7710.3	7669.7	40.6	238.6

Regression Output:

Constant	9003.17
Std Err of Y Est	147.112912
R Squared	0.369136337
No. of Observations	36
Degrees of Freedom	35
X Coefficient	-14.53754356
Std Err of Coef.	3.259311941


Tiger Bay
ANOHR -14.538 * NOF + 9003.17
Heat Rate BTU/KWH
8600
8400
8200
8000
7800
7600
7400
7200
40
50
60
70
80
90
100
Net Operating Factor

UNPLANNED OUTAGE RATE TABLES AND GRAPHS

UNIT UNAVAILABLE OUTAGE RATE SUMMARY

Progress Energy Florida
Period of: January 2004 - December 2004

UNIT	RATE	LOW RANGE	HIGH RANGE	TARGET
Anclote 1	FOR	0.41	1.57	0.78
	MOR	0.44	1.69	0.85
	FOR&MOR	0.86	3.26	1.63
	PFOR	0.84	3.21	1.60
	PMOR	1.56	5.93	2.97
	EUOR	3.23	12.06	6.11
	EUOF	2.94	10.98	5.57
Anclote 2	FOR	0.06	0.23	0.12
	MOR	1.88	7.15	3.57
	FOR&MOR	1.94	7.38	3.69
	PFOR	0.07	0.25	0.12
	PMOR	0.99	3.78	1.89
	EUOR	2.97	11.08	5.62
	EUOF	2.66	9.93	5.04
Crystal River 1	FOR	1.23	4.68	2.34
	MOR	1.58	6.04	3.02
	FOR&MOR	2.81	10.71	5.36
	PFOR	0.70	2.65	1.33
	PMOR	1.07	4.09	2.04
	EUOR	4.49	16.23	8.41
	EUOF	3.95	14.26	7.39
Crystal River 2	FOR	2.51	9.56	4.78
	MOR	4.98	18.99	9.49
	FOR&MOR	7.49	28.55	14.27
	PFOR	1.90	7.24	3.62
	PMOR	1.34	5.11	2.56
	EUOR	10.26	34.59	18.77
	EUOF	10.24	34.53	18.74
Crystal River 3	FOR	0.09	0.33	0.16
	MOR	1.10	4.20	2.10
	FOR&MOR	1.19	4.53	2.27
	PFOR	0.08	0.32	0.16
	PMOR	0.24	0.91	0.46
	EUOR	1.51	5.68	2.86
	EUOF	1.51	5.68	2.86
Crystal River 4	FOR	1.76	6.72	3.36
	MOR	0.54	2.06	1.03
	FOR&MOR	2.31	8.79	4.39
	PFOR	0.42	1.60	0.80
	PMOR	0.37	1.42	0.71
	EUOR	3.06	11.28	5.77
	EUOF	2.77	10.20	5.22
Crystal River 5	FOR	1.24	4.71	2.36
	MOR	1.38	5.27	2.63
	FOR&MOR	2.62	9.98	4.99
	PFOR	0.55	2.11	1.06
	PMOR	0.39	1.50	0.75
	EUOR	3.51	12.78	6.59
	EUOF	3.51	12.77	6.58
Hines 1	FOR	0.28	1.05	0.52
	MOR	0.31	1.20	0.60
	FOR&MOR	0.59	2.24	1.12
	PFOR	0.55	2.09	1.05
	PMOR	0.68	2.60	1.30
	EUOR	1.81	6.80	3.43
	EUOF	1.14	4.29	2.16
Tiger Bay	FOR	1.22	4.63	2.32
	MOR	1.06	4.03	2.02
	FOR&MOR	2.27	8.66	4.33
	PFOR	0.26	0.99	0.50
	PMOR	0.03	0.10	0.05
	EUOR	2.53	9.31	4.76
	EUOF	2.31	8.52	4.36

Anclote
Unit 1

	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	699.47	718.80	690.90	641.72	720.00	739.00	636.35	580.65	172.60	217.23	744.00	656.50	744.00	744.00	720.00	691.10	720.00	373.31
RSH	0.00	0.00	0.00	62.68	0.00	0.00	107.65	91.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	53.90	0.00	281.64
UH	44.53	25.20	29.10	40.60	0.00	5.00	0.00	0.00	571.40	501.77	0.00	63.50	0.00	0.00	0.00	0.00	0.00	89.05
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	552.50	501.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	44.53	25.20	0.00	0.00	0.00	5.00	0.00	0.00	18.90	0.00	0.00	33.85	0.00	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	29.10	40.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.65	0.00	0.00	0.00	0.00	0.00	89.05
PFOH	42.28	0.00	167.68	1.88	0.00	0.00	0.00	47.45	7.87	11.67	62.63	95.38	63.48	787.00	0.00	30.18	0.00	0.00
LRPF	96.17	156.56	56.40	170.66	0.00	0.00	0.00	242.19	168.46	263.68	54.54	74.53	68.12	30.38	0.00	23.00	0.00	0.00
EFOH	8.08	0.00	18.80	0.64	0.00	0.00	0.00	23.08	2.66	6.18	6.86	14.28	8.68	48.01	0.00	1.39	0.00	0.00
PMOH	54.62	279.42	49.67	59.18	47.28	18.35	0.00	38.32	0.00	0.00	60.37	54.15	71.38	82.17	66.65	86.05	55.28	15.50
LRPM	158.22	156.56	161.75	170.23	170.25	181.83	0.00	174.55	0.00	0.00	174.80	168.52	168.54	139.58	149.16	149.12	139.13	140.94
EMOH	17.18	86.97	15.97	20.03	16.00	6.63	0.00	13.43	0.00	0.00	21.19	18.32	24.16	23.03	19.96	25.77	15.44	4.39
NPC	503.00	503.00	503.00	503.00	503.00	503.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00

MONTHLY	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	5.99	3.39	0.00	0.00	0.00	0.67	0.00	0.00	9.87	0.00	0.00	4.90	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	4.04	5.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.32	0.00	0.00	0.00	0.00	0.00	19.26
PFOR	1.16	0.00	2.72	0.10	0.00	0.00	0.00	3.97	1.54	2.84	0.92	2.17	1.17	6.45	0.00	0.20	0.00	0.00
PMOR	2.46	12.10	2.31	3.12	2.22	0.90	0.00	2.31	0.00	0.00	2.85	2.79	3.25	3.10	2.77	3.73	2.14	1.18
EUOR	9.38	15.08	8.87	8.98	2.22	1.56	0.00	6.29	11.26	2.84	3.77	13.35	4.41	9.55	2.77	3.93	2.14	20.21
EUOF	9.38	15.08	8.87	8.22	2.22	1.56	0.00	5.43	2.90	0.86	3.77	13.35	4.41	9.55	2.77	3.65	2.14	12.56
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	74.26	69.79	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	90.62	84.92	91.13	91.78	97.78	98.44	100.00	94.57	22.84	29.35	96.23	86.65	95.59	90.45	97.23	96.35	97.86	87.44

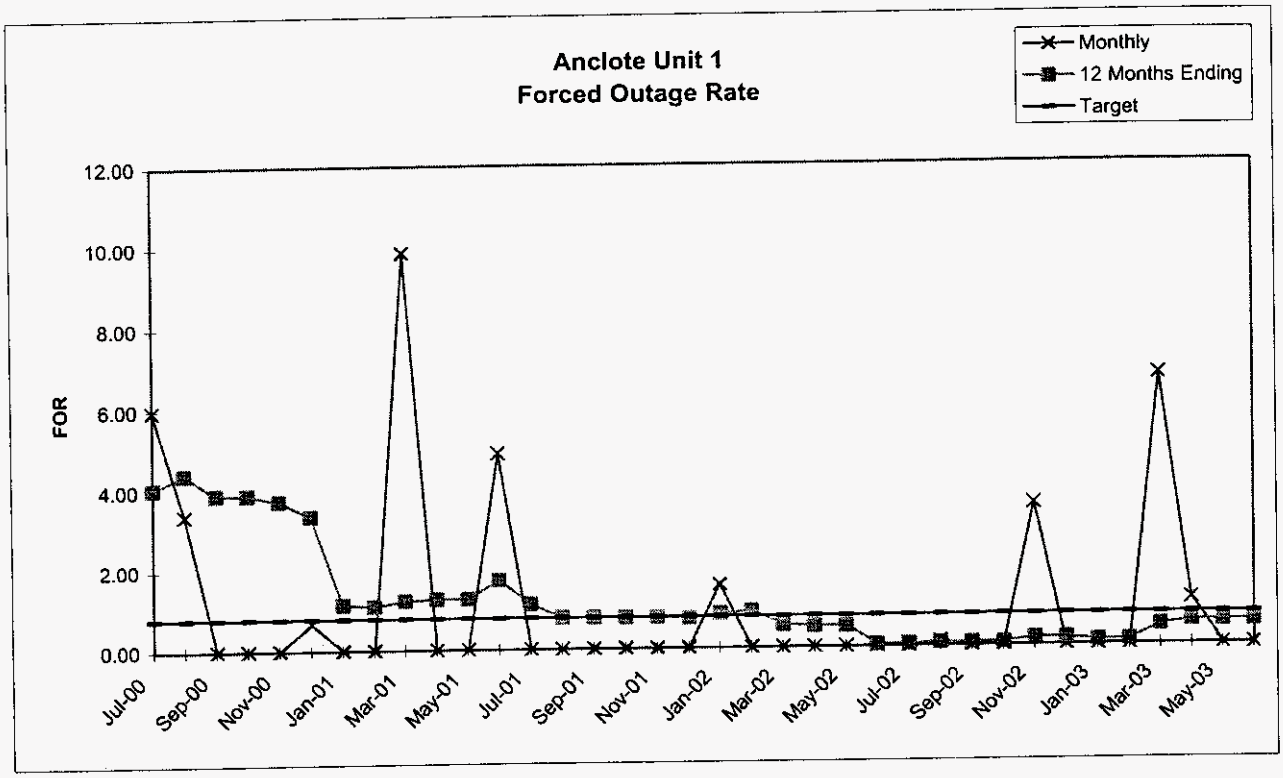
12 MONTHS	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	4.06	4.42	3.91	3.91	3.75	3.37	1.15	1.10	1.23	1.27	1.27	1.74	1.13	0.79	0.78	0.78	0.78	0.75
MOR	9.71	9.74	10.08	10.71	9.54	6.64	6.54	3.24	3.01	0.95	0.95	1.36	1.35	1.35	0.95	0.40	0.40	1.67
PFOR	0.76	0.59	0.78	0.60	0.58	0.54	0.53	0.80	0.87	0.86	0.94	1.12	1.12	1.77	1.51	1.51	1.51	1.59
PMOR	2.28	3.30	3.32	3.37	3.40	3.26	3.20	3.16	3.10	3.08	3.00	2.99	3.07	2.16	2.22	2.29	2.28	2.37
EUOR	15.68	16.73	16.82	17.27	16.10	13.01	10.99	8.06	7.97	6.05	6.05	7.03	6.53	5.98	5.39	4.92	4.92	6.25
EUOF	13.78	14.71	14.79	15.06	14.45	12.13	10.19	7.55	7.12	5.14	5.14	5.97	5.55	5.08	4.58	4.19	4.18	5.12
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.31	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04	12.04
EAF	86.22	85.29	85.21	84.94	85.55	87.87	89.81	92.45	86.58	82.83	82.82	81.99	82.41	82.88	83.39	83.78	83.78	82.85

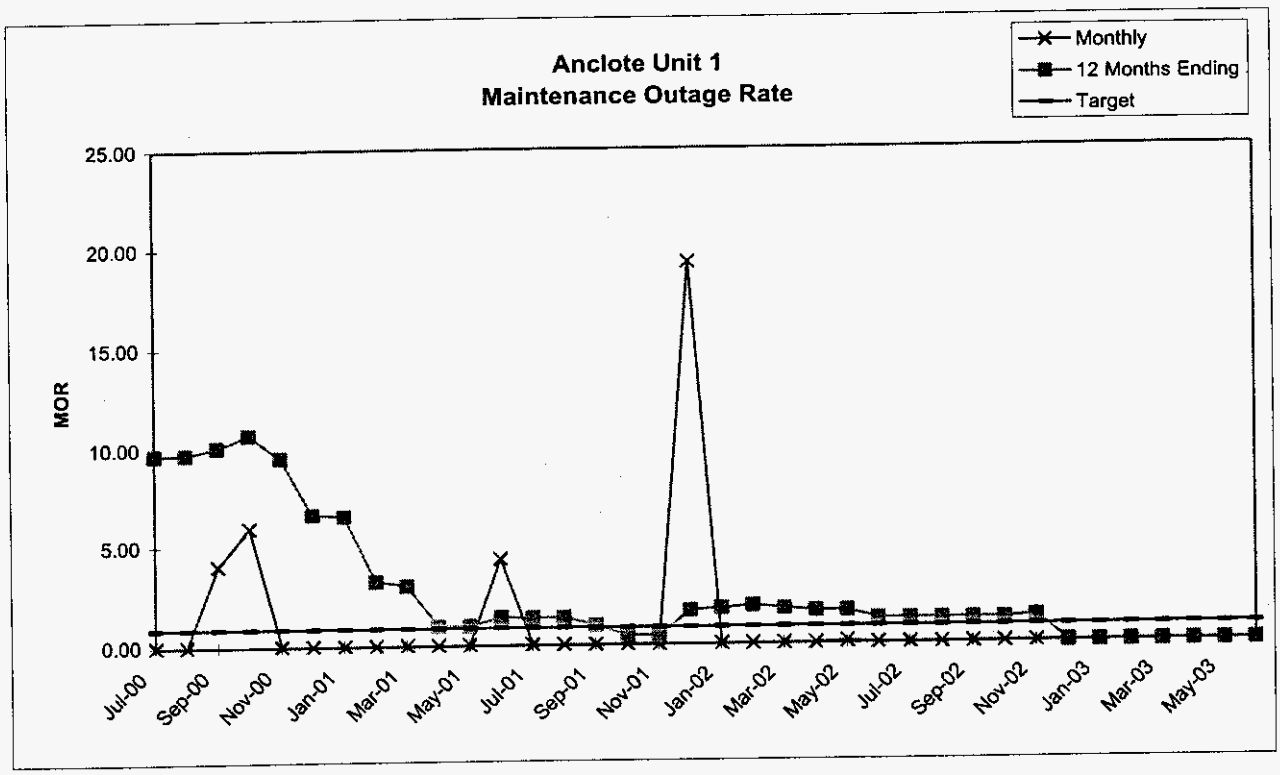
Anclote
Unit 1

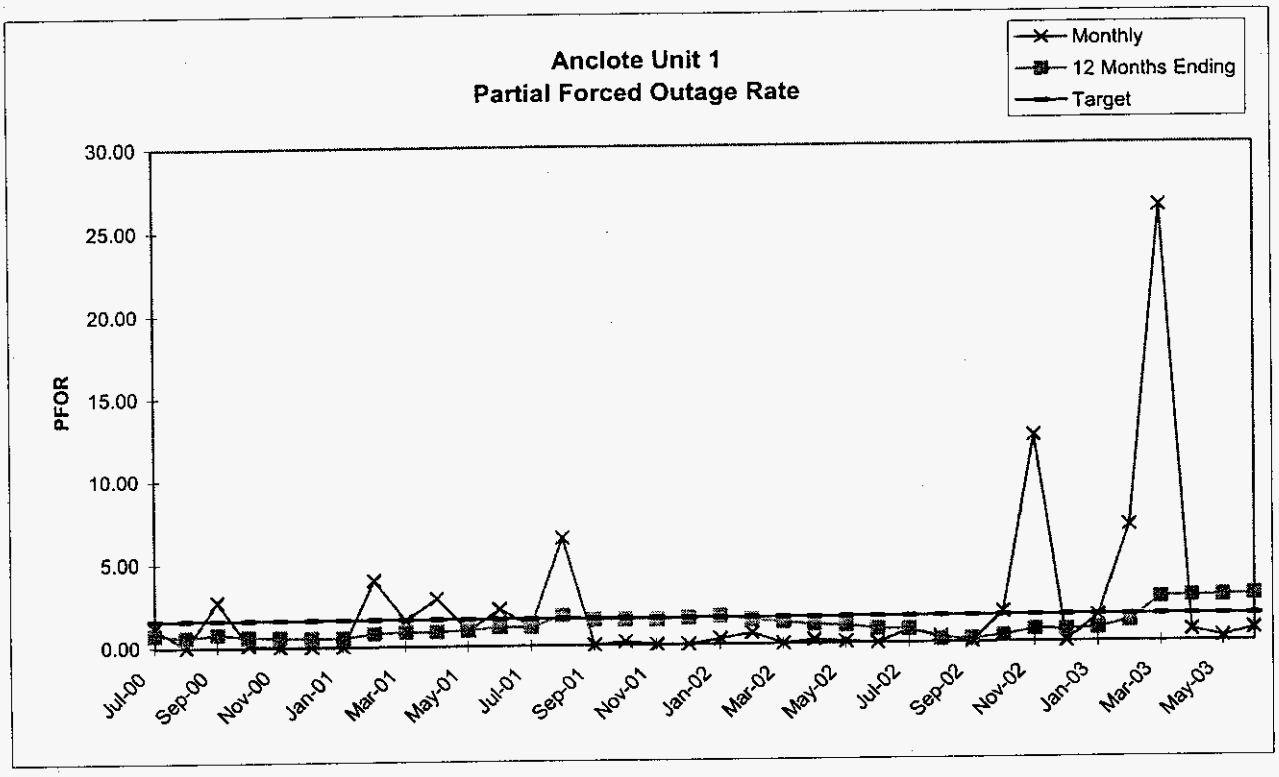
	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	245.23	130.37	744.00	719.00	743.48	720.00	744.00	743.17	720.00	745.00	200.38	744.00	744.00	565.00	397.76	576.88	744.00	720.00
RSH	494.85	541.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	107.00	317.50	135.45	0.00	0.00
UH	3.92	0.00	0.00	0.00	0.52	0.00	0.00	0.83	0.00	0.00	519.70	0.00	0.00	0.00	28.73	6.67	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	512.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	3.92	0.00	0.00	0.00	0.00	0.00	0.00	0.83	0.00	0.00	7.38	0.00	0.00	0.00	28.73	6.67	0.00	0.00
MOH	0.00	0.00	0.00	0.00	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	62.22	2.13	0.00	13.33	5.52	0.17	45.82	34.45	4.03	107.47	48.43	0.27	414.87	577.47	624.57	11.75	36.33	29.37
LRPF	6.40	198.26	0.00	56.19	61.98	108.41	61.82	36.86	33.00	62.08	256.01	254.52	13.57	33.99	83.31	159.00	24.78	88.61
EFOH	0.80	0.85	0.00	1.50	0.69	0.04	5.69	2.55	0.27	13.40	24.90	0.14	11.30	39.41	104.48	3.75	1.81	5.23
PMOH	10.12	10.00	56.18	105.73	123.07	82.27	72.25	91.22	83.10	104.52	0.00	11.40	31.32	17.87	4.33	53.80	97.82	85.05
LRPM	147.67	153.49	159.01	151.71	158.99	158.99	158.75	158.99	158.99	158.99	0.00	159.01	144.41	150.46	159.06	159.00	159.00	159.01
EMOH	3.00	3.08	17.94	32.21	39.29	26.27	23.03	29.12	26.53	33.37	0.00	3.64	9.08	5.40	1.38	17.18	31.23	27.16
NPC	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00	498.00

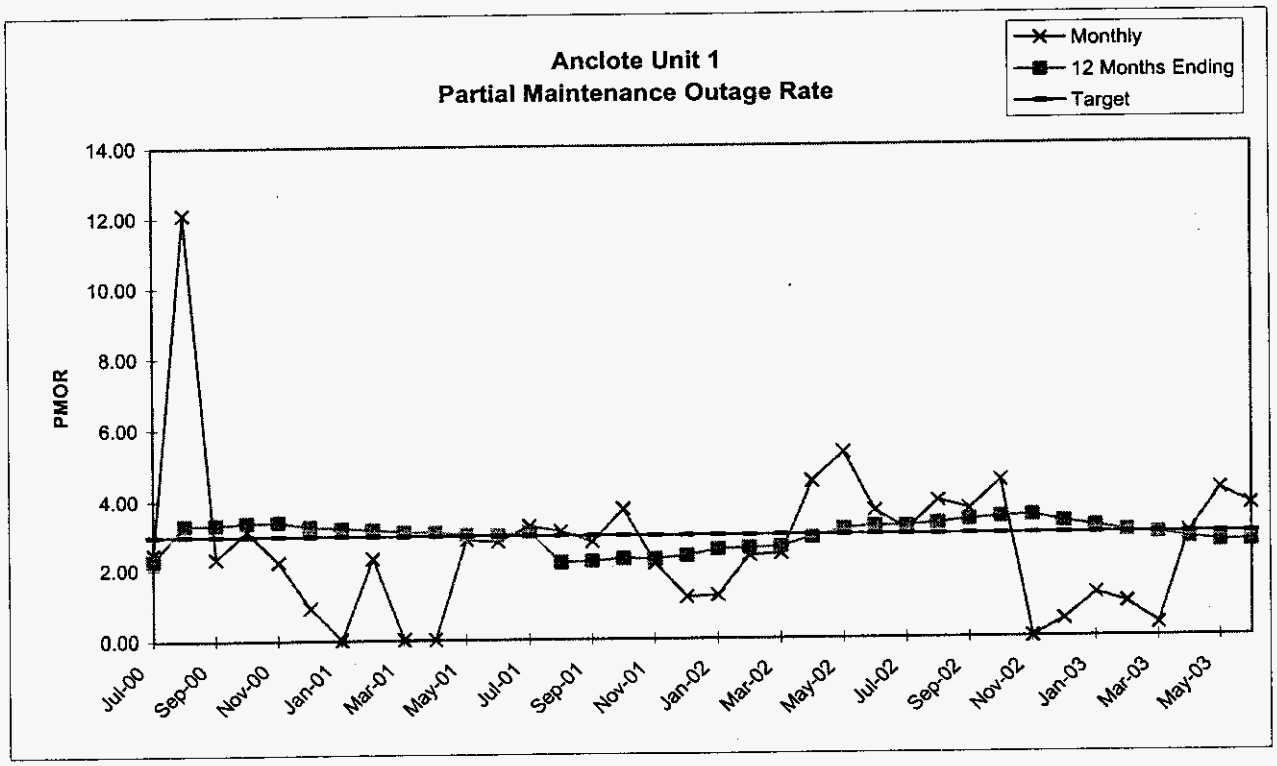
MONTHLY	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	1.57	0.00	0.00	0.00	0.00	0.00	0.00	0.11	0.00	0.00	3.55	0.00	0.00	0.00	6.74	1.14	0.00	0.00
MOR	0.00	0.00	0.00	0.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.33	0.65	0.00	0.21	0.09	0.01	0.76	0.34	0.04	1.80	12.42	0.02	1.52	6.97	26.27	0.65	0.24	0.73
PMOR	1.22	2.36	2.41	4.48	5.28	3.65	3.10	3.92	3.68	4.48	0.00	0.49	1.22	0.96	0.35	2.98	4.20	3.77
EUOR	3.10	3.01	2.41	4.69	5.44	3.65	3.86	4.37	3.72	6.28	15.54	0.51	2.74	7.93	31.56	4.73	4.44	4.50
EUOF	1.04	0.58	2.41	4.69	5.44	3.65	3.86	4.37	3.72	6.28	4.48	0.51	2.74	6.67	18.09	3.84	4.44	4.50
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	71.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	98.96	99.42	97.59	95.31	94.56	96.35	96.14	95.63	96.28	93.72	24.36	99.49	97.26	93.33	81.91	96.16	95.56	95.50

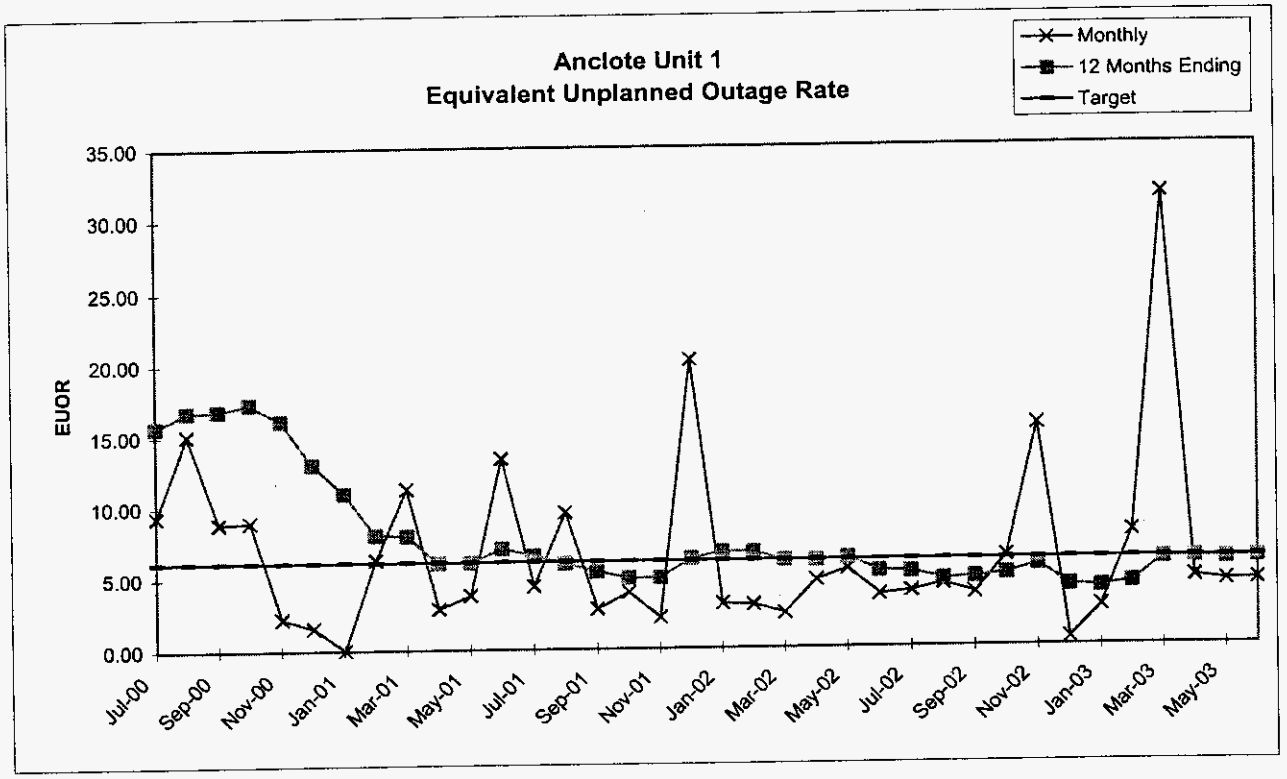
12 MONTHS	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	0.85	0.91	0.56	0.52	0.52	0.05	0.05	0.07	0.07	0.06	0.18	0.17	0.11	0.10	0.47	0.57	0.57	0.57
MOR	1.76	1.89	1.73	1.61	1.62	1.21	1.21	1.21	1.21	1.20	1.29	0.01	0.01	0.01	0.01	0.01	0.00	0.00
PFOR	1.69	1.46	1.29	1.14	1.05	0.85	0.81	0.19	0.19	0.35	0.74	0.71	0.80	1.23	2.62	2.70	2.72	2.79
PMOR	2.55	2.57	2.62	2.88	3.13	3.22	3.20	3.28	3.37	3.45	3.49	3.30	3.16	3.02	2.95	2.80	2.70	2.71
EUOR	6.72	6.69	6.10	6.05	6.22	5.28	5.22	4.70	4.79	5.02	5.64	4.17	4.07	4.35	6.02	6.05	5.95	6.03
EUOF	5.21	4.83	4.79	5.11	5.25	4.45	4.40	3.96	4.04	4.27	4.46	3.44	3.58	4.05	5.38	5.31	5.22	5.29
POF	12.04	12.04	5.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.85	5.85	5.85	5.85	5.85	5.85	5.85	5.85
EAF	82.76	83.13	89.48	94.89	94.75	95.55	95.60	96.04	95.96	95.73	89.69	90.72	90.57	90.10	88.77	88.84	88.93	88.86

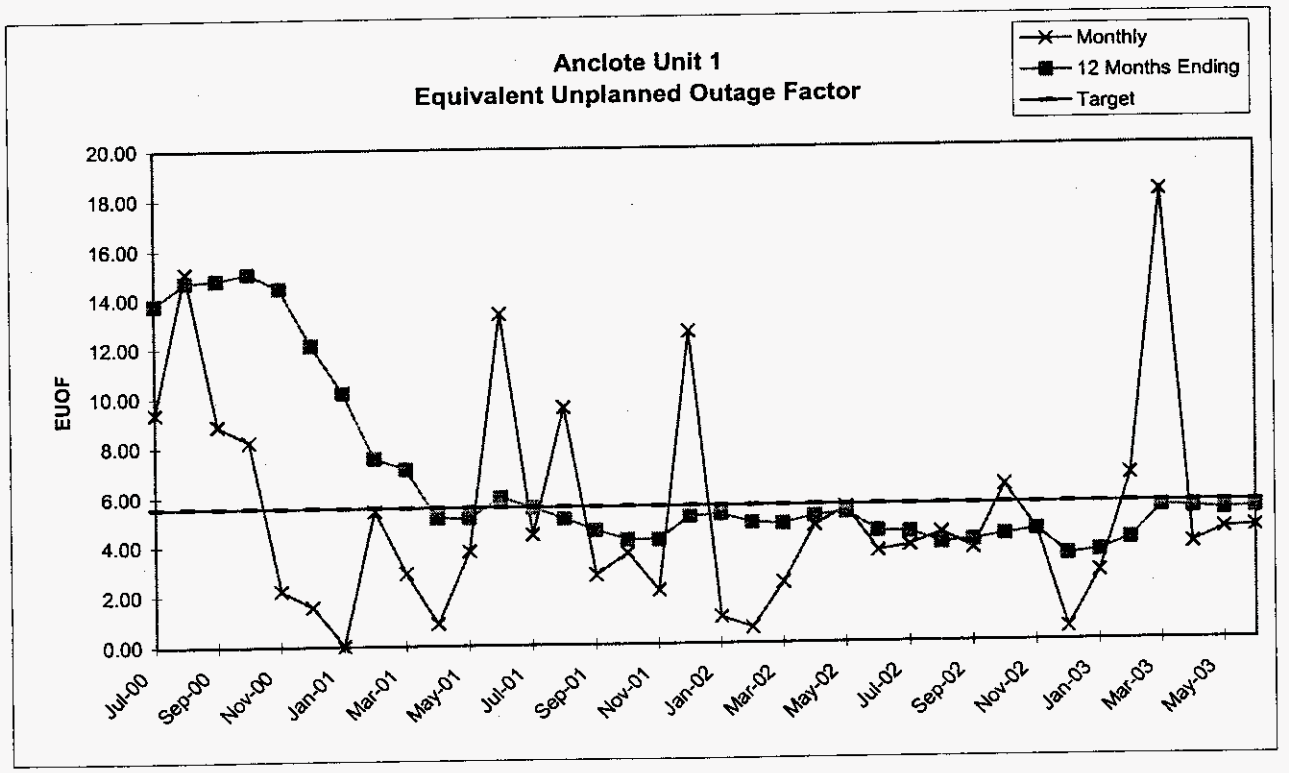

Anclote Unit 1
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Anclote Unit 1
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Anclote Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Anclote Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Anclote Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Anclote Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03

Anclote
Unit 2

	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	744.00	720.00	371.50	0.00	411.82	551.45	335.83	647.17	713.40	744.00	659.05	744.00	740.30	720.00	745.00	358.30	669.22
RSH	0.00	0.00	0.00	155.95	0.00	106.78	192.55	310.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.18	74.78
UH	0.00	0.00	0.00	217.55	720.00	225.40	0.00	25.98	96.83	5.60	0.00	60.95	0.00	3.70	0.00	0.00	322.52	0.00
POH	0.00	0.00	0.00	157.00	720.00	225.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.60	0.00	0.00	0.00	3.70	0.00	0.00	11.40	0.00
MOH	0.00	0.00	0.00	60.55	0.00	0.00	0.00	25.98	96.83	0.00	0.00	60.95	0.00	0.00	0.00	0.00	311.12	0.00
PFOH	4.58	3.70	6.17	0.00	0.00	1.92	0.00	0.00	0.00	1.92	61.36	0.00	0.50	8.63	0.00	0.00	0.00	0.00
LRPF	52.92	287.81	52.87	0.00	0.00	84.42	0.00	0.00	0.00	36.75	68.19	0.00	118.27	18.94	0.00	0.00	0.00	0.00
EFOH	0.48	2.12	0.65	0.00	0.00	0.32	0.00	0.00	0.00	0.14	8.45	0.00	0.12	0.33	0.00	0.00	0.00	0.00
PMOH	66.87	38.53	41.68	15.35	0.00	0.00	0.00	0.00	17.32	28.72	44.54	35.65	43.60	47.70	48.40	39.95	19.12	40.30
LRPM	162.00	168.33	164.95	168.29	0.00	0.00	0.00	0.00	165.56	165.61	180.85	165.64	165.64	161.07	145.55	145.57	137.22	135.02
EMOH	21.54	12.89	13.67	5.14	0.00	0.00	0.00	0.00	5.79	9.61	16.27	11.93	14.59	15.52	14.23	11.75	5.30	10.99
NPC	503.00	503.00	503.00	503.00	503.00	503.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00

MONTHLY	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.78	0.00	0.00	0.00	0.50	0.00	0.00	3.08	0.00
MOR	0.00	0.00	0.00	14.01	0.00	0.00	0.00	7.18	13.02	0.00	0.00	8.47	0.00	0.00	0.00	0.00	46.48	0.00
PFOR	0.06	0.28	0.09	0.00	0.00	0.08	0.00	0.00	0.00	0.02	1.14	0.00	0.02	0.04	0.00	0.00	0.00	0.00
PMOR	2.89	1.73	1.90	1.38	0.00	0.00	0.00	0.00	0.90	1.35	2.19	1.81	1.96	2.10	1.98	1.58	1.48	1.64
EUOR	2.96	2.02	1.99	15.20	0.00	0.08	0.00	7.18	13.79	2.14	3.32	10.12	1.98	2.63	1.98	1.58	48.15	1.64
EUOF	2.96	2.02	1.99	8.82	0.00	0.04	0.00	3.87	13.79	2.14	3.32	10.12	1.98	2.63	1.98	1.58	45.53	1.48
POF	0.00	0.00	0.00	21.07	100.00	30.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	97.04	97.98	98.01	70.11	0.00	69.66	100.00	96.13	86.21	97.86	96.68	89.88	98.02	97.37	98.02	98.42	54.47	98.52

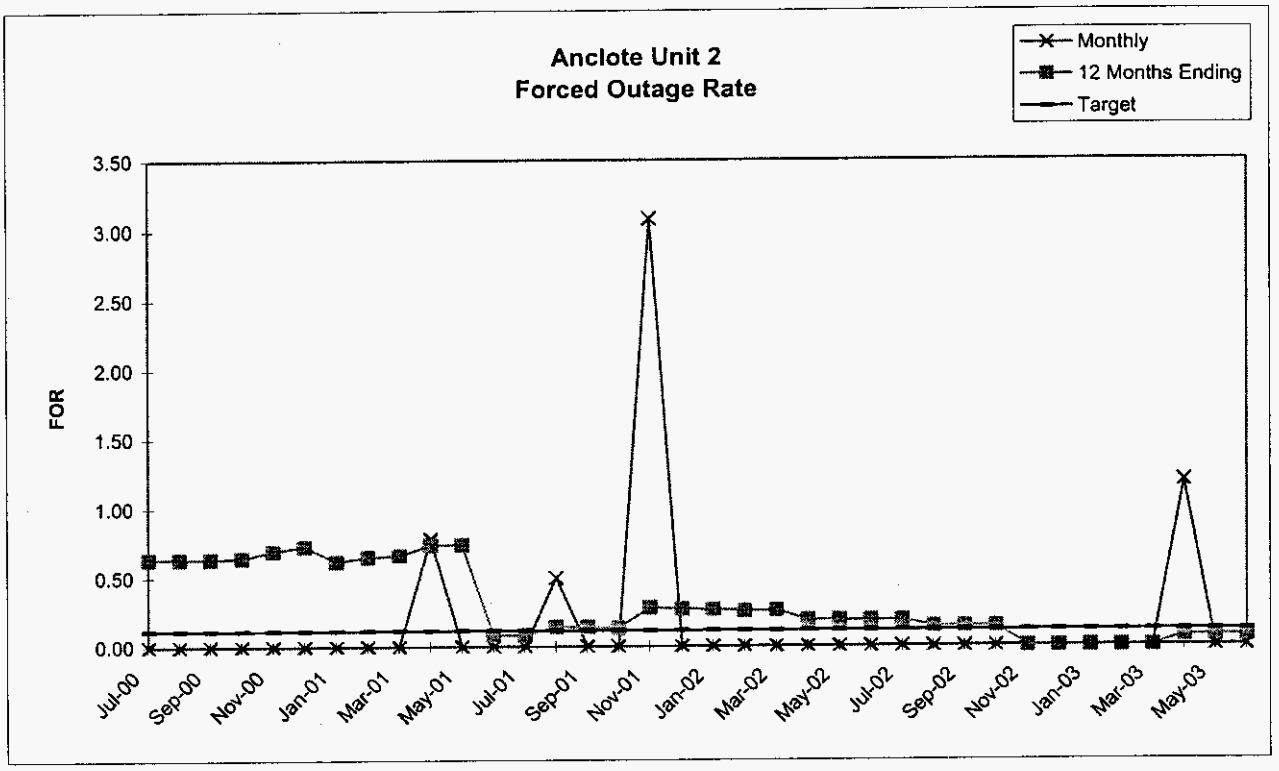
12 MONTHS	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	0.64	0.64	0.64	0.65	0.69	0.73	0.62	0.65	0.66	0.74	0.74	0.08	0.08	0.14	0.14	0.13	0.28	0.27
MOR	1.40	1.40	1.40	1.77	1.90	1.99	1.51	1.96	3.38	2.68	2.68	3.55	3.55	3.55	3.55	2.55	6.29	6.09
PFOR	1.24	1.03	0.75	0.37	0.39	0.17	0.11	0.11	0.12	0.09	0.22	0.18	0.18	0.15	0.14	0.13	0.13	0.12
PMOR	1.60	1.61	1.62	1.63	1.64	1.62	1.54	1.56	1.54	1.48	1.43	1.46	1.35	1.39	1.40	1.42	1.42	1.52
EUOR	4.80	4.61	4.34	4.35	4.55	4.43	3.72	4.22	5.59	4.90	4.97	5.21	5.10	5.17	5.17	4.19	7.99	7.87
EUOF	4.43	4.25	4.01	3.96	3.87	3.60	3.06	3.32	4.39	3.85	3.91	4.10	4.01	4.07	4.06	3.45	7.19	7.31
POF	0.00	0.00	0.00	1.79	9.98	12.55	12.55	12.58	12.58	12.58	12.58	12.58	12.58	12.58	12.58	10.79	2.57	0.00
EAF	95.57	95.75	95.99	94.25	86.14	83.85	84.39	84.09	83.02	83.56	83.50	83.32	83.40	83.35	83.35	85.76	90.24	92.69

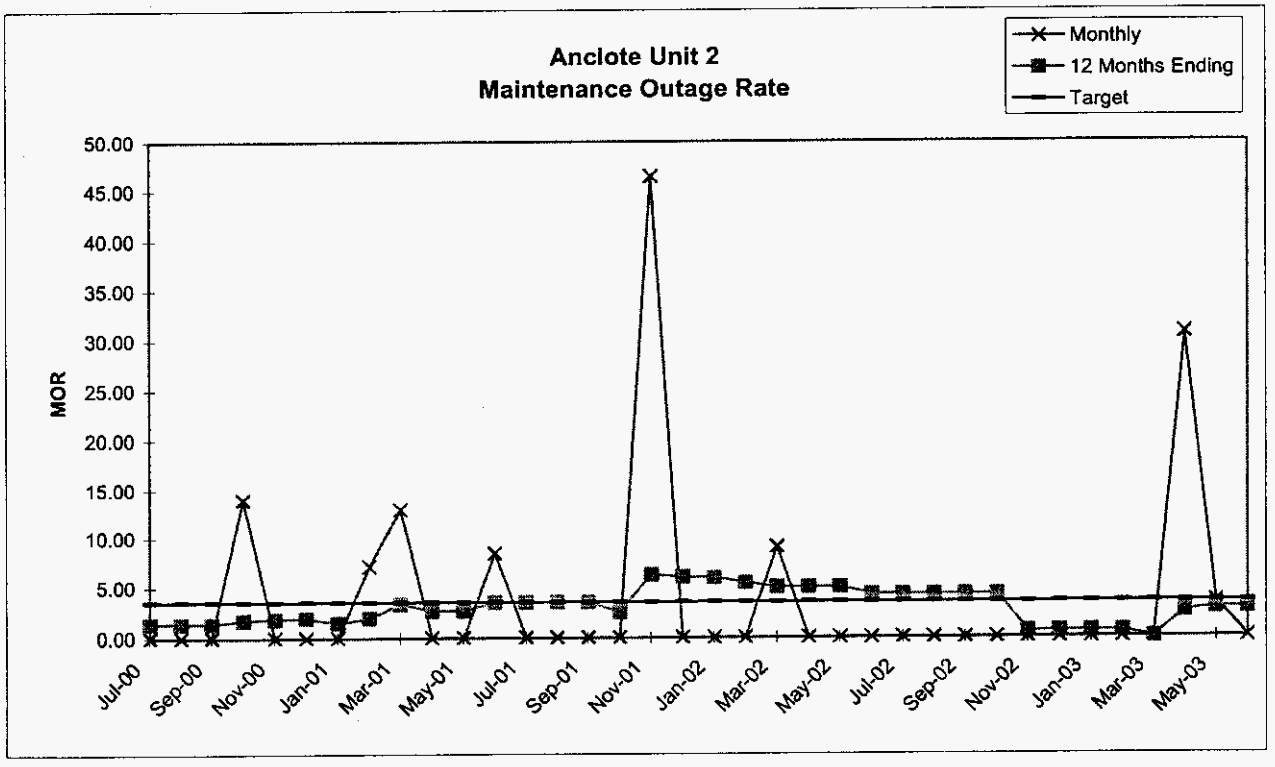
Anclote
Unit 2

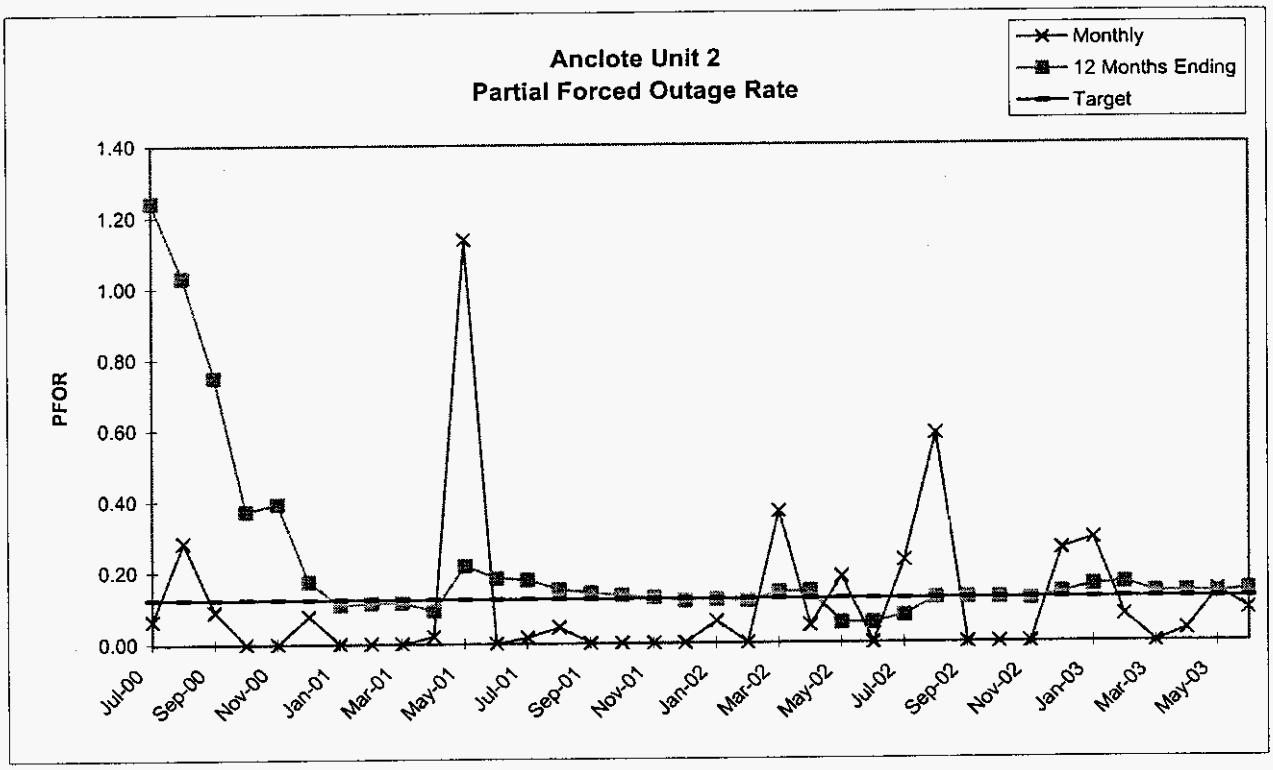
	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	698.47	672.00	501.38	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	520.10	744.00	672.00	744.00	493.73	718.00	720.00
RSH	45.53	0.00	192.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	223.90	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	50.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	225.27	26.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.97	0.00	0.00
MOH	0.00	0.00	50.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	219.30	26.00	0.00
PFOH	0.43	0.00	4.00	0.67	9.48	0.00	9.25	7.58	0.00	0.00	0.00	2.67	7.87	1.58	0.00	6.87	6.53	1.58
LRPF	484.65	0.00	229.06	251.94	71.74	0.00	91.46	285.11	0.00	0.00	0.00	251.76	135.35	156.34	0.00	11.96	77.77	204.27
EFOH	0.42	0.00	1.85	0.34	1.37	0.00	1.71	4.37	0.00	0.00	0.00	1.36	2.15	0.50	0.00	0.17	1.03	0.65
PMOH	25.12	10.50	39.23	54.75	133.48	85.62	44.17	55.85	53.48	65.85	11.68	25.73	33.10	33.83	35.48	53.60	34.15	41.97
LRPM	144.97	207.76	156.02	156.00	156.01	156.00	155.52	155.82	156.02	156.01	185.37	167.39	151.43	156.02	156.02	148.75	155.99	155.99
EMOH	7.36	4.41	12.37	17.26	42.07	26.98	13.88	17.58	16.86	20.75	4.37	8.70	10.13	10.66	11.18	16.11	10.76	13.23
NPC	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00	495.00

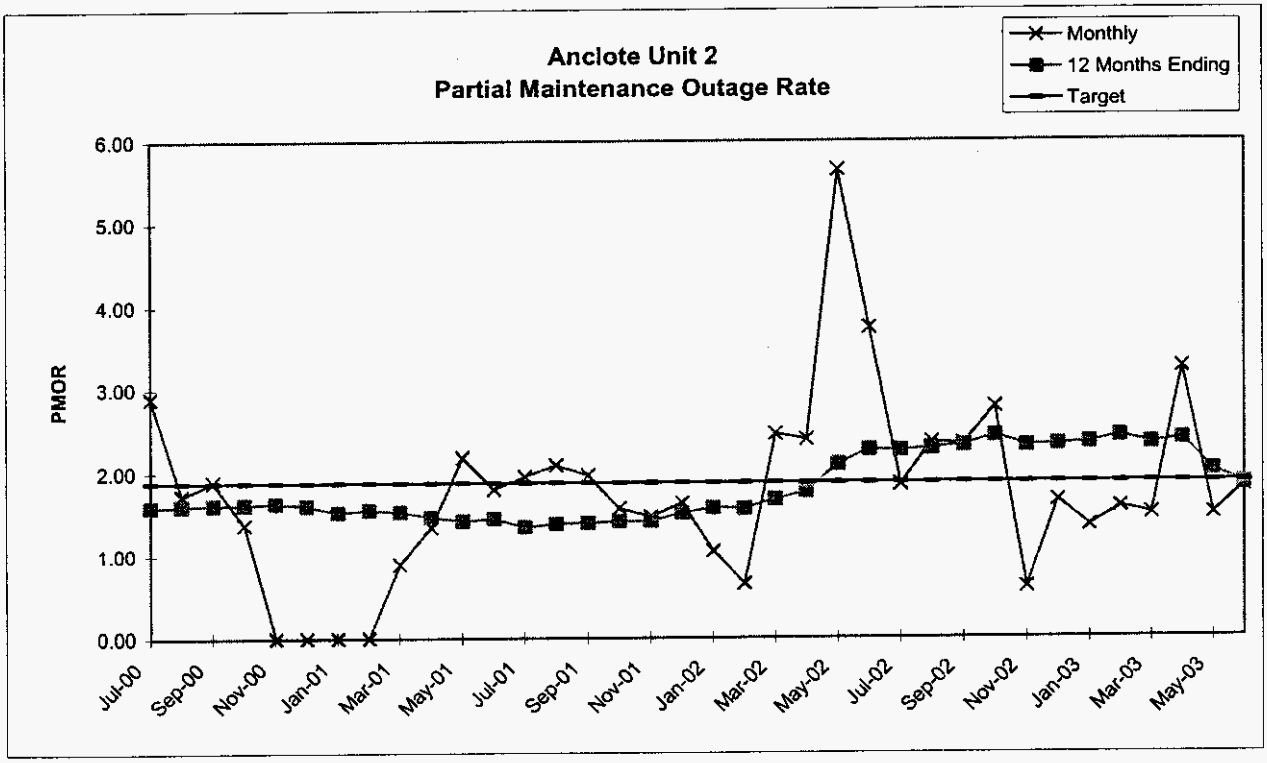
MONTHLY	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.19	0.00	0.00
MOR	0.00	0.00	9.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.76	3.49	0.00
PFOR	0.06	0.00	0.37	0.05	0.18	0.00	0.23	0.59	0.00	0.00	0.00	0.26	0.29	0.07	0.00	0.03	0.14	0.09
PMOR	1.05	0.66	2.47	2.40	5.65	3.75	1.87	2.36	2.34	2.79	0.61	1.67	1.36	1.59	1.50	3.26	1.50	1.84
EUOR	1.11	0.66	11.68	2.45	5.84	3.75	2.09	2.95	2.34	2.79	0.61	1.93	1.65	1.66	1.50	33.59	5.08	1.93
EUOF	1.05	0.66	8.66	2.45	5.84	3.75	2.09	2.95	2.34	2.79	0.61	1.35	1.65	1.66	1.50	33.59	5.08	1.93
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	98.95	99.34	91.34	97.55	94.16	96.25	97.91	97.05	97.66	97.21	99.39	98.65	98.35	98.34	98.50	66.41	94.92	98.07

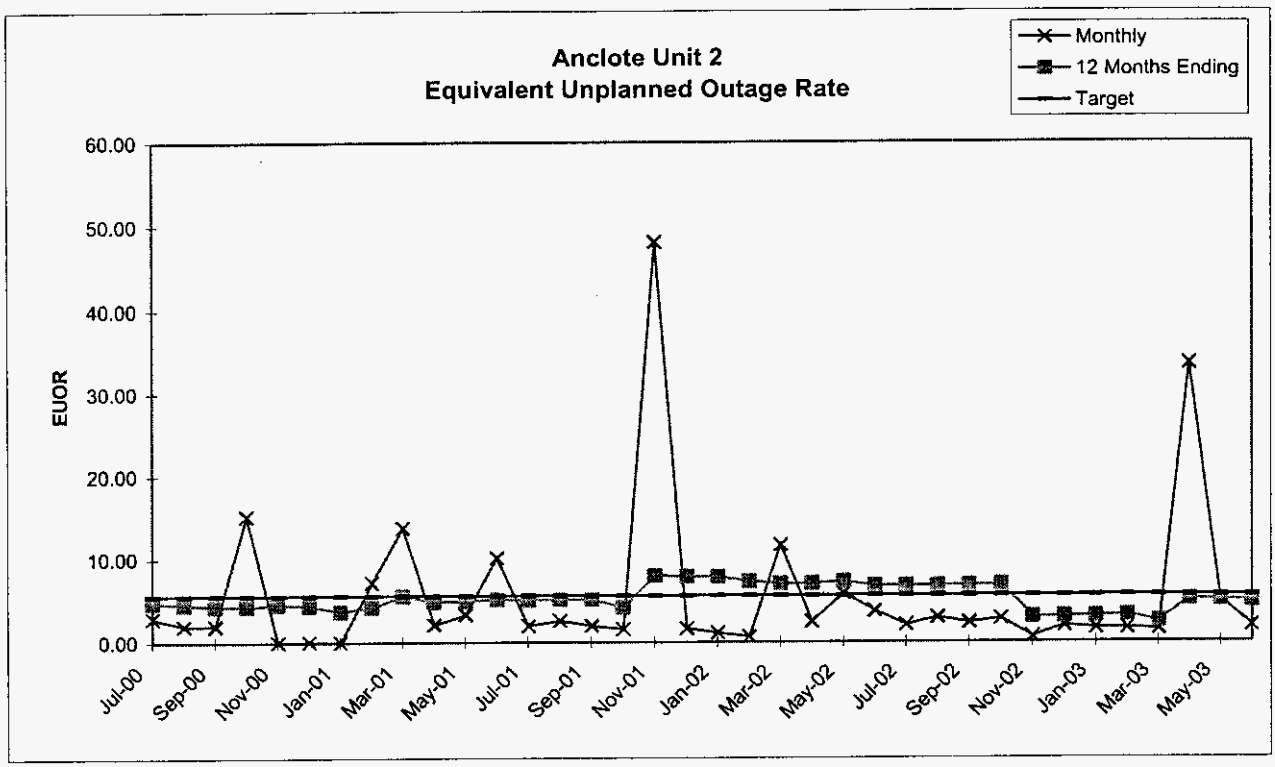
12 MONTHS	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	0.27	0.25	0.26	0.19	0.19	0.19	0.19	0.14	0.14	0.14	0.00	0.00	0.00	0.00	0.00	0.07	0.07	0.07
MOR	5.98	5.47	5.03	5.03	5.03	4.31	4.31	4.30	4.30	4.30	0.59	0.61	0.60	0.60	0.00	2.57	2.88	2.88
PFOR	0.12	0.12	0.14	0.14	0.06	0.06	0.08	0.13	0.13	0.13	0.12	0.14	0.16	0.16	0.14	0.14	0.14	0.14
PMOR	1.59	1.58	1.69	1.78	2.10	2.28	2.27	2.29	2.32	2.44	2.32	2.33	2.36	2.43	2.35	2.40	2.03	1.86
EUOR	7.82	7.29	7.00	7.03	7.25	6.70	6.71	6.74	6.77	6.88	3.02	3.06	3.10	3.18	2.49	5.11	5.04	4.89
EUOF	7.40	7.16	6.72	6.75	6.96	6.43	6.45	6.47	6.50	6.61	2.91	2.90	2.95	3.03	2.42	4.98	4.91	4.76
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	92.60	92.84	93.28	93.25	93.04	93.57	93.55	93.53	93.50	93.39	97.09	97.10	97.05	96.97	97.58	95.02	95.09	95.24

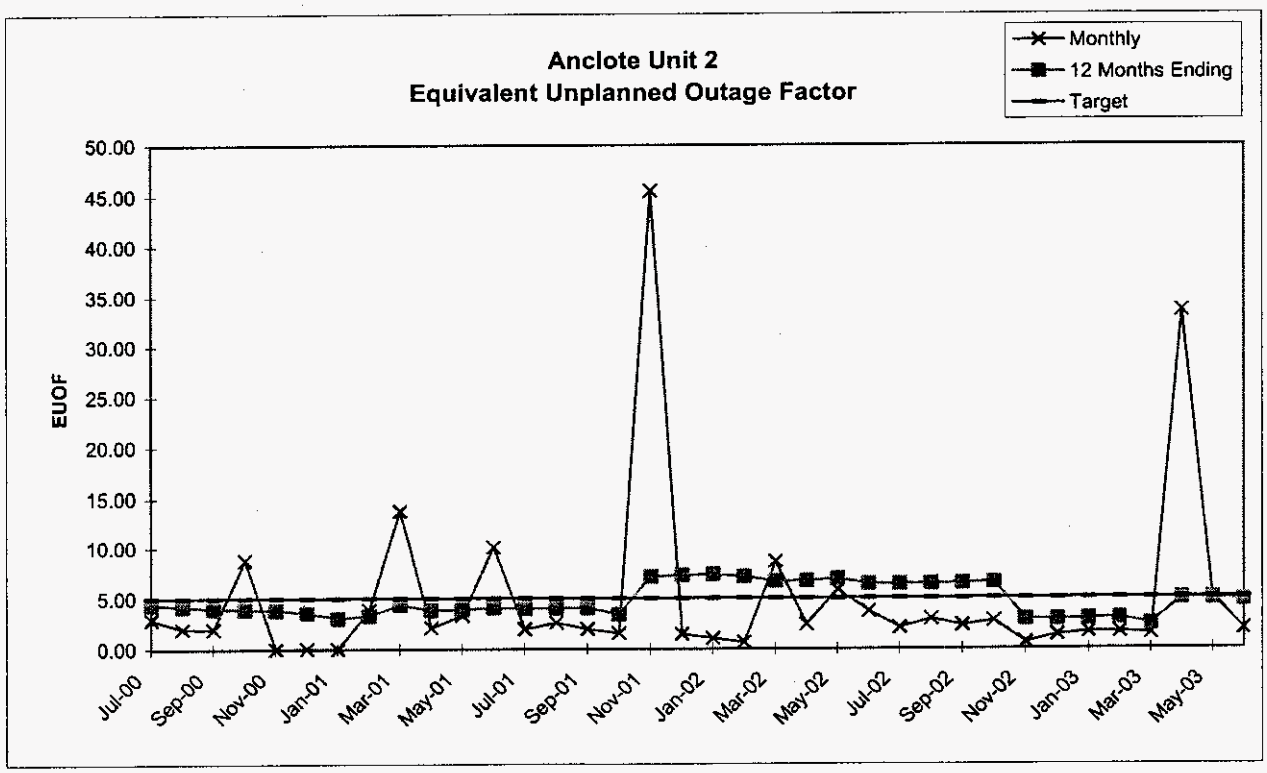

Anclote Unit 2
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Anclote Unit 2
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Anclote Unit 2
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Anclote Unit 2
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Anclote Unit 2
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Anclote Unit 2
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03

Crystal River
Unit 1

	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	656.02	744.00	627.20	673.23	720.00	618.95	642.83	427.37	744.00	675.33	744.00	720.00	698.98	744.00	720.00	740.00	263.87	368.37
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	87.98	0.00	92.80	71.77	0.00	125.05	101.17	244.63	0.00	43.67	0.00	0.00	45.02	0.00	0.00	5.00	456.13	375.63
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	456.13	365.48
FOH	1.93	0.00	19.27	0.83	0.00	2.40	2.35	0.00	0.00	4.37	0.00	0.00	45.02	0.00	0.00	5.00	0.00	10.15
MOH	86.05	0.00	73.53	70.93	0.00	122.65	98.82	244.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	73.80	22.63	0.00	2.10	12.58	3.00	150.54	7.48	25.95	4.78	4.05	34.16	35.05	127.22	55.10	87.47	0.00	258.55
LRPF	99.25	86.01	0.00	193.80	9.23	175.24	98.19	151.65	160.79	85.33	198.94	99.04	113.06	182.12	106.86	49.41	0.00	3.79
EFOH	19.85	5.27	0.00	1.10	0.31	1.42	39.00	2.99	11.01	1.08	2.13	8.93	10.46	61.13	15.54	11.40	0.00	2.59
PMOH	20.58	36.01	42.00	61.62	30.96	17.68	13.75	7.53	34.63	58.95	42.39	60.87	0.00	33.02	32.73	32.20	0.00	0.00
LRPM	180.42	199.85	193.71	108.85	119.87	78.15	89.76	104.26	232.51	104.63	177.03	150.32	0.00	198.11	100.53	109.08	0.00	0.00
EMOH	10.06	19.50	22.05	18.18	10.06	3.74	3.26	2.07	21.25	16.27	19.80	24.14	0.00	17.26	8.68	9.27	0.00	0.00
NPC	369.00	369.00	369.00	369.00	369.00	369.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00

MONTHLY	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	0.29	0.00	2.98	0.12	0.00	0.39	0.36	0.00	0.00	0.64	0.00	0.00	6.05	0.00	0.00	0.67	0.00	2.68
MOR	11.60	0.00	10.49	9.53	0.00	16.54	13.32	36.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	3.03	0.71	0.00	0.16	0.04	0.23	6.07	0.70	1.48	0.16	0.29	1.24	1.50	8.22	2.16	1.54	0.00	0.70
PMOR	1.53	2.62	3.52	2.70	1.40	0.60	0.51	0.48	2.86	2.41	2.66	3.35	0.00	2.32	1.21	1.25	0.00	0.00
EUOR	15.85	3.33	15.95	12.22	1.44	17.50	19.28	37.16	4.34	3.20	2.95	4.59	7.46	10.54	3.36	3.45	0.00	3.36
EUOF	15.85	3.33	15.95	12.22	1.44	17.50	19.28	37.16	4.34	3.02	2.95	4.59	7.46	10.54	3.36	3.45	0.00	1.71
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	63.35	49.12
EAF	84.15	96.67	84.05	87.78	98.56	82.50	80.72	62.84	95.66	96.98	97.05	95.41	92.54	89.46	96.64	96.55	36.65	49.16

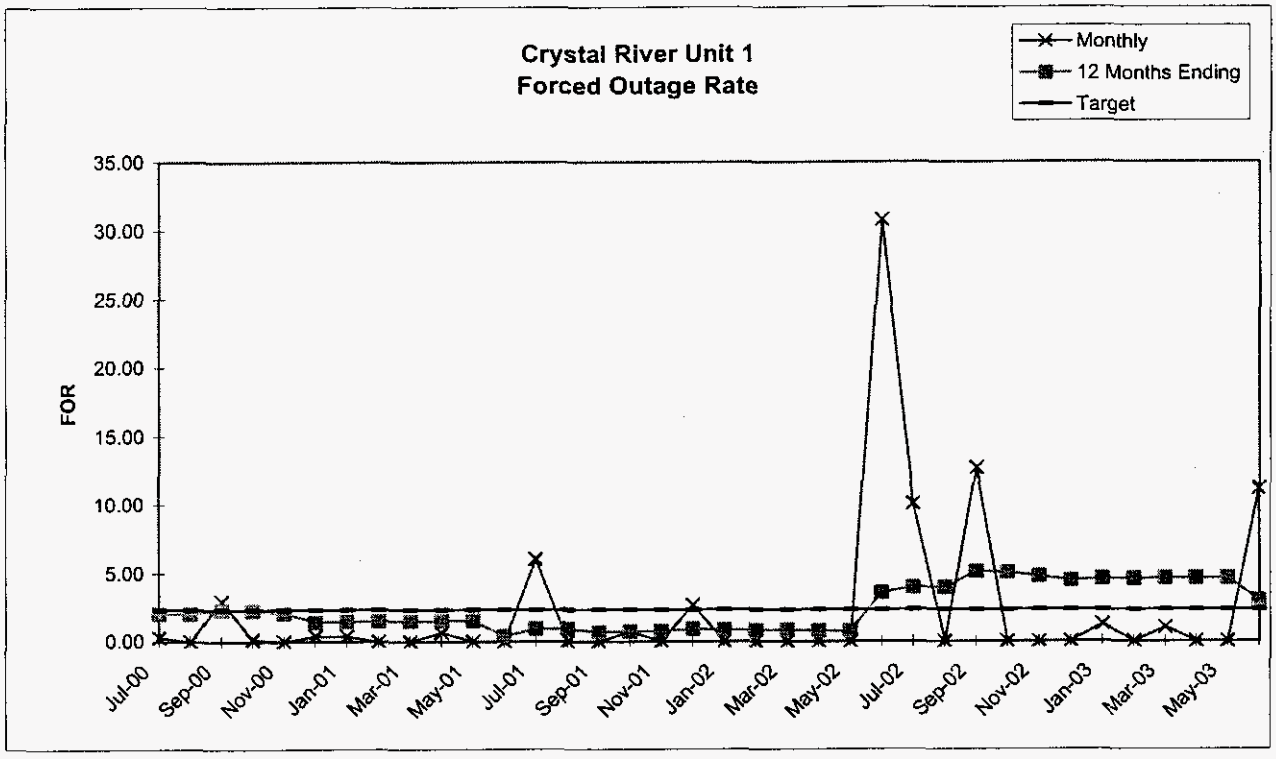
12 MONTHS	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	2.02	2.02	2.32	2.27	2.06	1.41	1.46	1.50	1.50	1.52	1.52	0.39	0.92	0.92	0.67	0.72	0.76	0.89
MOR	5.32	5.32	6.33	6.38	5.83	7.01	8.15	10.37	10.27	8.10	8.10	8.02	7.06	7.06	6.20	5.38	5.68	4.39
PFOR	2.59	2.42	2.35	2.29	2.09	1.30	1.64	1.71	1.77	1.72	1.69	1.16	1.04	1.74	1.91	2.02	2.13	2.22
PMOR	1.39	1.52	1.63	1.75	1.72	1.66	1.63	1.64	1.70	1.84	2.06	2.13	2.00	1.97	1.78	1.66	1.62	1.63
EUOR	10.83	10.79	12.01	12.08	11.17	10.94	12.34	14.54	14.54	12.62	12.79	11.37	10.65	11.27	10.23	9.48	9.87	8.84
EUOF	9.30	9.27	10.32	10.67	10.79	10.94	12.34	14.54	14.54	12.56	12.73	11.32	10.60	11.22	10.18	9.43	9.32	7.97
POF	14.11	14.11	14.11	11.65	3.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.21	9.38
EAF	76.59	76.62	75.57	77.68	85.76	89.06	87.66	85.46	85.46	87.44	87.27	88.68	89.40	88.78	89.82	90.57	85.48	82.65

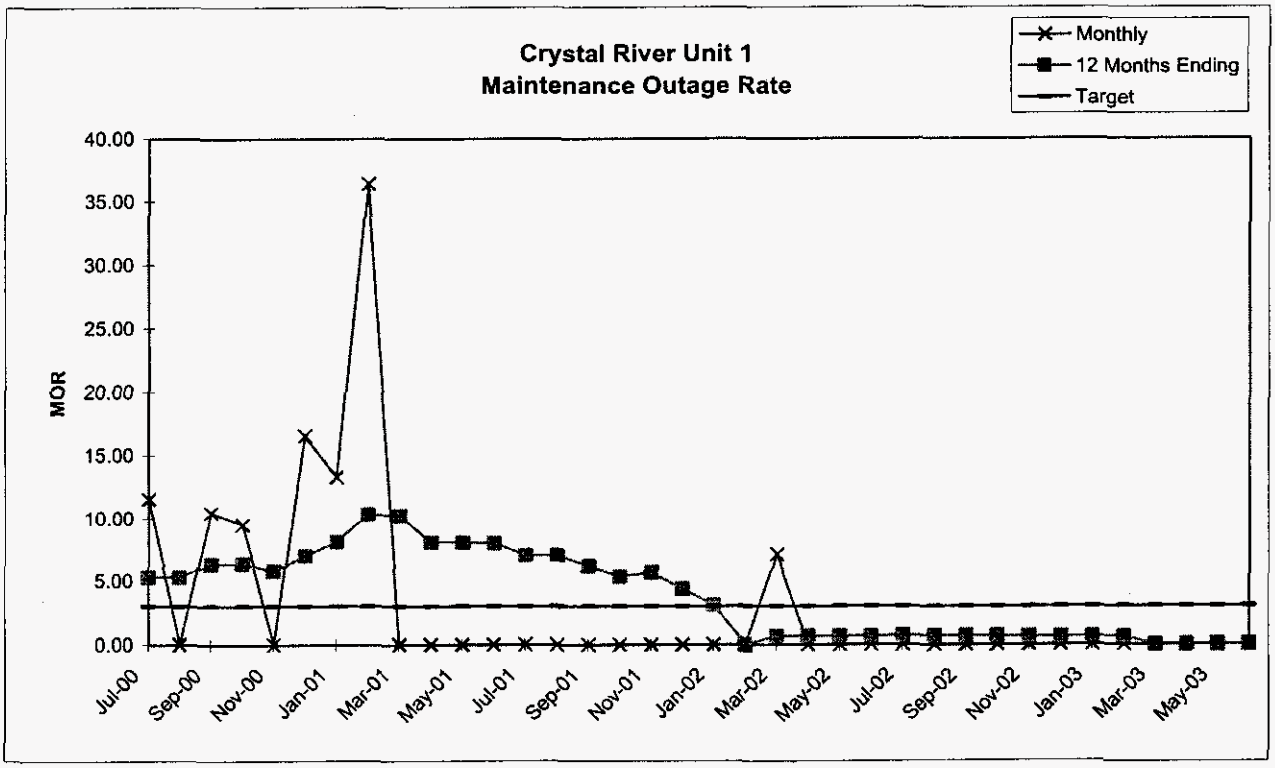
Crystal River
Unit 1

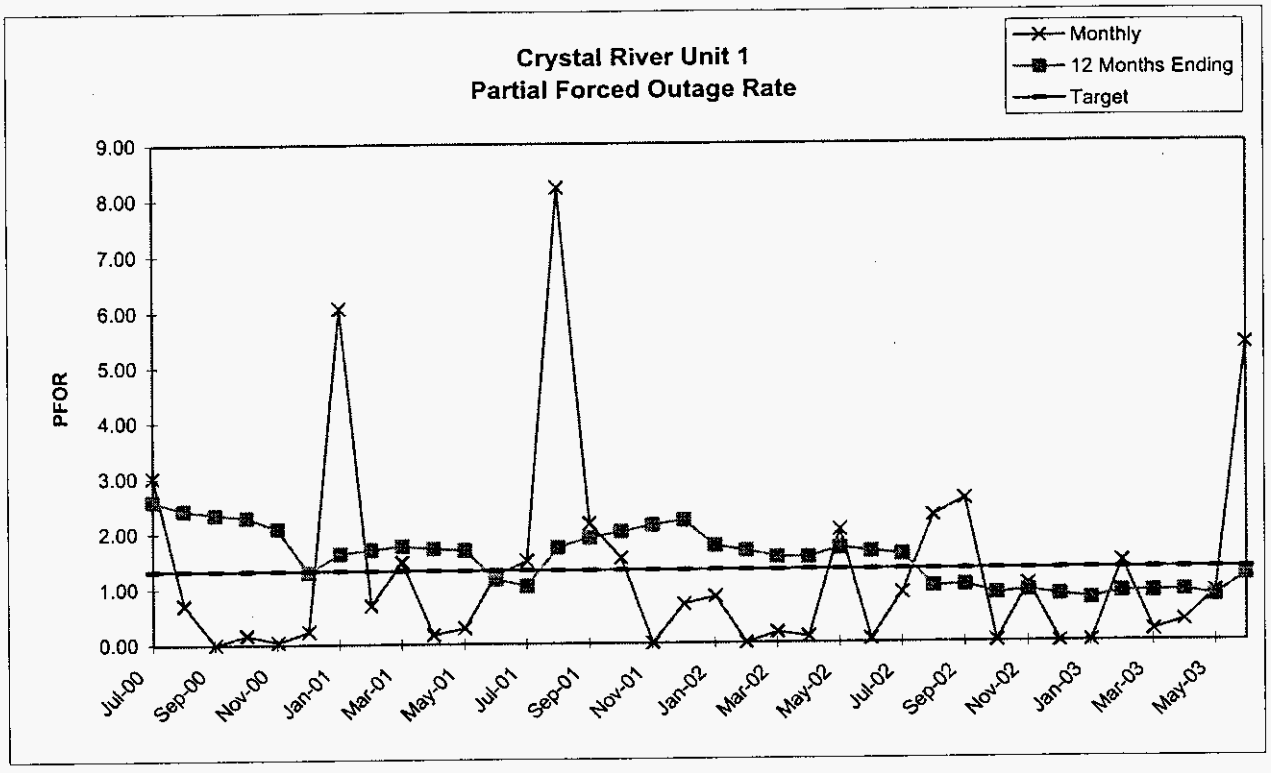
	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	744.00	672.00	691.10	719.00	744.00	497.95	668.98	744.00	628.50	745.00	720.00	744.00	734.70	672.00	736.38	719.00	744.00	639.48
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	52.90	0.00	0.00	222.05	75.02	0.00	91.50	0.00	0.00	0.00	9.30	0.00	7.62	0.00	0.00	80.52
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	222.05	75.02	0.00	91.50	0.00	0.00	0.00	9.30	0.00	7.45	0.00	0.00	80.52
MOH	0.00	0.00	52.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.17	0.00	0.00	0.00
PFOH	13.95	0.00	8.25	3.77	36.02	1.50	53.60	54.32	26.63	0.92	23.80	0.00	0.23	19.47	6.75	13.52	33.55	51.70
LRPF	168.99	0.00	58.99	77.91	159.78	75.04	42.42	118.42	231.53	55.62	119.37	0.00	75.78	188.97	79.90	74.99	74.53	252.31
EFOH	6.22	0.00	1.28	0.78	15.19	0.30	6.00	16.97	16.27	0.14	7.50	0.00	0.05	9.71	1.42	2.68	6.60	34.42
PMOH	0.00	6.67	0.00	87.88	0.00	39.23	36.17	24.68	23.37	39.13	11.00	111.94	47.48	48.07	195.97	64.02	65.32	158.57
LRPM	0.00	21.99	0.00	44.25	0.00	112.90	100.49	174.72	166.01	121.27	222.68	121.76	75.72	99.45	136.06	129.10	117.12	104.18
EMOH	0.00	0.39	0.00	10.26	0.00	11.69	9.59	11.38	10.24	12.52	6.46	35.96	9.49	12.61	70.36	21.81	20.19	43.59
NPC	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00	379.00

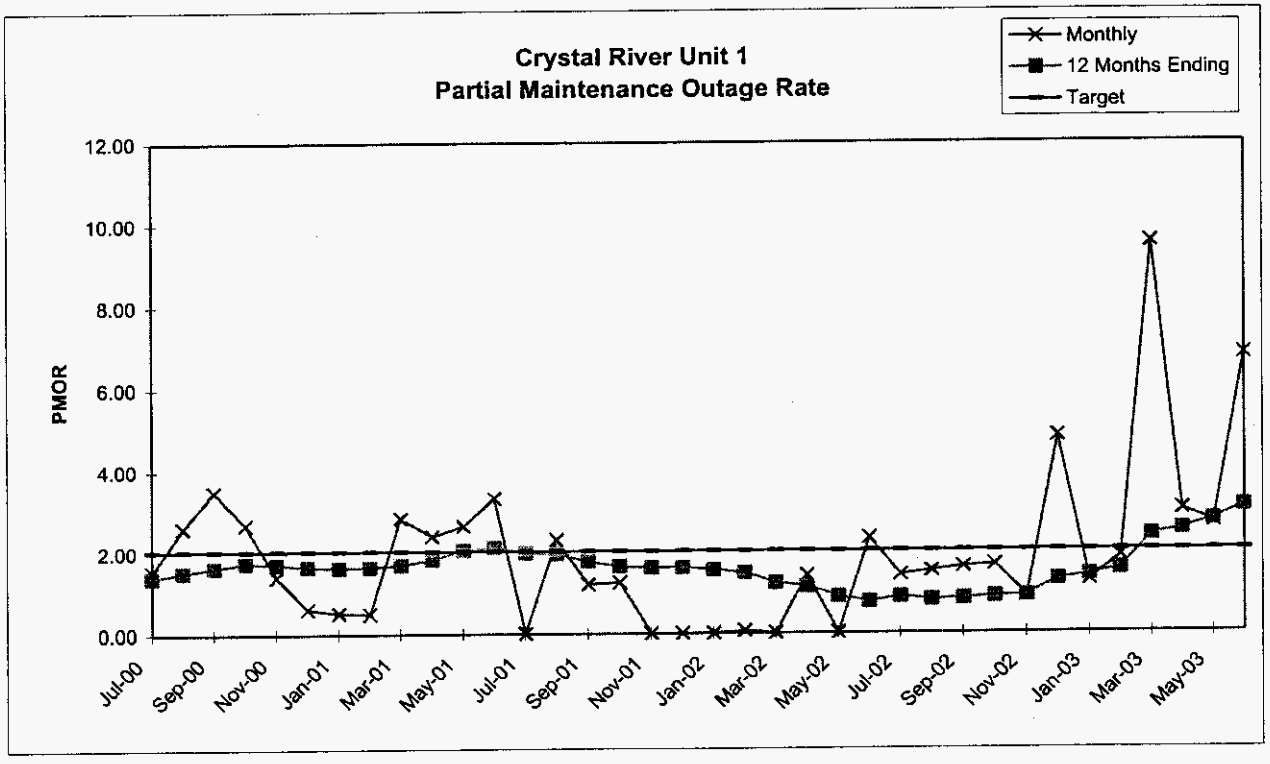
MONTHLY	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	0.00	0.00	0.00	0.00	0.00	30.84	10.08	0.00	12.71	0.00	0.00	0.00	1.25	0.00	1.00	0.00	0.00	11.18
MOR	0.00	0.00	7.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.00	0.00
PFOR	0.84	0.00	0.19	0.11	2.04	0.06	0.90	2.28	2.59	0.02	1.04	0.00	0.01	1.44	0.19	0.37	0.89	5.38
PMOR	0.00	0.06	0.00	1.43	0.00	2.35	1.43	1.53	1.63	1.68	0.90	4.83	1.29	1.88	9.55	3.03	2.71	6.82
EUOR	0.84	0.06	7.28	1.53	2.04	32.50	12.18	3.81	16.39	1.70	1.94	4.83	2.53	3.32	10.67	3.41	3.60	22.02
EUOF	0.84	0.06	7.28	1.53	2.04	32.50	12.18	3.81	16.39	1.70	1.94	4.83	2.53	3.32	10.67	3.41	3.60	22.02
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.16	99.94	92.72	98.47	97.96	67.50	87.82	96.19	83.61	98.30	98.06	95.17	97.47	96.68	89.33	96.59	96.40	77.98

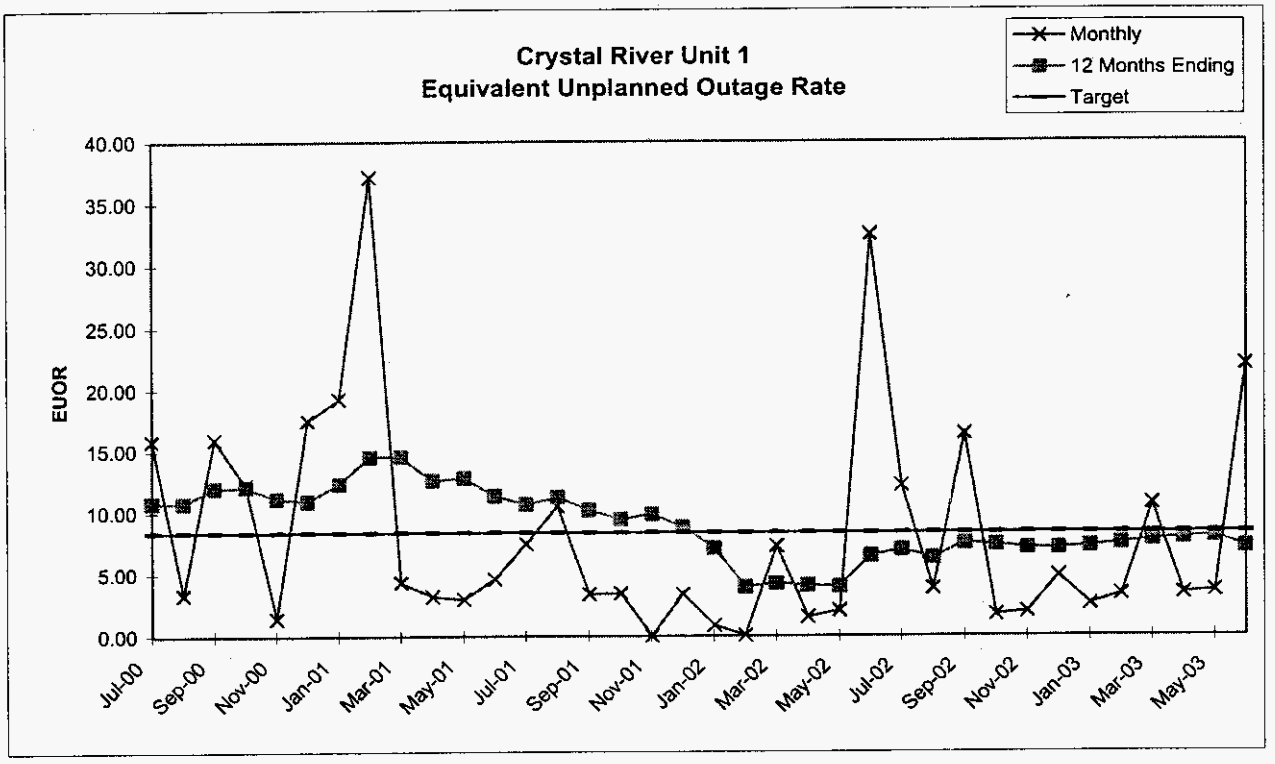
12 MONTHS	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	0.84	0.82	0.82	0.76	0.76	3.58	3.96	3.96	5.12	5.06	4.78	4.46	4.57	4.57	4.63	4.63	4.63	3.01
MOR	3.12	0.00	0.68	0.67	0.67	0.69	0.69	0.69	0.70	0.70	0.66	0.63	0.63	0.63	0.00	0.00	0.00	0.00
PFOR	1.76	1.67	1.55	1.54	1.71	1.64	1.59	1.01	1.03	0.88	0.92	0.85	0.78	0.89	0.89	0.91	0.81	1.20
PMOR	1.56	1.49	1.23	1.15	0.89	0.76	0.89	0.81	0.84	0.88	0.91	1.30	1.42	1.57	2.40	2.54	2.78	3.11
EUOR	7.11	3.95	4.23	4.07	3.99	6.52	6.96	6.33	7.51	7.35	7.12	7.08	7.23	7.48	7.77	7.92	8.05	7.19
EUOF	6.41	3.56	3.81	3.69	3.61	5.91	6.31	5.74	6.81	6.66	6.82	7.08	7.23	7.48	7.77	7.92	8.05	7.19
POF	9.38	9.38	9.38	9.38	9.38	9.38	9.38	9.38	9.38	9.38	4.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	84.21	87.06	86.81	86.93	87.01	84.71	84.31	84.88	83.81	83.96	89.01	92.92	92.77	92.52	92.23	92.08	91.95	92.81

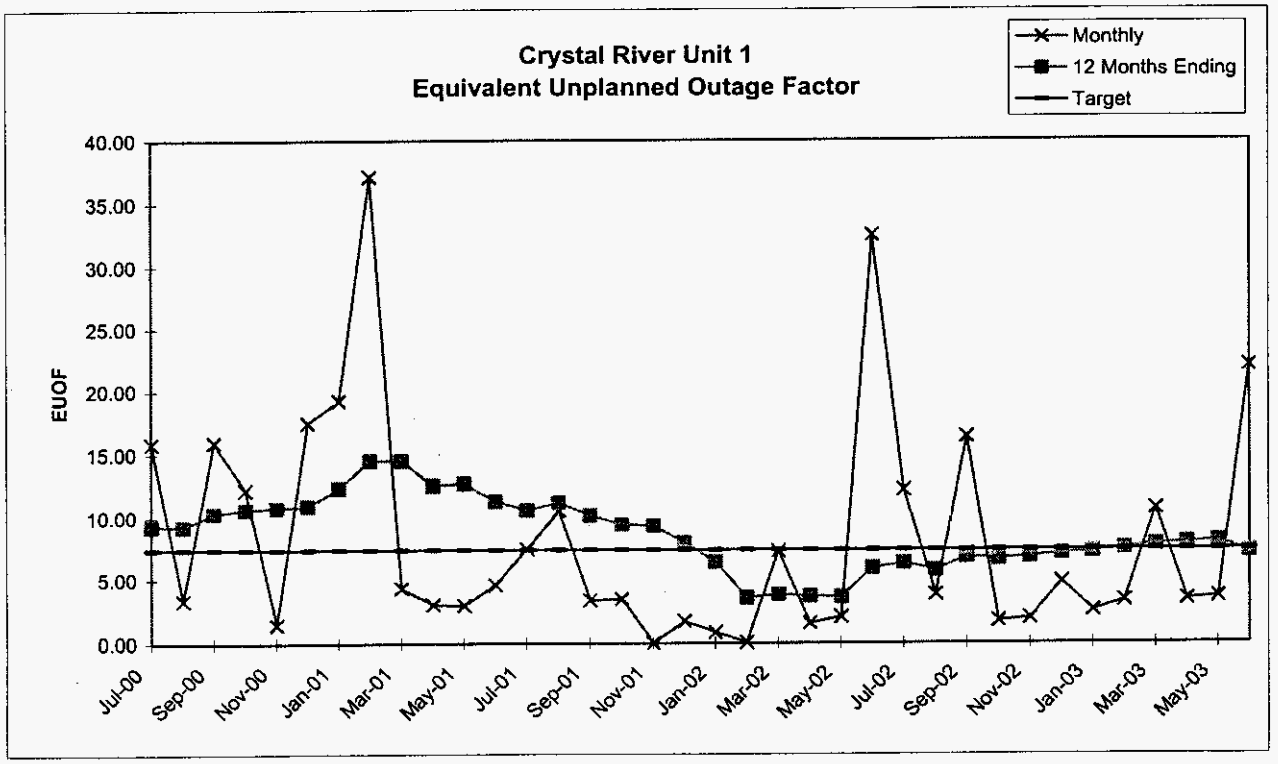

Crystal River Unit 1
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 1
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03

Crystal River
Unit 2

	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	0.03	0.02	596.55	745.00	720.00	695.05	744.00	405.32	99.72	689.73	629.48	670.47	744.00	659.63	676.00	459.00	503.80	697.93
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	743.97	743.98	123.45	0.00	0.00	48.95	0.00	266.68	644.28	29.27	114.52	49.53	0.00	84.37	44.00	286.00	216.20	46.07
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	266.68	582.43	0.00	0.00	0.00	0.00	0.00	0.00	286.00	209.78	0.00
FOH	0.00	0.00	3.88	0.00	0.00	0.00	0.00	0.00	61.85	29.27	0.00	49.53	0.00	84.37	0.00	0.00	1.00	46.07
MOH	743.97	743.98	119.57	0.00	0.00	48.95	0.00	0.00	0.00	0.00	114.52	0.00	0.00	0.00	44.00	0.00	5.42	0.00
PFOH	0.00	0.00	411.97	120.15	11.75	5.77	202.47	309.17	23.33	151.73	33.31	28.25	43.00	199.77	49.38	6.78	0.00	140.10
LRPF	0.00	0.00	87.12	174.88	232.57	193.33	40.29	79.28	205.89	34.32	79.50	134.96	212.76	45.94	76.05	179.48	0.00	119.34
EFOH	0.00	0.00	73.85	43.23	5.62	2.30	16.79	50.44	9.88	10.72	5.45	7.84	18.82	18.89	7.73	2.50	0.00	34.40
PMOH	0.00	0.00	0.00	49.62	39.17	28.99	31.78	0.00	0.00	46.25	72.14	64.15	6.25	31.87	26.43	38.00	1.77	0.00
LRPM	0.00	0.00	0.00	188.90	190.09	139.42	198.93	0.00	0.00	231.45	152.47	236.65	106.92	229.68	145.90	34.99	258.08	0.00
EMOH	0.00	0.00	0.00	19.29	15.32	8.32	13.01	0.00	0.00	22.03	22.63	31.24	1.37	15.06	7.93	2.74	0.94	0.00
NPC	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00

MONTHLY	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	0.00	0.00	0.65	0.00	0.00	0.00	0.00	0.00	38.28	4.07	0.00	6.88	0.00	11.34	0.00	0.00	0.20	6.19
MOR	100.00	100.00	16.70	0.00	0.00	6.58	0.00	0.00	0.00	0.00	15.39	0.00	0.00	0.00	6.11	0.00	1.06	0.00
PFOR	0.00	0.00	12.38	5.80	0.78	0.33	2.26	12.44	9.91	1.55	0.87	1.17	2.53	2.86	1.14	0.55	0.00	4.93
PMOR	0.00	0.00	0.00	2.59	2.13	1.20	1.75	0.00	0.00	3.19	3.60	4.66	0.18	2.28	1.17	0.60	0.19	0.00
EUOR	100.00	100.00	27.40	8.39	2.91	8.01	4.00	12.44	44.40	8.62	19.17	12.31	2.71	15.90	8.29	1.14	1.44	10.82
EUOF	100.00	100.00	27.40	8.39	2.91	8.01	4.00	7.51	9.64	8.62	19.17	12.31	2.71	15.90	8.29	0.70	1.02	10.82
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.68	78.28	0.00	0.00	0.00	0.00	0.00	0.00	38.39	29.14	0.00
EAF	0.00	0.00	72.60	91.61	97.09	91.99	96.00	52.81	12.07	91.38	80.83	87.69	97.29	84.10	91.71	60.91	69.84	89.18

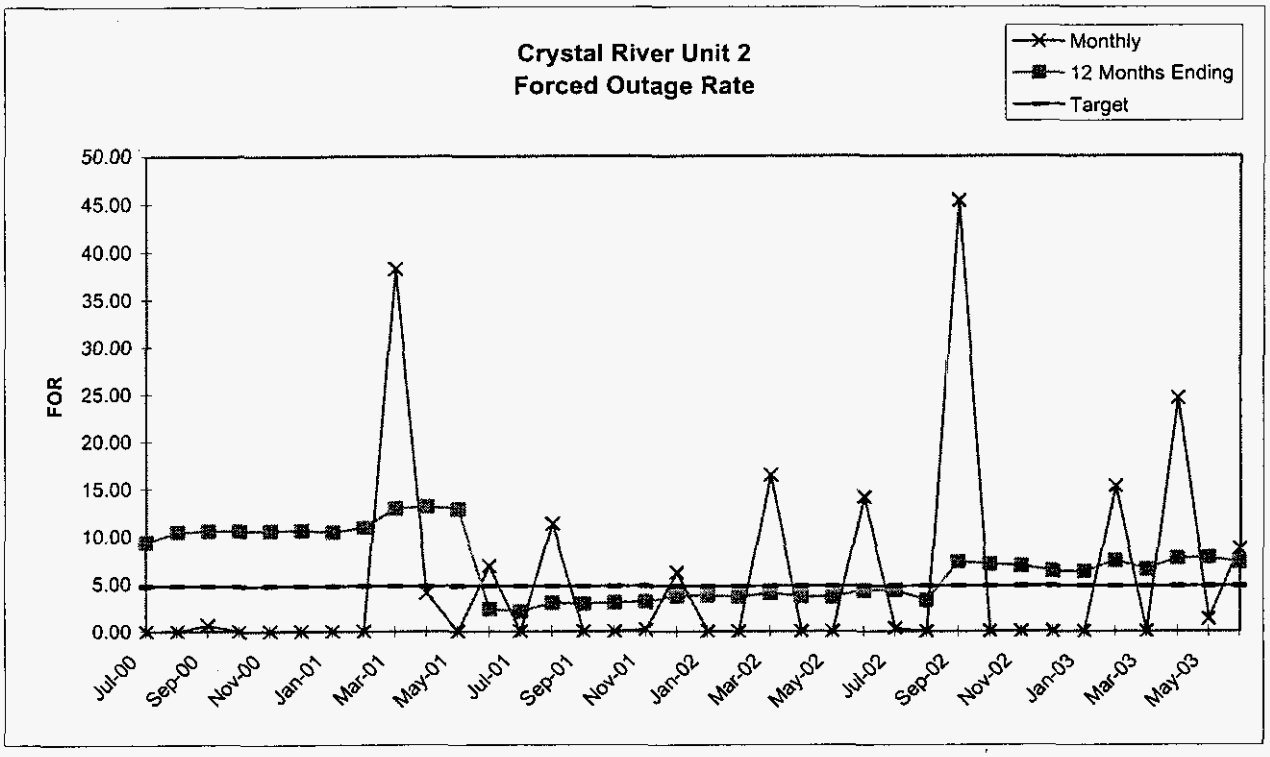
12 MONTHS	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	9.43	10.49	10.60	10.60	10.60	10.68	10.48	10.96	12.97	13.18	12.91	2.35	2.10	3.00	2.92	3.03	3.14	3.75
MOR	17.17	26.37	26.82	26.82	26.82	27.43	25.85	26.81	28.31	26.62	24.88	22.80	13.22	3.68	2.70	2.80	2.96	2.30
PFOR	2.62	1.86	2.08	2.75	2.68	2.74	2.84	3.83	4.46	4.17	4.08	3.77	3.63	3.57	2.64	2.18	2.17	2.63
PMOR	5.84	6.44	6.38	5.26	4.31	3.29	2.41	1.95	1.63	1.71	1.88	2.20	1.98	2.00	2.09	1.94	1.80	1.68
EUOR	30.20	37.85	38.36	38.06	37.37	37.25	35.35	36.74	39.17	37.85	36.44	28.74	19.59	11.68	9.94	9.56	9.65	9.93
EUOF	30.20	37.85	38.36	38.06	37.37	37.25	35.35	35.62	35.37	34.18	32.91	25.95	17.69	10.55	8.98	8.32	8.17	8.41
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.04	9.69	9.69	9.69	9.69	9.69	9.69	9.69	12.96	15.35	15.35
EAF	69.80	62.15	61.64	61.94	62.63	62.75	64.65	61.33	54.93	56.12	57.40	64.35	72.62	79.76	81.33	78.72	76.48	76.24

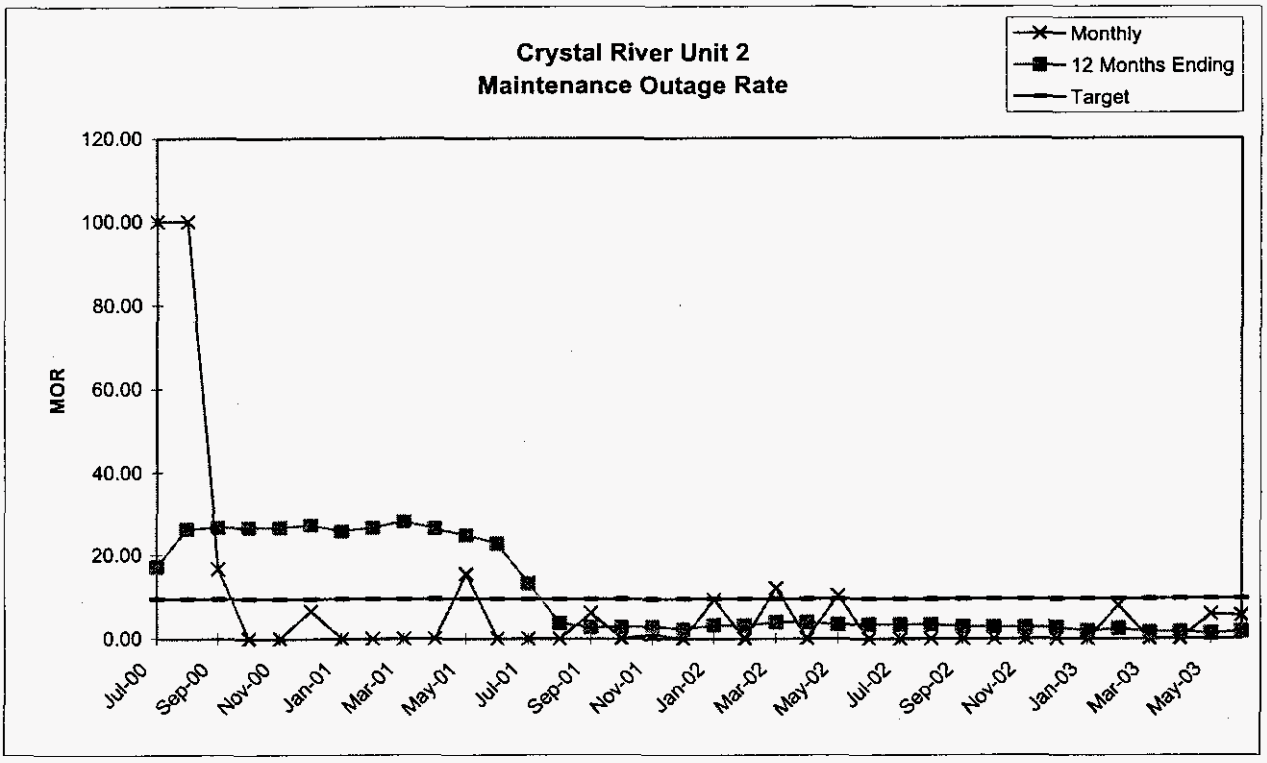
Crystal River
Unit 2

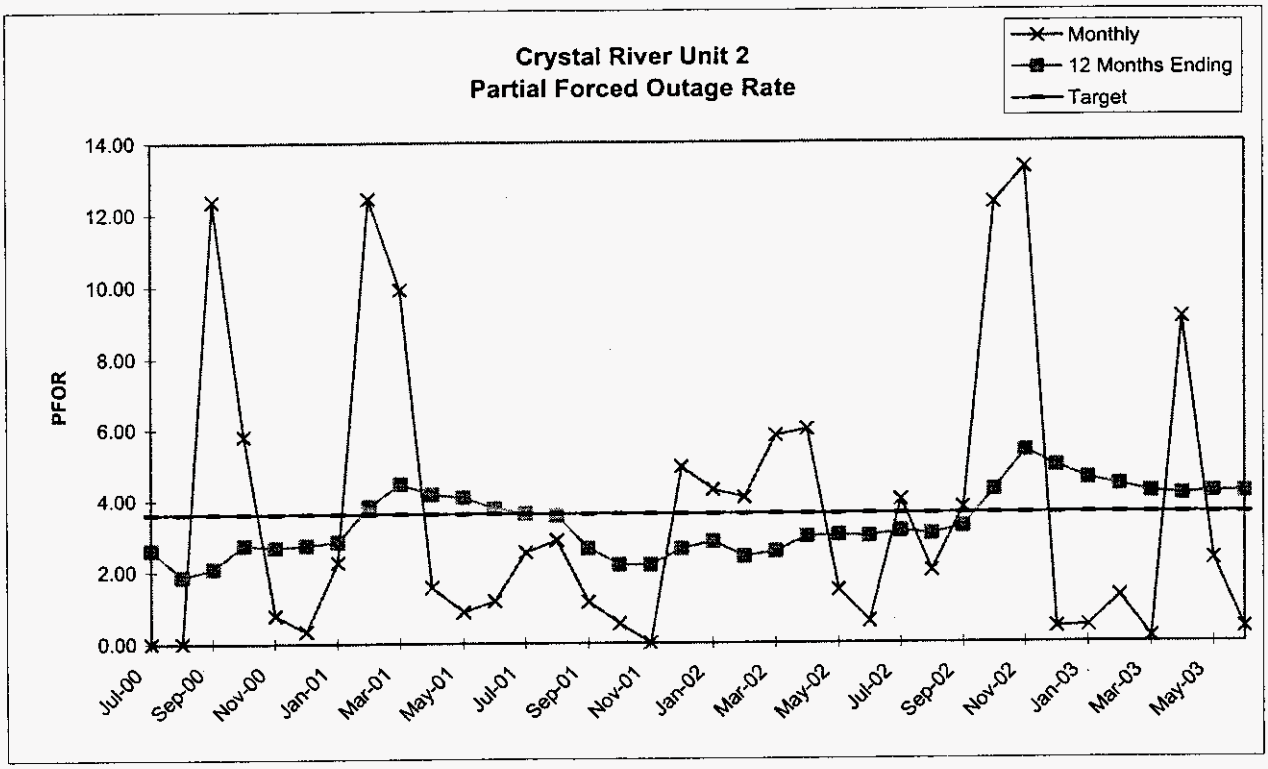
	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	674.48	672.00	557.60	719.00	667.23	618.07	741.38	744.00	393.07	745.00	720.00	744.00	744.00	530.49	169.40	167.80	692.33	624.15
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	69.52	0.00	186.40	0.00	76.77	101.93	2.62	0.00	326.93	0.00	0.00	0.00	0.00	141.51	574.60	551.20	51.67	95.85
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	574.60	496.37	0.00	0.00
FOH	0.00	0.00	110.10	0.00	0.00	101.93	2.62	0.00	326.93	0.00	0.00	0.00	0.00	96.13	0.00	54.83	9.00	59.57
MOH	69.52	0.00	76.30	0.00	76.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	45.38	0.00	0.00	42.67	36.28
PFOH	179.13	262.00	93.80	122.28	45.25	13.37	73.52	42.17	34.63	731.00	775.93	22.88	35.93	36.80	1.02	120.98	52.85	6.00
LRPF	78.39	50.72	167.66	170.84	105.00	133.04	195.91	171.27	208.17	61.00	59.93	67.02	45.95	89.57	123.40	61.37	147.49	202.66
EFOH	28.89	27.34	32.36	42.98	9.78	3.66	29.64	14.86	14.83	91.75	95.68	3.16	3.40	6.78	0.26	15.28	16.04	2.50
PMOH	309.25	76.90	106.68	20.57	17.50	26.12	85.98	36.33	21.67	57.85	75.02	410.63	47.60	23.25	0.00	49.33	40.85	206.60
LRPM	75.86	52.76	82.93	253.96	193.26	242.76	76.54	105.01	163.52	113.68	52.20	142.83	103.37	189.47	0.00	169.51	177.78	94.40
EMOH	48.27	8.35	18.20	10.75	6.96	13.05	13.54	7.85	7.29	13.53	8.06	120.68	10.12	9.06	0.00	17.21	14.94	40.13
NPC	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00	486.00

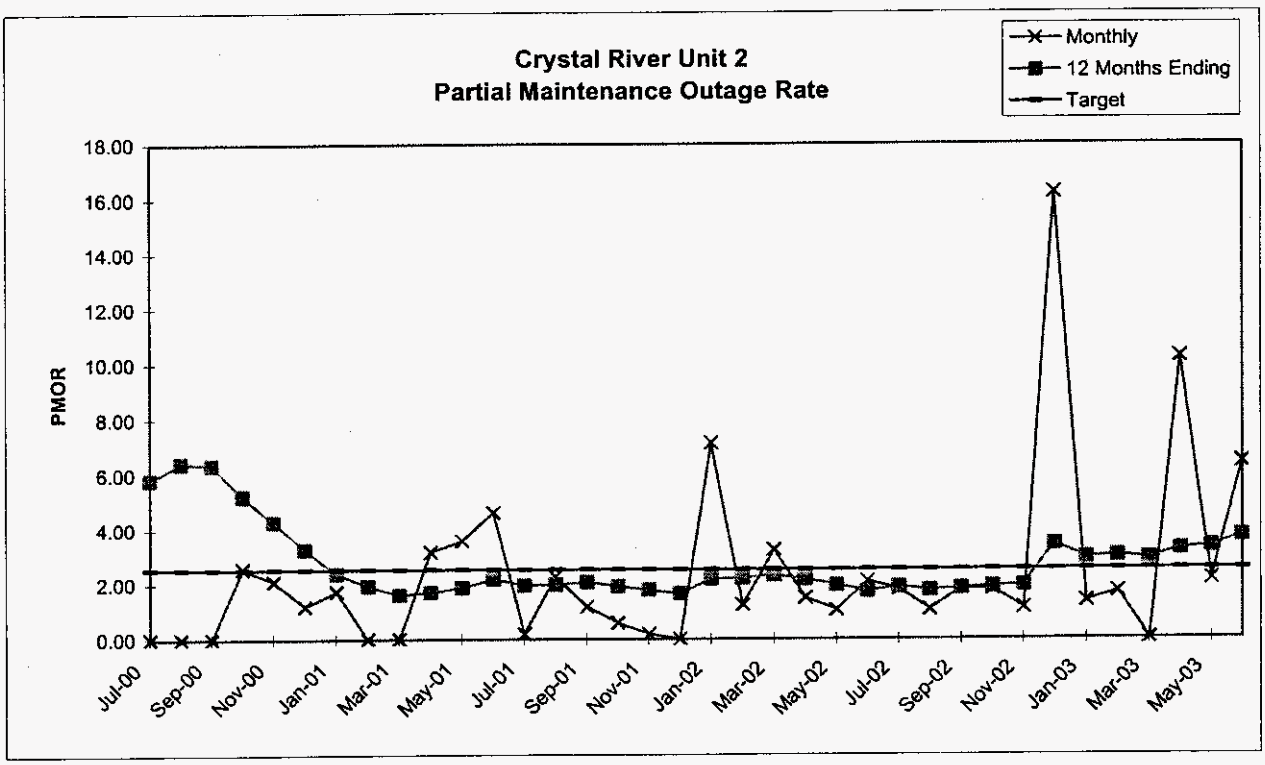
MONTHLY	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	0.00	0.00	16.49	0.00	0.00	14.16	0.35	0.00	45.41	0.00	0.00	0.00	0.00	15.34	0.00	24.63	1.28	8.71
MOR	9.34	0.00	12.04	0.00	10.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.88	0.00	0.00	5.81	5.49
PFOR	4.28	4.07	5.80	5.98	1.47	0.59	4.00	2.00	3.77	12.32	13.29	0.42	0.46	1.28	0.15	9.10	2.32	0.40
PMOR	7.16	1.24	3.26	1.49	1.04	2.11	1.83	1.06	1.85	1.82	1.12	16.22	1.36	1.71	0.00	10.25	2.16	6.43
EUOR	19.72	5.31	31.85	7.47	12.57	16.48	6.16	3.05	48.48	14.13	14.41	16.64	1.82	23.42	0.15	39.22	11.11	19.23
EUOF	19.72	5.31	31.85	7.47	12.57	16.48	6.16	3.05	48.48	14.13	14.41	16.64	1.82	23.42	0.03	12.14	11.11	19.23
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	77.23	69.04	0.00	0.00
EAF	80.28	94.69	68.15	92.53	87.43	83.52	93.84	96.95	51.52	85.87	85.59	83.36	98.18	76.58	22.73	18.82	88.89	80.77

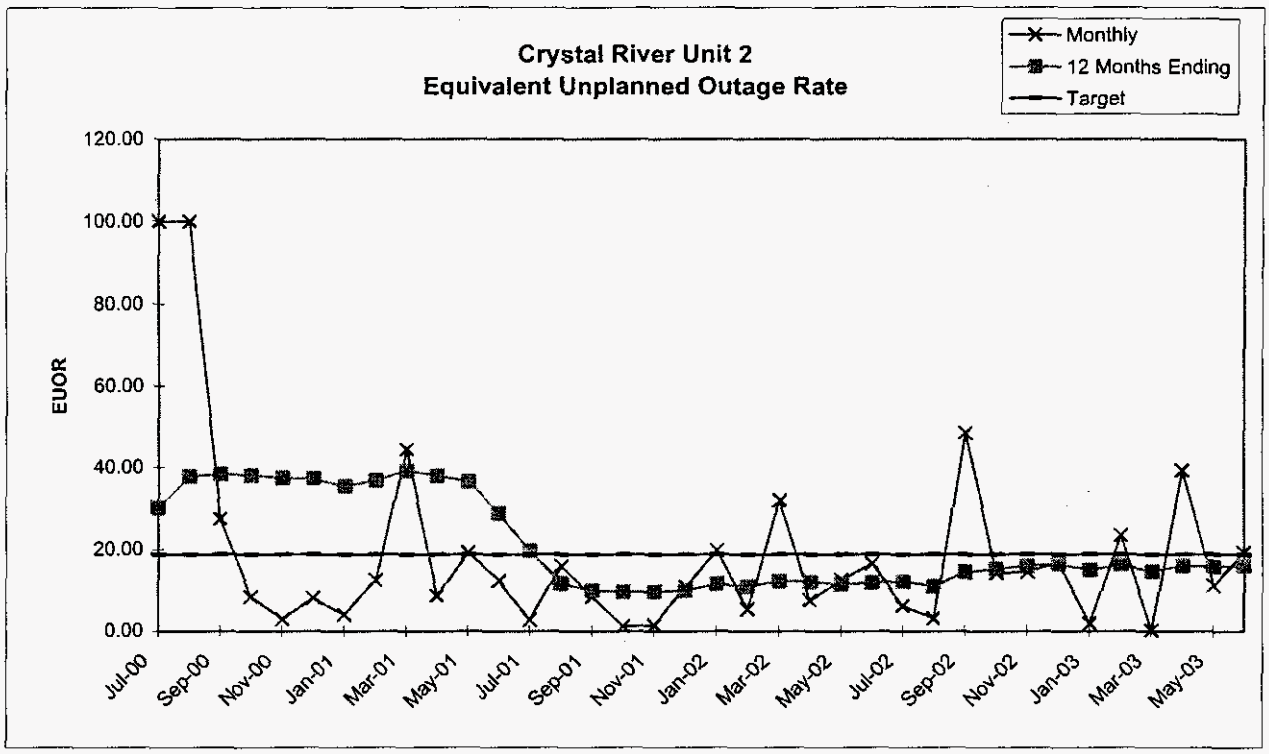
12 MONTHS	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	3.79	3.65	4.03	3.66	3.64	4.30	4.33	3.27	7.32	7.07	6.88	6.34	6.29	7.45	6.54	7.70	7.78	7.26
MOR	3.27	3.15	3.90	3.89	3.41	3.43	3.44	3.40	2.97	2.86	2.72	2.71	1.86	2.44	1.60	1.72	1.24	1.74
PFOR	2.83	2.40	2.55	2.96	3.01	2.97	3.11	3.03	3.24	4.27	5.36	4.94	4.58	4.40	4.20	4.14	4.21	4.19
PMOR	2.20	2.24	2.34	2.19	1.97	1.75	1.91	1.79	1.85	1.92	1.96	3.46	2.96	3.02	2.93	3.26	3.36	3.74
EUOR	11.51	10.92	12.15	12.05	11.45	11.82	12.13	10.97	14.47	15.16	15.89	16.39	14.87	16.26	14.51	15.88	15.74	16.00
EUOF	9.74	9.57	11.46	11.36	10.80	11.15	11.44	10.35	13.65	14.79	15.89	16.39	14.87	16.26	13.56	13.94	13.81	14.04
POF	15.35	12.31	5.66	5.66	5.66	5.66	5.66	5.66	5.66	2.39	0.00	0.00	0.00	0.00	6.56	12.23	12.23	12.23
EAF	74.91	78.12	82.88	82.98	83.54	83.19	82.90	83.99	80.69	82.81	84.11	83.61	85.13	83.74	79.89	73.84	73.96	73.73

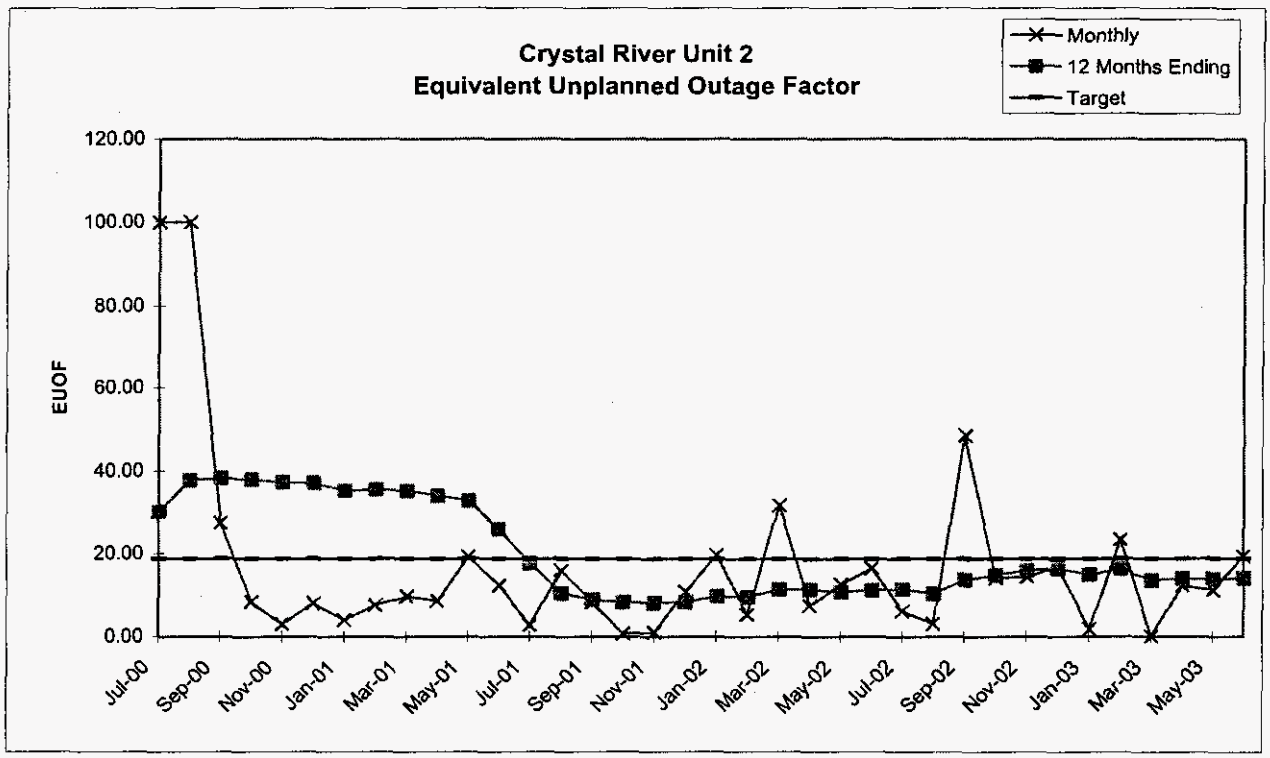

Crystal River Unit 2
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 2
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 2
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 2
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 2
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 2
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
120.00
100.00
80.00
60.00
40.00
20.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03

Crystal River
Unit 3

	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	744.00	546.58	745.00	720.00	744.00	744.00	672.00	744.00	719.00	412.27	713.63	744.00	744.00	672.00	156.30	720.00	744.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	173.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	331.73	6.37	0.00	0.00	48.00	588.70	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.00	588.70	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	173.42	0.00	0.00	0.00	0.00	0.00	0.00	0.00	331.73	6.37	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	34.17	0.00	30.25	0.00	0.00	0.00	0.00	0.00	0.00	132.93	9.65	0.00	10.17	0.00	0.00	0.00	0.00
LRPF	0.00	144.52	0.00	4.70	0.00	0.00	0.00	0.00	0.00	0.00	105.89	334.84	0.00	26.70	0.00	0.00	0.00	0.00
EFOH	0.00	6.55	0.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	18.40	4.22	0.00	0.35	0.00	0.00	0.00	0.00
PMOH	0.00	0.00	23.48	56.25	0.00	0.00	0.00	3.57	0.00	4.50	0.00	18.05	0.00	0.00	12.00	74.58	168.42	42.22
LRPM	0.00	0.00	295.52	146.66	0.00	0.00	0.00	35.34	0.00	27.67	0.00	1.90	0.00	0.00	68.65	199.36	1.91	270.88
EMOH	0.00	0.00	9.20	10.94	0.00	0.00	0.00	0.16	0.00	0.16	0.00	0.04	0.00	0.00	1.08	19.44	0.42	14.95
NPC	754.00	754.00	754.00	754.00	754.00	754.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00

MONTHLY	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	24.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	44.59	0.88	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.88	0.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	4.46	0.59	0.00	0.05	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	1.68	1.47	0.00	0.00	0.00	0.02	0.00	0.02	0.00	0.01	0.00	0.00	0.16	12.44	0.06	2.01
EUOR	0.00	0.88	25.36	1.49	0.00	0.00	0.00	0.02	0.00	0.02	47.06	1.48	0.00	0.05	0.16	12.44	0.06	2.01
EUOF	0.00	0.88	25.36	1.49	0.00	0.00	0.00	0.02	0.00	0.02	47.06	1.48	0.00	0.05	0.15	2.61	0.06	2.01
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.67	79.02	0.00	0.00
EAF	100.00	99.12	74.64	98.51	100.00	100.00	100.00	99.98	100.00	99.98	52.94	98.52	100.00	99.95	93.18	18.37	99.94	97.99

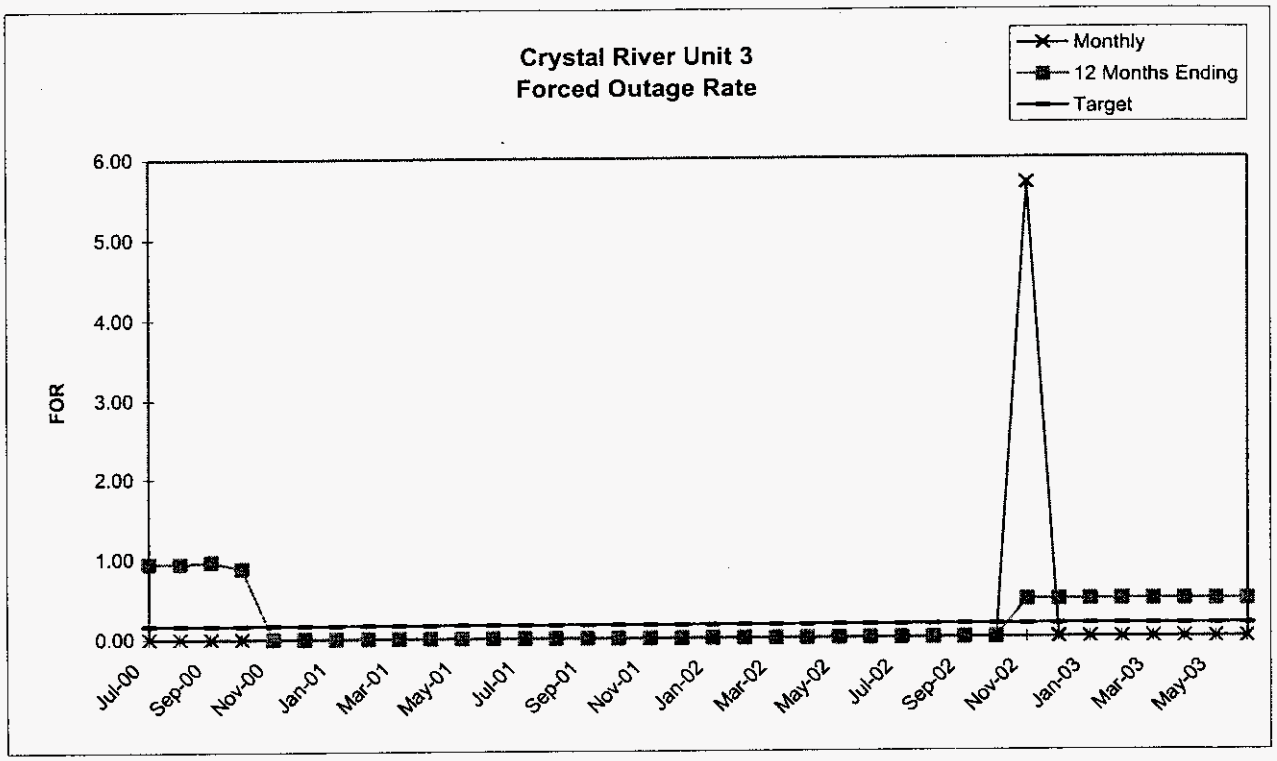
12 MONTHS	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	0.95	0.95	0.97	0.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.71	0.71	2.97	2.70	2.60	2.60	2.60	2.61	2.61	1.98	5.77	5.84	5.84	5.84	3.88	4.16	4.16	4.16
PFOR	0.67	0.71	0.72	0.66	0.22	0.22	0.22	0.22	0.08	0.08	0.30	0.36	0.36	0.28	0.28	0.30	0.30	0.30
PMOR	1.12	1.12	1.20	1.22	0.44	0.43	0.43	0.38	0.38	0.24	0.25	0.25	0.25	0.25	0.15	0.27	0.27	0.47
EUOR	3.41	3.44	5.72	5.35	3.24	3.23	3.23	3.19	3.05	2.29	6.29	6.41	6.41	6.34	4.29	4.70	4.71	4.89
EUOF	3.02	3.05	5.06	5.19	3.24	3.23	3.23	3.19	3.05	2.29	6.29	6.41	6.41	6.34	4.27	4.36	4.37	4.54
POF	11.52	11.52	11.52	3.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.55	7.27	7.27	7.27
EAF	85.46	85.43	83.41	91.77	96.76	96.77	96.77	96.81	96.95	97.71	93.71	93.59	93.59	93.66	95.19	88.37	88.37	88.20

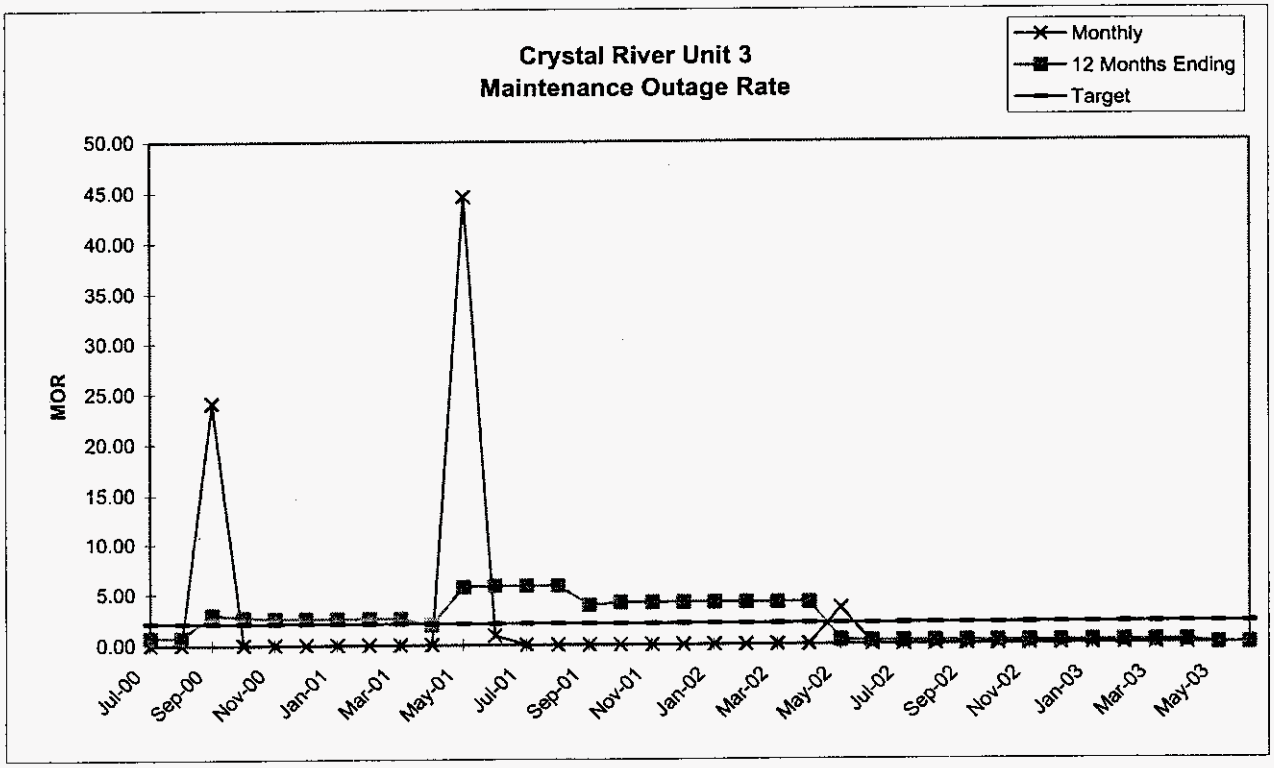
Crystal River
Unit 3

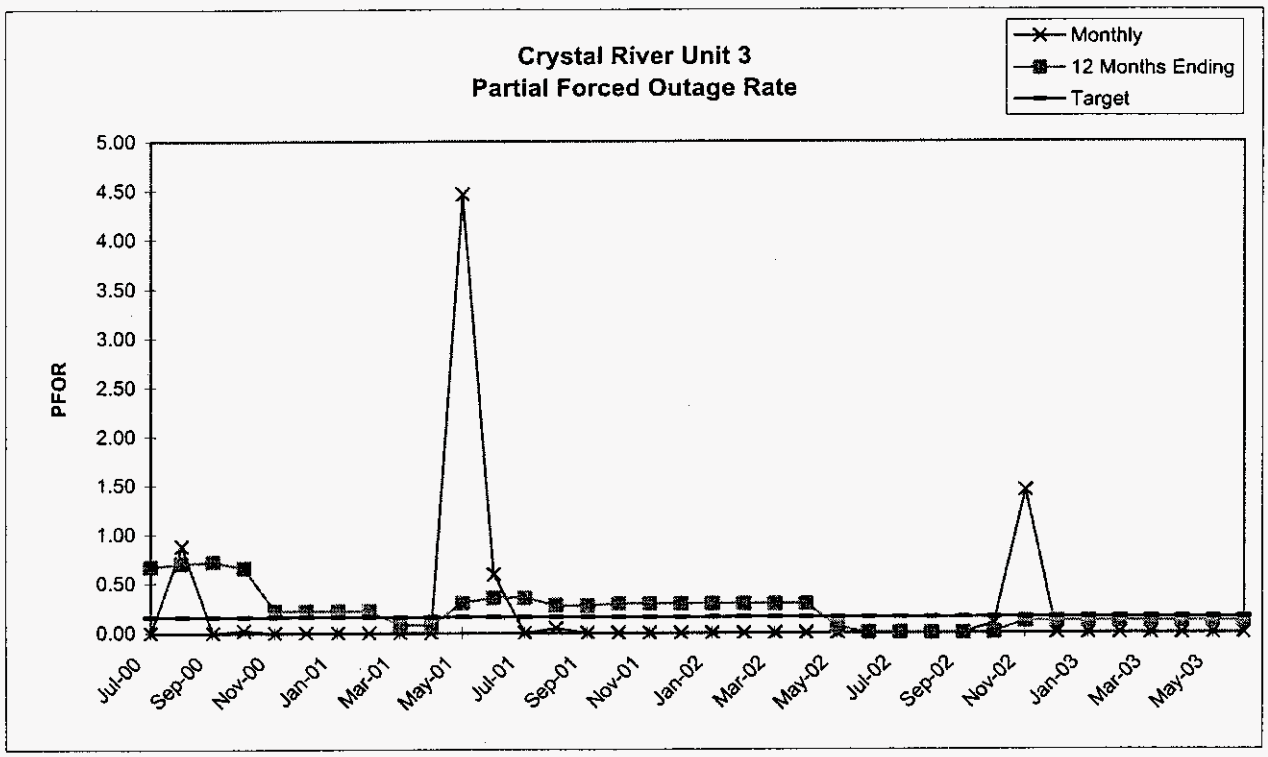
	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	744.00	672.00	744.00	719.00	717.40	720.00	744.00	744.00	720.00	745.00	679.02	744.00	744.00	672.00	744.00	719.00	744.00	720.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	0.00	26.60	0.00	0.00	0.00	0.00	0.00	40.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOH	0.00	0.00	0.00	0.00	26.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.52	50.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	53.52	150.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.74	9.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOH	0.00	0.00	0.00	0.00	38.27	66.56	0.00	0.00	7.17	0.00	171.93	0.00	0.00	0.00	6.58	76.08	55.10	6.60
LRPM	0.00	0.00	0.00	0.00	165.41	0.09	0.00	0.00	27.95	0.00	123.06	0.00	0.00	0.00	36.97	167.68	52.90	95.05
EMOH	0.00	0.00	0.00	0.00	8.28	0.01	0.00	0.00	0.26	0.00	27.66	0.00	0.00	0.00	0.32	16.68	3.81	0.82
NPC	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00	765.00

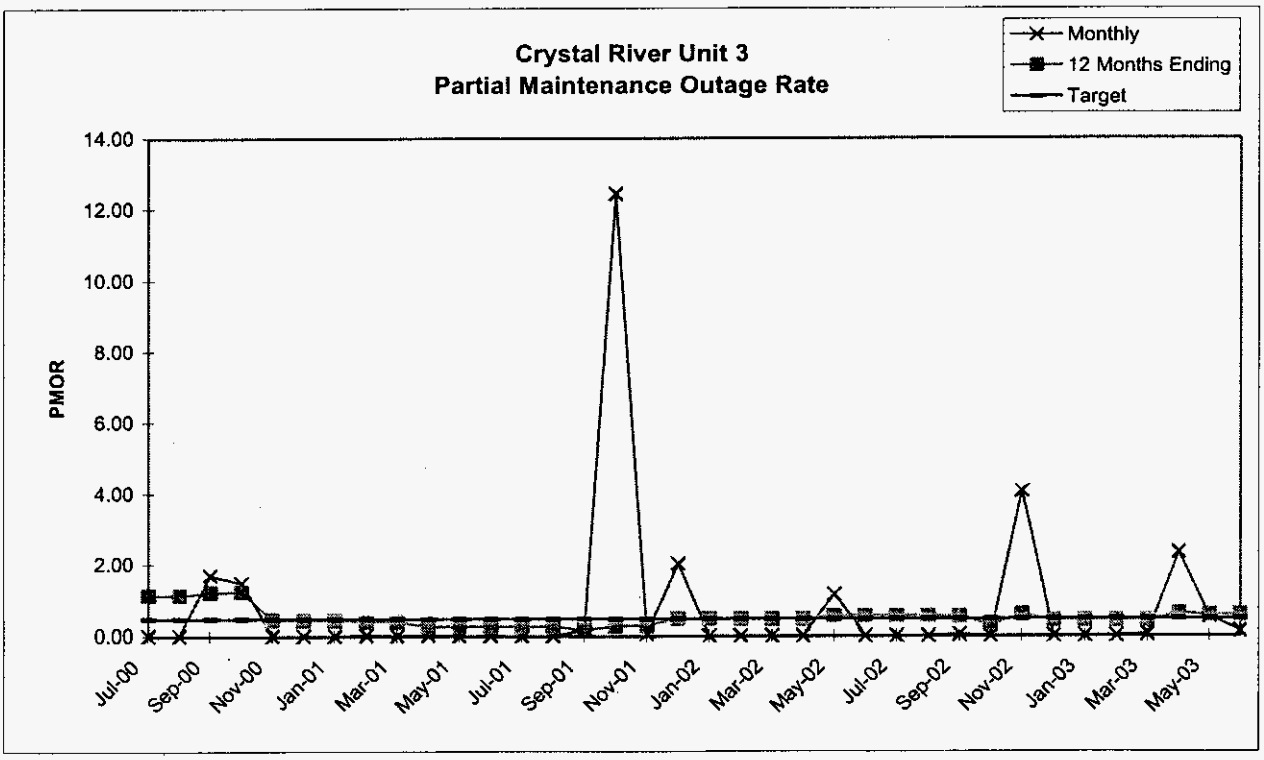
MONTHLY	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MOR	0.00	0.00	0.00	0.00	3.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	1.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	1.15	0.00	0.00	0.00	0.04	0.00	4.07	0.00	0.00	0.00	0.04	2.32	0.51	0.11
EUOR	0.00	0.00	0.00	0.00	4.69	0.00	0.00	0.00	0.04	0.10	10.90	0.00	0.00	0.00	0.04	2.32	0.51	0.11
EUOF	0.00	0.00	0.00	0.00	4.69	0.00	0.00	0.00	0.04	0.10	10.90	0.00	0.00	0.00	0.04	2.32	0.51	0.11
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	100.00	100.00	100.00	100.00	95.31	100.00	100.00	100.00	99.96	99.90	89.10	100.00	100.00	100.00	99.96	97.68	99.49	99.89

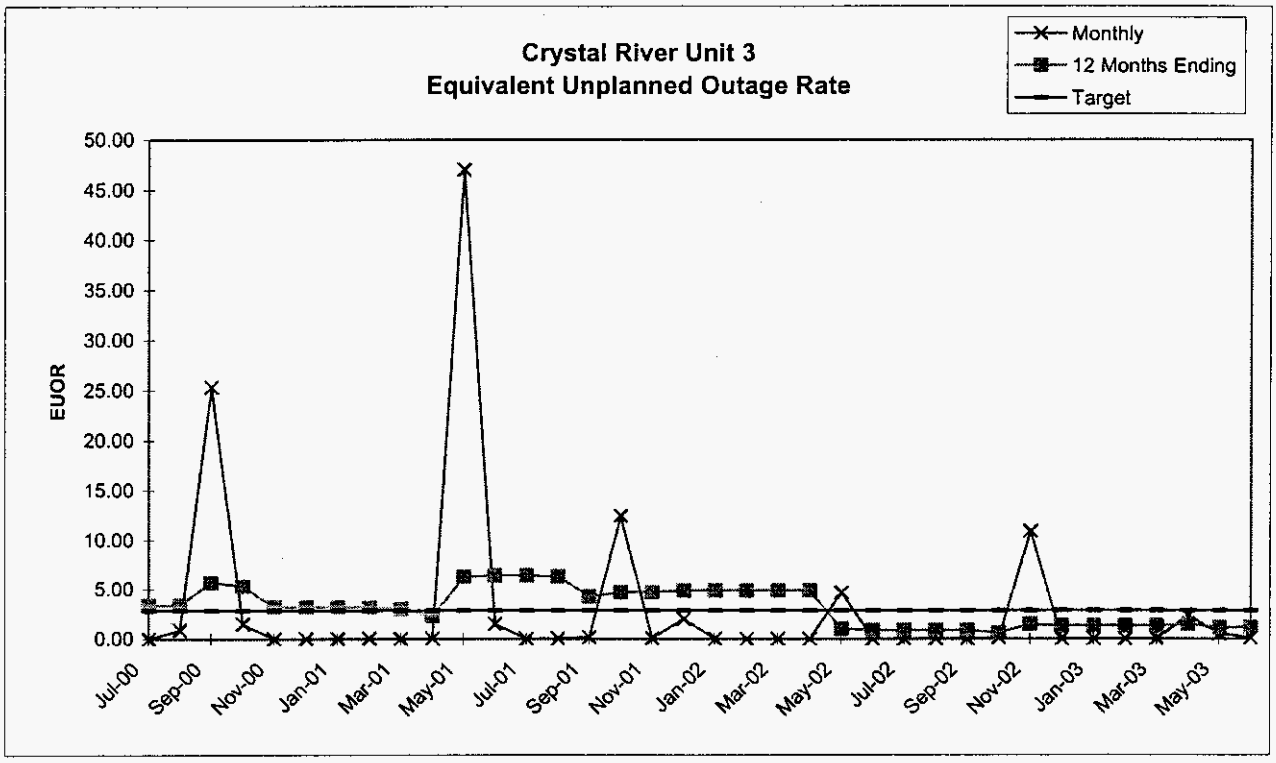
12 MONTHS	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
MOR	4.16	4.16	4.16	4.16	0.41	0.33	0.33	0.33	0.33	0.30	0.31	0.31	0.31	0.31	0.31	0.31	0.00	0.00
PFOR	0.30	0.30	0.30	0.30	0.06	0.00	0.00	0.00	0.00	0.01	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
PMOR	0.47	0.46	0.46	0.46	0.55	0.55	0.55	0.55	0.53	0.27	0.59	0.42	0.42	0.42	0.42	0.61	0.56	0.57
EUOR	4.89	4.89	4.89	4.89	1.01	0.88	0.88	0.87	0.86	0.59	1.48	1.31	1.31	1.31	1.31	1.50	1.15	1.15
EUOF	4.54	4.53	4.53	4.53	0.93	0.81	0.81	0.81	0.80	0.59	1.48	1.31	1.31	1.31	1.31	1.50	1.15	1.15
POF	7.27	7.27	7.27	7.27	7.27	7.27	7.27	7.27	6.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	88.20	88.20	88.20	88.20	91.80	91.92	91.92	91.92	92.48	99.41	98.52	98.69	98.69	98.69	98.69	98.50	98.85	98.85

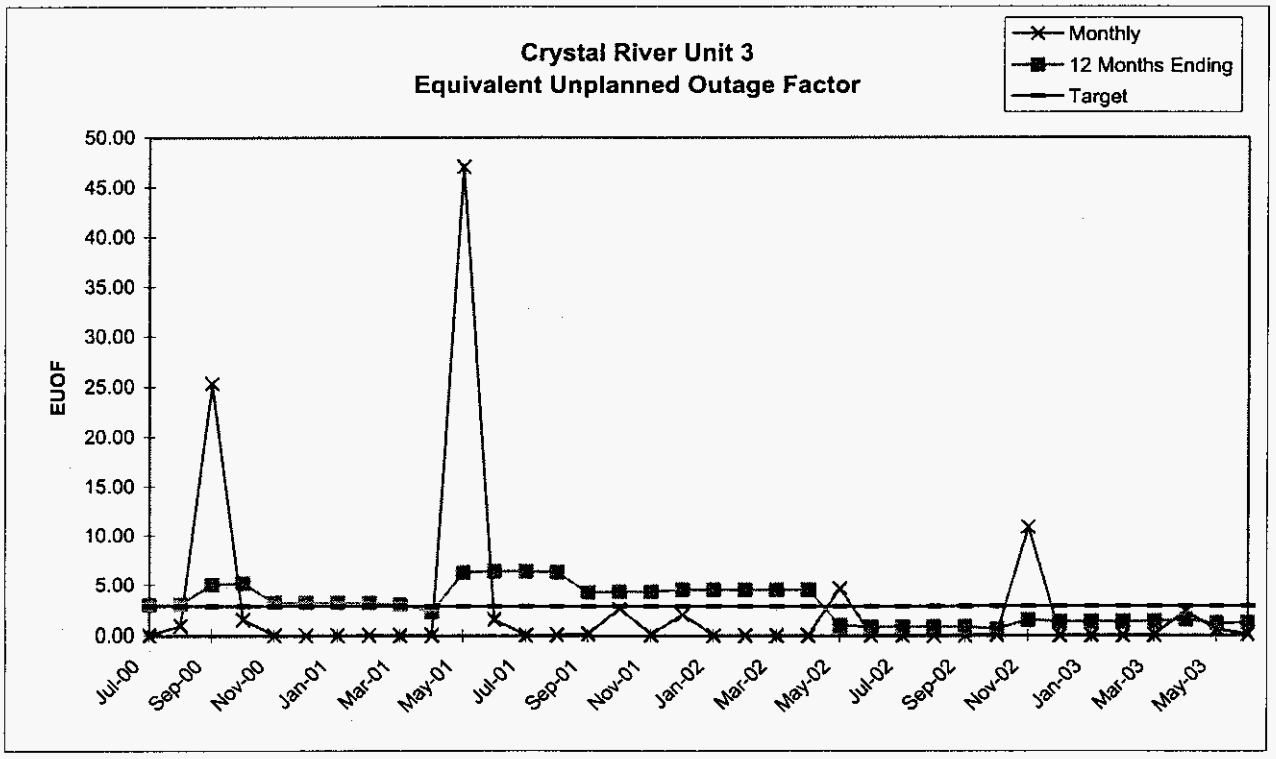

Crystal River Unit 3
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 3
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 3
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
5.00
4.50
4.00
3.50
3.00
2.50
2.00
1.50
1.00
0.50
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 3
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 3
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 3
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
50.00
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03

Crystal River
Unit 4

	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	744.00	720.00	611.67	589.30	575.90	744.00	672.00	744.00	719.00	744.00	710.10	744.00	744.00	720.00	612.00	720.00	507.64
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	133.33	130.70	168.10	0.00	0.00	0.00	0.00	0.00	9.90	0.00	0.00	0.00	133.00	0.00	236.37
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	103.67	50.00	80.60	0.00	0.00	0.00	0.00	0.00	9.90	0.00	0.00	0.00	133.00	0.00	236.37
MOH	0.00	0.00	0.00	29.67	80.70	87.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	4.83	36.67	0.00	21.07	86.05	0.00	46.85	7.10	69.47	0.00	0.80	9.98	100.05	7.02	27.90	42.98	29.88	14.13
LRPF	92.96	84.73	0.00	337.38	227.13	0.00	128.21	246.61	107.34	0.00	591.78	356.74	293.30	175.87	59.18	333.82	136.32	69.05
EFOH	0.64	4.46	0.00	10.20	28.04	0.00	8.34	2.43	10.36	0.00	0.66	4.94	40.76	1.71	2.29	19.93	5.66	1.36
PMOH	0.00	11.45	0.00	0.00	68.00	5.00	6.85	0.00	0.00	121.80	18.16	47.87	19.00	0.00	58.17	4.50	0.00	169.77
LRPM	0.00	85.93	0.00	0.00	85.93	525.18	591.78	0.00	0.00	88.77	114.10	78.07	98.62	0.00	261.49	69.12	0.00	69.04
EMOH	0.00	1.41	0.00	0.00	8.38	3.77	5.63	0.00	0.00	15.02	2.88	5.19	2.60	0.00	21.13	0.43	0.00	16.28
NPC	697.00	697.00	697.00	697.00	697.00	697.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00

MONTHLY	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	0.00	0.00	0.00	14.49	7.82	12.28	0.00	0.00	0.00	0.00	0.00	1.38	0.00	0.00	0.00	17.85	0.00	31.77
MOR	0.00	0.00	0.00	4.63	12.04	13.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.09	0.60	0.00	1.67	4.76	0.00	1.12	0.36	1.39	0.00	0.09	0.70	5.48	0.23	0.32	3.26	0.79	0.27
PMOR	0.00	0.19	0.00	0.00	1.42	0.65	0.76	0.00	0.00	2.09	0.39	0.73	0.35	0.00	2.93	0.07	0.00	3.21
EUOR	0.09	0.79	0.00	19.27	23.21	23.10	1.88	0.36	1.39	2.09	0.48	2.78	5.83	0.23	3.25	20.59	0.79	34.14
EUOF	0.09	0.79	0.00	19.27	23.21	23.10	1.88	0.36	1.39	2.09	0.48	2.78	5.83	0.23	3.25	20.59	0.79	34.14
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.91	99.21	100.00	80.73	76.79	76.90	98.12	99.64	98.61	97.91	99.52	97.22	94.17	99.77	96.75	79.41	99.21	65.86

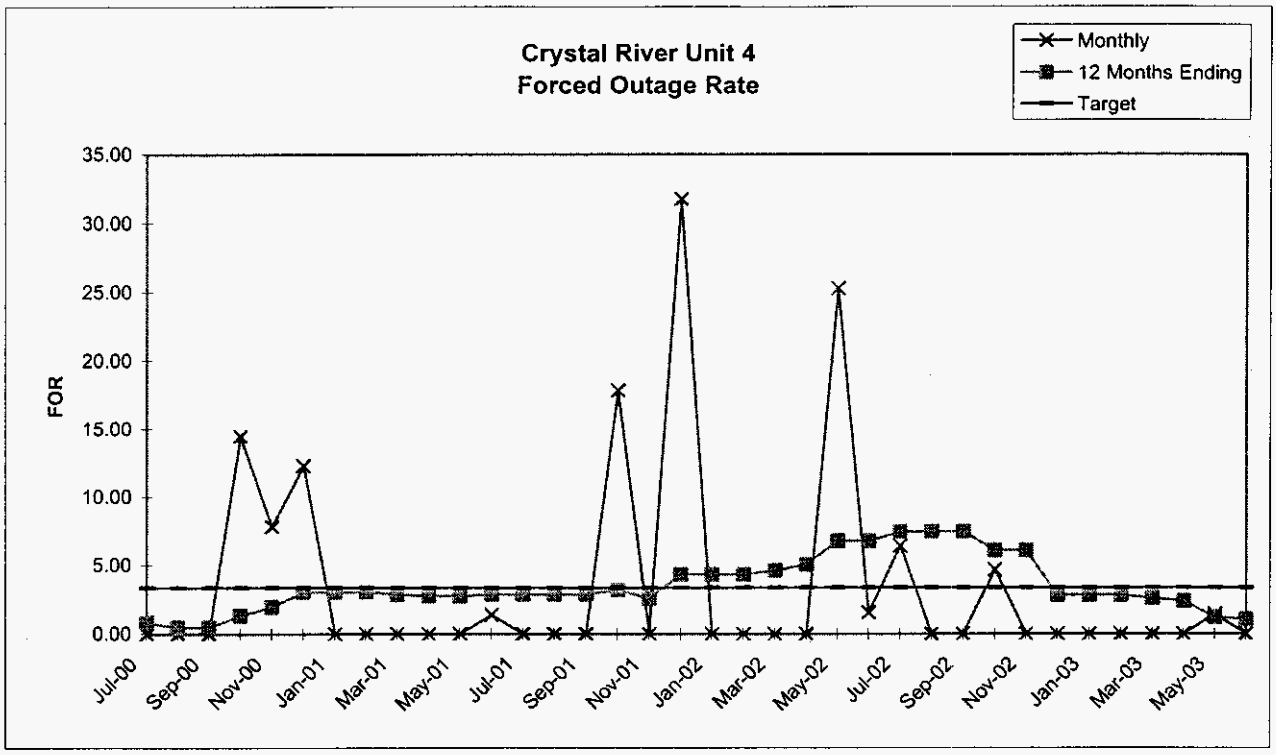
12 MONTHS	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	0.83	0.48	0.48	1.33	1.97	3.03	3.03	3.04	2.86	2.74	2.74	2.85	2.85	2.85	2.85	3.18	2.58	4.33
MOR	0.82	0.81	0.11	0.49	1.42	2.57	2.57	2.58	2.43	2.32	2.32	2.32	2.32	2.32	2.32	1.98	1.03	0.00
PFOR	1.72	0.99	0.90	0.91	1.23	1.26	1.32	1.36	1.41	1.34	1.34	0.84	1.32	1.29	1.32	1.44	1.15	1.17
PMOR	0.61	0.59	0.13	0.14	0.25	0.26	0.34	0.34	0.32	0.48	0.45	0.51	0.54	0.52	0.78	0.78	0.67	0.83
EUOR	3.93	2.85	1.62	2.84	4.76	6.89	7.02	7.07	6.79	6.67	6.64	6.33	6.82	6.77	7.04	7.15	5.31	6.24
EUOF	3.55	2.57	1.46	2.56	4.30	6.22	6.34	6.38	6.50	6.67	6.64	6.33	6.82	6.77	7.04	7.15	5.31	6.24
POF	9.73	9.73	9.73	9.73	9.73	9.73	9.73	9.76	4.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	86.72	87.70	88.81	87.70	85.97	84.04	83.93	83.86	89.21	93.33	93.36	93.67	93.18	93.23	92.96	92.85	94.69	93.76

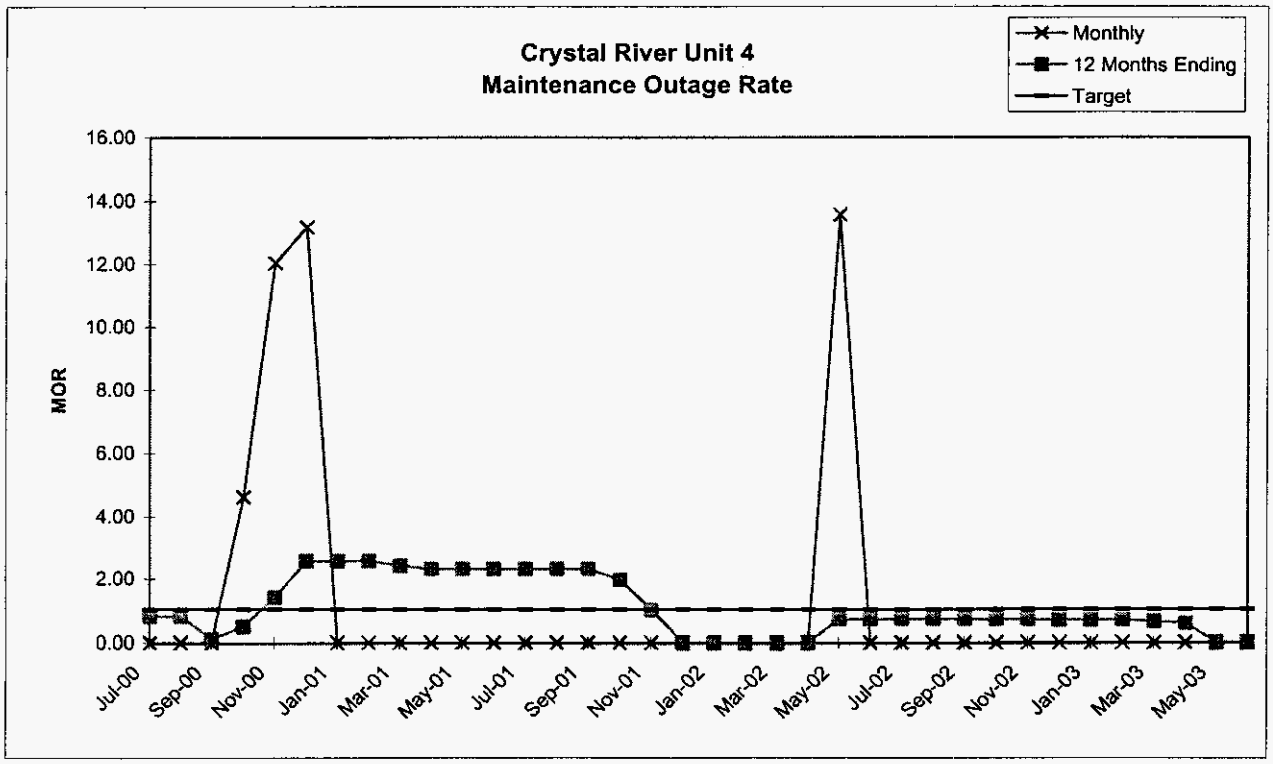
Crystal River
Unit 4

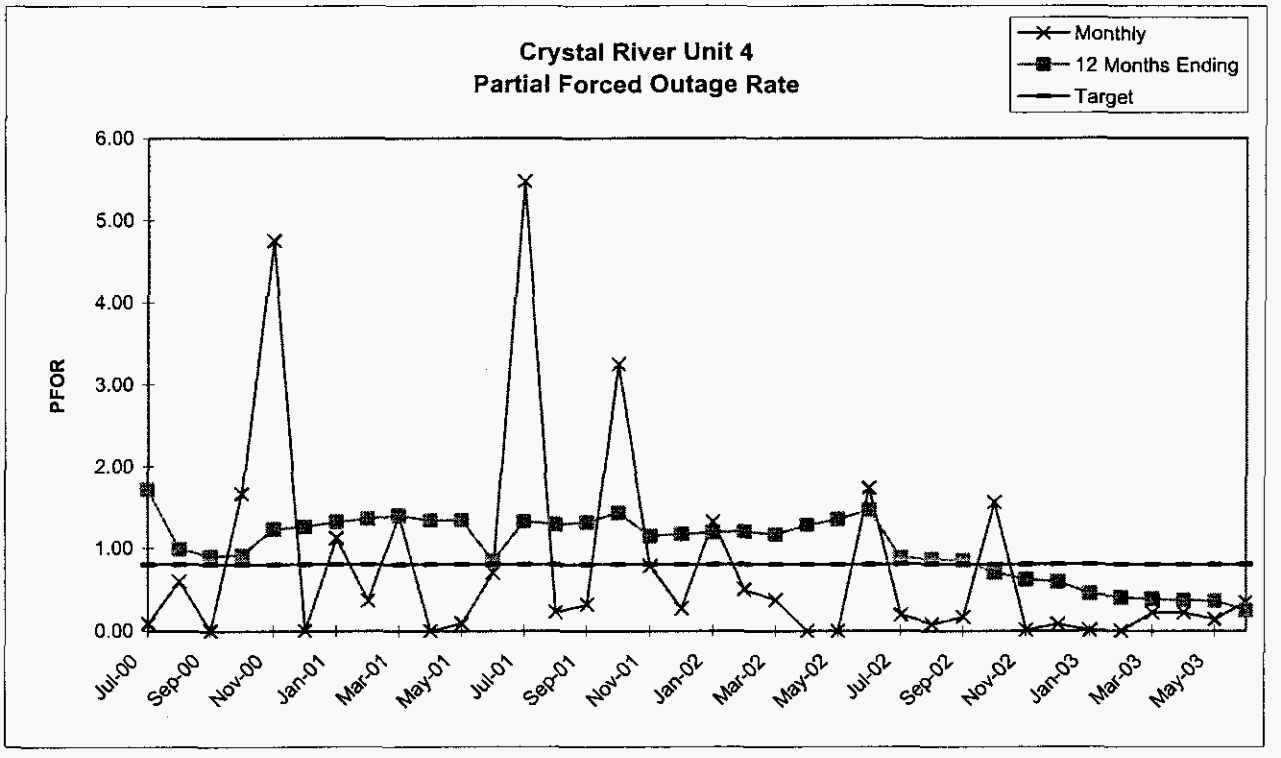
	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	744.00	672.00	195.10	0.00	311.40	708.90	696.20	744.00	720.00	710.33	720.00	744.00	744.00	672.00	744.00	719.00	733.53	720.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	548.90	719.00	432.60	11.10	47.80	0.00	0.00	34.67	0.00	0.00	0.00	0.00	0.00	0.00	10.47	0.00
POH	0.00	0.00	548.90	719.00	278.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	105.50	11.10	47.80	0.00	0.00	34.67	0.00	0.00	0.00	0.00	0.00	0.00	10.47	0.00
MOH	0.00	0.00	0.00	0.00	48.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	12.00	19.40	7.50	0.00	0.00	53.73	7.33	4.58	21.42	54.28	0.83	3.55	0.37	0.00	16.63	19.75	13.43	16.13
LRPF	589.44	124.70	69.98	0.00	0.00	165.15	132.21	92.12	40.71	147.08	78.07	118.04	101.19	0.00	69.84	56.83	54.90	110.43
EFOH	9.82	3.36	0.73	0.00	0.00	12.32	1.35	0.59	1.21	11.09	0.09	0.58	0.05	0.00	1.61	1.56	1.02	2.47
PMOH	10.43	0.00	0.00	0.00	63.30	0.00	0.00	22.48	0.00	9.00	3.00	0.00	0.00	157.67	16.47	0.00	4.67	17.40
LRPM	388.10	0.00	0.00	0.00	434.00	0.00	0.00	92.02	0.00	132.16	149.04	0.00	0.00	73.00	176.22	0.00	386.83	553.32
EMOH	5.62	0.00	0.00	0.00	38.16	0.00	0.00	2.87	0.00	1.65	0.62	0.00	0.00	15.99	4.03	0.00	2.51	13.37
NPC	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00	720.00

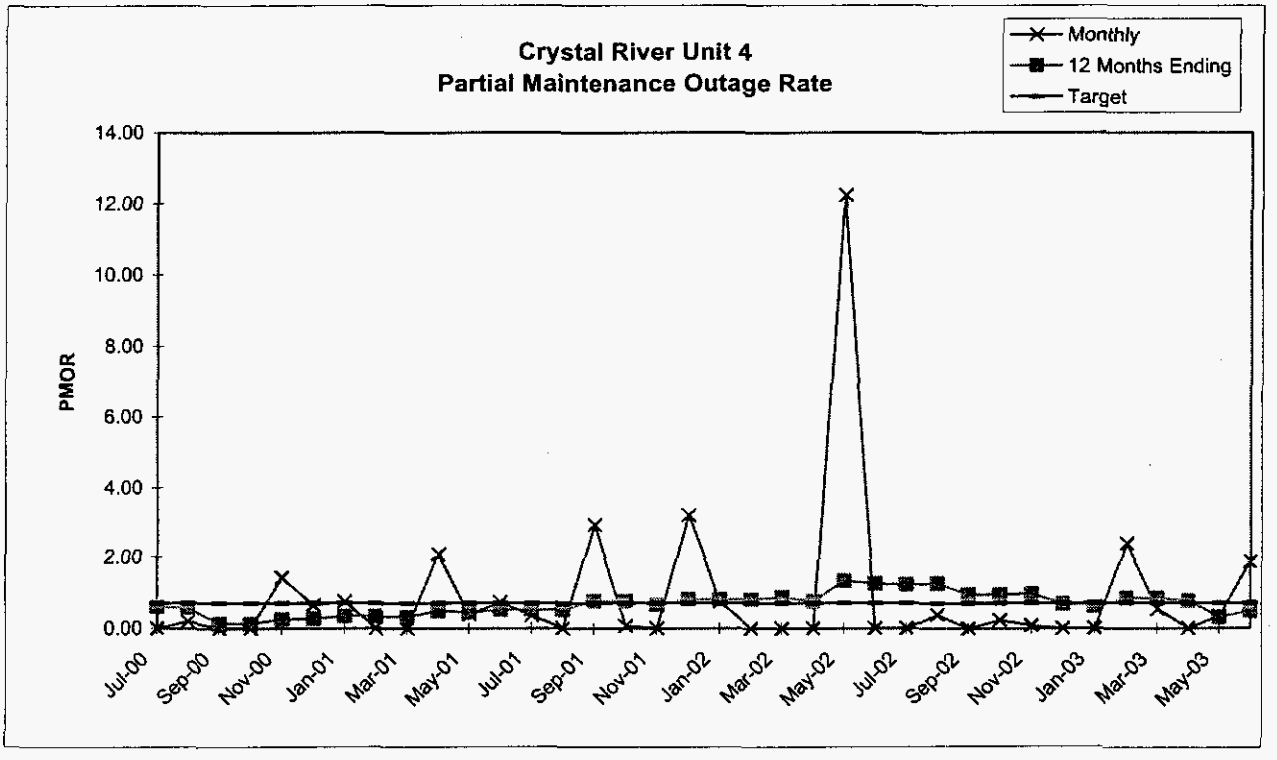
MONTHLY	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	0.00	0.00	0.00	0.00	25.31	1.54	6.42	0.00	0.00	4.65	0.00	0.00	0.00	0.00	0.00	0.00	1.41	0.00
MOR	0.00	0.00	0.00	0.00	13.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	1.32	0.50	0.37	0.00	0.00	1.74	0.19	0.08	0.17	1.56	0.01	0.08	0.01	0.00	0.22	0.22	0.14	0.34
PMOR	0.76	0.00	0.00	0.00	12.25	0.00	0.00	0.39	0.00	0.23	0.09	0.00	0.00	2.38	0.54	0.00	0.34	1.86
EUOR	2.08	0.50	0.37	0.00	41.34	3.25	6.61	0.46	0.17	6.36	0.10	0.08	0.01	2.38	0.76	0.22	1.88	2.20
EUOF	2.08	0.50	0.10	0.00	25.88	3.25	6.61	0.46	0.17	6.36	0.10	0.08	0.01	2.38	0.76	0.22	1.88	2.20
POF	0.00	0.00	73.78	100.00	37.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	97.92	99.50	26.13	0.00	36.73	96.75	93.39	99.54	99.83	93.64	99.90	99.92	99.99	97.62	99.24	99.78	98.12	97.80

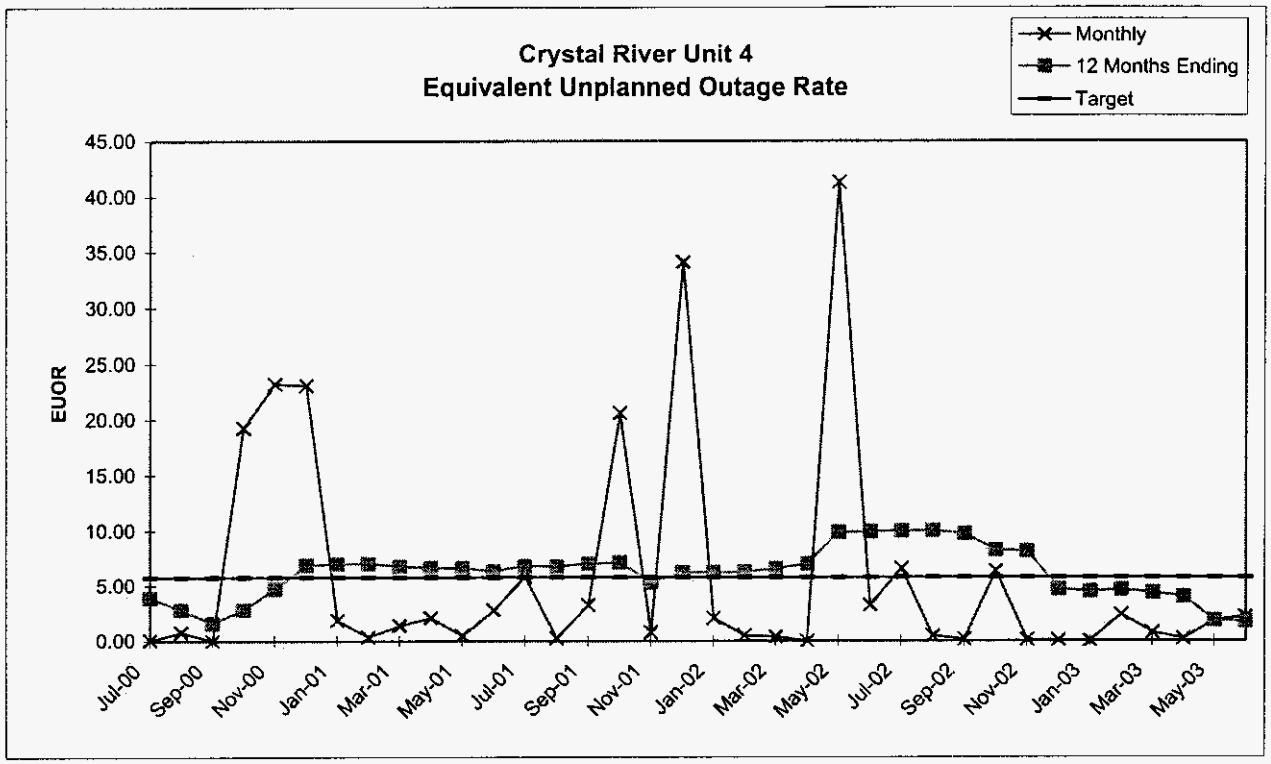
12 MONTHS	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	4.33	4.33	4.62	5.06	6.77	6.78	7.45	7.45	7.45	6.08	6.08	2.78	2.78	2.78	2.58	2.36	1.19	1.06
MOR	0.00	0.00	0.00	0.00	0.73	0.73	0.73	0.73	0.73	0.72	0.72	0.70	0.70	0.70	0.65	0.59	0.00	0.00
PFOR	1.19	1.20	1.16	1.28	1.36	1.47	0.88	0.87	0.85	0.71	0.62	0.59	0.45	0.40	0.38	0.37	0.36	0.25
PMOR	0.83	0.83	0.88	0.76	1.34	1.26	1.23	1.27	0.96	0.96	0.97	0.70	0.62	0.85	0.84	0.77	0.32	0.47
EUOR	6.26	6.27	6.57	7.00	9.89	9.94	10.02	10.04	9.74	8.27	8.20	4.69	4.47	4.65	4.38	4.03	1.86	1.78
EUOF	6.26	6.27	6.16	5.99	8.15	8.19	8.25	8.27	8.02	6.81	6.75	3.86	3.68	3.83	3.88	3.90	1.86	1.78
POF	0.00	0.00	6.27	14.47	17.65	17.65	17.65	17.65	17.65	17.65	17.65	17.65	17.65	17.65	11.38	3.18	0.00	0.00
EAF	93.74	93.73	87.57	79.54	74.20	74.17	74.10	74.08	74.33	75.54	75.60	78.49	78.67	78.52	84.73	92.92	98.14	98.22

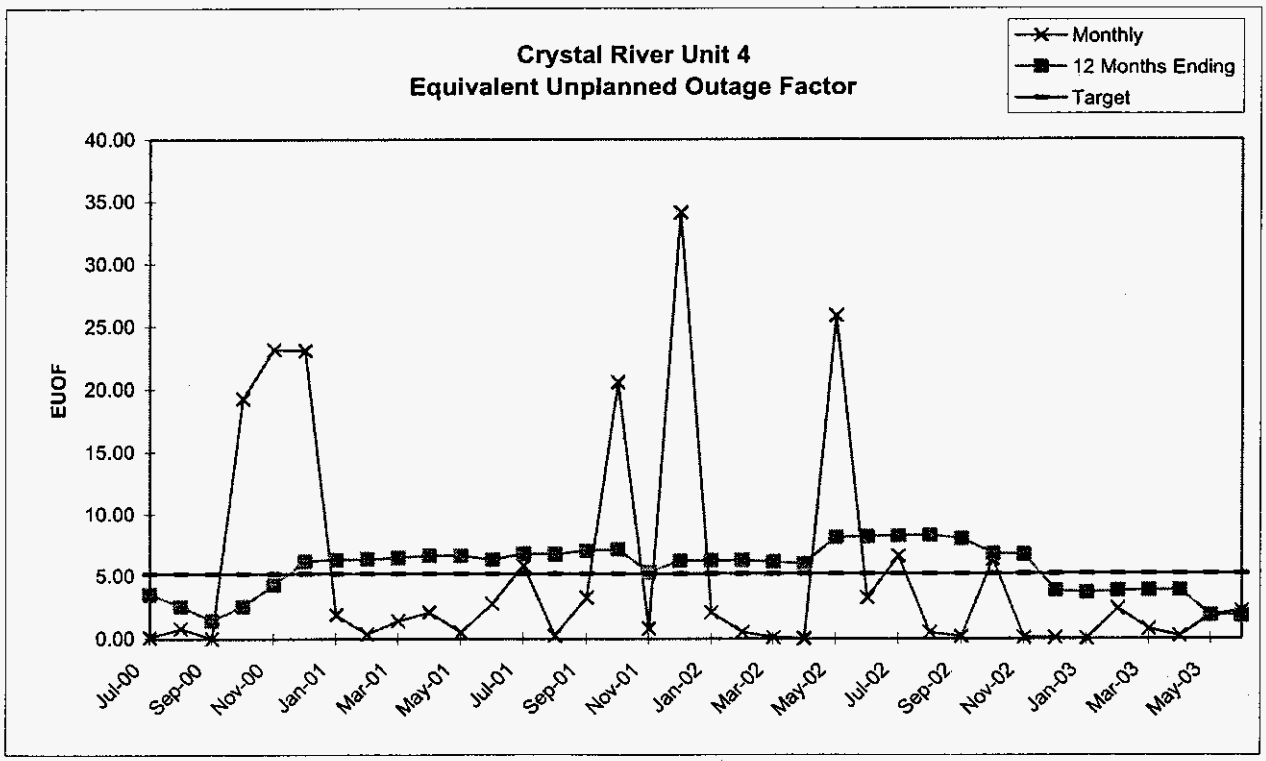

Crystal River Unit 4
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 4
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 4
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 4
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 4
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 4
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03

Crystal River
Unit 5

	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	738.67	741.55	718.50	743.00	638.78	359.70	618.20	672.00	736.40	312.60	245.70	716.60	457.00	711.62	720.00	745.00	720.00	737.70
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	5.33	2.45	1.50	2.00	81.22	384.30	125.80	0.00	7.60	406.40	498.30	3.40	287.00	32.38	0.00	0.00	0.00	6.30
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	406.40	491.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	5.33	2.45	1.50	2.00	8.32	22.80	5.40	0.00	7.60	0.00	6.70	3.40	287.00	32.38	0.00	0.00	0.00	6.30
MOH	0.00	0.00	0.00	0.00	72.90	361.50	120.40	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	22.85	3.50	2.05	507.73	63.80	0.00	0.00	3.25	0.00	84.25	18.07	0.00	63.00	21.00	234.73	5.33	0.00	38.70
LRPF	46.74	141.38	282.38	97.30	93.68	0.00	0.00	103.65	0.00	55.67	94.98	0.00	202.62	296.57	54.71	64.30	0.00	232.26
EFOH	1.50	0.69	0.81	69.19	8.37	0.00	0.00	0.47	0.00	6.54	2.39	0.00	17.80	8.69	17.91	0.48	0.00	12.54
PMOH	8.00	0.00	0.00	0.00	238.38	0.00	0.00	16.00	0.00	0.00	0.00	9.75	0.00	22.75	2.67	0.00	125.33	18.25
LRPM	103.24	0.00	0.00	0.00	72.65	0.00	0.00	103.68	0.00	0.00	0.00	535.56	0.00	103.65	54.64	0.00	72.27	67.54
EMOH	1.16	0.00	0.00	0.00	24.25	0.00	0.00	2.31	0.00	0.00	0.00	7.28	0.00	3.29	0.20	0.00	12.63	1.72
NPC	714.00	714.00	714.00	714.00	714.00	714.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00

MONTHLY	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	0.72	0.33	0.21	0.27	1.29	5.96	0.87	0.00	1.02	0.00	2.65	0.47	38.58	4.35	0.00	0.00	0.00	0.85
MOR	0.00	0.00	0.00	0.00	10.24	50.12	16.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.20	0.09	0.11	9.31	1.31	0.00	0.00	0.07	0.00	2.09	0.97	0.00	3.90	1.22	2.49	0.06	0.00	1.70
PMOR	0.16	0.00	0.00	0.00	3.80	0.00	0.00	0.34	0.00	0.00	0.00	1.02	0.00	0.46	0.03	0.00	1.75	0.23
EUOR	1.07	0.42	0.32	9.56	15.81	51.65	16.91	0.41	1.02	2.09	3.60	1.48	40.97	5.96	2.52	0.06	1.75	2.76
EUOF	1.07	0.42	0.32	9.56	15.81	51.65	16.91	0.41	1.02	0.91	1.22	1.48	40.97	5.96	2.52	0.06	1.75	2.76
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	56.52	66.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	98.93	99.58	99.68	90.44	84.19	48.35	83.09	99.59	98.98	42.57	32.70	98.52	59.03	94.04	97.48	99.94	98.25	97.24

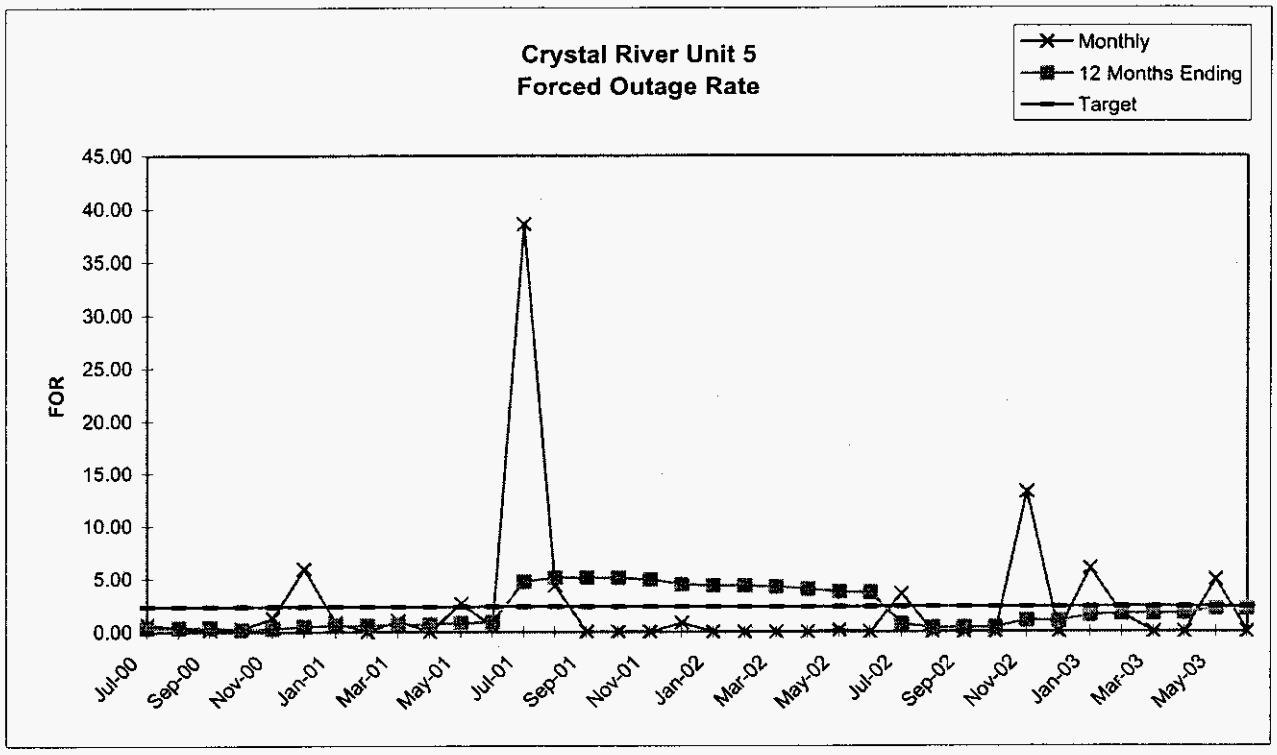
12 MONTHS	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	0.37	0.40	0.41	0.20	0.30	0.51	0.58	0.58	0.68	0.71	0.85	0.90	4.75	5.16	5.14	5.11	4.95	4.51
MOR	1.09	1.09	1.09	1.08	1.92	4.97	6.35	6.37	6.37	6.69	7.11	7.12	7.38	7.41	7.41	7.41	6.43	1.60
PFOR	0.18	0.17	0.18	0.98	1.09	1.10	1.07	1.08	1.07	1.18	1.30	1.24	1.53	1.65	1.90	0.90	0.77	0.90
PMOR	0.32	0.32	0.32	0.32	0.60	0.62	0.59	0.42	0.34	0.36	0.38	0.48	0.49	0.54	0.54	0.54	0.37	0.37
EUOR	1.93	1.96	1.99	2.56	3.86	7.05	8.40	8.27	8.28	8.73	9.39	9.48	13.25	13.78	13.98	13.08	11.79	7.17
EUOF	1.93	1.96	1.99	2.56	3.86	7.05	8.40	8.27	8.28	8.33	8.43	8.51	11.90	12.37	12.55	11.74	10.58	6.43
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.64	10.25	10.25	10.25	10.25	10.25	10.25	10.25	10.25
EAF	98.07	98.04	98.01	97.44	96.14	92.95	91.60	91.73	91.72	87.03	81.32	81.24	77.85	77.38	77.20	78.01	79.16	83.32

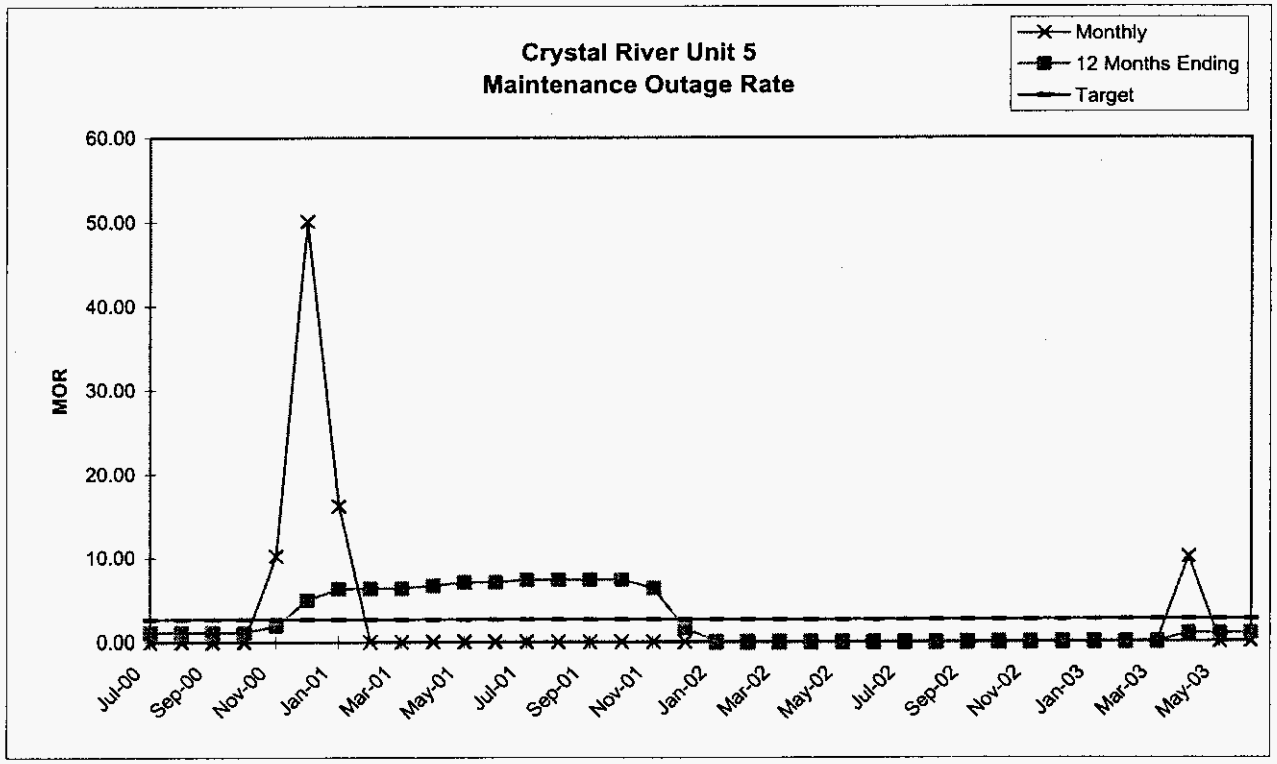
Crystal River
Unit 5

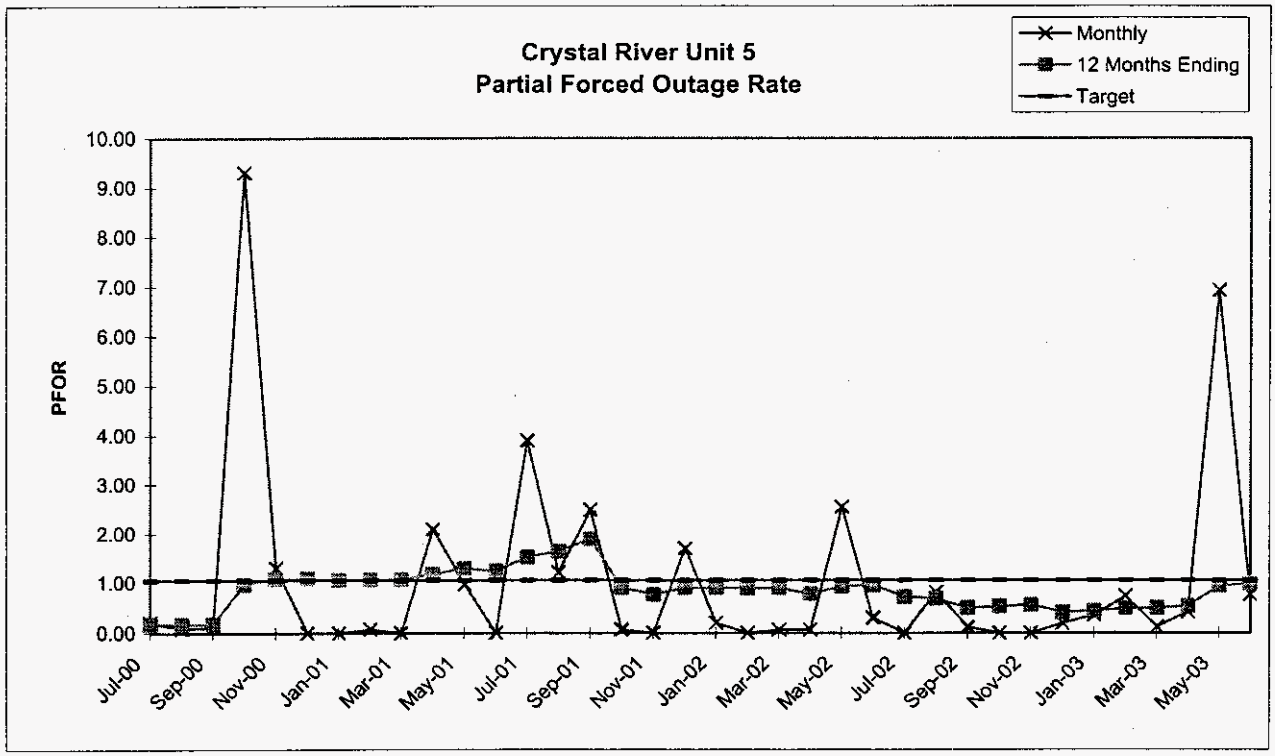
	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	744.00	672.00	744.00	719.00	742.78	720.00	717.20	744.00	720.00	97.27	313.84	744.00	699.13	661.00	744.00	646.55	707.45	720.00
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	0.00	1.22	0.00	26.80	0.00	0.00	647.73	406.16	0.00	44.87	11.00	0.00	72.45	36.55	0.00
POH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	647.73	358.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FOH	0.00	0.00	0.00	0.00	1.22	0.00	26.80	0.00	0.00	0.00	47.93	0.00	44.87	11.00	0.00	0.00	36.55	0.00
MOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	72.45	0.00	0.00
PFOH	2.57	0.00	0.82	2.08	156.08	3.62	0.00	57.10	19.58	0.00	0.00	11.48	8.72	49.67	3.22	19.83	304.95	20.02
LRPF	411.51	0.00	420.59	166.15	87.00	431.59	0.00	76.71	30.14	0.00	0.00	88.75	206.06	70.11	203.52	99.00	115.20	197.73
EFOH	1.48	0.00	0.48	0.48	18.94	2.18	0.00	6.11	0.82	0.00	0.00	1.42	2.51	4.86	0.91	2.74	49.00	5.52
PMOH	12.05	0.00	0.00	0.00	5.83	0.00	22.35	0.00	0.00	0.00	0.00	0.00	0.00	135.73	40.08	0.00	116.03	30.42
LRPM	70.99	0.00	0.00	0.00	336.12	0.00	120.24	0.00	0.00	0.00	0.00	0.00	0.00	183.81	223.28	0.00	384.48	104.23
EMOH	1.19	0.00	0.00	0.00	2.73	0.00	3.75	0.00	0.00	0.00	0.00	0.00	0.00	34.80	12.48	0.00	62.22	4.42
NPC	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00	717.00

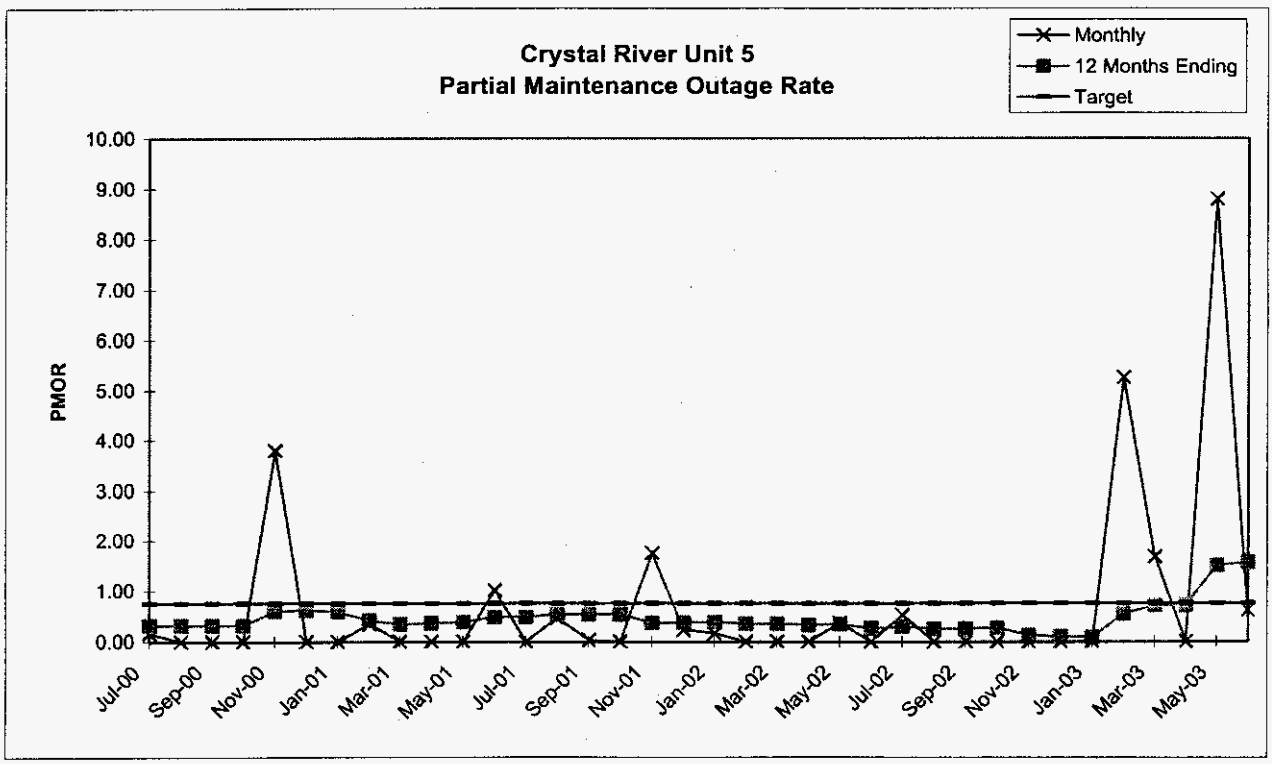
MONTHLY	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	0.00	0.00	0.00	0.00	0.16	0.00	3.60	0.00	0.00	0.00	13.25	0.00	6.03	1.64	0.00	0.00	4.91	0.00
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.08	0.00	0.00
PFOR	0.20	0.00	0.06	0.07	2.55	0.30	0.00	0.82	0.11	0.00	0.00	0.19	0.36	0.73	0.12	0.42	6.93	0.77
PMOR	0.16	0.00	0.00	0.00	0.37	0.00	0.52	0.00	0.00	0.00	0.00	0.00	0.00	5.26	1.68	0.00	8.79	0.61
EUOR	0.36	0.00	0.06	0.07	3.08	0.30	4.11	0.82	0.11	0.00	13.25	0.19	6.37	7.54	1.80	10.46	19.86	1.38
EUOF	0.36	0.00	0.06	0.07	3.08	0.30	4.11	0.82	0.11	0.00	6.66	0.19	6.37	7.54	1.80	10.46	19.86	1.38
POF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	86.94	49.75	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EAF	99.64	100.00	99.94	99.93	96.92	99.70	95.89	99.18	99.89	13.06	43.59	99.81	93.63	92.46	98.20	89.54	80.14	98.62

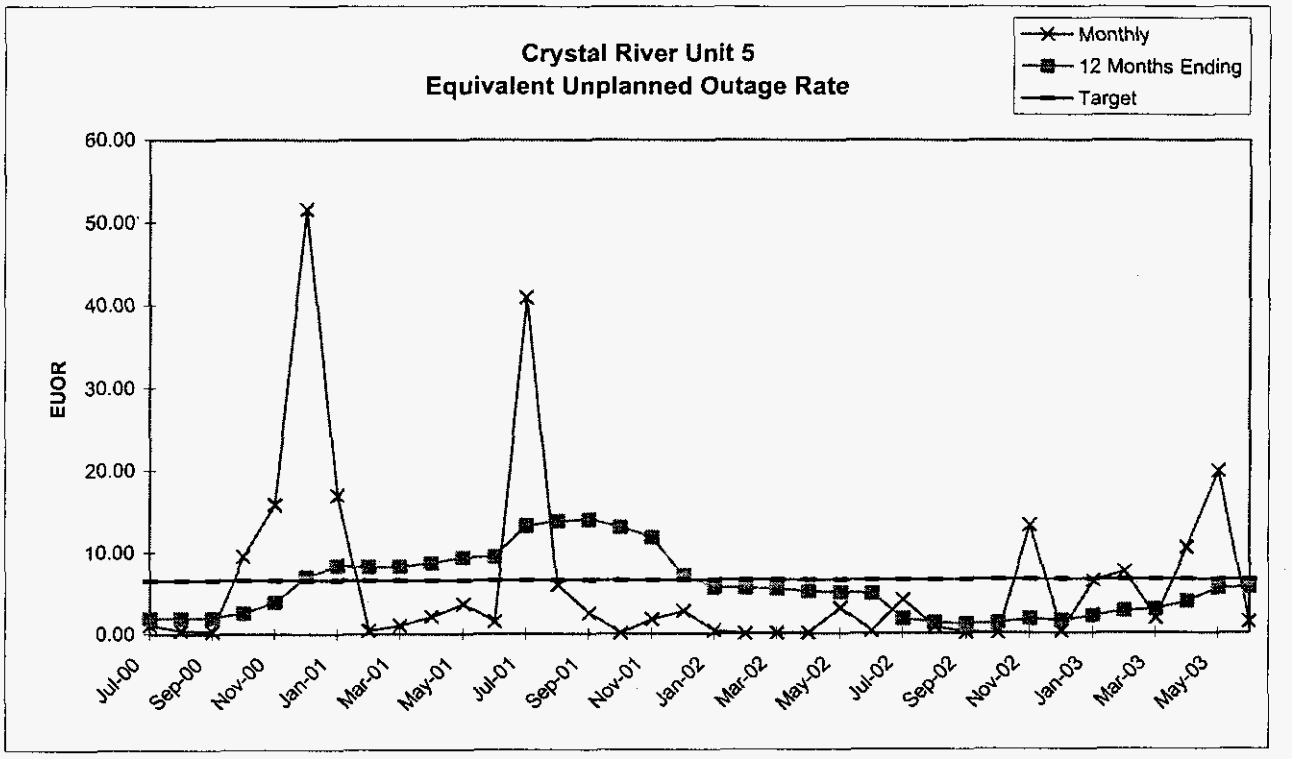
12 MONTHS	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	4.37	4.37	4.27	4.06	3.77	3.73	0.76	0.39	0.39	0.42	1.06	0.98	1.56	1.70	1.70	1.72	2.18	2.18
MOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.95	0.95	0.95
PFOR	0.91	0.90	0.91	0.78	0.93	0.96	0.73	0.69	0.50	0.53	0.56	0.42	0.43	0.50	0.50	0.54	0.94	0.98
PMOR	0.38	0.35	0.35	0.33	0.34	0.26	0.29	0.25	0.25	0.27	0.12	0.10	0.08	0.54	0.71	0.71	1.51	1.57
EUOR	5.60	5.57	5.47	5.13	5.00	4.90	1.77	1.34	1.14	1.22	1.74	1.49	2.07	2.72	2.89	3.85	5.46	5.56
EUOF	5.03	4.99	4.91	4.84	5.00	4.90	1.77	1.34	1.14	1.13	1.54	1.32	1.83	2.41	2.55	3.41	4.83	4.92
POF	10.25	10.25	10.25	5.61	0.00	0.00	0.00	0.00	0.00	7.39	11.48	11.48	11.48	11.48	11.48	11.48	11.48	11.48
EAF	84.72	84.75	84.84	89.54	95.00	95.10	98.23	98.66	98.86	91.47	86.98	87.20	86.69	86.11	85.96	85.11	83.68	83.59

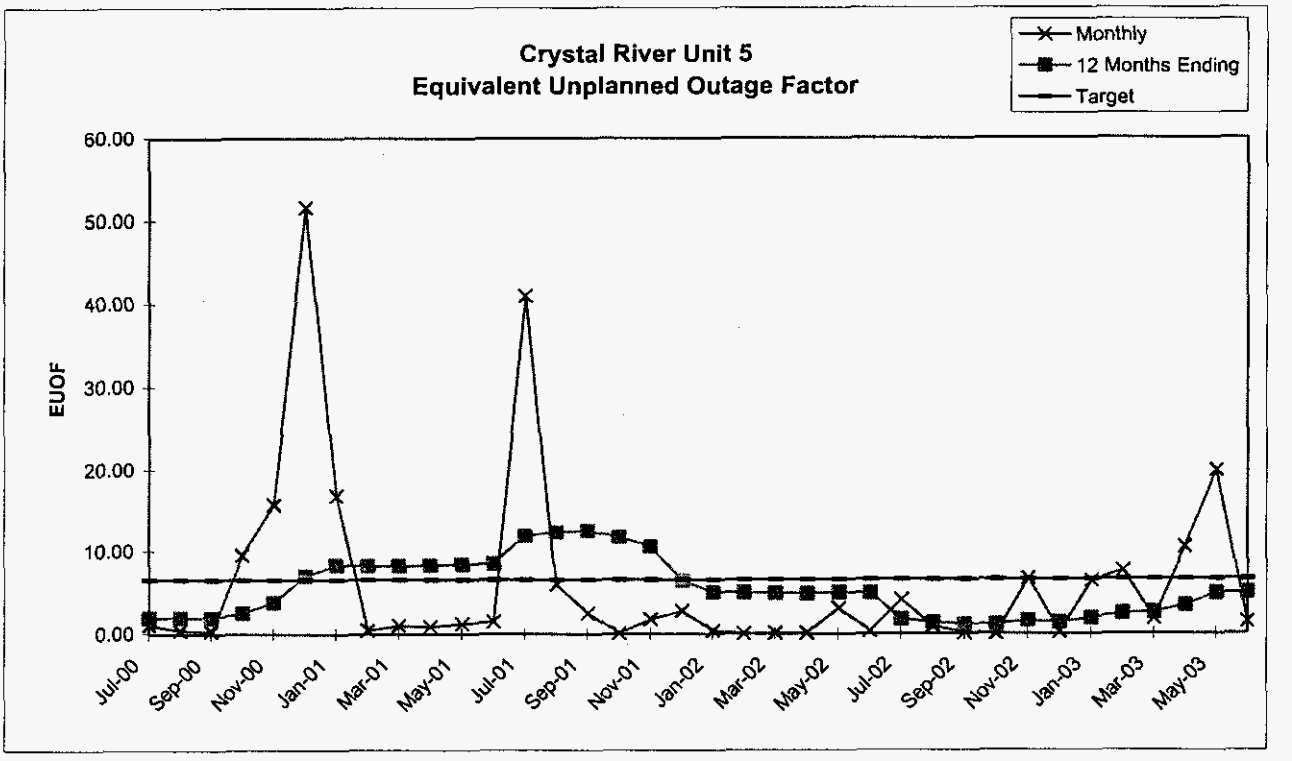

Crystal River Unit 5
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 5
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 5
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 5
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 5
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Crystal River Unit 5
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
60.00
50.00
40.00
30.00
20.00
10.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03

Hines
Unit 1

	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	691.07	665.75	745.00	317.05	511.52	417.05	0.00	650.55	478.50	257.50	720.00	744.00	744.00	720.00	744.37	29.87	743.20
RSH	0.00	0.00	0.00	0.00	0.00	230.25	326.95	672.00	93.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	52.93	54.25	0.00	402.95	2.23	0.00	0.00	0.00	240.50	486.50	0.00	0.00	0.00	0.00	0.63	690.13	0.80
POH	0.00	0.00	0.00	0.00	397.82	0.00	0.00	0.00	0.00	240.50	436.63	0.00	0.00	0.00	0.00	0.63	690.13	0.00
FOH	0.00	0.00	0.00	0.00	5.13	2.23	0.00	0.00	0.00	0.00	49.87	0.00	0.00	0.00	0.00	0.00	0.00	0.80
MOH	0.00	52.93	54.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	168.50	0.00	3.15	114.77	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPF	0.00	226.00	0.00	231.05	231.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EFOH	0.00	79.01	0.00	1.51	55.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOH	0.00	0.00	2.65	0.00	0.00	0.00	0.00	0.00	0.00	28.37	0.00	68.72	0.00	0.00	0.00	232.77	0.00	0.00
LRPM	0.00	0.00	245.91	0.00	0.00	0.00	0.00	0.00	0.00	216.98	0.00	256.99	0.00	0.00	0.00	132.00	0.00	0.00
EMOH	0.00	0.00	1.35	0.00	0.00	0.00	0.00	0.00	0.00	12.77	0.00	36.64	0.00	0.00	0.00	63.75	0.00	0.00
NPC	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00

MONTHLY	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	0.00	0.00	0.00	0.00	1.59	0.43	0.00	0.00	0.00	0.00	16.22	0.00	0.00	0.00	0.00	0.00	0.00	0.11
MOR	0.00	7.11	7.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	11.43	0.00	0.20	17.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	2.67	0.00	5.09	0.00	0.00	0.00	8.56	0.00	0.00
EUOR	0.00	17.73	7.72	0.20	18.66	0.43	0.00	0.00	0.00	2.67	16.22	5.09	0.00	0.00	0.00	8.56	0.00	0.11
EUOF	0.00	17.73	7.72	0.20	8.35	0.30	0.00	0.00	0.00	1.78	6.70	5.09	0.00	0.00	0.00	8.56	0.00	0.11
POF	0.00	0.00	0.00	0.00	55.25	0.00	0.00	0.00	0.00	33.45	58.69	0.00	0.00	0.00	0.00	0.08	95.85	0.00
EAF	100.00	82.27	92.28	99.80	36.40	99.70	100.00	100.00	100.00	64.77	34.61	94.91	100.00	100.00	100.00	91.36	4.15	99.89

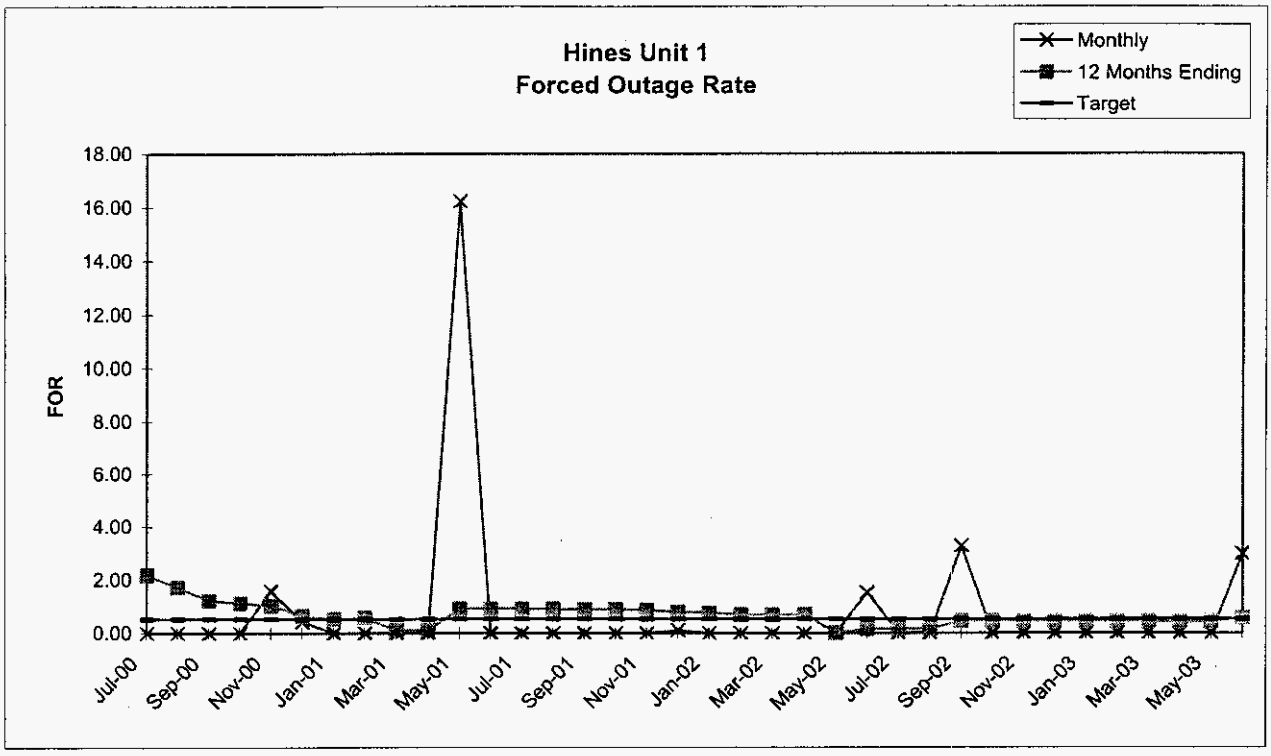
12 MONTHS	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	2.19	1.74	1.23	1.13	1.05	0.65	0.53	0.58	0.11	0.11	0.91	0.91	0.91	0.91	0.90	0.90	0.86	0.80
MOR	0.18	0.93	1.70	1.68	1.67	1.62	1.48	1.64	1.61	1.58	1.70	1.70	1.70	0.86	0.00	0.00	0.00	0.00
PFOR	3.75	4.87	4.44	3.57	4.28	3.28	3.01	3.21	3.09	3.02	2.19	2.19	2.19	0.90	0.90	0.87	0.00	0.00
PMOR	3.11	3.12	2.86	0.82	0.82	0.46	0.47	0.52	0.02	0.21	0.23	0.82	0.82	0.81	0.78	1.79	1.88	1.81
EUOR	9.06	10.42	9.98	7.05	7.64	5.90	5.40	5.85	4.77	4.86	4.94	5.51	5.51	3.44	2.56	3.54	2.72	2.60
EUOF	7.38	8.49	8.13	5.79	6.31	5.01	4.48	4.39	3.63	3.77	3.59	4.00	4.00	2.50	1.86	2.57	1.89	1.87
POF	13.92	13.92	13.92	13.92	13.59	10.36	10.36	10.39	8.20	7.29	12.27	12.27	12.27	12.27	12.27	12.28	15.62	15.62
EAF	78.70	77.59	77.95	80.29	80.10	84.63	85.17	85.22	88.17	88.94	84.14	83.73	83.73	85.23	85.87	85.15	82.50	82.51

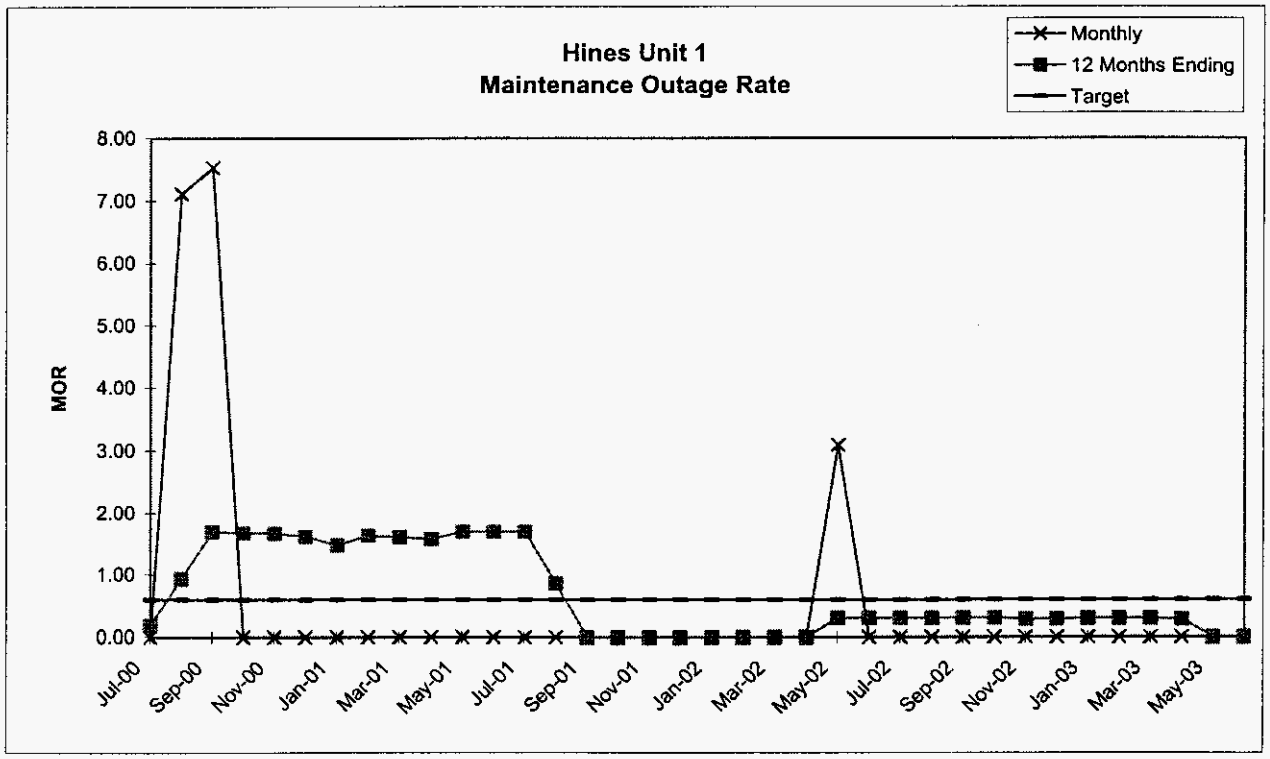
Hines
Unit 1

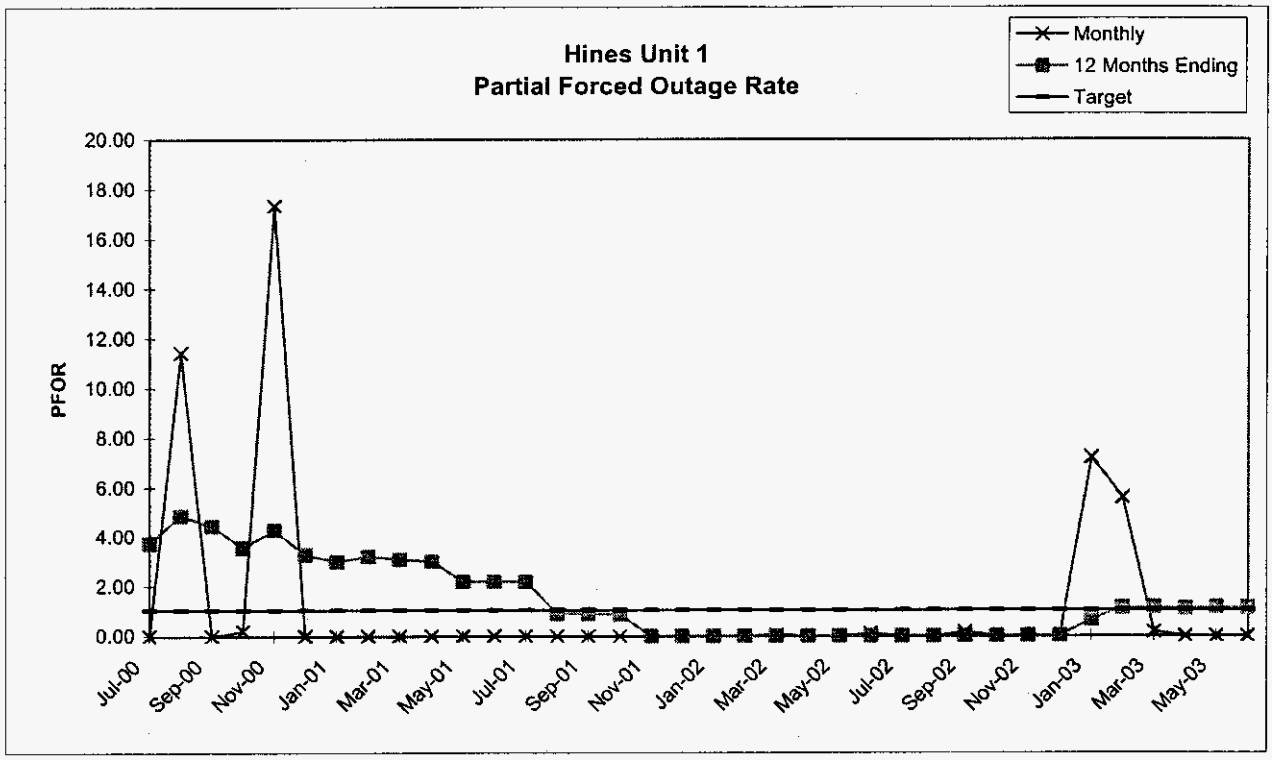
	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	744.00	672.00	737.17	297.68	721.00	709.07	744.00	744.00	696.35	745.00	530.83	538.02	686.65	672.00	744.00	669.35	372.07	698.50
RSH	0.00	0.00	6.83	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.33	57.35	0.00	0.00	0.00	0.00	0.00
UH	0.00	0.00	0.00	421.32	23.00	10.93	0.00	0.00	23.65	0.00	189.17	201.65	0.00	0.00	0.00	49.65	371.93	21.50
POH	0.00	0.00	0.00	421.32	0.00	0.00	0.00	0.00	0.00	0.00	189.17	201.65	0.00	0.00	0.00	49.65	371.93	0.00
FOH	0.00	0.00	0.00	0.00	0.00	10.93	0.00	0.00	23.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.50
MOH	0.00	0.00	0.00	0.00	23.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.00	0.50	0.00	0.00	1.40	0.00	0.00	2.30	0.00	0.00	0.00	96.77	72.00	4.02	0.00	0.00	0.00
LRPF	0.00	0.00	381.74	0.00	0.00	248.92	0.00	0.00	234.08	0.00	0.00	0.00	246.99	252.00	146.88	0.00	0.00	0.00
EFOH	0.00	0.00	0.40	0.00	0.00	0.72	0.00	0.00	1.12	0.00	0.00	0.00	49.59	37.64	1.23	0.00	0.00	0.00
PMOH	37.37	0.00	0.00	10.05	37.47	0.00	0.00	0.00	53.82	0.00	0.00	0.00	51.88	0.00	0.00	113.23	23.33	0.00
LRPM	251.98	0.00	0.00	251.98	241.98	0.00	0.00	0.00	233.99	0.00	0.00	0.00	247.01	0.00	0.00	250.01	240.03	0.00
EMOH	19.54	0.00	0.00	5.25	18.81	0.00	0.00	0.00	26.13	0.00	0.00	0.00	26.59	0.00	0.00	58.73	11.62	0.00
NPC	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00	482.00

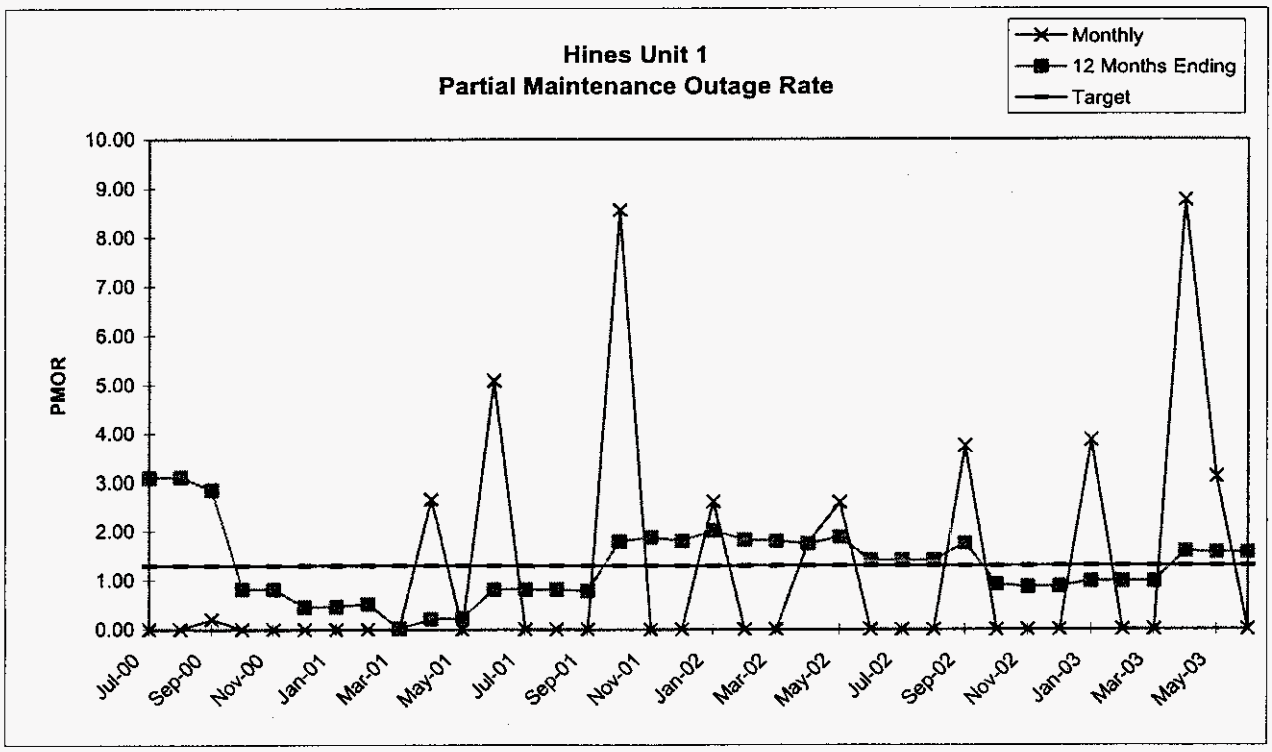
MONTHLY	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	0.00	0.00	0.00	0.00	0.00	1.52	0.00	0.00	3.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.99
MOR	0.00	0.00	0.00	0.00	3.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.00	0.05	0.00	0.00	0.10	0.00	0.00	0.16	0.00	0.00	0.00	7.22	5.60	0.16	0.00	0.00	0.00
PMOR	2.63	0.00	0.00	1.76	2.61	0.00	0.00	0.00	3.75	0.00	0.00	0.00	3.87	0.00	0.00	8.77	3.12	0.00
EUOR	2.63	0.00	0.05	1.76	5.62	1.62	0.00	0.00	7.07	0.00	0.00	0.00	11.09	5.60	0.16	8.77	3.12	2.99
EUOF	2.63	0.00	0.05	0.73	5.62	1.62	0.00	0.00	7.07	0.00	0.00	0.00	10.24	5.60	0.16	8.17	1.56	2.99
POF	0.00	0.00	0.00	58.60	0.00	0.00	0.00	0.00	0.00	0.00	26.27	27.10	0.00	0.00	0.00	6.91	49.99	0.00
EAF	97.37	100.00	99.95	40.67	94.38	98.38	100.00	100.00	92.93	100.00	73.73	72.90	89.76	94.40	99.84	84.93	48.45	97.01

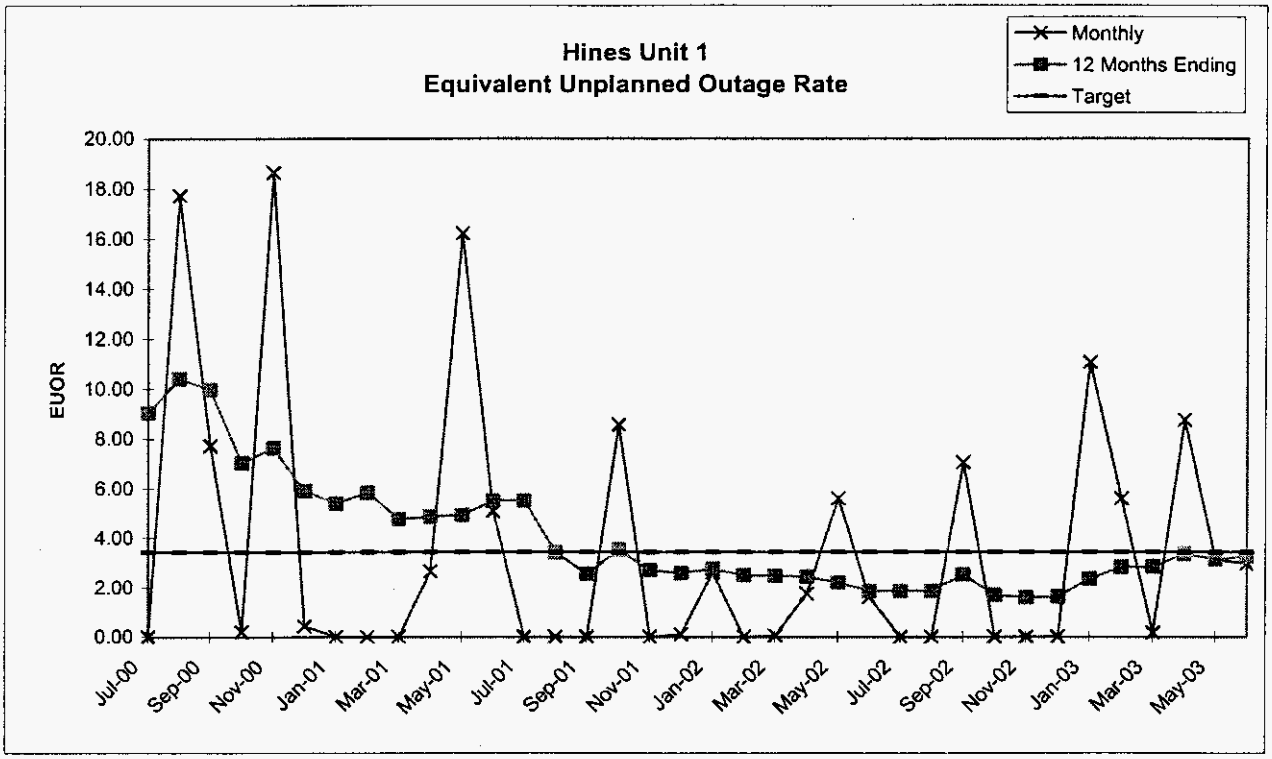
12 MONTHS	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	0.76	0.69	0.69	0.70	0.01	0.15	0.15	0.15	0.46	0.46	0.44	0.44	0.44	0.44	0.44	0.42	0.44	0.57
MOR	0.00	0.00	0.00	0.00	0.30	0.30	0.30	0.30	0.30	0.30	0.28	0.29	0.29	0.29	0.29	0.28	0.00	0.00
PFOR	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.03	0.03	0.03	0.03	0.66	1.14	1.15	1.10	1.15	1.14
PMOR	2.02	1.83	1.81	1.75	1.89	1.41	1.41	1.41	1.76	0.92	0.86	0.88	0.98	0.98	0.98	1.59	1.57	1.57
EUOR	2.77	2.51	2.49	2.45	2.20	1.87	1.87	1.87	2.54	1.71	1.60	1.63	2.36	2.84	2.85	3.37	3.14	3.27
EUOF	2.09	2.09	2.10	2.01	1.92	1.63	1.63	1.63	2.22	1.49	1.49	1.48	2.13	2.56	2.56	3.18	2.83	2.94
POF	15.62	15.62	15.62	17.68	12.69	12.69	12.69	12.69	12.69	12.69	6.97	9.27	9.27	9.27	9.27	5.03	9.27	9.27
EAF	82.29	82.29	82.29	80.31	85.39	85.67	85.67	85.67	85.09	85.82	91.54	89.25	88.60	88.17	88.16	91.80	87.90	87.78

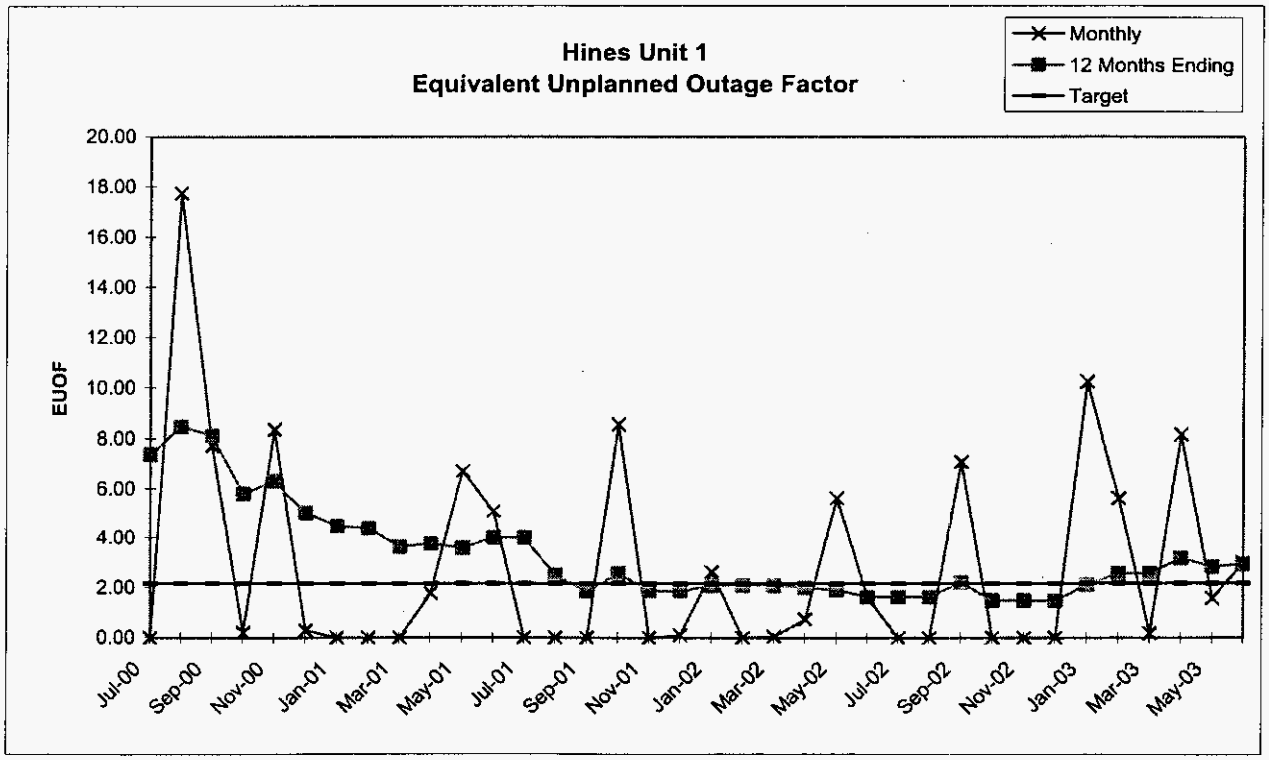

Hines Unit 1
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Hines Unit 1
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Hines Unit 1
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Hines Unit 1
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Hines Unit 1
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
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Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Hines Unit 1
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
20.00
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03

Tiger Bay

	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
PER HOURS	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00
SER HOURS	744.00	651.97	720.00	574.13	396.38	684.60	744.00	577.15	385.93	375.67	669.57	715.37	744.00	744.00	699.67	614.33	713.08	744.00
RSH	0.00	0.00	0.00	96.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	0.00	92.03	0.00	73.95	323.62	59.40	0.00	94.85	358.07	343.33	74.43	4.63	0.00	0.00	20.33	130.67	6.92	0.00
POH	0.00	0.00	0.00	0.00	246.50	0.00	0.00	0.00	358.07	328.23	0.00	0.00	0.00	0.00	0.00	130.67	0.00	0.00
FOH	0.00	92.03	0.00	73.95	77.12	0.00	0.00	94.85	0.00	15.10	12.25	0.00	0.00	0.00	20.33	0.00	6.92	0.00
MOH	0.00	0.00	0.00	0.00	0.00	59.40	0.00	0.00	0.00	0.00	62.18	4.63	0.00	0.00	0.00	0.00	0.00	0.00
PFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.62	0.00	0.00	322.52	0.00	0.00	0.00
LRPF	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	150.21	0.00	0.00	73.01	0.00	0.00	0.00
EFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.18	0.00	0.00	113.76	0.00	0.00	0.00
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	206.00	206.00	206.00	206.00	206.00	206.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00

MONTHLY	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	0.00	12.37	0.00	11.41	16.29	0.00	0.00	14.11	0.00	3.86	1.80	0.00	0.00	0.00	2.82	0.00	0.96	0.00
MOR	0.00	0.00	0.00	0.00	0.00	7.98	0.00	0.00	0.00	0.00	8.50	0.64	0.00	0.00	0.00	0.00	0.00	0.00
PFOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.00	0.00	16.26	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	0.00	12.37	0.00	11.41	16.29	7.98	0.00	14.11	0.00	3.86	10.00	0.81	0.00	0.00	18.62	0.00	0.96	0.00
EUOF	0.00	12.37	0.00	9.93	10.71	7.98	0.00	14.11	0.00	2.10	10.00	0.81	0.00	0.00	18.62	0.00	0.96	0.00
POF	0.00	0.00	0.00	0.00	34.24	0.00	0.00	0.00	48.13	45.65	0.00	0.00	0.00	0.00	0.00	17.54	0.00	0.00
EAF	100.00	87.63	100.00	90.07	55.05	92.02	100.00	85.89	51.87	52.25	90.00	99.19	100.00	100.00	81.38	82.46	99.04	100.00

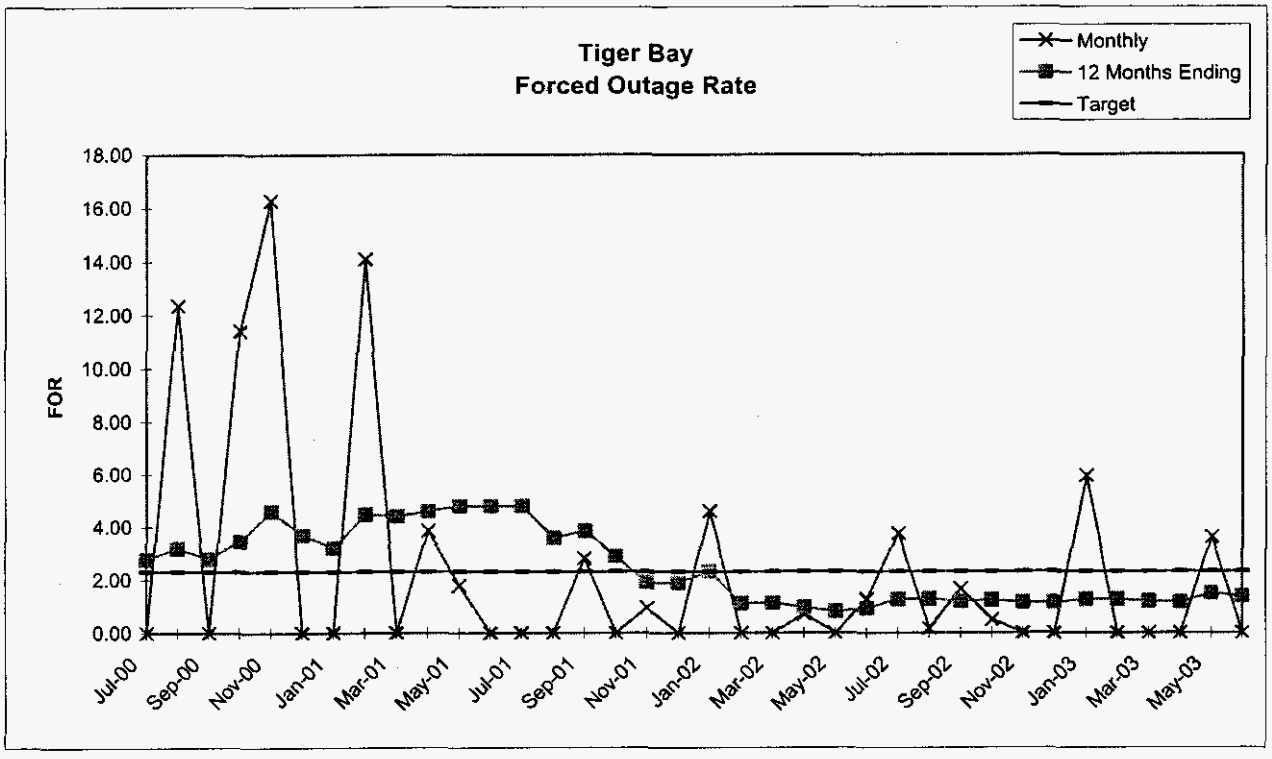
12 MONTHS	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01
FOR	2.79	3.20	2.80	3.47	4.60	3.70	3.22	4.49	4.42	4.60	4.80	4.80	4.80	3.59	3.86	2.90	1.91	1.90
MOR	0.11	0.11	0.11	0.11	0.11	0.82	0.81	0.82	0.81	0.81	1.65	1.71	1.71	1.69	1.70	1.69	1.62	0.86
PFOR	0.06	0.06	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.00	0.02	0.02	0.02	1.57	1.56	1.50	1.49
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	2.95	3.36	2.94	3.60	4.74	4.49	4.00	5.26	5.19	5.36	6.30	6.37	6.37	5.18	6.92	5.99	4.92	4.17
EUOF	2.65	3.02	2.64	3.20	4.08	3.86	3.47	4.56	4.56	4.73	5.56	5.62	5.62	4.57	6.10	5.26	4.46	3.78
POF	9.36	9.36	9.36	9.36	12.17	12.17	12.17	12.20	11.02	10.65	10.65	10.65	10.65	10.65	10.65	12.14	9.33	9.33
EAF	87.99	87.62	88.00	87.44	83.76	83.97	84.36	83.23	84.41	84.62	83.79	83.73	83.73	84.78	83.25	82.60	86.21	86.89

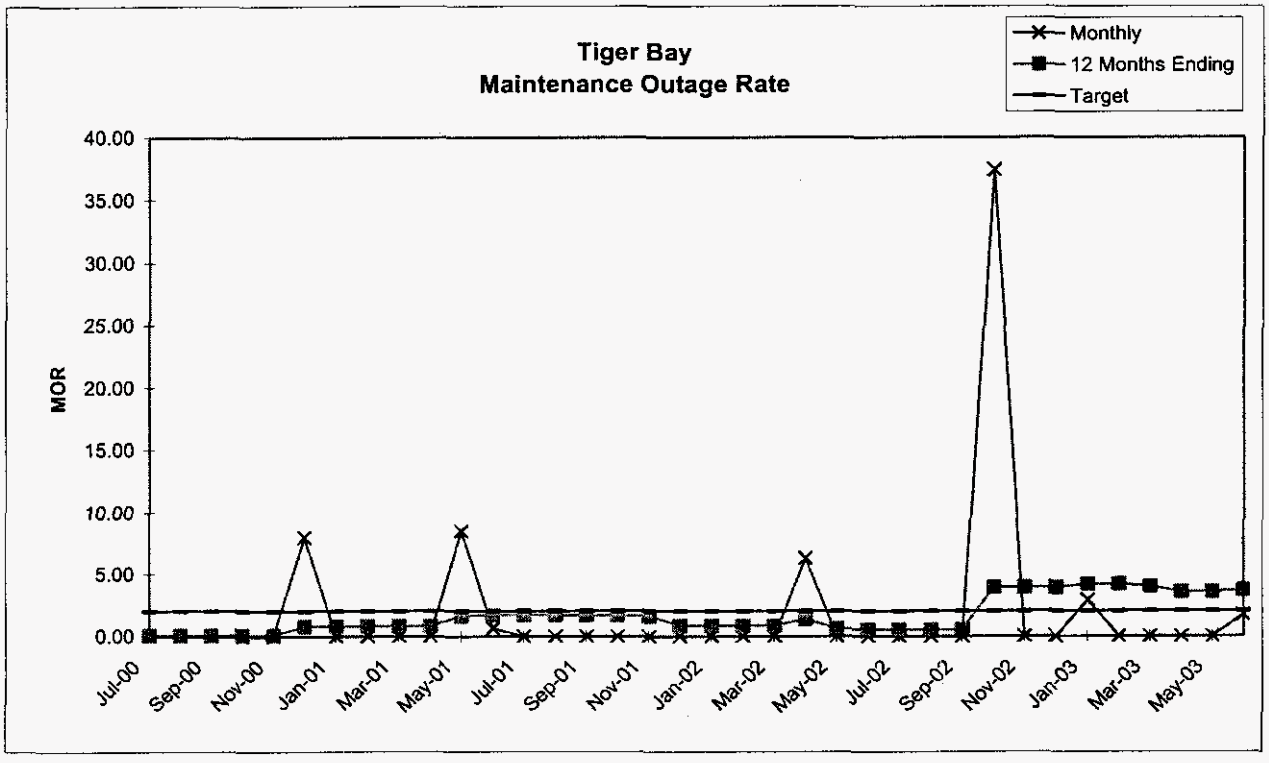
Tiger Bay

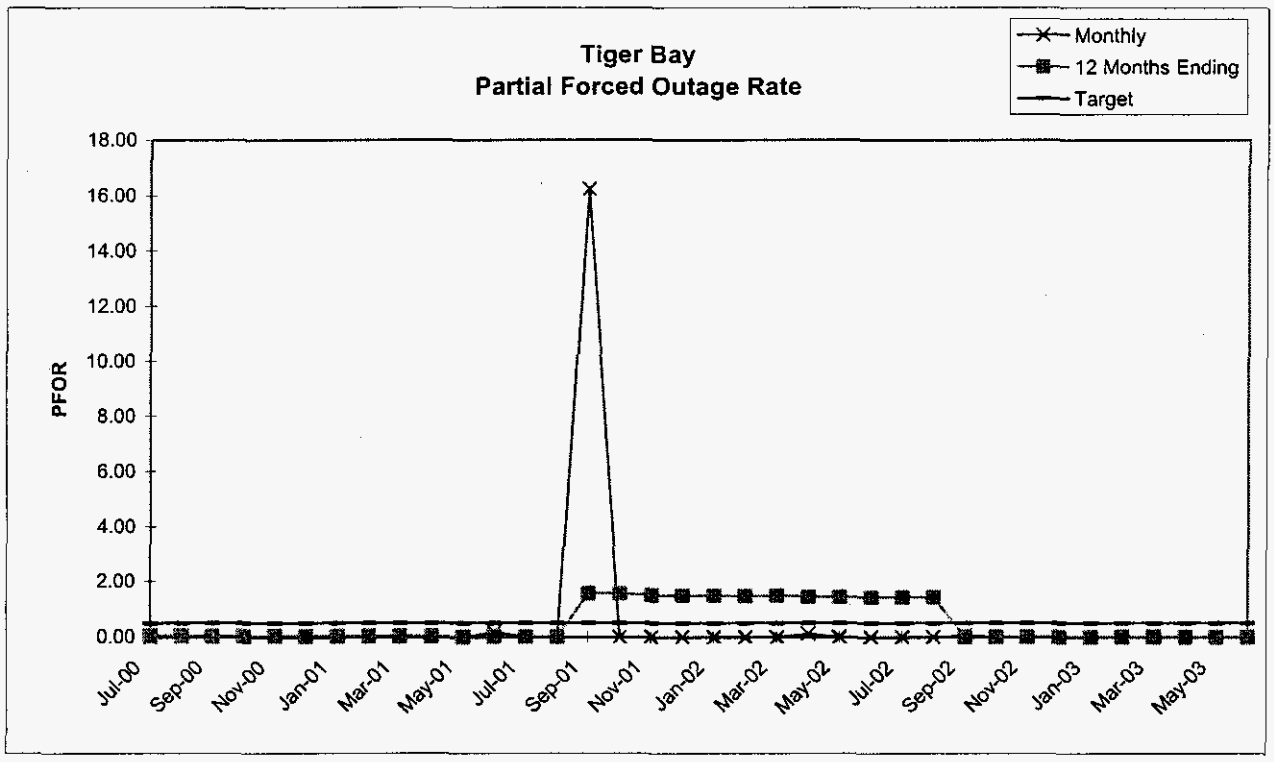
	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
PER HOURS	744.00	672.00	744.00	719.00	744.00	720.00	744.00	744.00	720.00	745.00	720.00	744.00	744.00	672.00	744.00	719.00	744.00	720.00
SER HOURS	709.72	672.00	286.37	669.33	744.00	710.92	716.00	742.70	708.00	464.70	720.00	744.00	680.52	672.00	744.00	485.95	717.08	707.75
RSH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
UH	34.28	0.00	457.63	49.67	0.00	9.08	28.00	1.30	12.00	280.30	0.00	0.00	63.48	0.00	0.00	233.05	26.92	12.25
POH	0.00	0.00	457.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	233.05	0.00	0.00
FOH	34.28	0.00	0.00	4.82	0.00	9.08	28.00	1.30	12.00	2.38	0.00	0.00	43.05	0.00	0.00	0.00	26.92	0.00
MOH	0.00	0.00	0.00	44.85	0.00	0.00	0.00	0.00	0.00	277.92	0.00	0.00	20.43	0.00	0.00	0.00	0.00	12.25
PFOH	0.00	0.00	0.00	0.85	0.00	0.00	0.00	0.00	0.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPF	0.00	0.00	0.00	198.96	0.00	0.00	0.00	0.00	182.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EFOH	0.00	0.00	0.00	0.82	0.00	0.00	0.00	0.00	0.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.38	0.00	9.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
LRPM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	207.26	0.00	190.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.38	0.00	8.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NPC	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00	207.00

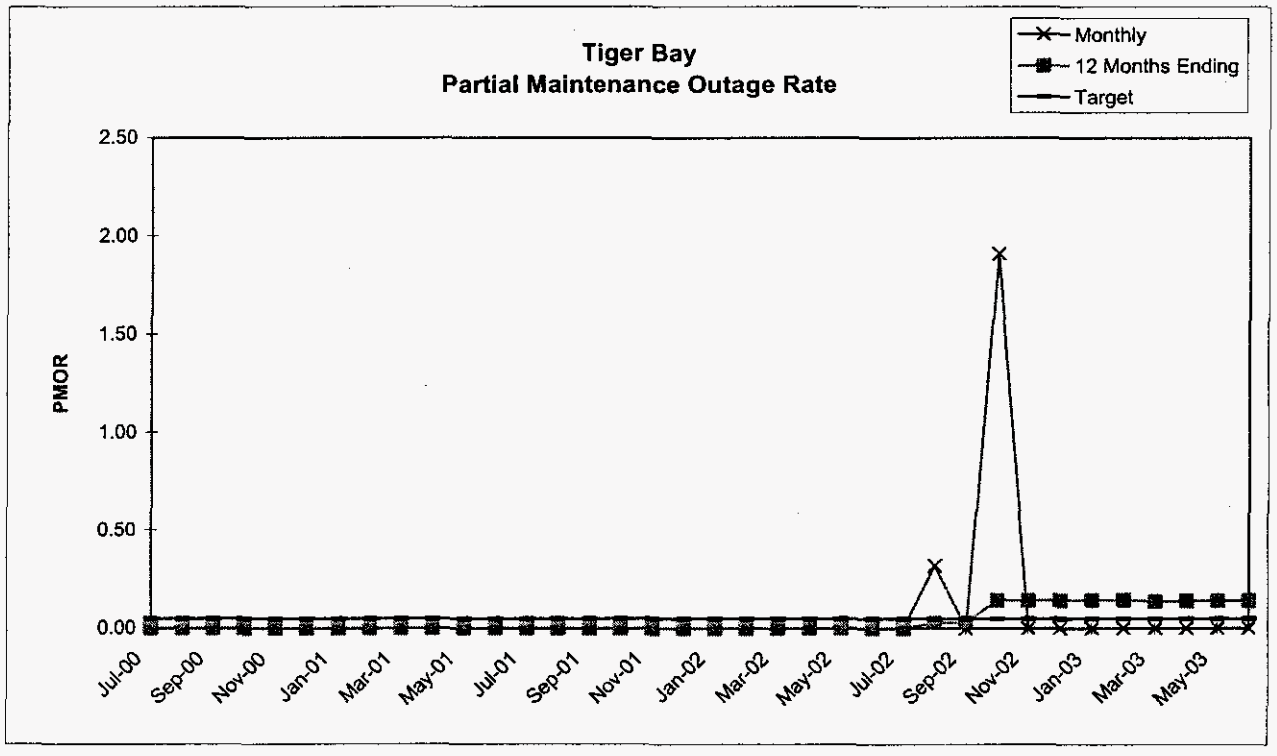
MONTHLY	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	4.61	0.00	0.00	0.71	0.00	1.26	3.76	0.17	1.67	0.51	0.00	0.00	5.95	0.00	0.00	0.00	3.62	0.00
MOR	0.00	0.00	0.00	6.28	0.00	0.00	0.00	0.00	0.00	37.42	0.00	0.00	2.91	0.00	0.00	0.00	0.00	1.70
PFOR	0.00	0.00	0.00	0.12	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.32	0.00	1.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EUOR	4.61	0.00	0.00	7.02	0.00	1.26	3.76	0.50	1.72	38.82	0.00	0.00	8.53	0.00	0.00	0.00	3.62	1.70
EUOF	4.61	0.00	0.00	7.02	0.00	1.26	3.76	0.50	1.72	38.82	0.00	0.00	8.53	0.00	0.00	0.00	3.62	1.70
POF	0.00	0.00	61.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	32.41	0.00	0.00
EAF	95.39	100.00	38.49	92.98	100.00	98.74	96.24	99.50	98.28	61.18	100.00	100.00	91.47	100.00	100.00	67.59	96.38	98.30

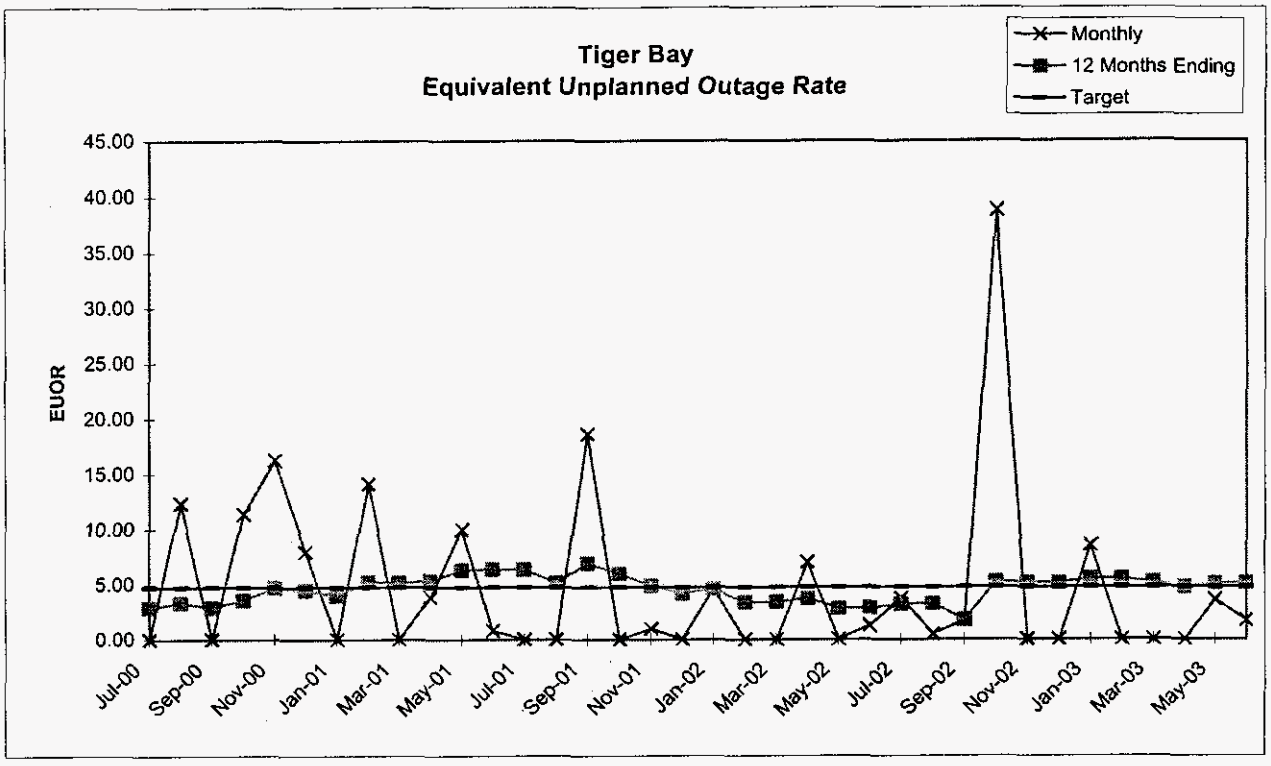
12 MONTHS	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FOR	2.33	1.13	1.14	0.98	0.82	0.93	1.27	1.29	1.19	1.24	1.15	1.15	1.26	1.26	1.20	1.16	1.49	1.38
MOR	0.86	0.85	0.86	1.38	0.61	0.55	0.56	0.56	0.56	3.93	3.93	3.93	4.18	4.18	3.96	3.54	3.55	3.69
PFOR	1.49	1.48	1.50	1.45	1.44	1.42	1.43	1.43	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.01	0.01
PMOR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14
EUOR	4.60	3.41	3.45	3.74	2.83	2.87	3.22	3.26	1.77	5.23	5.14	5.14	5.50	5.50	5.21	4.76	5.08	5.11
EUOF	4.17	3.09	3.09	3.49	2.64	2.68	3.00	3.04	1.65	4.95	4.88	4.88	5.21	5.21	5.21	4.63	4.94	4.98
POF	9.33	9.33	10.46	6.72	6.72	6.72	6.72	6.72	6.72	5.22	5.22	5.22	5.22	5.22	0.00	2.66	2.66	2.66
EAF	86.50	87.58	86.45	89.79	90.64	90.60	90.28	90.24	91.63	89.82	89.90	89.90	89.57	89.57	94.79	92.71	92.40	92.36


Tiger Bay
Forced Outage Rate
Monthly
12 Months Ending
Target
FOR
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Tiger Bay
Maintenance Outage Rate
Monthly
12 Months Ending
Target
MOR
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Tiger Bay
Partial Forced Outage Rate
Monthly
12 Months Ending
Target
PFOR
18.00
16.00
14.00
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Tiger Bay
Partial Maintenance Outage Rate
Monthly
12 Months Ending
Target
PMOR
2.50
2.00
1.50
1.00
0.50
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03


Tiger Bay
Equivalent Unplanned Outage Rate
Monthly
12 Months Ending
Target
EUOR
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03

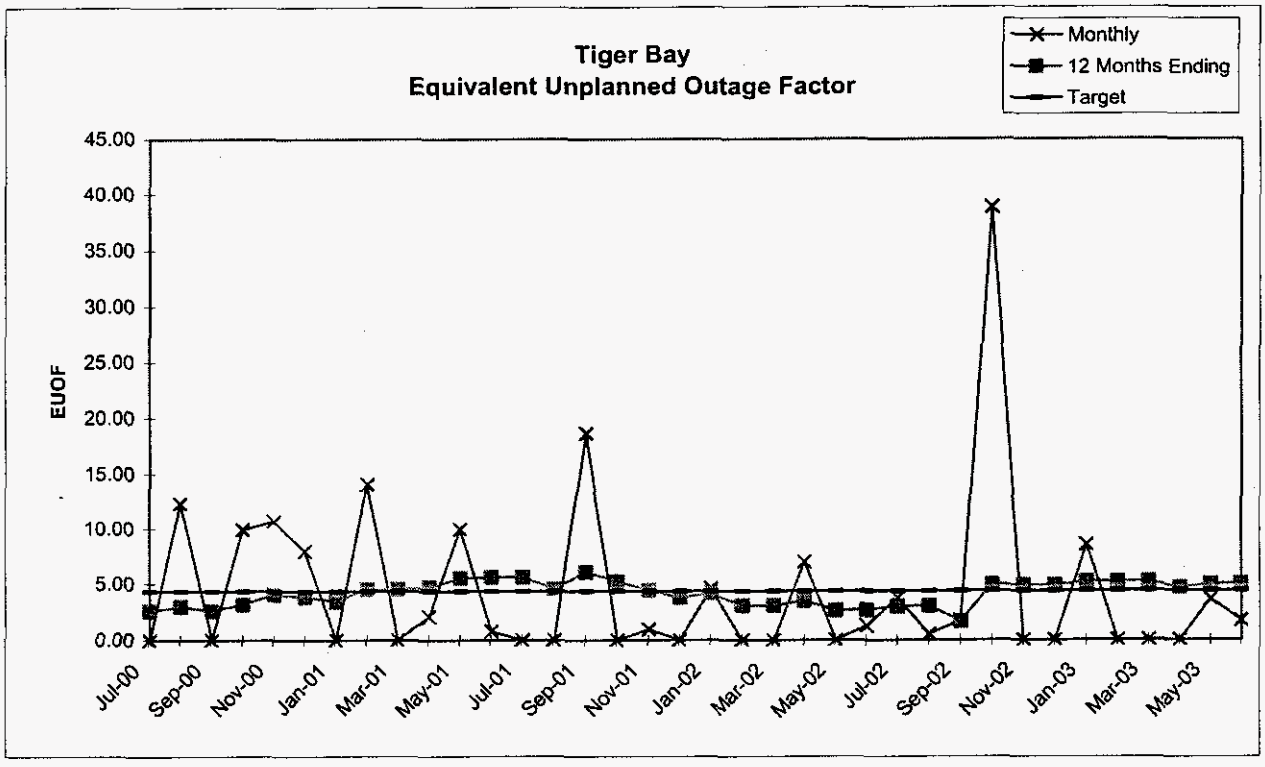

Tiger Bay
Equivalent Unplanned Outage Factor
Monthly
12 Months Ending
Target
EUOF
45.00
40.00
35.00
30.00
25.00
20.00
15.00
10.00
5.00
0.00
Jul-00
Sep-00
Nov-00
Jan-01
Mar-01
May-01
Jul-01
Sep-01
Nov-01
Jan-02
Mar-02
May-02
Jul-02
Sep-02
Nov-02
Jan-03
Mar-03
May-03

EXHIBIT NO. 8
DOCKET NO. 030001-EI
TAMPA ELECTRIC COMPANY
(WAS-1)

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2002 - DECEMBER 2002

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. Comp Ex. 8
COMPANY/ WITNESS: TECO WAS-1 + WAS-2
DATE: 11-12-03

DOCUMENT NUMBER-DATE
03072 APR-18
FPSC-COMMISSION CLERK

EXHIBIT NO. _____
DOCKET NO. 030001-EI
TAMPA ELECTRIC COMPANY
(WAS-1)

GENERATING PERFORMANCE INCENTIVE FACTOR

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1	GPIF Schedules	11
2	Actual Unit Performance Data	44

EXHIBIT NO. _____
DOCKET NO. 030001-EI
TAMPA ELECTRIC COMPANY
(WAS-1)
DOCUMENT NO. 1

EXHIBITS TO THE TESTIMONY OF

WILLIAM A. SMOTHERMAN

DOCKET NO. 030001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2002 - DECEMBER 2002

TRUE-UP

DOCUMENT NO. 1

GPIF SCHEDULES

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2002 - DECEMBER 2002
TRUE-UP
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ACTUAL
JANUARY 2002 - DECEMBER 2002

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	27,494.5	5,691.7
+9	24,745.1	5,122.6
+8	21,995.6	4,553.4
+7	19,246.2	3,984.2
+6	16,496.7	3,415.0
+5	13,747.3	2,845.9
+4	10,997.8	2,276.7
+3	8,248.4	1,707.5
+2	5,498.9	1,138.3
+1	2,749.5	569.2
0	0.0	0.0
-1	(3,951.9)	(569.2)
-2	(7,903.7)	(1,138.3)
-3	(11,855.6)	(1,707.5)
-4	(15,807.4)	(2,276.7)
-5	(19,759.3)	(2,845.9)
-6	(23,711.1)	(3,415.0)
-7	(27,663.0)	(3,984.2)
-8	(31,614.8)	(4,553.4)
-9	(35,566.7)	(5,122.6)
-10	(39,518.5)	(5,691.7)

GPI POINTS -4.385 → REWARD DOLLARS ($2,496,021)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS - ACTUAL
JANUARY 2002 - DECEMBER 2002

Line 1	Beginning of period balance of common equity: End of month common equity:		$ 1,417,501,000
Line 2	Month of January	2002	$ 1,407,610,000
Line 3	Month of February	2002	$ 1,421,392,000
Line 4	Month of March	2002	$ 1,435,310,000
Line 5	Month of April	2002	$ 1,431,555,000
Line 6	Month of May	2002	$ 1,445,572,000
Line 7	Month of June	2002	$ 1,459,727,000
Line 8	Month of July	2002	$ 1,449,603,000
Line 9	Month of August	2002	$ 1,463,797,000
Line 10	Month of September	2002	$ 1,478,130,000
Line 11	Month of October	2002	$ 1,474,200,000
Line 12	Month of November	2002	$ 1,488,635,000
Line 13	Month of December	2002	$ 1,503,211,000
Line 14	(Summation of line 1 through line 13 divided by 13)		$ 1,452,018,692
Line 15	25 Basis points		0.0025
Line 16	Revenue Expansion Factor		61.38%
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$ 5,913,978
Line 18	Jurisdictional Sales		17,751,526 MWH
Line 19	Total Sales		18,444,683 MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)		96.24%
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$ 5,691,728**

TAMPA ELECTRIC COMPANY
CALCULATION OF SYSTEM GPIF POINTS - ACTUAL
JANUARY 2002 - DECEMBER 2002

PLANT / UNIT	12 MONTH ADJ. ACTUAL PERFORMANCE		WEIGHTING FACTOR	UNIT POINTS	WEIGHTED UNIT POINTS
BIG BEND 1	71.1%	EAF	5.32%	-7.750	-0.412
BIG BEND 2	52.4%	EAF	6.17%	-10.000	-0.617
BIG BEND 3	53.8%	EAF	5.82%	-10.000	-0.582
BIG BEND 4	84.3%	EAF	3.03%	6.538	0.198
GANNON 5	65.2%	EAF	6.19%	10.000	0.619
GANNON 6	61.6%	EAF	10.46%	-2.556	-0.267
POLK 1	84.6%	EAF	4.98%	10.000	0.498
BIG BEND 1	10,519	ANOHR	11.35%	-5.957	-0.676
BIG BEND 2	10,398	ANOHR	6.97%	-10.000	-0.697
BIG BEND 3	10,275	ANOHR	9.96%	-2.966	-0.295
BIG BEND 4	10,488	ANOHR	7.48%	-10.000	-0.748
GANNON 5	11,202	ANOHR	4.28%	-6.661	-0.285
GANNON 6	11,192	ANOHR	6.87%	-7.792	-0.536
POLK 1	10,565	ANOHR	11.12%	-5.268	-0.586
			100.00%		-4.385

GPIF REWARD	**$**	**(2,496,021)**

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)	EAF ADJUSTED ACTUAL (%)	ACTUAL FUEL SAVINGS/ LOSS ($000)
BIG BEND 1	5.32	77.3	81.2	69.3	1,461.7	(3,173.6)	71.1	(2,459.5)
BIG BEND 2	6.17	66.7	70.4	59.1	1,697.2	(3,261.5)	52.4	(3,261.5)
BIG BEND 3	5.82	67.5	71.7	59.1	1,600.4	(3,650.6)	53.8	(3,650.6)
BIG BEND 4	3.03	82.6	85.2	77.4	833.3	(1,684.1)	84.3	1,101.1
GANNON 5	6.19	56.7	63.1	44.0	1,702.3	(3,830.7)	65.2	3,830.7
GANNON 6	10.46	63.9	68.4	54.9	2,875.0	(6,015.5)	61.6	(1,537.3)
POLK 1	4.98	78.0	81.3	71.5	1,370.4	(1,948.3)	84.6	1,948.3
GPIF SYSTEM	**41.97**				**11,540.3**	**(23,564.3)**		

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR (Btu/kwh)	TARGET NOF (%)	ANOHR TARGET RANGE MIN.	ANOHR TARGET RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)	ACTUAL ADJUSTED ANOHR	ACTUAL *FUEL* SAVINGS/ LOSS ($000)
BIG BEND 1	11.35	10,111	91.9	9,477	10,745	3,120.1	(3,120.1)	10,519.0	(1,858.7)
BIG BEND 2	*6.97*	*9,815*	*95.4*	*9,400*	*10,230*	1,916.1	(1,916.1)	10,398.0	(1,916.1)
BIG BEND 3	9.96	10,036	78.3	9,408	10,664	2,737.5	(2,737.5)	10,275.0	(811.8)
BIG BEND 4	*7.48*	*10,089*	82.7	*9,710*	*10,468*	2,055.3	(2,055.3)	10,488.0	(2,055.3)
GANNON 5	4.28	10,716	71.5	10,024	11,408	1,177.3	(1,177.3)	11,202.0	(784.2)
GANNON 6	6.87	10,704	78.4	*10,099*	*11,309*	1,889.6	(1,889.6)	11,192.0	(1,472.5)
POLK 1	11.12	10,087	98.2	9,247	10,927	3,058.3	(3,058.3)	10,565.0	(1,611.1)
GPIF SYSTEM	**58.03**					***15,954.2***	***(15,954.2)***		

TAMPA ELECTRIC COMPANY
UNIT PERFORMANCE DATA - ACTUAL
JANUARY 2002 - DECEMBER 2002

PLANT / UNIT	ACTUAL EAF (%)	ADJUSTMENTS (1) TO EAF (%)	EAF ADJUSTED ACTUAL (%)
BIG BEND 1	70.7	0.4	71.1
BIG BEND 2	49.6	2.8	52.4
BIG BEND 3	53.2	0.6	53.8
BIG BEND 4	84.0	0.3	84.3
GANNON 5	61.0	4.2	65.2
GANNON 6	59.8	1.8	61.6
POLK 1	89.5	-4.9	84.6

PLANT / UNIT	ACTUAL ANOHR (Btu/kwh)	ADJUSTMENTS (2) TO ANOHR (Btu/kwh)	ANOHR ADJUSTED ACTUAL (Btu/kwh)
BIG BEND 1	10,740	-221	10,519
BIG BEND 2	10,656	-258	10,398
BIG BEND 3	10,619	-344	10,275
BIG BEND 4	10,562	-74	10,488
GANNON 5	11,192	10	11,202
GANNON 6	11,040	152	11,192
POLK 1	10,725	-160	10,565

(1) Documentation of adjustments to Actual EAF on pages 7 - 13

(2) Documentation of adjustments to Actual ANOHR on pages 14 - 20

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 1
JANUARY 2002 - DECEMBER 2002

WEIGHTING FACTOR = 5.32%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	77.3	70.7	71.1
POH	336.0	372.6	336.0
FOH + EFOH	733.0	1,387.6	1,393.7
MOH + EMOH	927.0	797.9	801.4
POF	3.8	4.3	3.8
EFOF	8.4	15.8	15.9
EMOF	10.6	9.1	9.1
	-7.750	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 336}{8760 - 372.6} \times (1387.6 + 797.9) = 2,195.0$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 3.8 - \frac{2195.0}{8760.0} \times 100 = 71.1$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 2
JANUARY 2002 - DECEMBER 2002

WEIGHTING FACTOR = 6.17%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	66.7	49.6	52.4
POH	1,681.0	2,038.5	1,681.0
FOH + EFOH	623.0	1,693.0	1,783.0
MOH + EMOH	616.0	669.7	705.3
POF	19.2	23.3	19.2
EFOF	7.1	19.3	20.4
EMOF	7.0	7.6	8.1
	-10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 1681}{8760 - 2038.5} \times (1693 + 669.7 = 2{,}488.4$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 19.2 - \frac{2488.4}{8760.0} \times 100 = 52.4$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 3
JANUARY 2002 - DECEMBER 2002

WEIGHTING FACTOR = 5.82%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	67.5	53.2	53.8
POH	1,344.0	1,420.6	1,344.0
FOH + EFOH	601.0	2,276.3	2,300.1
MOH + EMOH	905.0	403.8	408.0
POF	15.3	16.2	15.3
EFOF	6.9	26.0	26.3
EMOF	10.3	4.6	4.7
	-10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 1344}{8760 - 1420.6} \times (2276.3 + 403.8) = 2{,}708.1$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 15.3 - \frac{2708.1}{8760.0} \times 100 = 53.8$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
BIG BEND UNIT NO. 4
JANUARY 2002 - DECEMBER 2002

WEIGHTING FACTOR = 3.03%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	82.6	84.0	84.3
POH	504.0	537.8	504.0
FOH + EFOH	504.0	641.8	644.4
MOH + EMOH	512.0	224.0	224.9
POF	5.8	6.1	5.8
EFOF	5.8	7.3	7.4
EMOF	5.8	2.6	2.6
	6.538	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 504}{8760 - 537.8} \times (641.8 + 224) = 869.4$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 5.8 - \frac{869.4}{8760.0} \times 100 = 84.3$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
GANNON UNIT NO. 5
JANUARY 2002 - DECEMBER 2002

WEIGHTING FACTOR = 6.19%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	56.7	61.0	65.2
POH	1,344.0	1,824.2	1,344.0
FOH + EFOH	1,854.0	1,454.8	1,555.5
MOH + EMOH	593.0	140.5	150.2
POF	15.3	20.8	15.3
EFOF	21.2	16.6	17.8
EMOF	6.8	1.6	1.7
	10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 1344}{8760 - 1824.2} \times (1454.8 + 140.5 = 1{,}705.8$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 15.3 - \frac{1705.8}{8760.0} \times 100 = 65.2$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
GANNON UNIT NO. 6
JANUARY 2002 - DECEMBER 2002

WEIGHTING FACTOR = 10.46%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	63.9	59.8	61.6
POH	1,584.0	1,803.5	1,584.0
FOH + EFOH	1,076.0	1,227.9	1,266.6
MOH + EMOH	502.0	493.5	509.1
POF	18.1	20.6	18.1
EFOF	12.3	14.0	14.5
EMOF	5.7	5.6	5.8
	-2.556	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 1584}{8760 - 1803.5} \times (1227.9 + 493.5) = 1,775.7$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 18.1 - \frac{1775.7}{8760.0} \times 100 = 61.6$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO PERFORMANCE
POLK UNIT NO. 1
JANUARY 2002 - DECEMBER 2002

WEIGHTING FACTOR = 4.98%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE	ADJUSTED ACTUAL PERFORMANCE
PH	8,760.0	8,760.0	8,760.0
EAF	78.0	89.5	84.6
POH	672.0	199.1	672.0
FOH + EFOH	971.0	485.4	458.6
MOH + EMOH	283.0	232.4	219.6
POF	7.7	2.3	7.7
EFOF	11.1	5.5	5.2
EMOF	3.2	2.7	2.5
	10.000	**EQUIVALENT AVAILABILITY POINTS**	

ADJUSTMENTS TO ACTUAL EAF FOR COMPARISON

$$\frac{PH - POH_{TARGET}}{PH - POH_{ACTUAL}} \times (FOH + EFOH + MOH + EMOH) = EUOH_{ADJUSTED}$$

$$\frac{8760 - 672}{8760 - 199.1} \times (485.4 + 232.4) = 678.1$$

$$100 - POF_{TARGET} - \frac{EUOH_{ADJUSTED}}{PH} \times 100 = EAF_{ADJUSTED}$$

$$100 - 7.7 - \frac{678.1}{8760.0} \times 100 = 84.6$$

PH = PERIOD HOURS
EAF = EQUIVALENT AVAILABILITY FACTOR
POH = PLANNED OUTAGE HOURS
FOH = FORCED OUTAGE HOURS
EFOH = EQUIVALENT FORCED OUTAGE HOURS
MOH = MAINTENANCE OUTAGE HOURS
EMOH = EQUIVALENT MAINTENANCE OUTAGE HOURS
POF = PLANNED OUTAGE FACTOR
EFOF = EQUIVALENT FORCED OUTAGE FACTOR
EMOF = EQUIVALENT MAINTENANCE OUTAGE FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 1
JANUARY 2002 - DECEMBER 2002

WEIGHTING FACTOR = 11.35%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,111	10,740
NET GENERATION (GWH)	2,567.8	2,265.6
OPERATING BTU (10^9)	25,962.9	24,331.8
NET OUTPUT FACTOR	91.9	74.0

-5.957 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-12.328) + 11244 = ANOHR

		74 * (-12.328) + 11244	=	10,332	
10,740	-	10,332	=	408	
10,111	+	408	=	10,519	← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 2
JANUARY 2002 - DECEMBER 2002

WEIGHTING FACTOR = 6.97%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	9,815	10,656
NET GENERATION (GWH)	2,382.6	1,674.5
OPERATING BTU (10^9)	23,385.4	17,843.8
NET OUTPUT FACTOR	95.4	74.7

-10.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-12.51) + 11008 = ANOHR

	74.7 * (-12.51) + 11008	=	10,074		
10,656	-	10,074	=	583	
9,815	+	583	=	10,398	← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 3
JANUARY 2002 - DECEMBER 2002

WEIGHTING FACTOR = 9.96%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,036	10,619
NET GENERATION (GWH)	2,164.9	1,776.9
OPERATING BTU (10^9)	21,725.9	18,868.7
NET OUTPUT FACTOR	78.3	72.3

-2.966 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-57.476) + 14536 = ANOHR

	72.3 * (-57.476) + 14536	=	10,380		
10,619	-	10,380	=	239	
10,036	+	239	=	10,275	← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
BIG BEND UNIT NO. 4
JANUARY 2002 - DECEMBER 2002

WEIGHTING FACTOR = 7.48%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,089	10,562
NET GENERATION (GWH)	2,678.3	2,846.7
OPERATING BTU (10^9)	27,020.9	30,067.1
NET OUTPUT FACTOR	82.7	80.5

-10.000 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-33.833) + 12887 = ANOHR

	80.5 * (-33.833) + 12887	=	10,163		
10,562	-	10,163	=	399	
10,089	+	399	=	10,488	← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
GANNON UNIT NO. 5
JANUARY 2002 - DECEMBER 2002

WEIGHTING FACTOR = 4.28%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,716	11,192
NET GENERATION (GWH)	834.0	908.3
OPERATING BTU (10^9)	8,937.1	10,165.2
NET OUTPUT FACTOR	71.5	73.7

-6.661 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-4.3274) + 11025 = ANOHR

73.7 * (-4.3274) + 11025 = 10,706

11,192 - 10,706 = 486

10,716 + 486 = 11,202 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
GANNON UNIT NO. 6
JANUARY 2002 - DECEMBER 2002

WEIGHTING FACTOR = 6.87%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,704	11,040
NET GENERATION (GWH)	1,633.4	1,612.3
OPERATING BTU (10^9)	17,484.1	17,799.2
NET OUTPUT FACTOR	78.4	72.5

-7.792 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(25.825) + 8679.5 = ANOHR

72.5 * (25.825) + 8679.5 = 10,552

11,040 - 10,552 = 488

10,704 + 488 = 11,192 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
ADJUSTMENTS TO HEAT RATE
POLK UNIT NO. 1
JANUARY 2002 - DECEMBER 2002

WEIGHTING FACTOR = 11.12%

	12 MONTH TARGET	12 MONTH ACTUAL PERFORMANCE
ANOHR (Btu/kwh)	10,087	10,725
NET GENERATION (GWH)	1,632.9	1,712.4
OPERATING BTU (10^9)	16,470.9	18,366.2
NET OUTPUT FACTOR	98.2	87.4

-5.268 **HEAT RATE POINTS**

ADJUSTMENTS TO ACTUAL HEAT RATE FOR COMPARISON

CURRENT EQUATION: NOF*(-14.839) + 11544 = ANOHR

87.4 * (-14.839) + 11544 = 10,247

10,725 - 10,247 = 478

10,087 + 478 = 10,565 ← ADJUSTED ACTUAL HEAT RATE AT TARGET NOF

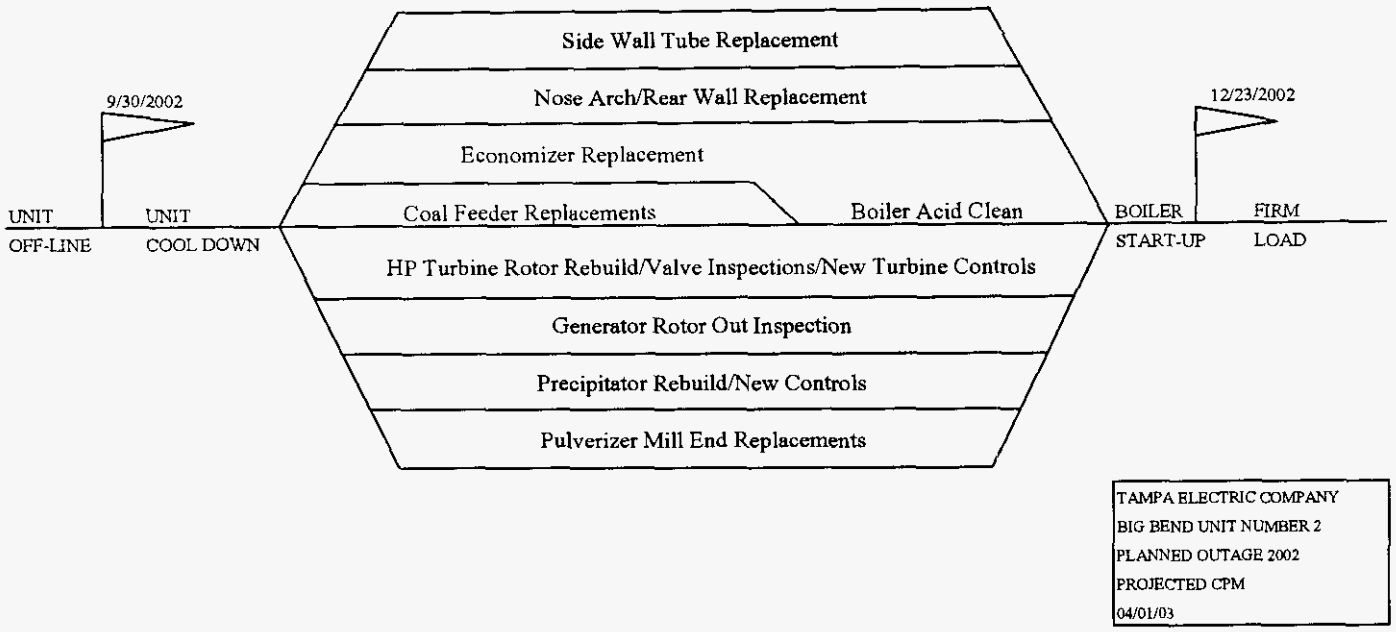
ANOHR = AVERAGE NET OPERATING HEAT RATE
NOF = NET OPERATING FACTOR

TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ACTUAL)
GPIF UNITS
JANUARY 2002 - DECEMBER 2002

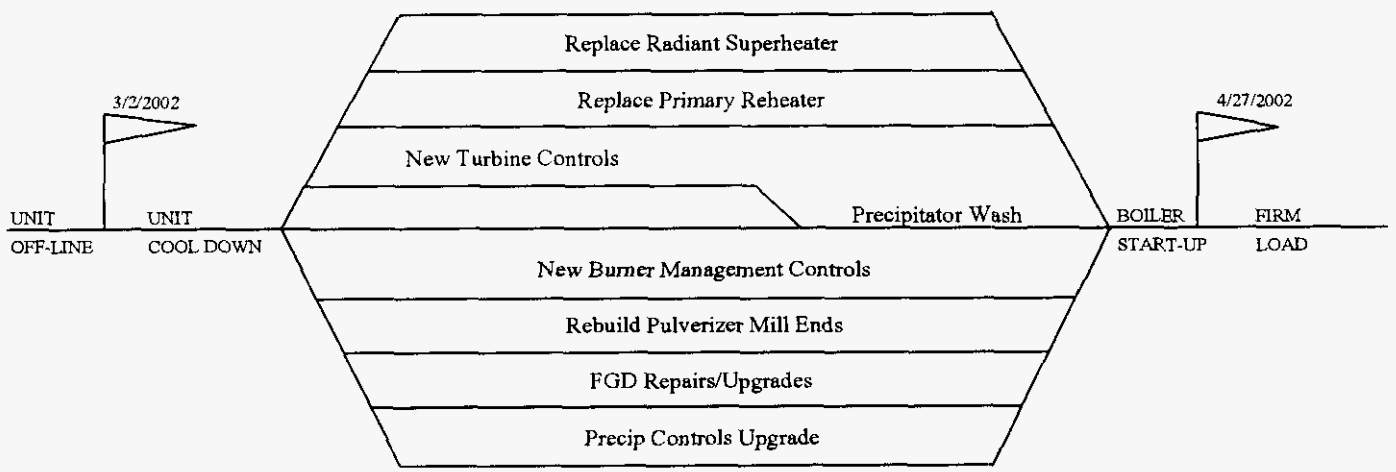
	PLANT / UNIT	PLANNED OUTAGE DATES			OUTAGE DESCRIPTION
+	BIG BEND 1	Feb 16	-	Mar 03	Fuel System Clean-up
	BIG BEND 2	Sep 30	-	Dec 23	Side Wall Tube Replacement, Nose Arch/Rear Wall Replacement, Economizer Replacement, Coal Feeder Replacements, Pulverizer Mill End Replacements, Precipitator Rebuild/New Controls, HP Turbine Rotor Rebuild/Valve Inspections/New Turbine Controls, Generator Rotor Out Inspection, Boiler Acid Clean
	BIG BEND 3	Mar 02		Apr 27	Replace Radiant Superheater, Replace Primary Reheater, Precipitator Wash, Rebuild Pulverizer Mill Ends, FGD Repairs/Upgrades, New Burner Management Controls, New Turbine Controls, Precip Controls Upgrade
+	BIG BEND 4	May 02	-	Jun 02	Fuel System Clean-up
	GANNON 5	Feb 13	-	Apr 30	Replace Tubes in Condenser, Replace Wall Tubes, Rewind Generator, Turbine Controls Upgrade, Excitation Sys Upgrade, Feedwtr Bypass 1-2 & 3-4 Instl, Turb Lp Blade Insp , Boiler Insp
	GANNON 6	Oct 06	-	Dec 09	Boiler Build Up Removal, Condenser Upgrade, Turbine Controls Upgrade, Precipitator Insp, Slag Tank Duct Work Repair, Turb Lp Blade Insp & Repl, Hot Air Duct Expansion Joint Replacement , Gland Steam Condenser Repl
+	POLK 1	May 18	-	May 26	Fuel System Clean-up

+ CPM for units with less than or equal to 4 weeks are not included.

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2002 - DECEMBER 2002

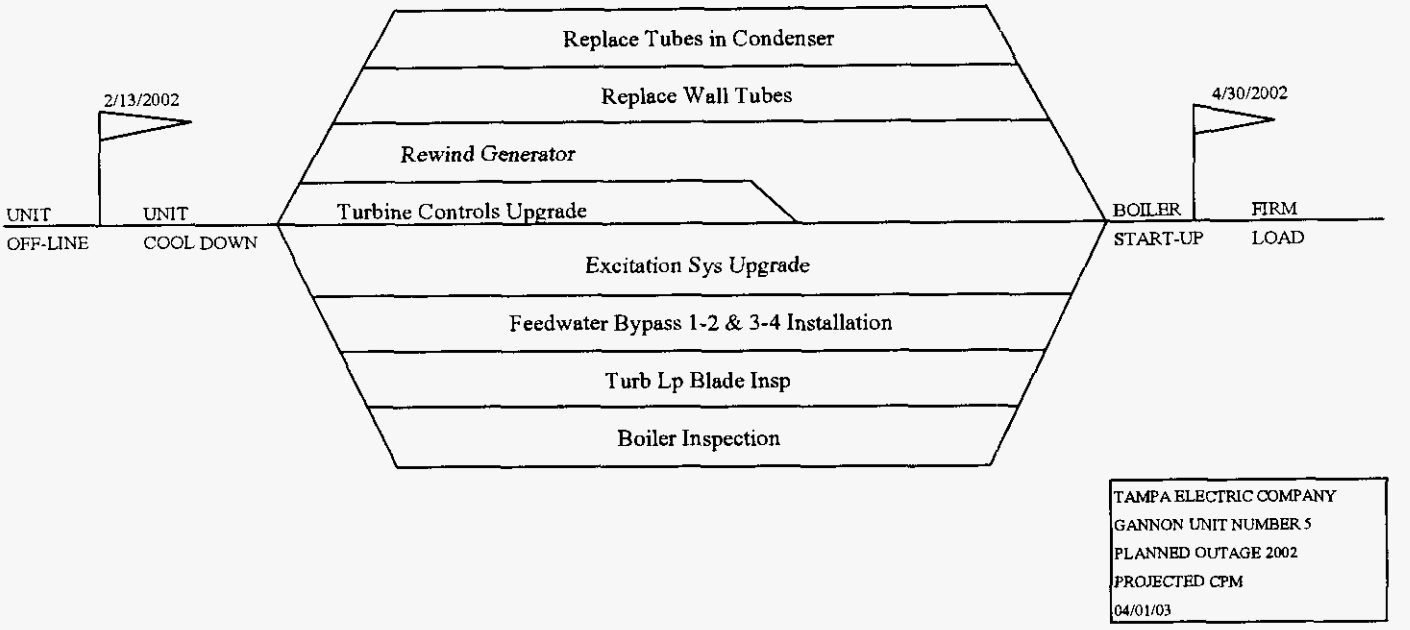


TAMPA ELECTRIC COMPANY
BIG BEND UNIT NUMBER 2
PLANNED OUTAGE 2002
PROJECTED CPM
04/01/03

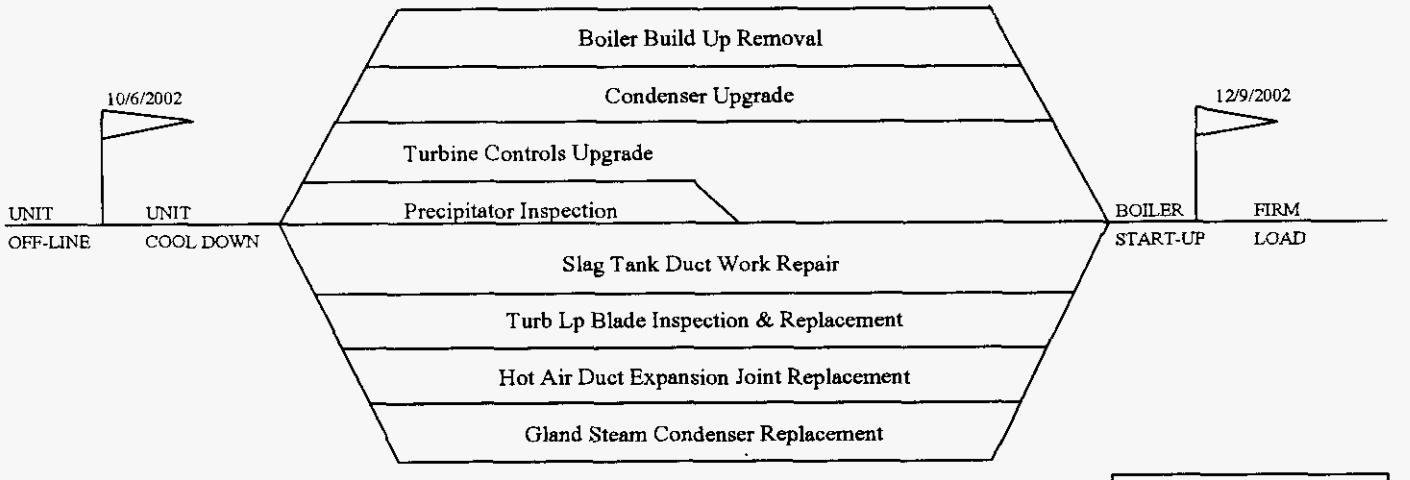


TAMPA ELECTRIC COMPANY
BIG BEND UNIT NUMBER 3
PLANNED OUTAGE 2002
PROJECTED CPM
04/01/03

TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2002 - DECEMBER 2002



TAMPA ELECTRIC COMPANY
GANNON UNIT NUMBER 5
PLANNED OUTAGE 2002
PROJECTED CPM
04/01/03



TAMPA ELECTRIC COMPANY
GANNON UNIT NUMBER 6
PLANNED OUTAGE 2002
PROJECTED CPM
04/01/03

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2002 - DECEMBER 2002

BIG BEND 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,461.7	81.2	+10	3,120.1	9,477
+9	1,315.5	80.8	+9	2,808.1	9,533
+8	1,169.4	80.4	+8	2,496.1	9,589
+7	1,023.2	80.0	+7	2,184.1	9,645
+6	877.0	79.6	+6	1,872.1	9,701
+5	730.9	79.3	+5	1,560.1	9,757
+4	584.7	78.9	+4	1,248.0	9,812
+3	438.5	78.5	+3	936.0	9,868
+2	292.3	78.1	+2	624.0	9,924
+1	146.2	77.7	+1	312.0	9,980
					10,036
0	0.0	77.3	0	0.0	10,111
					10,186
-1	(317.4)	76.5	-1	(312.0)	10,242
-2	(634.7)	75.7	-2	(624.0)	10,298
-3	(952.1)	74.9	-3	(936.0)	10,354
-4	(1,269.4)	74.1	-4	(1,248.0)	10,410
-5	(1,586.8)	73.3	-5	(1,560.1)	10,466
-6	(1,904.2)	72.5	-6	(1,872.1)	10,521
-7	(2,221.5)	71.7	-7	(2,184.1)	10,577
-8	(2,538.9)	70.9	-8	(2,496.1)	10,633
-9	(2,856.2)	70.1	-9	(2,808.1)	10,689
-10	(3,173.6)	69.3	-10	(3,120.1)	10,745

EAF POINTS 7.750 → Adjusted EAF 71.1

AHR POINTS 5.957 → Adjusted ANOHR 10,519

Weighting Factor = 5.32%

Weighting Factor = 11.35%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2002 - DECEMBER 2002

BIG BEND 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,697.2	70.4	+10	1,916.1	9,400
+9	1,527.5	70.0	+9	1,724.5	9,434
+8	1,357.8	69.7	+8	1,532.9	9,468
+7	1,188.0	69.3	+7	1,341.3	9,502
+6	1,018.3	68.9	+6	1,149.7	9,536
+5	848.6	68.6	+5	958.1	9,570
+4	678.9	68.2	+4	766.4	9,604
+3	509.2	67.8	+3	574.8	9,638
+2	339.4	67.4	+2	383.2	9,672
+1	169.7	67.1	+1	191.6	9,706
					9,740
0	0.0	66.7	0	0.0	9,815
					9,890
-1	(326.2)	65.9	-1	(191.6)	9,924
-2	(652.3)	65.2	-2	(383.2)	9,958
-3	(978.5)	64.4	-3	(574.8)	9,992
-4	(1,304.6)	63.7	-4	(766.4)	10,026
-5	(1,630.8)	62.9	-5	(958.1)	10,060
-6	(1,956.9)	62.1	-6	(1,149.7)	10,094
-7	(2,283.1)	61.4	-7	(1,341.3)	10,128
-8	(2,609.2)	60.6	-8	(1,532.9)	10,162
-9	(2,935.4)	59.9	-9	(1,724.5)	10,196
-10	(3,261.5)	59.1	-10	(1,916.1)	10,230

EAF POINTS -10.000 → Adjusted EAF 52.4 → AHR POINTS -10.000 → Adjusted ANOHR 10,398

Weighting Factor = 6.17%

Weighting Factor = 6.97%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2002 - DECEMBER 2002

BIG BEND 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	1,600.4	71.7	+10	2,737.5	9,408
+9	1,440.4	71.3	+9	2,463.8	9,463
+8	1,280.3	70.9	+8	2,190.0	9,519
+7	1,120.3	70.4	+7	1,916.3	9,574
+6	960.2	70.0	+6	1,642.5	9,629
+5	800.2	69.6	+5	1,368.8	9,685
+4	640.2	69.2	+4	1,095.0	9,740
+3	480.1	68.8	+3	821.3	9,795
+2	320.1	68.3	+2	547.5	9,850
+1	160.0	67.9	+1	273.8	9,906
					9,961
0	0.0	67.5	0	0.0	10,036
					10,111
-1	(365.1)	66.7	-1	(273.8)	10,166
-2	(730.1)	65.8	-2	(547.5)	10,222
-3	(1,095.2)	65.0	-3	(821.3)	10,277
-4	(1,460.2)	64.1	-4	(1,095.0)	10,332
-5	(1,825.3)	63.3	-5	(1,368.8)	10,388
-6	(2,190.4)	62.5	-6	(1,642.5)	10,443
-7	(2,555.4)	61.6	-7	(1,916.3)	10,498
-8	(2,920.5)	60.8	-8	(2,190.0)	10,553
-9	(3,285.5)	59.9	-9	(2,463.8)	10,609
-10	(3,650.6)	59.1	-10	(2,737.5)	10,664

EAF POINTS 10.000 →

Adjusted EAF 53.8 →

AHR POINTS 2.960 →

Adjusted ANOHR 10.275 →

Weighting Factor = 5.82%

Weighting Factor = 9.96%

TAMPA ELECTRIC COMPANY

***GENERATING* PERFORMANCE INCENTIVE POINTS TABLE**

JANUARY 2002 - DECEMBER 2002

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	833.3	85.2	+10	2,055.3	9,710
+9	750.0	84.9	+9	1,849.8	9,740
+8	666.6	84.7	+8	1,644.2	9,771
+7	583.3	84.4	+7	1,438.7	9,801
+6	500.0	84.2	+6	1,233.2	9,832
+5	416.7	83.9	+5	1,027.7	9,862
+4	333.3	83.6	+4	822.1	9,892
+3	250.0	83.4	+3	616.6	9,923
+2	166.7	83.1	+2	411.1	9,953
+1	83.3	82.9	+1	205.5	9,984
					10,014
0	0.0	82.6	0	0.0	10,089
					10,164
-1	(168.4)	82.1	-1	(205.5)	10,194
-2	(336.8)	81.6	-2	(411.1)	10,225
-3	(505.2)	81.0	-3	(616.6)	10,255
-4	(673.6)	80.5	-4	(822.1)	10,286
-5	(842.1)	80.0	-5	(1,027.7)	10,316
-6	(1,010.5)	79.5	-6	(1,233.2)	10,346
-7	(1,178.9)	79.0	-7	(1,438.7)	10,377
-8	(1,347.3)	78.4	-8	(1,644.2)	10,407
-9	(1,515.7)	77.9	-9	(1,849.8)	10,438
-10	(1,684.1)	77.4	-10	(2,055.3)	10,468

EAF POINTS 6.538 → Adjusted EAF 84.3 →

AHR POINTS 10.000 → Adjusted ANOHR 10,488 →

Weighting Factor = 3.03%

Weighting Factor = 7.48%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2002 - DECEMBER 2002

GANNON 5

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
EAF POINTS 10.000 → +10	1,702.3	Adjusted EAF 65.2 → 63.1	+10	1,177.3	10,024
+9	1,532.1	62.5	+9	1,059.6	10,086
+8	1,361.8	61.8	+8	941.8	10,147
+7	1,191.6	61.2	+7	824.1	10,209
+6	1,021.4	60.5	+6	706.4	10,271
+5	851.2	59.9	+5	588.7	10,333
+4	680.9	59.3	+4	470.9	10,394
+3	510.7	58.6	+3	353.2	10,456
+2	340.5	58.0	+2	235.5	10,518
+1	170.2	57.3	+1	117.7	10,579
					10,641
0	0.0	56.7	0	0.0	10,716
					10,791
-1	(383.1)	55.4	-1	(117.7)	10,853
-2	(766.1)	54.2	-2	(235.5)	10,914
-3	(1,149.2)	52.9	-3	(353.2)	10,976
-4	(1,532.3)	51.6	-4	(470.9)	11,038
-5	(1,915.4)	50.4	-5	(588.7)	11,100
-6	(2,298.4)	49.1 AHR POINTS -6.661 →	-6	(706.4) Adjusted ANOHR 11,202 →	11,161
-7	(2,681.5)	47.8	-7	(824.1)	11,223
-8	(3,064.6)	46.5	-8	(941.8)	11,285
-9	(3,447.6)	45.3	-9	(1,059.6)	11,346
-10	(3,830.7)	44.0	-10	(1,177.3)	11,408

Weighting Factor = 6.19%

Weighting Factor = 4.28%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2002 - DECEMBER 2002

GANNON 6

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	2,875.0	68.4	+10	1,889.6	10,099
+9	2,587.5	68.0	+9	1,700.6	10,152
+8	2,300.0	67.5	+8	1,511.7	10,205
+7	2,012.5	67.1	+7	1,322.7	10,258
+6	1,725.0	66.6	+6	1,133.8	10,311
+5	1,437.5	66.2	+5	944.8	10,364
+4	1,150.0	65.7	+4	755.8	10,417
+3	862.5	65.3	+3	566.9	10,470
+2	575.0	64.8	+2	377.9	10,523
+1	287.5	64.4	+1	189.0	10,576
					10,629
0	0.0	63.9	0	0.0	10,704
					10,779
-1	(601.6)	63.0	-1	(189.0)	10,832
-2	(1,203.1)	62.1	-2	(377.9)	10,885
-3	(1,804.7)	61.2	-3	(566.9)	10,938
-4	(2,406.2)	60.3	-4	(755.8)	10,991
-5	(3,007.8)	59.4	-5	(944.8)	11,044
-6	(3,609.3)	58.5	-6	(1,133.8)	11,097
-7	(4,210.9)	57.6	-7	(1,322.7)	11,150
-8	(4,812.4)	56.7	-8	(1,511.7)	11,203
-9	(5,414.0)	55.8	-9	(1,700.6)	11,256
-10	(6,015.5)	54.9	-10	(1,889.6)	11,309

EAF POINTS 2.556 → Adjusted EAF 61.6 →

AHR POINTS .7792 → Adjusted ANOHR 11,192 →

Weighting Factor = 10.46%

Weighting Factor = 6.87%

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

JANUARY 2002 - DECEMBER 2002

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
EAF POINTS 10.000 → +10	1,370.4	Adjusted EAF 84.6 → 81.3	+10	3,058.3	9,247
+9	1,233.4	81.0	+9	2,752.5	9,324
+8	1,096.3	80.6	+8	2,446.6	9,400
+7	959.3	80.3	+7	2,140.8	9,477
+6	822.2	80.0	+6	1,835.0	9,553
+5	685.2	79.7	+5	1,529.2	9,630
+4	548.2	79.3	+4	1,223.3	9,706
+3	411.1	79.0	+3	917.5	9,783
+2	274.1	78.7	+2	611.7	9,859
+1	137.0	78.3	+1	305.8	9,936
					10,012
0	0.0	78.0	0	0.0	10,087
					10,162
-1	(194.8)	77.4	-1	(305.8)	10,239
-2	(389.7)	76.7	-2	(611.7)	10,315
-3	(584.5)	76.1	-3	(917.5)	10,392
-4	(779.3)	75.4	-4	(1,223.3)	10,468
-5	(974.2)	74.8 AHR POINTS 5.268 →	-5	(1,529.2) Adjusted ANOHR 10.568 →	10,545
-6	(1,169.0)	74.1	-6	(1,835.0)	10,621
-7	(1,363.8)	73.5	-7	(2,140.8)	10,698
-8	(1,558.6)	72.8	-8	(2,446.6)	10,774
-9	(1,753.5)	72.2	-9	(2,752.5)	10,851
-10	(1,948.3)	71.5	-10	(3,058.3)	10,927

Weighting Factor = 4.98%

Weighting Factor = 11.12%

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	TARGET TARGET WEIGHTING FACTOR	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 02 - DEC 02 POF	TARGET PERIOD JAN 02 - DEC 02 EUOF	TARGET PERIOD JAN 02 - DEC 02 EUOR	ACTUAL PERFORMANCE JAN 02 - DEC 02 POF	ACTUAL PERFORMANCE JAN 02 - DEC 02 EUOF	ACTUAL PERFORMANCE JAN 02 - DEC 02 EUOR
BIG BEND 1	5.32%	12.7%	3.8	16.8	17.5	4.3	24.9	26.1
BIG BEND 2	6.17%	14.7%	19.2	9.9	12.3	23.3	27.0	35.2
BIG BEND 3	5.82%	13.9%	15.3	29.6	35.0	16.2	30.6	36.5
BIG BEND 4	3.03%	7.2%	5.8	29.2	31.0	6.1	9.9	10.5
GANNON 5	6.19%	14.8%	15.3	0.0	0.0	20.8	18.2	23.0
GANNON 6	10.46%	24.9%	18.1	0.0	0.0	20.6	19.7	24.7
POLK 1	4.98%	11.9%	7.7	27.7	30.0	2.3	8.2	8.4
GPIF SYSTEM	**41.97%**	**100.0%**	**13.5**	**13.1**	**14.7**	**15.1**	**20.6**	**24.8**

GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%) 73.4 64.2

3 PERIOD AVERAGE POF	3 PERIOD AVERAGE EUOF	3 PERIOD AVERAGE EUOR	3 PERIOD AVERAGE EAF
9.3	**21.8**	**24.3**	**68.9**

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	TARGET WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 02 - DEC 02	ADJUSTED ACTUAL HEAT RATE JAN 02 - DEC 02
BIG BEND 1	11.35%	19.6%	10,111	10,519
BIG BEND 2	6.97%	12.0%	9,815	10,398
BIG BEND 3	9.96%	17.2%	10,036	10,275
BIG BEND 4	7.48%	12.9%	10,089	10,488
GANNON 5	4.28%	7.4%	10,716	11,202
GANNON 6	6.87%	11.8%	10,704	11,192
POLK 1	11.12%	19.2%	10,087	10,565
GPIF SYSTEM	**58.03%**	**100.0%**		

GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh) 10,170 10,598

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE POINTS CALCULATION
JANUARY 2002 - DECEMBER 2002

Points are calculated according to the formula:

$$GPIP = \sum_{i=1}^{n} \left[a_i(EAP_i) + e_i(AHRP_i) \right]$$

Where:

$GPIP$ = Generating performance incentive points

a_i = Percentage of total system fuel cost reduction attributed to maximum reasonably attainable equivalent availability of unit i during the period

e_i = Percentage of total system fuel cost reduction attributed to minimum reasonably attainable average heat rate of unit i during the period

EAP_i = Equivalent availability points awarded/deducted for unit i

$AHRP_i$ = Average heat rate points awarded/deducted for unit i

Weighting factors and point values are listed on page 4.

GPIP =	5.32%	*	(BB 1 EAP)	+	6.17%	*	(BB 2 EAP)	+	5.82%	*	(BB 3 EAP)
+	3.03%	*	(BB 4 EAP)	+	6.19%	*	(GN 5 EAP)	+	10.46%	*	(GN 6 EAP)
+	4.98%	*	(PK 1 EAP)	+	11.35%	*	(BB 1 AHRP)	+	6.97%	*	(BB 2 AHRP)
+	9.96%	*	(BB 3 AHRP)	+	7.48%	*	(BB 4 AHRP)	+	4.28%	*	(GN 5 AHRP)
+	6.87%	*	(GN 6 AHRP)	+	11.12%	*	(PK 1 AHRP)				

GPIP =	5.32%	*	-7.750	+	6.17%	*	-10.000	+	5.82%	*	-10.000
+	3.03%	*	6.538	+	6.19%	*	10.000	+	10.46%	*	-2.556
+	4.98%	*	10.000	+	11.35%	*	-5.957	+	6.97%	*	-10.000
+	9.96%	*	-2.966	+	7.48%	*	-10.000	+	4.28%	*	-6.661
+	6.87%	*	-7.792	+	11.12%	*	-5.268				

GPIP =	-0.412 +	-0.617 +	-0.582
+	0.198 +	0.619 +	-0.267
+	0.498 +	-0.676 +	-0.697
+	-0.295 +	-0.748 +	-0.285
+	-0.536 +	-0.586	

GPIP = -4.385 POINTS

REWARD/PENALTY dollar amounts of the Generating Performance Incentive Factor (GPIF) are determined directly from the table for the corresponding Generating Performance Points (GPIP) on page 2.

GPIF REWARD = ($2,496,021)

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EXHIBITS TO THE TESTIMONY OF

WILLIAM A. SMOTHERMAN

DOCKET NO. 030001-EI

TAMPA ELECTRIC COMPANY

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2002 - DECEMBER 2002

TRUE-UP

DOCUMENT NO. 2

ACTUAL UNIT PERFORMANCE DATA

TAMPA ELECTRIC COMPANY
ACTUAL UNIT PERFORMANCE DATA
JANUARY 2002 - DECEMBER 2002
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ORIGINAL SHEET NO. 8.401.02A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2002 - DECEMBER 2002

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1	JAN 02	FEB 02	MAR 02	APR 02	MAY 02	JUN 02	JUL 02	AUG 02	SEP 02	OCT 02	NOV 02	DEC 02	2002
1. EAF (%)	71.8	46.7	78.0	76.7	69.1	63.8	80.9	58.4	84.3	69.2	64.7	82.1	70.7
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8,760.0
3. SH	577.0	359.6	634.9	647.5	603.3	561.7	674.8	512.6	720.0	628.2	552.8	744.0	7,216.4
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	167.0	312.5	109.1	71.5	140.7	158.3	69.3	231.4	0.0	116.8	167.2	0.0	1,543.6
6. POH	0.0	311.1	61.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	372.6
7. FOH	167.0	1.4	46.8	36.0	0.0	81.6	69.3	118.9	0.0	0.0	167.2	0.0	688.2
8. MOH	0.0	0.0	0.8	35.4	140.7	76.7	0.0	112.6	0.0	116.8	0.0	0.0	482.9
9. PFOH	349.7	226.0	455.1	471.0	496.8	129.5	622.8	434.5	655.8	578.3	516.7	732.9	5,669.2
10. LR PF (MW)	28.8	72.3	45.2	56.1	57.3	18.5	28.5	42.3	47.5	65.2	64.0	74.3	52.4
11. PMOH	44.3	15.9	13.5	59.8	41.0	172.4	51.3	57.8	63.5	38.4	13.7	10.8	582.4
12. LR PM (MW)	186.5	201.7	199.1	226.0	207.2	232.9	241.8	245.9	250.5	241.0	231.5	221.8	229.5
13. NSC (MW)	426	426	426	416	416	416	416	416	416	416	416	426	419
14. OPR BTU(GBTU)	1,927.5697	1,132.9977	2,253.3298	2,215.1259	1,992.5846	1,793.5948	2,365.3490	1,769.5521	2,550.3469	2,166.4589	1,850.9238	2,313.9816	24,331.8147
15. NET GEN (MWH)	179,770	105,397	210,314	195,388	185,181	164,010	218,014	156,729	225,793	189,295	172,711	223,156	2,225,758
16. ANOHR (BTU/KWH)	10,722	10,750	10,714	11,337	10,760	10,936	10,850	11,291	11,295	11,445	10,717	10,369	10,932
17. NOF (%)	73.1	68.8	77.8	72.5	73.8	70.2	77.7	73.5	75.4	72.4	75.1	70.4	73.6
18. NPC (MW)	426	426	426	416	416	416	416	416	416	416	416	426	419
19. ANOHR EQUATION	ANOHR = NOF(-12.328)+ 11.244												

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TAMPA ELECTRIC COMPANY

UNIT PERFORMANCE DATA w/o FGD

JANUARY 2002 - DECEMBER 2002

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1 w/o FGD	JAN 02	FEB 02	MAR 02	APR 02	MAY 02	JUN 02	JUL 02	AUG 02	SEP 02	OCT 02	NOV 02	DEC 02	2002
1. OPR BTU (GBTU)	1,927.6	1,133.0	2,253.3	2,215.1	1,992.6	1,793.6	2,365.3	1,769.6	2,550.3	2,166.5	1,850.9	2,314.0	24,331.8
2. NET GEN w/FGD (MWH)	179,770	105,397	210,314	195,388	185,181	164,010	218,014	156,729	225,793	189,295	172,711	223,156	2,225,758
3. FGD CONSUMED (MWH)	2,932.0	2,126.5	3,539.6	3,678.6	2,953.1	2,897.0	3,445.8	2,853.6	2,893.4	4,196.9	4,001.0	4,302.7	39,820.1
4. NET GEN w/o FGD (MWH)	182,702.4	107,523.3	213,853.6	199,066.4	188,134.0	166,906.5	221,460.1	159,582.8	228,686.6	193,491.7	176,712.4	227,458.5	2,265,578.4
5. ANOHR w/FGD (BTU/KWH)	10,722.4	10,749.8	10,714.1	11,337.1	10,760.2	10,935.9	10,849.5	11,290.5	11,295.1	11,444.9	10,716.9	10,369.4	10,932.0
6. ANOHR w/o FGD (BTU/KWH)	10,550.3	10,537.2	10,536.8	11,127.6	10,591.3	10,746.1	10,680.7	11,088.6	11,152.1	11,196.7	10,474.2	10,173.2	10,739.8
7. NOF w/FGD (%)	73.1	68.8	77.8	72.5	73.8	70.2	77.7	73.5	75.4	72.4	75.1	70.4	73.6
8. NOF w/o FGD (%)	73.5	69.4	78.1	73.0	74.1	70.6	78.0	74.0	75.4	73.2	75.9	70.9	74.0
9. NPC (MW) w/FGD	426	426	426	416	416	416	416	416	416	416	416	426	419
10. NPC (MW) w/o FGD	431	431	431	421	421	421	421	421	421	421	421	431	424

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ACTUAL UNIT PERFORMANCE DATA

JANUARY 2002 - DECEMBER 2002

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2	JAN 02	FEB 02	MAR 02	APR 02	MAY 02	JUN 02	JUL 02	AUG 02	SEP 02	OCT 02	NOV 02	DEC 02	2002
1. EAF (%)	84.4	39.0	60.3	37.9	86.0	69.2	67.1	73.2	59.9	0.0	0.0	16.4	49.6
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	675.2	276.4	558.7	305.1	744.0	682.3	587.8	671.1	589.4	0.0	0.0	193.5	5,283.4
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	68.8	395.6	185.3	413.9	0.0	37.7	156.2	72.9	130.6	745.0	720.0	550.5	3,476.6
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	23.0	745.0	720.0	550.5	2,038.5
7. FOH	0.0	251.5	43.5	413.9	0.0	37.7	0.0	72.9	107.6	0.0	0.0	0.0	927.2
8. MOH	68.8	144.1	141.8	0.0	0.0	0.0	156.2	0.0	0.0	0.0	0.0	0.0	510.9
9. PFOH	499.7	78.5	334.6	212.2	692.2	632.4	541.4	617.2	532.9	0.0	0.0	217.3	4,358.5
10. LR PF (MW)	14.9	42.3	135.2	57.8	50.6	106.8	53.9	67.5	99.0	0.0	0.0	140.2	74.6
11. PMOH	63.0	18.2	12.0	10.4	51.5	47.7	40.5	53.4	56.1	0.0	0.0	0.0	352.6
12. LR PM (MW)	199.5	153.0	124.4	133.4	163.7	187.8	190.0	205.6	233.6	0.0	0.0	0.0	191.1
13. NSC (MW)	426	426	426	416	416	416	416	416	416	416	416	426	419
14. OPR BTU(GBTU)	2,382.7082	928.2685	1,823.3343	1,093.3442	2,730.4471	2,104.2029	2,025.2097	2,362.5319	1,876.4185	0.0000	0.0000	517.2927	17,843.7581
15. NET GEN (MWH)	227,352	89,239	172,920	101,042	251,345	188,592	190,833	210,930	166,375	0	0	48,051	1,646,679
16. ANOHR (BTU/KWH)	10,480	10,402	10,544	10,821	10,863	11,157	10,612	11,201	11,278	N/A	N/A	10,765	10,836
17. NOF (%)	79.0	75.8	72.7	79.6	81.2	66.4	78.0	75.6	67.9	0.0	0.0	58.3	74.3
18. NPC (MW)	426	426	426	416	416	416	416	416	416	416	416	426	419
19. ANOHR EQUATION	ANOHR = NOF(-12.51) + 11,008												

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UNIT PERFORMANCE DATA w/o FGD

JANUARY 2002 - DECEMBER 2002

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2 w/o FGD	JAN 02	FEB 02	MAR 02	APR 02	MAY 02	JUN 02	JUL 02	AUG 02	SEP 02	OCT 02	NOV 02	DEC 02	2002
1. OPR BTU (GBTU)	2,382.7	928.3	1,823.3	1,093.3	2,730.4	2,104.2	2,025.2	2,362.5	1,876.4	0.0	0.0	517.3	17,843.8
2. NET GEN w/FGD (MWH)	227,352.2	89,238.8	172,920.2	101,041.6	251,344.6	188,592.1	190,832.7	210,930.3	166,375.1	0.0	0.0	48,051.1	1,646,678.8
3. FGD CONSUMED (MWH)	3,680.8	1,811.0	2,896.6	1,894.4	3,980.2	3,265.7	3,310.2	3,810.0	2,087.8	0.0	0.0	1,075.7	27,812.4
4. NET GEN w/o FGD (MWH)	231,033.1	91,049.8	175,816.8	102,936.0	255,324.8	191,857.8	194,142.9	214,740.3	168,463.0	0.0	0.0	49,126.8	1,674,491.2
5. ANOHR w/FGD (BTU/KWH)	10,480.2	10,402.1	10,544.4	10,820.7	10,863.4	11,157.4	10,612.5	11,200.5	11,278.2	N/A	N/A	10,765.5	10,836.0
6. ANOHR w/o FGD (BTU/KWH)	10,313.3	10,195.2	10,370.7	10,621.6	10,694.0	10,967.5	10,431.5	11,001.8	11,138.5	N/A	N/A	10,529.8	10,656.2
7. NOF w/FGD (%)	79.0	75.8	72.7	79.6	81.2	66.4	78.0	75.6	67.9	0.0	0.0	58.3	74.3
8. NOF w/o FGD (%)	79.4	76.4	73.0	80.1	81.5	66.8	78.5	76.0	67.9	0.0	0.0	58.9	74.7
9. NPC (MW) w/FGD	426	426	426	416	416	416	416	416	416	416	416	426	419
10. NPC (MW) w/o FGD	431	431	431	421	421	421	421	421	421	421	421	431	424

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ACTUAL UNIT PERFORMANCE DATA

JANUARY 2002 - DECEMBER 2002

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 3	JAN 02	FEB 02	MAR 02	APR 02	MAY 02	JUN 02	JUL 02	AUG 02	SEP 02	OCT 02	NOV 02	DEC 02	2002
1. EAF (%)	59.6	81.3	3.2	1.6	32.5	51.1	40.0	55.5	71.4	89.8	71.5	82.9	53.2
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	579.8	606.4	24.0	16.8	518.4	421.1	356.8	455.3	625.7	741.4	585.9	744.0	5,675.5
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	164.3	65.6	720.0	702.2	225.6	298.9	387.3	288.8	94.3	3.6	134.2	0.0	3,084.5
6. POH	0.0	0.0	720.0	700.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,420.6
7. FOH	60.6	54.4	0.0	0.0	225.6	276.4	387.3	171.8	94.3	3.6	134.2	0.0	1,408.1
8. MOH	103.6	11.1	0.0	1.6	0.0	22.5	0.0	117.0	0.0	0.0	0.0	0.0	255.8
9. PFOH	550.4	517.8	24.0	12.0	577.5	302.3	313.5	373.5	548.0	654.3	562.7	716.2	5,152.2
10. LR PF (MW)	99.7	40.2	9.6	202.2	205.6	44.8	69.1	18.3	72.8	37.1	44.2	66.9	73.0
11. PMOH	18.7	31.7	0.0	0.0	9.3	42.2	20.5	71.7	35.6	33.2	22.7	32.2	317.7
12. LR PM (MW)	219.8	168.0	0.0	0.0	105.9	225.2	190.2	158.8	239.5	218.9	263.6	220.3	201.6
13. NSC (MW)	433	433	433	433	433	433	433	433	433	433	433	433	433
14. OPR BTU(GBTU)	1,725.7115	1,994.4522	71.2082	28.8088	1,741.2920	1,436.8077	1,188.8761	1,599.2665	2,088.4900	2,737.7655	2,068.3956	2,187.6122	18,868.6863
15. NET GEN (MWH)	160,327	189,583	7,905	2,533	164,896	137,274	112,095	147,523	194,783	251,708	190,457	217,841	1,776,925
16. ANOHR BTU/KWH	10,764	10,520	9,008	11,373	10,560	10,467	10,606	10,841	10,722	10,877	10,860	10,042	10,619
17. NOF (%)	63.9	72.2	76.0	34.9	73.5	75.3	72.6	74.8	71.9	78.4	75.1	67.6	72.3
18. NPC (MW)	433	433	433	433	433	433	433	433	433	433	433	433	433
19. ANOHR EQUATION	ANOHR = NOF(-57.476) + 14,536												

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ORIGINAL SHEET NO. 8.401.02A
TAMPA ELECTRIC COMPANY

ACTUAL UNIT PERFORMANCE DATA

JANUARY 2002 - DECEMBER 2002

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	JAN 02	FEB 02	MAR 02	APR 02	MAY 02	JUN 02	JUL 02	AUG 02	SEP 02	OCT 02	NOV 02	DEC 02	2002
1. EAF (%)	90.1	95.3	97.8	96.5	90.8	90.8	89.3	87.2	22.6	77.3	82.1	87.4	84.0
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	682.3	653.1	744.0	719.0	744.0	720.0	742.1	744.0	182.2	706.5	628.0	705.0	7,970.2
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	61.8	18.9	0.0	0.0	0.0	0.0	1.9	0.0	537.8	38.5	92.0	39.0	789.8
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	537.8	0.0	0.0	0.0	537.8
7. FOH	61.8	18.9	0.0	0.0	0.0	0.0	1.9	0.0	0.0	22.2	92.0	39.0	235.7
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	16.4	0.0	0.0	16.4
9. PFOH	161.9	194.3	80.5	175.0	346.2	248.7	546.1	682.8	102.1	304.8	526.8	704.5	4,073.7
10. LR PF (MW)	12.9	14.1	23.3	21.8	49.1	34.3	34.3	37.1	45.4	182.8	29.0	34.7	44.2
11. PMOH	13.4	10.9	31.1	36.0	69.9	81.8	60.5	59.3	15.1	15.7	4.6	0.0	398.4
12. LR PM (MW)	240.8	258.8	169.9	202.6	191.1	252.7	255.7	282.9	265.7	131.4	251.2	0.0	231.3
13. NSC (MW)	447	447	447	442	442	442	442	442	442	442	442	447	444
14. OPR BTU(GBTU)	2,533.1057	2,615.2941	3,011.1787	2,912.3374	2,760.3586	2,662.2062	2,737.2615	2,715.4427	666.5524	2,528.0773	2,376.6646	2,548.5879	30,067.0671
15. NET GEN (MWH)	246,026	253,321	292,678	275,996	258,891	254,361	258,189	248,022	55,348	227,995	226,376	249,537	2,846,741
16. ANOHR BTU/KWH	10,296	10,324	10,288	10,552	10,662	10,466	10,602	10,948	12,043	11,088	10,499	10,213	10,562
17. NOF (%)	80.7	86.8	88.0	86.8	78.7	79.9	78.7	75.4	68.7	73.0	81.6	79.2	80.5
18. NPC (MW)	447	447	447	442	442	442	442	442	442	442	442	447	444
19. ANOHR EQUATION	ANOHR = NOF(-33.833) + 12,887												

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ACTUAL UNIT PERFORMANCE DATA

JANUARY 2002 - DECEMBER 2002

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GANNON 5	JAN 02	FEB 02	MAR 02	APR 02	MAY 02	JUN 02	JUL 02	AUG 02	SEP 02	OCT 02	NOV 02	DEC 02	2002
1. EAF (%)	57.0	31.1	0.0	1.7	77.1	81.5	74.1	95.4	71.6	67.0	85.7	86.2	61.0
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	477.2	245.2	0.0	12.4	583.9	594.3	556.2	744.0	555.7	518.9	691.5	703.1	5,682.4
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	266.8	426.8	744.0	706.6	160.1	125.7	187.8	0.0	164.3	226.1	28.5	40.9	3,077.7
6. POH	0.0	366.0	744.0	706.6	7.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,824.2
7. FOH	266.8	60.8	0.0	0.0	152.5	125.7	184.4	0.0	139.9	187.9	28.5	40.9	1,187.5
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	3.4	0.0	24.4	38.2	0.0	0.0	66.0
9. PFOH	255.3	211.3	0.0	0.0	16.3	9.0	41.4	55.0	385.6	244.7	265.3	265.4	1,749.3
10. LR PF (MW)	42.0	31.1	0.0	0.0	63.8	106.3	19.0	53.2	22.7	13.0	36.3	50.7	33.2
11. PMOH	19.8	11.5	0.0	0.0	8.5	5.3	2.1	34.6	0.0	7.9	59.3	0.0	149.1
12. LR PM (MW)	38.8	112.8	0.0	0.0	132.1	113.2	113.2	128.3	0.0	141.5	111.0	0.0	108.5
13. NSC (MW)	217	217	217	217	217	217	217	217	217	217	217	217	217
14. OPR BTU(GBTU)	829.9717	331.2911	0.0000	11.6093	1,062.8164	1,134.1916	1,102.9012	1,380.3824	1,068.0967	949.8616	1,155.5937	1,138.5127	10,165.2284
15. NET GEN (MWH)	72,050	34,488	0	573	99,739	110,417	94,688	122,031	89,300	83,099	102,738	99,138	908,261
16. ANOHR BTU/KWH	11,519	9,606	N/A	20,261	10,656	10,272	11,648	11,312	11,961	11,430	11,248	11,484	11,192
17. NOF (%)	69.6	64.8	0.0	21.4	78.7	85.6	78.5	75.6	74.1	73.8	68.5	65.0	73.7
18. NPC (MW)	217	217	217	217	217	217	217	217	217	217	217	217	217
19. ANOHR EQUATION	ANOHR = NOF(-4.3274) + 11,025												

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ACTUAL UNIT PERFORMANCE DATA

JANUARY 2002 - DECEMBER 2002

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
GANNON 6	JAN 02	FEB 02	MAR 02	APR 02	MAY 02	JUN 02	JUL 02	AUG 02	SEP 02	OCT 02	NOV 02	DEC 02	2002
1. EAF (%)	70.8	86.7	62.6	69.2	80.2	75.6	65.0	79.0	79.5	17.8	0.0	33.1	59.8
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8,760.0
3. SH	568.3	623.2	556.0	669.9	655.8	565.7	510.3	626.0	636.4	143.2	0.0	317.9	5,872.5
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	175.8	48.9	188.0	49.2	88.2	154.3	233.8	118.0	83.6	601.8	720.0	426.1	2,887.5
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	103.0	0.0	601.8	720.0	378.7	1,803.5
7. FOH	0.0	48.9	188.0	49.2	88.2	57.6	71.6	15.0	83.6	0.0	0.0	47.4	649.4
8. MOH	175.8	0.0	0.0	0.0	0.0	96.8	162.2	0.0	0.0	0.0	0.0	0.0	434.7
9. PFOH	338.9	408.6	678.5	1025.7	559.3	71.1	130.3	113.6	425.9	125.3	0.0	196.2	4,073.5
10. LR PF (MW)	44.4	34.7	51.1	60.0	37.4	49.8	50.1	84.2	49.7	30.8	0.0	143.0	53.8
11. PMOH	6.6	8.6	3.9	13.4	4.9	23.4	19.3	23.1	13.4	0.0	0.0	0.0	116.6
12. LR PM (MW)	193.6	188.8	154.9	195.9	206.6	184.9	173.5	205.1	205.6	0.0	0.0	0.0	191.4
13. NSC (MW)	392	392	392	372	372	372	372	372	372	372	372	392	379
14. OPR BTU(GBTU)	1,664.2136	1,834.6835	1,722.4490	1,857.9248	2,061.8756	1,773.5777	1,757.1696	1,975.1797	1,945.9264	426.0286	0.0000	780.2115	17,799.2400
15. NET GEN (MWH)	153,653	169,401	153,458	165,068	189,537	171,501	154,914	179,658	178,356	39,227	0	57,508	1,612,283
16. ANOHR BTU/KWH	10,831	10,830	11,224	11,255	10,879	10,342	11,343	10,994	10,910	10,860	N/A	13,567	11,040
17. NOF (%)	69.0	69.3	70.4	66.2	77.7	81.5	81.6	77.1	75.3	73.6	0.0	46.2	72.5
18. NPC (MW)	392	392	392	372	372	372	372	372	372	372	372	392	379
19. ANOHR EQUATION	ANOHR = NOF(25.825) + 8,679.5												

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ACTUAL UNIT PERFORMANCE DATA

JANUARY 2002 - DECEMBER 2002

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POLK 1	JAN 02	FEB 02	MAR 02	APR 02	MAY 02	JUN 02	JUL 02	AUG 02	SEP 02	OCT 02	NOV 02	DEC 02	2002
1. EAF (%)	84.3	80.6	98.4	96.1	66.6	91.2	87.7	94.4	89.7	96.4	97.5	91.1	89.5
2. PH	744	672	744	719	744	720	744	744	720	745	720	744	8,760
3. SH	721.8	566.8	666.3	679.2	469.2	716.6	691.2	696.7	637.1	746.1	707.4	603.0	7,901.3
4. RSH	-53.2	-25.2	66.7	16.1	264.5	-7.9	34.7	29.2	51.6	-1.7	5.6	83.2	463.6
5. UH	75.4	130.5	11.0	23.7	10.2	11.3	18.1	18.2	31.3	0.6	7.0	57.8	395.1
6. POH	0.0	0.0	0.0	0.0	199.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	199.1
7. FOH	75.4	3.8	11.0	23.7	10.2	11.3	5.5	8.3	23.7	0.6	5.7	7.3	186.6
8. MOH	0.0	126.7	0.0	0.0	0.0	0.0	12.6	9.9	7.7	0.0	1.3	50.5	208.5
9. PFOH	225.6	0.0	11.0	47.3	350.2	571.5	578.6	656.3	515.7	731.2	361.0	75.0	4,123.4
10. LR PF (MW)	20.3	0.0	2.4	23.8	27.8	22.8	31.6	8.9	20.7	9.1	7.6	26.9	18.1
11. PMOH	1,086.3	0.0	11.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1,097.9
12. LR PM (MW)	5.3	0.0	16.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.5
13. NSC (MW) **	250	250	250	250	250	250	250	250	250	250	250	250	250
14. OPR BTU(GBTU)	1,703.4969	1,349.8490	1,413.5952	1,464.8225	1,045.0853	1,731.7257	1,607.0607	1,664.1672	1,441.5762	1,821.5342	1,715.0418	1,408.2083	18,366.1629
15. NET GEN (MWH)	162,073	130,652	137,706	143,684	95,319	151,115	140,667	154,583	132,143	174,042	160,992	129,448	1,712,425
16. ANOHR BTU/KWH	10,511	10,332	10,265	10,195	10,964	11,460	11,425	10,766	10,909	10,466	10,653	10,879	10,725
17. NOF (%)	89.9	92.3	83.2	87.2	82.2	85.1	82.2	89.2	83.8	93.4	91.4	86.0	87.4
18. NPC (MW) **	250	250	250	250	250	250	250	250	250	250	250	250	250
19. ANOHR EQUATION	ANOHR = NOF(-14.839) + 11,544												

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GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2004 - DECEMBER 2004

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EXHIBITS TO THE TESTIMONY OF

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GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2004 - DECEMBER 2004

DOCUMENT NO. 1

GPIF SCHEDULES

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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
JANUARY 2004 - DECEMBER 2004
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TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
REWARD / PENALTY TABLE - ESTIMATED
JANUARY 2004 - DECEMBER 2004

GENERATING PERFORMANCE INCENTIVE POINTS (GPIP)	FUEL SAVINGS / (LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	27,344.8	5,752.6
+9	24,610.4	5,177.3
+8	21,875.9	4,602.1
+7	19,141.4	4,026.8
+6	16,406.9	3,451.6
+5	13,672.4	2,876.3
+4	10,937.9	2,301.0
+3	8,203.5	1,725.8
+2	5,469.0	1,150.5
+1	2,734.5	575.3
0	0.0	0.0
-1	(4,295.9)	(575.3)
-2	(8,591.8)	(1,150.5)
-3	(12,887.7)	(1,725.8)
-4	(17,183.6)	(2,301.0)
-5	(21,479.5)	(2,876.3)
-6	(25,775.4)	(3,451.6)
-7	(30,071.3)	(4,026.8)
-8	(34,367.2)	(4,602.1)
-9	(38,663.0)	(5,177.3)
-10	(42,958.9)	(5,752.6)

TAMPA ELECTRIC COMPANY
GENERATING PERFORMANCE INCENTIVE FACTOR
CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS
(ESTIMATED)
JANUARY 2004 - DECEMBER 2004

Line 1	Beginning of period balance of common equity: End of month common equity:		$	1,395,385,000
Line 2	Month of January	2004	$	1,430,582,145
Line 3	Month of February	2004	$	1,444,589,928
Line 4	Month of March	2004	$	1,458,734,871
Line 5	Month of April	2004	$	1,409,668,446
Line 6	Month of May	2004	$	1,423,471,449
Line 7	Month of June	2004	$	1,437,409,607
Line 8	Month of July	2004	$	1,472,809,507
Line 9	Month of August	2004	$	1,487,230,767
Line 10	Month of September	2004	$	1,501,793,235
Line 11	Month of October	2004	$	1,452,114,666
Line 12	Month of November	2004	$	1,466,333,289
Line 13	Month of December	2004	$	1,480,691,135
Line 14	(Summation of line 1 through line 13 divided by 13)		$	1,450,831,850
Line 15	25 Basis points			0.0025
Line 16	Revenue Expansion Factor			61.38%
Line 17	Maximum Allowed Incentive Dollars (line 14 times line 15 divided by line 16)		$	5,909,146
Line 18	Jurisdictional Sales			18,768,886 MWH
Line 19	Total Sales			19,279,615 MWH
Line 20	Jurisdictional Separation Factor (line 18 divided by line 19)			97.35%
Line 21	**Maximum Allowed Jurisdictional Incentive Dollars (line 17 times line 20)**		**$**	**5,752,609**

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2004 - DECEMBER 2004

EQUIVALENT AVAILABILITY

PLANT / UNIT	WEIGHTING FACTOR (%)	EAF TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	14.90%	67.2	72.9	55.7	4,074.5	(8,083.0)
BIG BEND 2	16.04%	66.7	72.5	55.1	4,386.4	(8,770.2)
BIG BEND 3	13.98%	67.6	73.2	56.4	3,822.1	(7,513.0)
BIG BEND 4	10.47%	78.2	81.7	71.2	2,862.2	(5,826.8)
POLK 1	2.09%	85.6	87.8	81.2	571.1	(1,137.4)
GPIF SYSTEM	**57.47%**					

AVERAGE NET OPERATING HEAT RATE

PLANT / UNIT	WEIGHTING FACTOR (%)	ANOHR Btu/kwh	TARGET NOF	ANOHR RANGE MIN.	ANOHR RANGE MAX.	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
BIG BEND 1	7.58%	10,708	77.9	10,204	11,212	2,073.1	(2,073.1)
BIG BEND 2	8.85%	10,384	82.2	9,821	10,948	2,421.0	(2,421.0)
BIG BEND 3	10.33%	10,278	78.5	9,622	10,935	2,825.9	(2,825.9)
BIG BEND 4	10.30%	10,272	83.9	9,767	10,777	2,815.9	(2,815.9)
POLK 1	5.46%	10,569	89.3	10,135	11,003	1,492.6	(1,492.6)
GPIF SYSTEM	**42.53%**					**11,628.5**	**(11,628.5)**

TAMPA ELECTRIC COMPANY
COMPARISON OF GPIF TARGETS VS PRIOR PERIOD ACTUAL PERFORMANCE

EQUIVALENT AVAILABILITY (%)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET PERIOD JAN 03 - DEC 03 POF	EUOF	EUOR	TARGET PERIOD JUL 01 - JUN 02 POF	EUOF	EUOR	TARGET PERIOD JUL 00 - JUN 01 POF	EUOF	EUOR	TARGET PERIOD JUL 99 - JUN 00 POF	EUOF	EUOR
BIG BEND 1	14.90%	25.9%	5.7	27.1	28.8	0.0	28.9	28.9	4.5	24.8	26.0	14.3	23.7	27.7
BIG BEND 2	16.04%	27.9%	5.7	27.6	29.3	23.3	24.4	31.8	0.0	28.2	28.2	6.1	18.5	19.7
BIG BEND 3	13.98%	24.3%	5.7	26.7	28.3	0.0	28.6	28.6	16.2	27.7	33.1	0.0	16.7	16.7
BIG BEND 4	10.47%	18.2%	5.7	16.1	17.1	6.1	16.0	17.1	0.0	12.4	12.4	8.5	12.6	13.8
POLK 1	2.09%	3.6%	4.4	10.0	10.5	11.1	7.1	8.0	0.7	14.3	14.4	4.3	8.7	9.1
GPIF SYSTEM	**57.47%**	**100.0%**	**5.7**	**24.5**	**26.0**	**8.0**	**24.4**	**26.7**	**5.1**	**23.8**	**25.4**	**7.1**	**18.0**	**19.6**
GPIF SYSTEM WEIGHTED EQUIVALENT AVAILABILITY (%)				**69.8**			**67.6**			**71.1**			**74.9**	

3 PERIOD AVERAGE POF	EUOF	EUOR	3 PERIOD AVERAGE EAF
6.8	**22.1**	**23.9**	**71.2**

AVERAGE NET OPERATING HEAT RATE (Btu/kwh)

PLANT / UNIT	WEIGHTING FACTOR (%)	NORMALIZED WEIGHTING FACTOR	TARGET HEAT RATE JAN 03 - DEC 03	ADJUSTED PRIOR HEAT RATE JUL 01 - JUN 02	ADJUSTED PRIOR HEAT RATE JUL 00 - JUN 01	ADJUSTED PRIOR HEAT RATE JUL 99 - JUN 00
BIG BEND 1	7.58%	17.8%	10,708	10,805	10,559	10,419
BIG BEND 2	8.85%	20.8%	10,384	10,658	10,300	9,985
BIG BEND 3	10.33%	24.3%	10,278	10,563	10,205	10,056
BIG BEND 4	10.30%	24.2%	10,272	10,283	10,378	10,070
POLK 1	5.46%	12.8%	10,569	10,226	10,539	10,206
GPIF SYSTEM	**42.53%**	**100.0%**				
GPIF SYSTEM WEIGHTED AVERAGE HEAT RATE (Btu/kwh)			**10,413**	**10,515**	**10,372**	**10,129**

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TAMPA ELECTRIC COMPANY
DERIVATION OF WEIGHTING FACTORS
JANUARY 2004 - DECEMBER 2004
PRODUCTION COSTING SIMULATION
FUEL COST ($000)

UNIT PERFORMANCE INDICATOR	AT TARGET (1)	AT MAXIMUM IMPROVEMENT (2)	SAVINGS (3)	WEIGHTING FACTOR (% OF SAVINGS)
EQUIVALENT AVAILABILITY				
EA_1 BIG BEND 1	665,093	661,018	4,075	14.90%
EA_2 BIG BEND 2	665,093	660,706	4,386	16.04%
EA_3 BIG BEND 3	665,093	661,271	3,822	13.98%
EA_4 BIG BEND 4	665,093	662,230	2,862	10.47%
EA_7 POLK 1	665,093	664,522	571	2.09%
AVERAGE HEAT RATE				
AHR_1 BIG BEND 1	665,093	663,020	2,073	7.58%
AHR_2 BIG BEND 2	665,093	662,672	2,421	8.85%
AHR_3 BIG BEND 3	665,093	662,267	2,826	10.33%
AHR_4 BIG BEND 4	665,093	662,277	2,816	10.30%
AHR_7 POLK 1	665,093	663,600	1,493	5.46%
TOTAL SAVINGS			**27,345**	**100.00%**

(1) Fuel Adjustment Base Case - All unit performance indicators at target.
(2) All other units performance indicators at target.
(3) Expressed in replacement energy cost.

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2004 - DECEMBER 2004

BIG BEND 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	4,074.5	72.9	+10	2,073.1	10,204
+9	3,667.1	72.3	+9	1,865.8	10,247
+8	3,259.6	71.8	+8	1,658.5	10,290
+7	2,852.2	71.2	+7	1,451.2	10,333
+6	2,444.7	70.6	+6	1,243.9	10,375
+5	2,037.3	70.0	+5	1,036.5	10,418
+4	1,629.8	69.5	+4	829.2	10,461
+3	1,222.4	68.9	+3	621.9	10,504
+2	814.9	68.3	+2	414.6	10,547
+1	407.5	67.7	+1	207.3	10,590
					10,633
0	0.0	67.2	0	0.0	10,708
					10,783
-1	(808.3)	66.0	-1	(207.3)	10,826
-2	(1,616.6)	64.9	-2	(414.6)	10,869
-3	(2,424.9)	63.7	-3	(621.9)	10,911
-4	(3,233.2)	62.6	-4	(829.2)	10,954
-5	(4,041.5)	61.4	-5	(1,036.5)	10,997
-6	(4,849.8)	60.3	-6	(1,243.9)	11,040
-7	(5,658.1)	59.2	-7	(1,451.2)	11,083
-8	(6,466.4)	58.0	-8	(1,658.5)	11,126
-9	(7,274.7)	56.9	-9	(1,865.8)	11,169
-10	(8,083.0)	55.7	-10	(2,073.1)	11,212
	Weighting Factor =	14.90%		Weighting Factor =	7.58%

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2004 - DECEMBER 2004

BIG BEND 2

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	4,386.4	72.5	+10	2,421.0	9,821
+9	3,947.8	71.9	+9	2,178.9	9,870
+8	3,509.1	71.3	+8	1,936.8	9,919
+7	3,070.5	70.8	+7	1,694.7	9,968
+6	2,631.8	70.2	+6	1,452.6	10,017
+5	2,193.2	69.6	+5	1,210.5	10,065
+4	1,754.6	69.0	+4	968.4	10,114
+3	1,315.9	68.4	+3	726.3	10,163
+2	877.3	67.9	+2	484.2	10,212
+1	438.6	67.3	+1	242.1	10,261
					10,309
0	0.0	66.7	0	0.0	10,384
					10,459
-1	(877.0)	65.5	-1	(242.1)	10,508
-2	(1,754.0)	64.4	-2	(484.2)	10,557
-3	(2,631.1)	63.2	-3	(726.3)	10,606
-4	(3,508.1)	62.1	-4	(968.4)	10,655
-5	(4,385.1)	60.9	-5	(1,210.5)	10,704
-6	(5,262.1)	59.7	-6	(1,452.6)	10,752
-7	(6,139.1)	58.6	-7	(1,694.7)	10,801
-8	(7,016.2)	57.4	-8	(1,936.8)	10,850
-9	(7,893.2)	56.3	-9	(2,178.9)	10,899
-10	(8,770.2)	55.1	-10	(2,421.0)	10,948
	Weighting Factor =	16.04%		Weighting Factor =	8.85%

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2004 - DECEMBER 2004

BIG BEND 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	3,822.1	73.2	+10	2,825.9	9,622
+9	3,439.9	72.6	+9	2,543.3	9,680
+8	3,057.7	72.1	+8	2,260.7	9,738
+7	2,675.5	71.5	+7	1,978.1	9,796
+6	2,293.3	71.0	+6	1,695.5	9,854
+5	1,911.0	70.4	+5	1,413.0	9,913
+4	1,528.8	69.8	+4	1,130.4	9,971
+3	1,146.6	69.3	+3	847.8	10,029
+2	764.4	68.7	+2	565.2	10,087
+1	382.2	68.2	+1	282.6	10,145
					10,203
0	0.0	67.6	0	0.0	10,278
					10,353
-1	(751.3)	66.5	-1	(282.6)	10,411
-2	(1,502.6)	65.4	-2	(565.2)	10,470
-3	(2,253.9)	64.2	-3	(847.8)	10,528
-4	(3,005.2)	63.1	-4	(1,130.4)	10,586
-5	(3,756.5)	62.0	-5	(1,413.0)	10,644
-6	(4,507.8)	60.9	-6	(1,695.5)	10,702
-7	(5,259.1)	59.7	-7	(1,978.1)	10,760
-8	(6,010.4)	58.6	-8	(2,260.7)	10,818
-9	(6,761.7)	57.5	-9	(2,543.3)	10,877
-10	(7,513.0)	56.4	-10	(2,825.9)	10,935
	Weighting Factor =	13.98%		Weighting Factor =	10.33%

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2004 - DECEMBER 2004

BIG BEND 4

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	2,862.2	81.7	+10	2,815.9	9,767
+9	2,576.0	81.3	+9	2,534.3	9,810
+8	2,289.8	81.0	+8	2,252.7	9,853
+7	2,003.5	80.6	+7	1,971.1	9,896
+6	1,717.3	80.3	+6	1,689.6	9,939
+5	1,431.1	79.9	+5	1,408.0	9,982
+4	1,144.9	79.6	+4	1,126.4	10,025
+3	858.7	79.2	+3	844.8	10,068
+2	572.4	78.9	+2	563.2	10,111
+1	286.2	78.5	+1	281.6	10,154
					10,197
0	0.0	78.2	0	0.0	10,272
					10,347
-1	(582.7)	77.5	-1	(281.6)	10,390
-2	(1,165.4)	76.8	-2	(563.2)	10,433
-3	(1,748.0)	76.1	-3	(844.8)	10,476
-4	(2,330.7)	75.4	-4	(1,126.4)	10,519
-5	(2,913.4)	74.7	-5	(1,408.0)	10,562
-6	(3,496.1)	74.0	-6	(1,689.6)	10,605
-7	(4,078.8)	73.3	-7	(1,971.1)	10,648
-8	(4,661.4)	72.6	-8	(2,252.7)	10,691
-9	(5,244.1)	71.9	-9	(2,534.3)	10,734
-10	(5,826.8)	71.2	-10	(2,815.9)	10,777
	Weighting Factor =	10.47%		Weighting Factor =	10.30%

TAMPA ELECTRIC COMPANY
GPIF TARGET AND RANGE SUMMARY
JANUARY 2004 - DECEMBER 2004

POLK 1

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS / (LOSS) ($000)	ADJUSTED ACTUAL AVERAGE HEAT RATE
+10	571.1	87.8	+10	1,492.6	10,135
+9	514.0	87.6	+9	1,343.4	10,171
+8	456.9	87.4	+8	1,194.1	10,207
+7	399.8	87.1	+7	1,044.8	10,243
+6	342.7	86.9	+6	895.6	10,279
+5	285.5	86.7	+5	746.3	10,315
+4	228.4	86.5	+4	597.0	10,351
+3	171.3	86.3	+3	447.8	10,387
+2	114.2	86.0	+2	298.5	10,423
+1	57.1	85.8	+1	149.3	10,458
					10,494
0	0.0	85.6	0	0.0	10,569
					10,644
-1	(113.7)	85.2	-1	(149.3)	10,680
-2	(227.5)	84.7	-2	(298.5)	10,716
-3	(341.2)	84.3	-3	(447.8)	10,752
-4	(455.0)	83.8	-4	(597.0)	10,788
-5	(568.7)	83.4	-5	(746.3)	10,824
-6	(682.4)	82.9	-6	(895.6)	10,860
-7	(796.2)	82.5	-7	(1,044.8)	10,896
-8	(909.9)	82.0	-8	(1,194.1)	10,932
-9	(1,023.7)	81.6	-9	(1,343.4)	10,967
-10	(1,137.4)	81.2	-10	(1,492.6)	11,003
	Weighting Factor =	2.09%		Weighting Factor =	5.46%

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2004 - DECEMBER 2004

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 1	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	2004
1. EAF (%)	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	71.2	28.5	64.3	67.2
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	60.0	9.7	5.74
3. EUOF	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	11.5	26.0	27.11
4. EUOR	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8	28.8
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	590	550	598	565	578	556	582	585	575	602	223	515	6519
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	154	146	146	155	166	164	162	159	145	142	497	229	2265
9. POH	0	0	0	0	0	0	0	0	0	0	432	72	504
10. FOH & EFOH	168	158	168	163	168	163	168	168	163	168	65	152	1,875
11. MOH & EMOH	46	43	46	44	46	44	46	46	44	46	18	41	506
12. OPER BTU (GBTU)	2,098	1,966	2,135	1,971	1,973	1,949	2,038	2,061	2,028	2,147	804	1,844	23,014
13. NET GEN (MWH)	195,710	183,649	199,411	183,674	182,742	182,012	190,141	192,675	189,663	201,524	75,731	172,317	2,149,249
14. ANOHR (Btu/kwh)	10,718	10,705	10,709	10,728	10,799	10,711	10,717	10,697	10,690	10,653	10,620	10,700	10,708
15. NOF (%)	77.6	78.0	77.9	77.3	75.1	77.8	77.6	78.2	78.4	79.5	80.5	78.1	77.9
16. NPC (MW)	428	428	428	421	421	421	421	421	421	421	421	428	423
17. ANOHR EQUATION	ANOHR = NOF (	-32.945	) +	13,274									

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2004 - DECEMBER 2004

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 2	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	2004
1. EAF (%)	70.7	31.7	59.3	70.7	70.7	70.7	70.7	70.7	70.7	70.7	70.7	70.7	66.7
2. POF	0.0	55.2	16.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.74
3. EUOF	29.3	13.1	24.5	29.3	29.3	29.3	29.3	29.3	29.3	29.3	29.3	29.3	27.57
4. EUOR	29.3	29.3	29.3	29.3	29.3	29.3	29.3	29.3	29.3	29.3	29.3	29.3	29.3
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	599	250	502	580	596	577	593	594	580	599	577	599	6,647
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	145	446	242	140	148	143	151	150	140	145	143	145	2137
9. POH	0	384	120	0	0	0	0	0	0	0	0	0	504
10. FOH & EFOH	173	73	145	168	173	168	173	173	168	173	168	173	1,927
11. MOH & EMOH	45	19	37	43	45	43	45	45	43	45	43	45	495
12. OPER BTU (GBTU)	2,199	920	1,844	2,050	2,091	2,054	2,094	2,103	2,056	2,134	2,034	2,159	23,748
13. NET GEN (MWH)	211,471	88,502	177,342	197,723	201,336	198,366	201,942	202,874	198,387	206,066	196,046	206,850	2,286,905
14. ANOHR (Btu/kwh)	10,400	10,397	10,397	10,369	10,387	10,354	10,371	10,366	10,364	10,355	10,377	10,437	10,384
15. NOF (%)	81.5	81.7	81.6	83.0	82.1	83.7	82.9	83.1	83.2	83.7	82.6	79.7	82.2
16. NPC (MW)	433	433	433	411	411	411	411	411	411	411	411	433	418
17. ANOHR EQUATION	ANOHR = NOF (		-20.911	) +		12,104							

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2004 - DECEMBER 2004

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 3	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	2004
1. EAF (%)	71.7	71.7	27.8	66.9	71.7	71.7	71.7	71.7	71.7	71.7	71.7	71.7	67.6
2. POF	0.0	0.0	61.3	6.7	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.74
3. EUOF	28.3	28.3	11.0	26.4	28.3	28.3	28.3	28.3	28.3	28.3	28.3	28.3	26.66
4. EUOR	28.3	28.3	28.3	28.3	28.3	28.3	28.3	28.3	28.3	28.3	28.3	28.3	28.3
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	599	561	232	541	599	577	596	596	580	599	580	599	6,659
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	145	135	512	179	145	143	148	148	140	145	140	145	2125
9. POH	0	0	456	48	0	0	0	0	0	0	0	0	504
10. FOH & EFOH	181	170	70	164	181	175	181	181	175	181	175	181	2,017
11. MOH & EMOH	29	27	11	26	29	28	29	29	28	29	28	29	325
12. OPER BTU (GBTU)	2,161	1,987	809	1,872	2,051	1,982	2,051	2,063	2,013	2,099	2,058	2,119	23,269
13. NET GEN (MWH)	211,498	193,440	78,443	182,173	199,007	192,550	199,416	200,877	196,128	203,740	200,503	206,159	2,263,934
14. ANOHR (Btu/kwh)	10,219	10,271	10,318	10,274	10,305	10,292	10,287	10,271	10,264	10,304	10,266	10,278	10,278
15. NOF (%)	80.6	78.8	77.1	78.6	77.6	78.0	78.2	78.8	79.0	77.6	78.9	78.5	78.5
16. NPC (MW)	438	438	438	428	428	428	428	428	428	438	438	438	433
17. ANOHR EQUATION	ANOHR = NOF(	-28.979	) +	12,553									

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PAGE 14 OF 31

TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2004 - DECEMBER 2004

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
BIG BEND 4	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	2004
1. EAF (%)	82.9	82.9	82.9	82.9	82.9	82.9	82.9	82.9	82.9	26.8	82.9	82.9	78.2
2. POF	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	67.7	0.0	0.0	5.74
3. EUOF	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	5.5	17.1	17.1	16.09
4. EUOR	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	660	618	660	639	660	631	656	656	639	213	639	660	7,332
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	84	78	84	81	84	89	88	88	81	531	81	84	1452
9. POH	0	0	0	0	0	0	0	0	0	504	0	0	504
10. FOH & EFOH	102	96	102	99	102	99	102	102	99	33	99	102	1,140
11. MOH & EMOH	24	23	24	24	24	24	24	24	24	8	24	24	273
12. OPER BTU (GBTU)	2,604	2,441	2,607	2,491	2,573	2,447	2,566	2,570	2,497	836	2,507	2,611	28,745
13. NET GEN (MWH)	252,428	236,986	252,968	242,569	250,558	237,213	250,424	251,036	243,544	81,779	245,233	253,610	2,798,348
14. ANOHR (Btu/kwh)	10,314	10,299	10,305	10,269	10,271	10,314	10,247	10,238	10,252	10,220	10,222	10,294	10,272
15. NOF (%)	83.1	83.4	83.3	84.0	84.0	83.1	84.4	84.6	84.3	85.0	84.9	83.5	83.9
16. NPC (MW)	460	460	460	452	452	452	452	452	452	452	452	460	455
17. ANOHR EQUATION	ANOHR = NOF(	-51.316	) +	14,580									

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TAMPA ELECTRIC COMPANY

ESTIMATED UNIT PERFORMANCE DATA

JANUARY 2004 - DECEMBER 2004

PLANT/UNIT	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	MONTH OF:	PERIOD
POLK 1	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	2004
1. EAF (%)	89.5	89.5	89.5	65.6	89.5	89.5	89.5	89.5	89.5	66.4	89.5	89.5	85.6
2. POF	0.0	0.0	0.0	26.7	0.0	0.0	0.0	0.0	0.0	25.8	0.0	0.0	4.37
3. EUOF	10.5	10.5	10.5	7.7	10.5	10.5	10.5	10.5	10.5	7.8	10.5	10.5	10.03
4. EUOR	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5
5. PH	744	696	744	720	744	720	744	744	720	744	720	744	8,784
6. SH	669	626	669	432	669	648	669	669	648	497	648	669	7,515
7. RSH	0	0	0	0	0	0	0	0	0	0	0	0	0
8. UH	75	70	75	288	75	72	75	75	72	247	72	75	1269
9. POH	0	0	0	192	0	0	0	0	0	192	0	0	384
10. FOH & EFOH	54	51	54	39	54	53	54	54	53	40	53	54	614
11. MOH & EMOH	24	22	24	17	24	23	24	24	23	18	23	24	267
12. OPER BTU (GBTU)	1,711	1,604	1,715	1,066	1,541	1,491	1,541	1,541	1,491	1,232	1,631	1,692	18,272
13. NET GEN (MWH)	165,102	154,913	165,605	101,976	142,976	138,363	142,976	142,976	138,363	117,169	156,112	162,252	1,728,783
14. ANOHR (Btu/kwh)	10,365	10,355	10,354	10,449	10,776	10,776	10,776	10,776	10,776	10,518	10,446	10,426	10,569
15. NOF (%)	94.9	95.1	95.1	92.6	83.8	83.8	83.8	83.8	83.8	90.7	92.7	93.2	89.3
16. NPC (MW)	260	260	260	255	255	255	255	255	255	260	260	260	258
17. ANOHR EQUATION	ANOHR = NOF(		-37.017	) +	13,876								

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TAMPA ELECTRIC COMPANY
PLANNED OUTAGE SCHEDULE (ESTIMATED)
GPIF UNITS
JANUARY 2004 - DECEMBER 2004

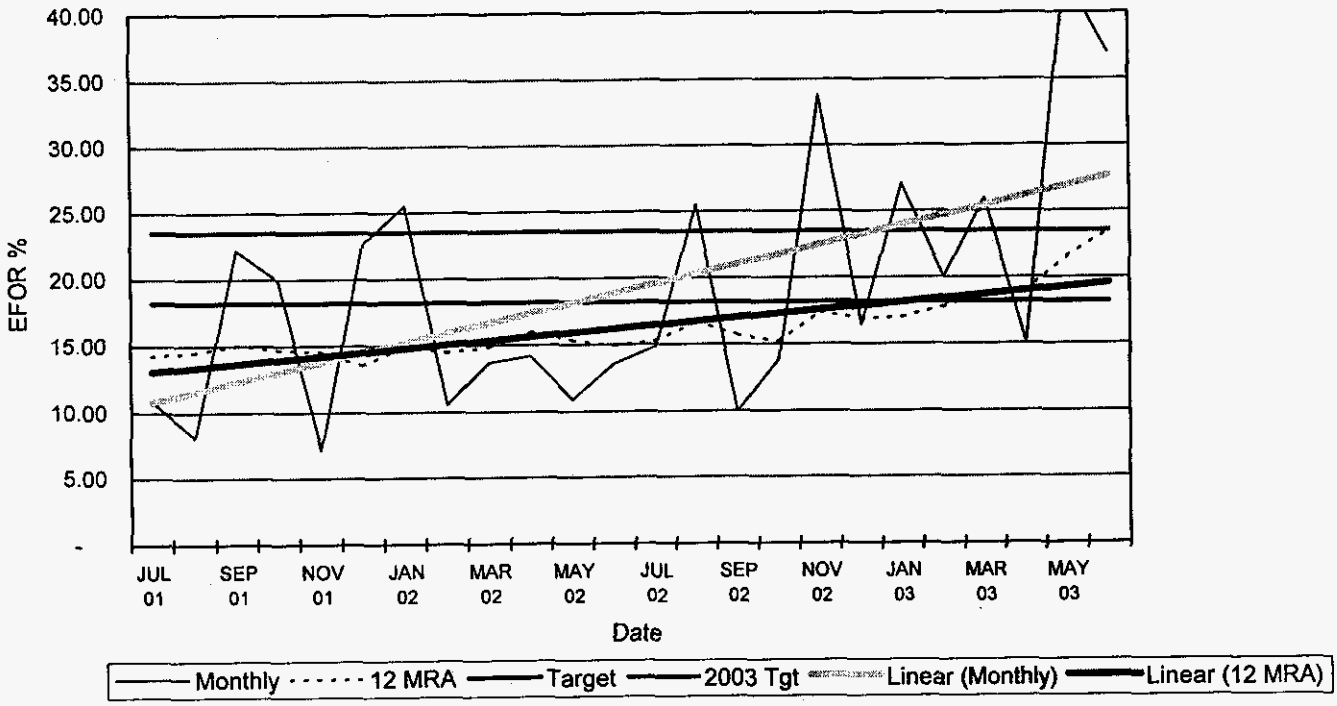
PLANT / UNIT	PLANNED OUTAGE DATES +			OUTAGE DESCRIPTION
BIG BEND 1	Nov 13	-	Dec 03	Fuel System Clean-up
BIG BEND 2	Feb 14	-	Mar 05	Fuel System Clean-up
BIG BEND 3	Mar 13	-	Apr 02	Fuel System Clean-up
BIG BEND 4	Oct 02	-	Oct 22	Fuel System Clean -up
POLK 1	Apr 03	-	Apr 10	#1CT Combustion Path
	Oct 04		Oct 11	Fuel System Clean-up

\+ CPM diagrams for units with outages of less than or equal to 4 weeks are not included.

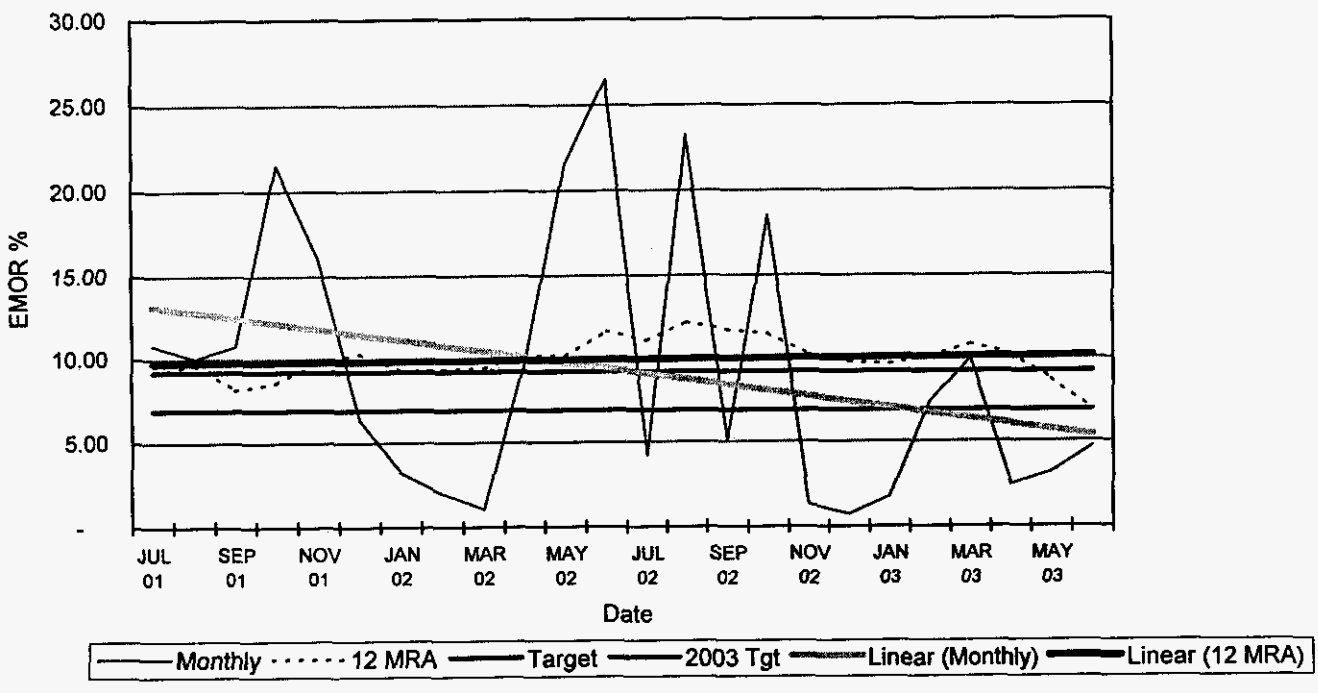
TAMPA ELECTRIC COMPANY
CRITICAL PATH METHOD DIAGRAMS
GPIF UNITS > FOUR WEEKS
JANUARY 2004 - DECEMBER 2004

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because no scheduled outages apply.

Big Bend Unit 1
EFOR

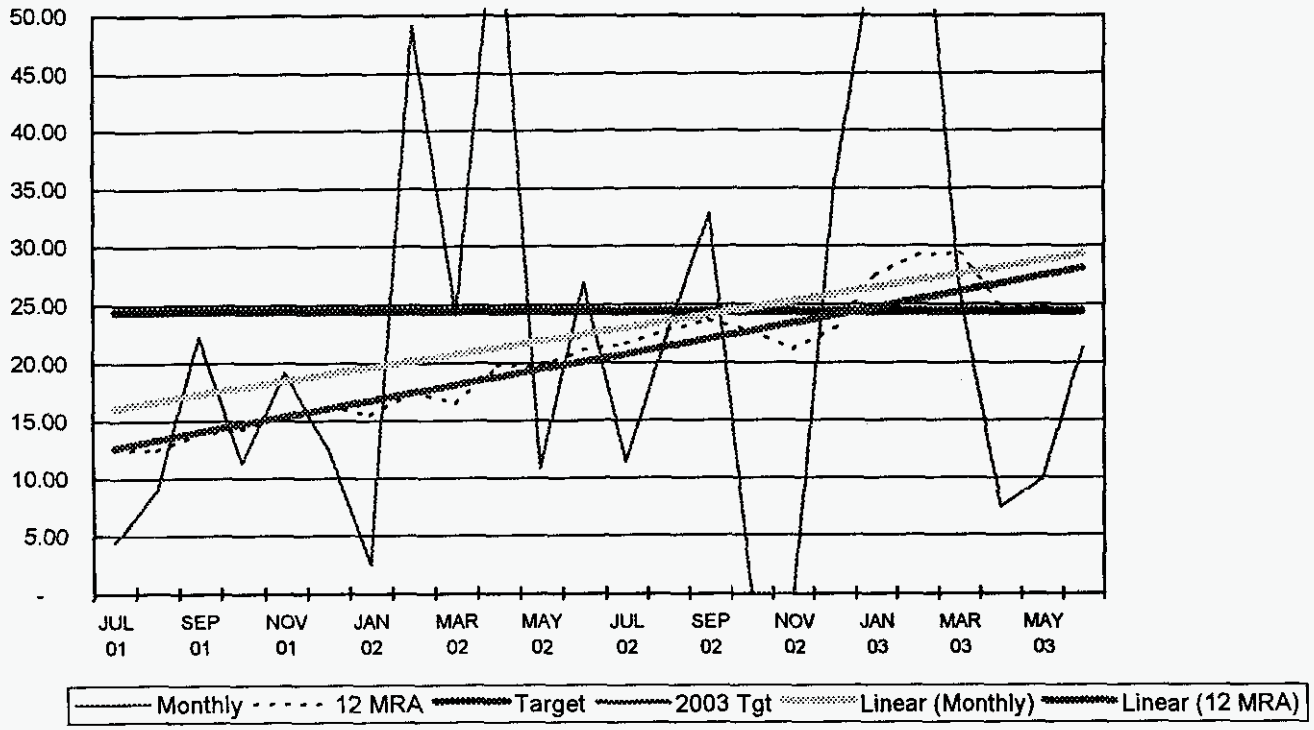


Big Bend Unit 1
EMOR

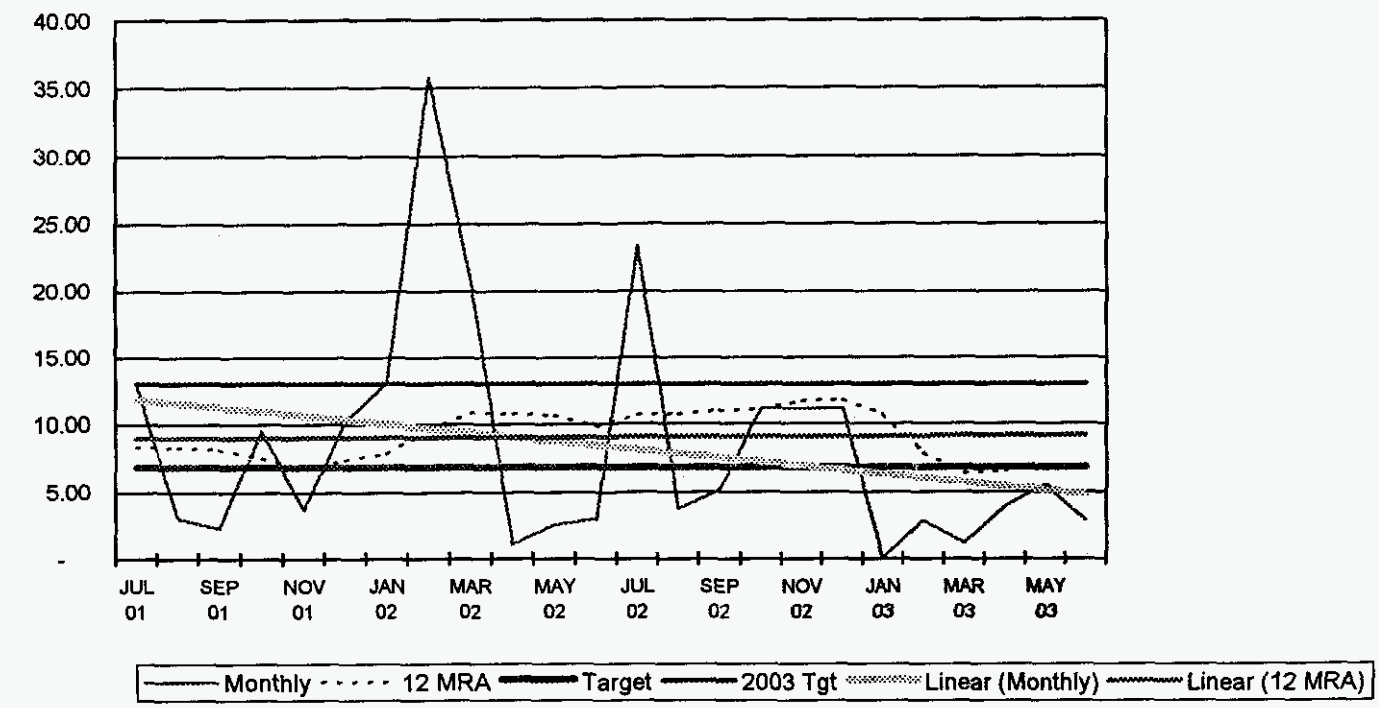


12 MRA = 12 Month Rolling Average

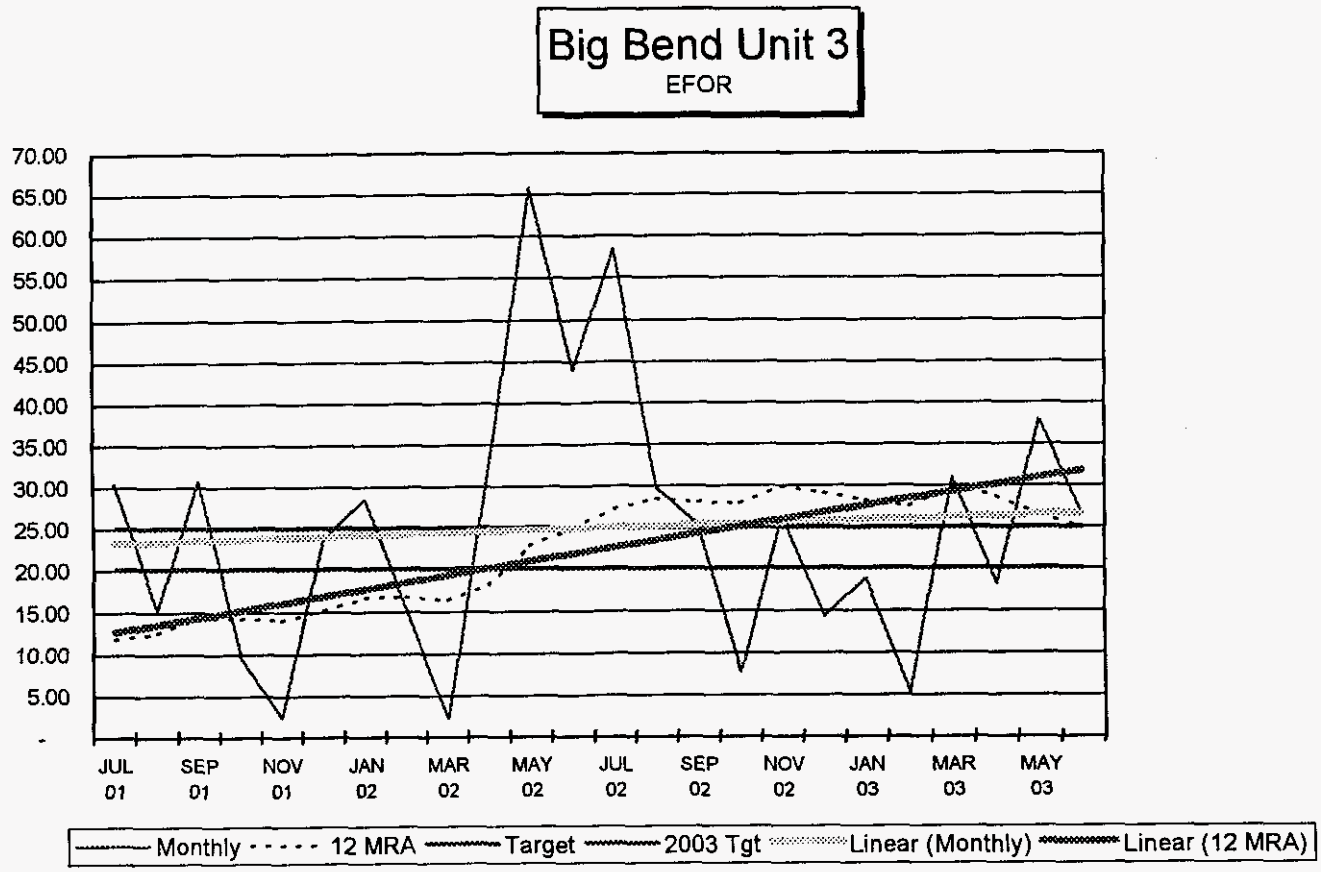
Big Bend Unit 2
EFOR

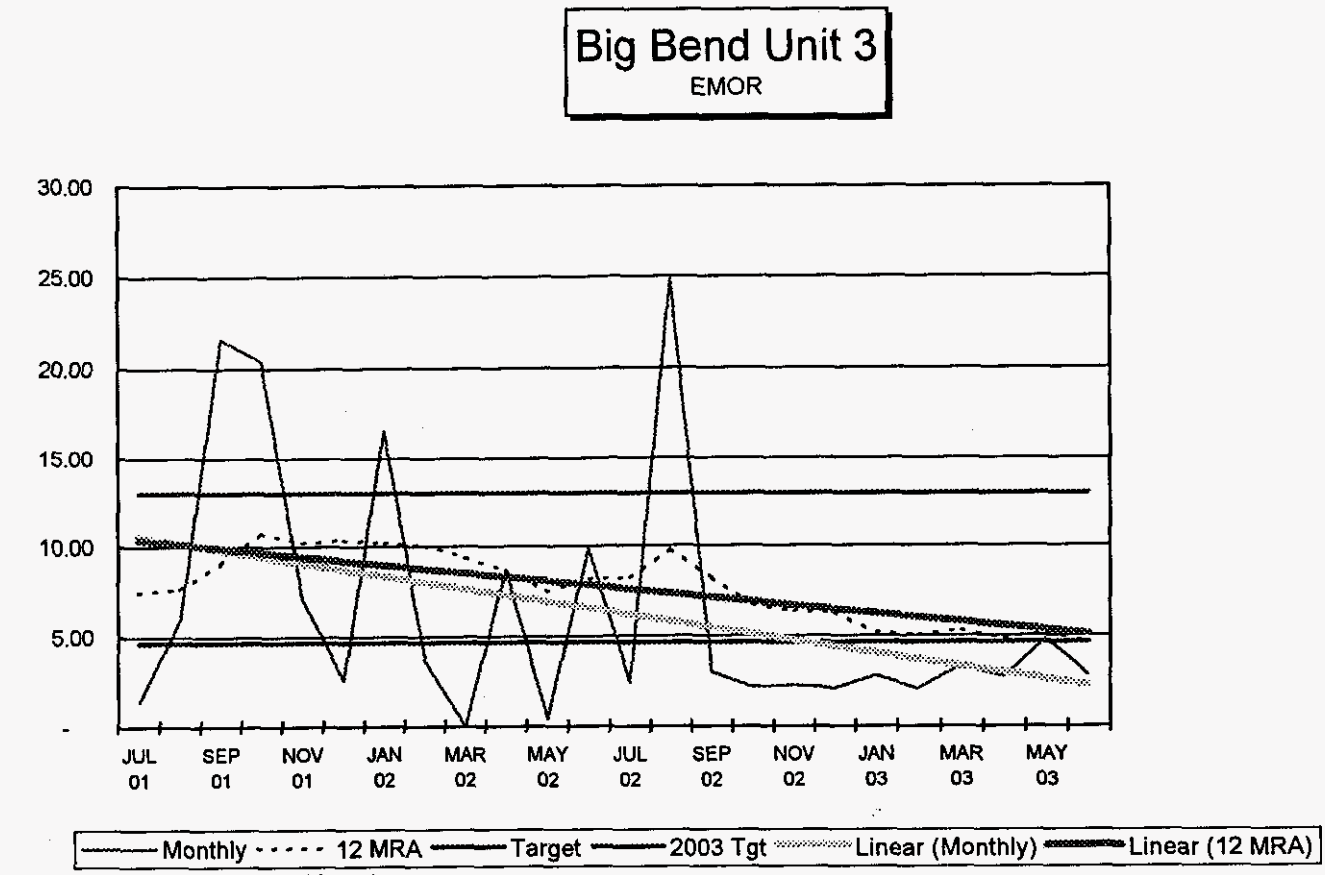


Big Bend Unit 2
EMOR



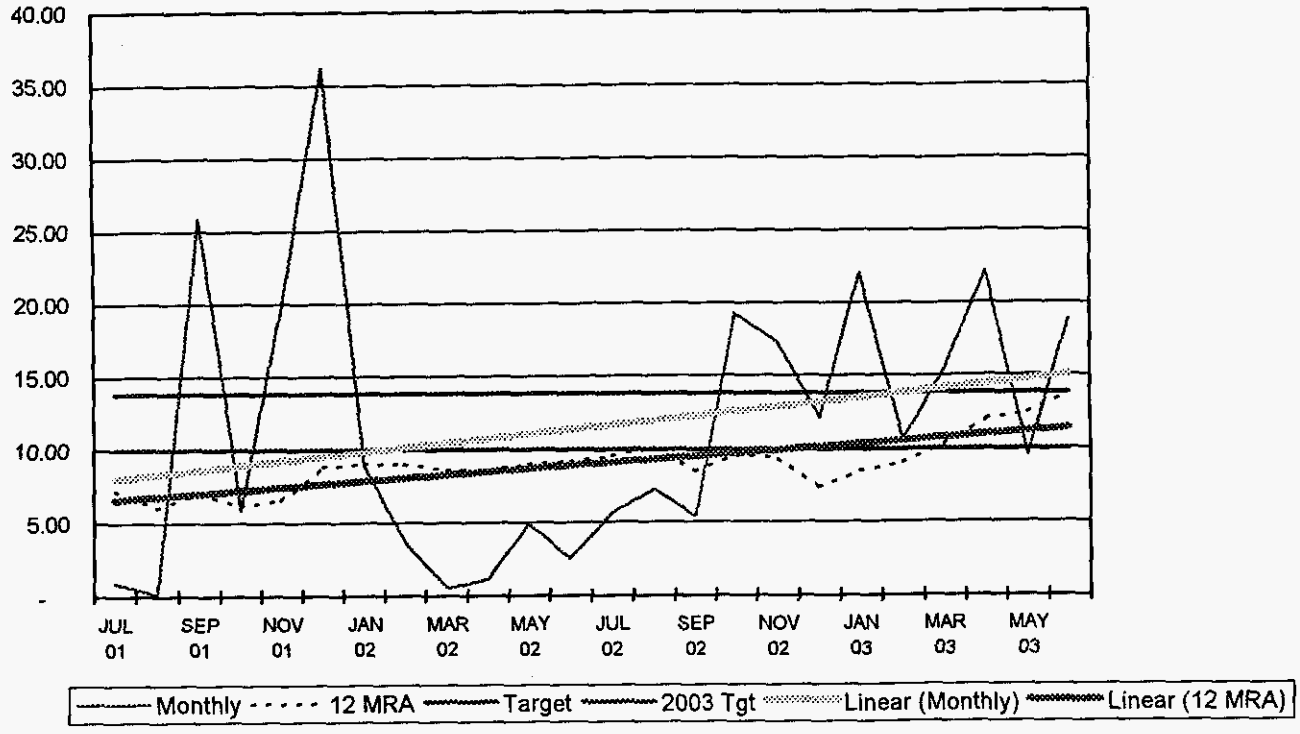
12 MRA = 12 Month Rolling Average



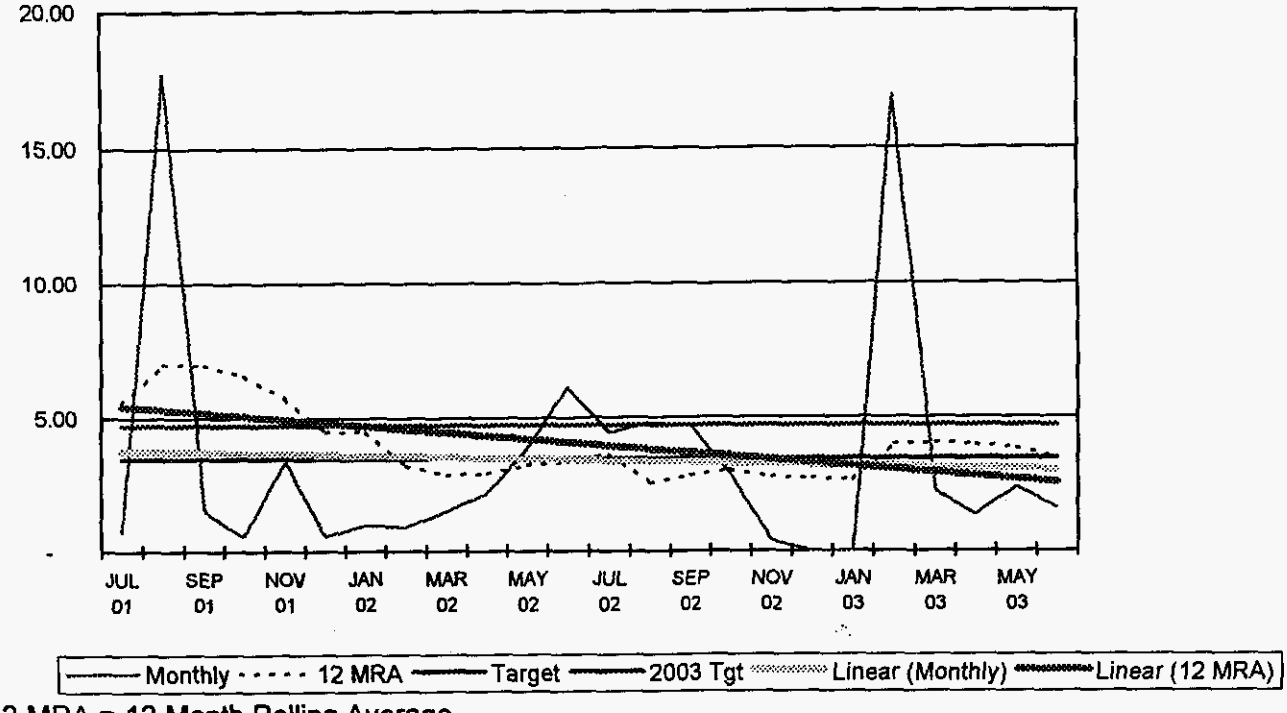


12 MRA = 12 Month Rolling Average

Big Bend Unit 4
EFOR

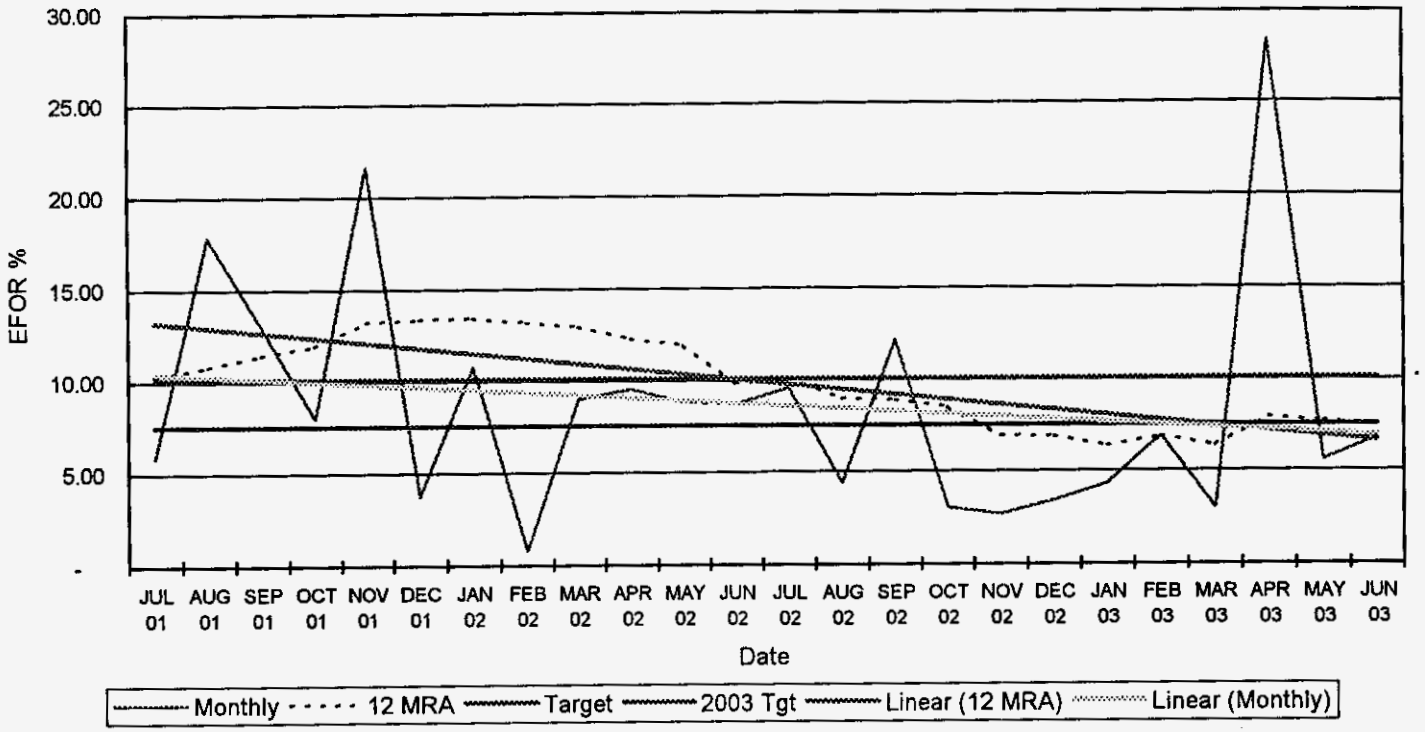


Big Bend Unit 4
EMOR

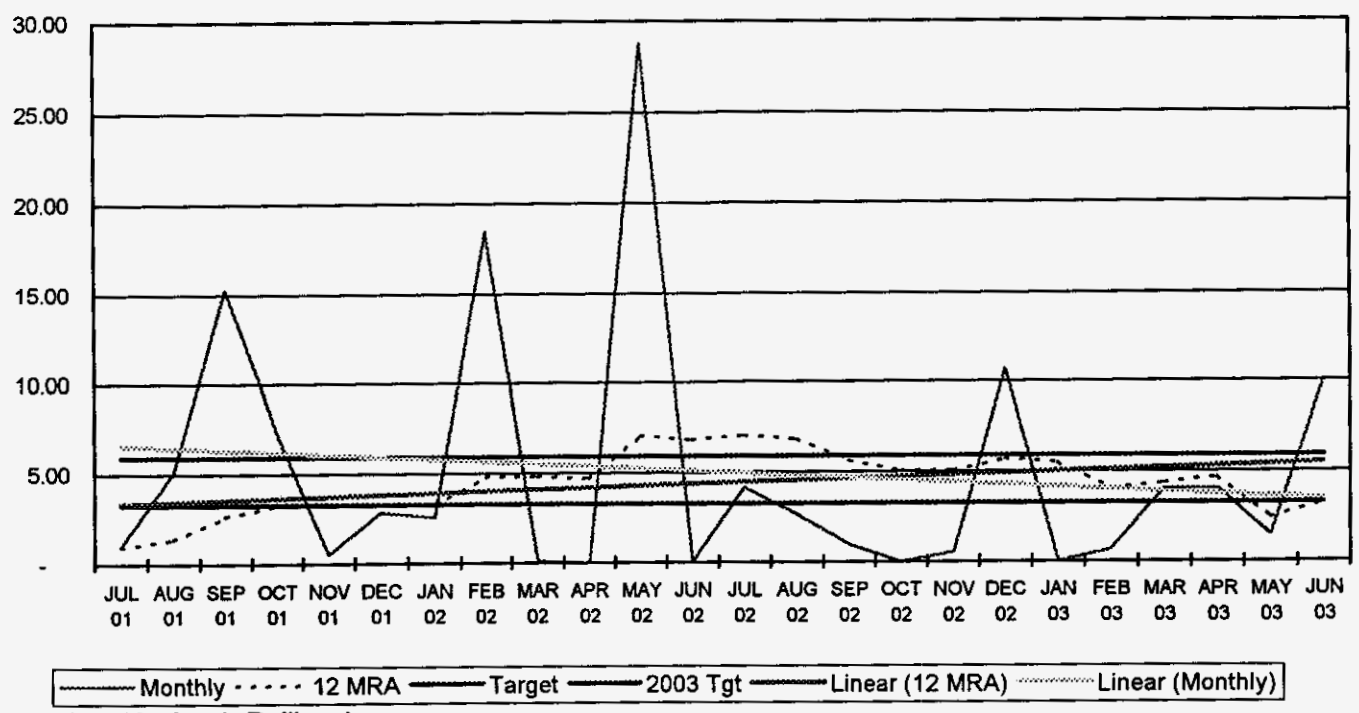


12 MRA = 12 Month Rolling Average

Polk Unit 1
EFOR

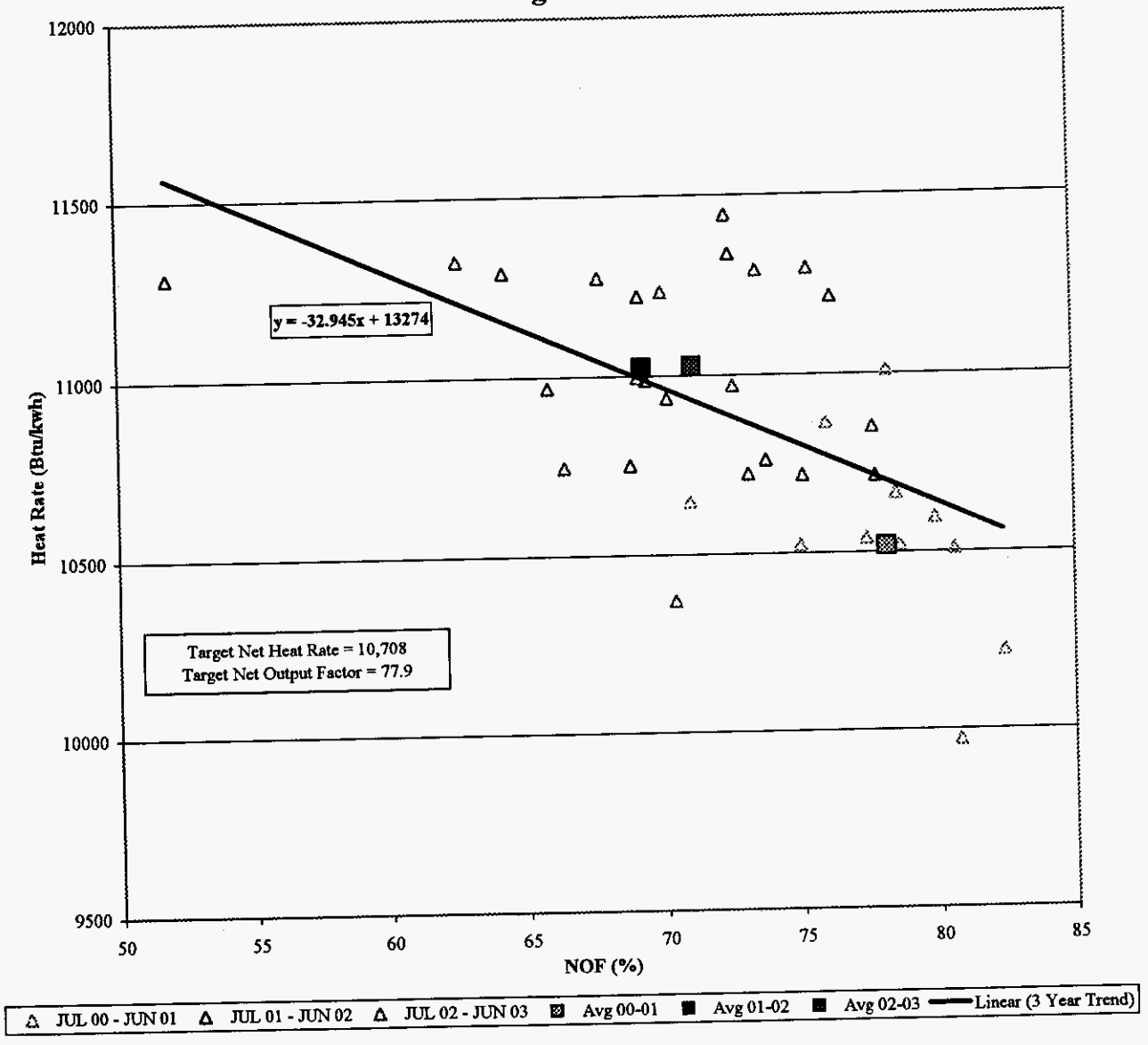


Polk Unit 1
EMOR

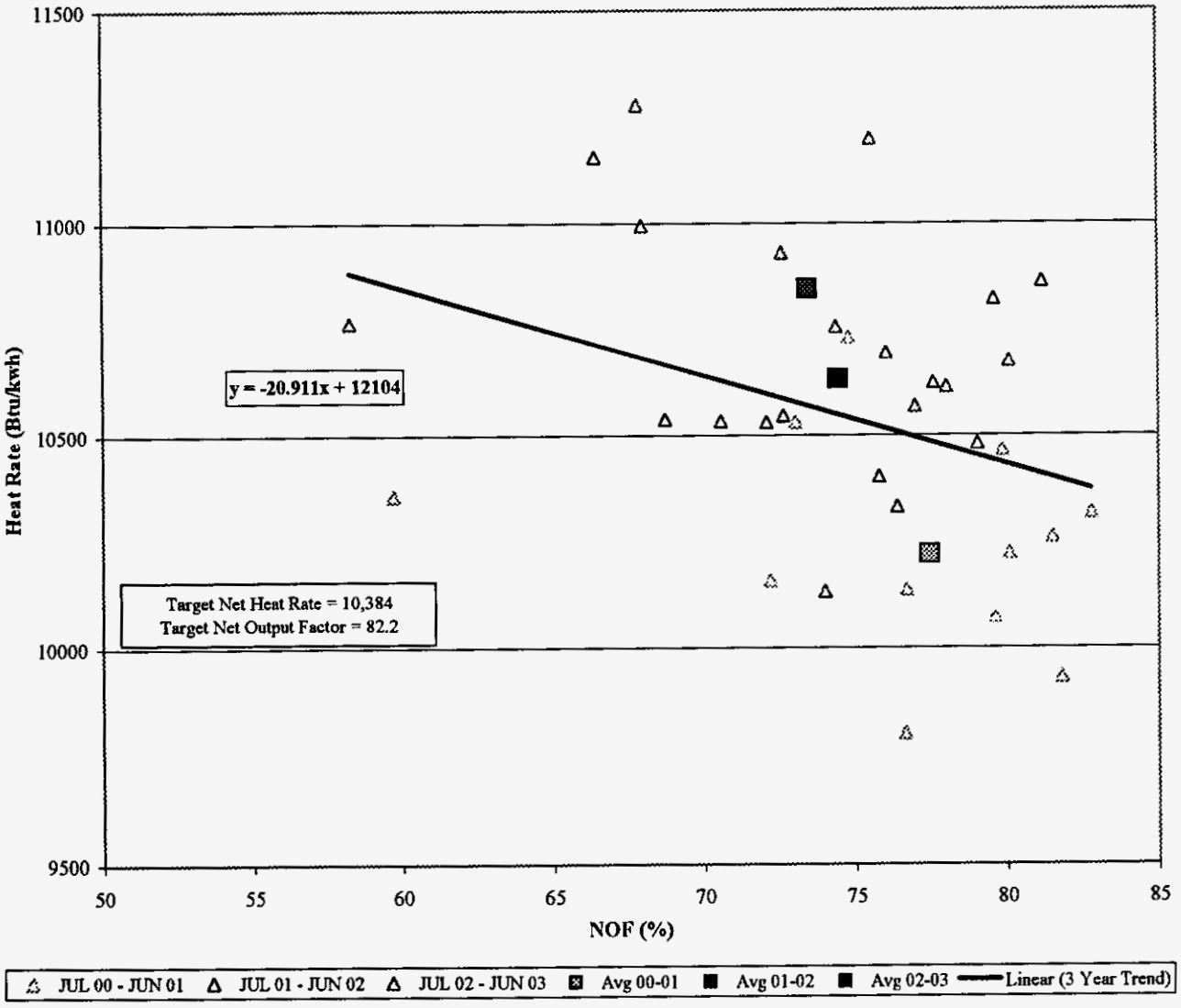


12 MRA = 12 Month Rolling Avreage

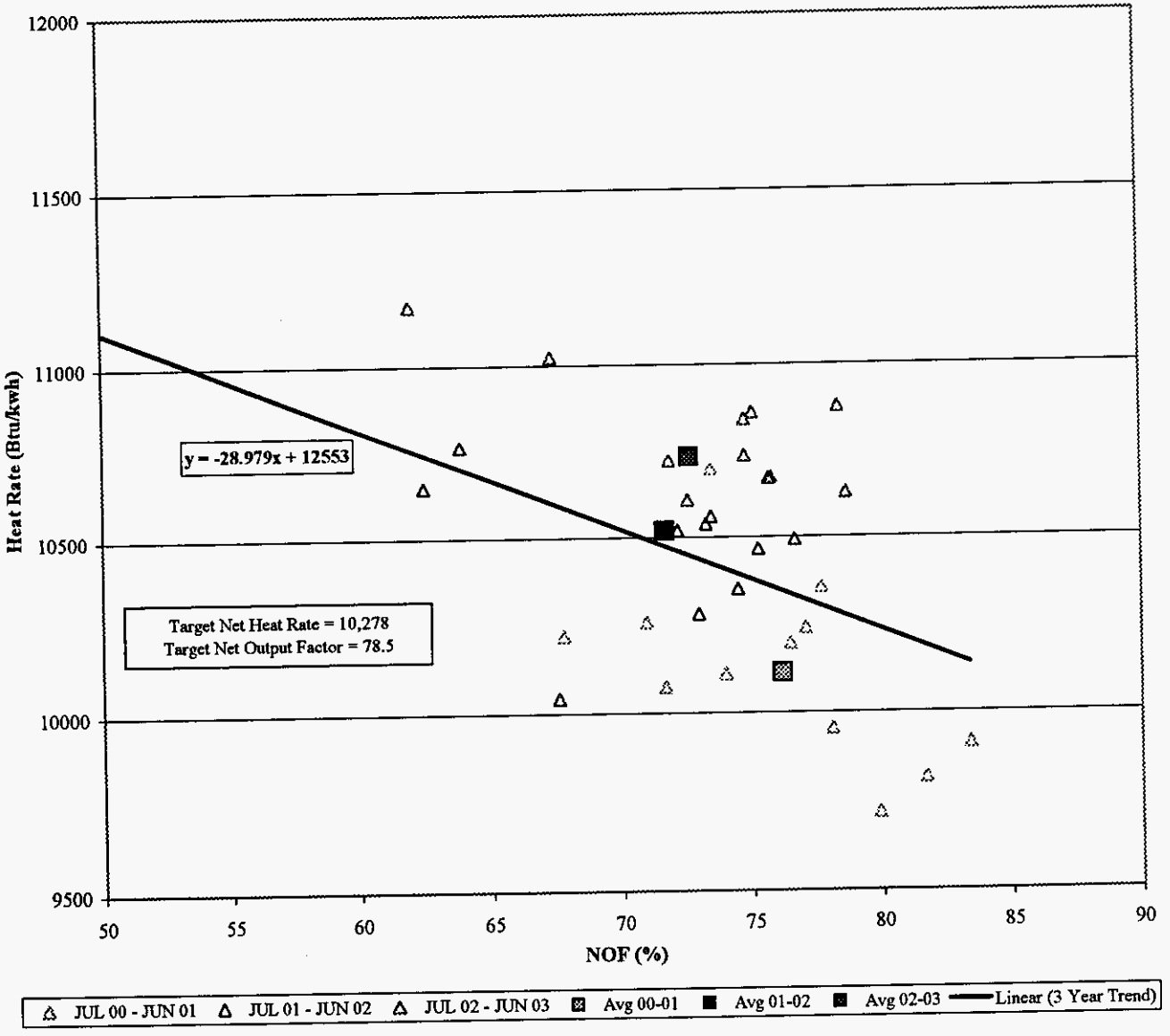
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #1



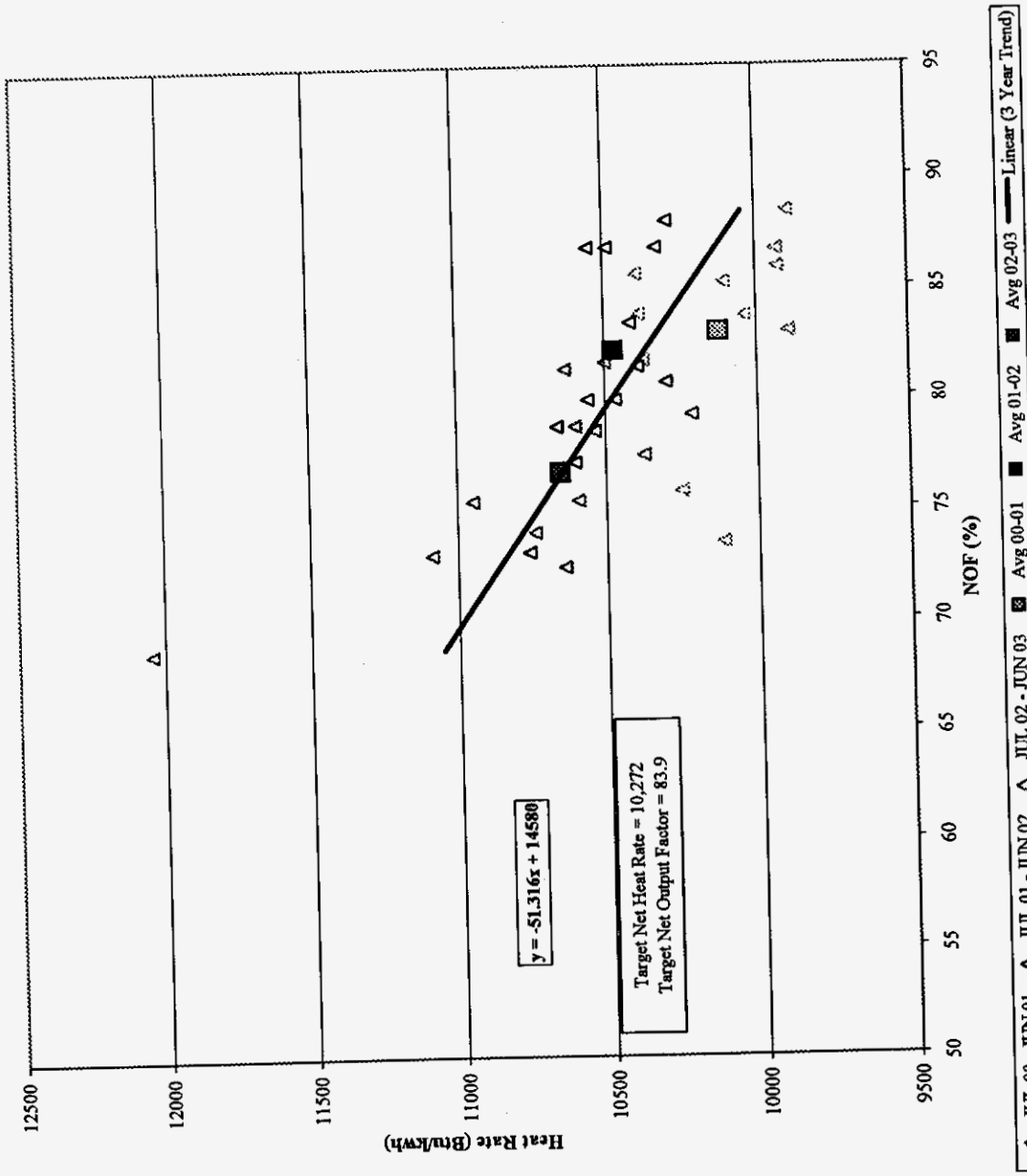
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #2



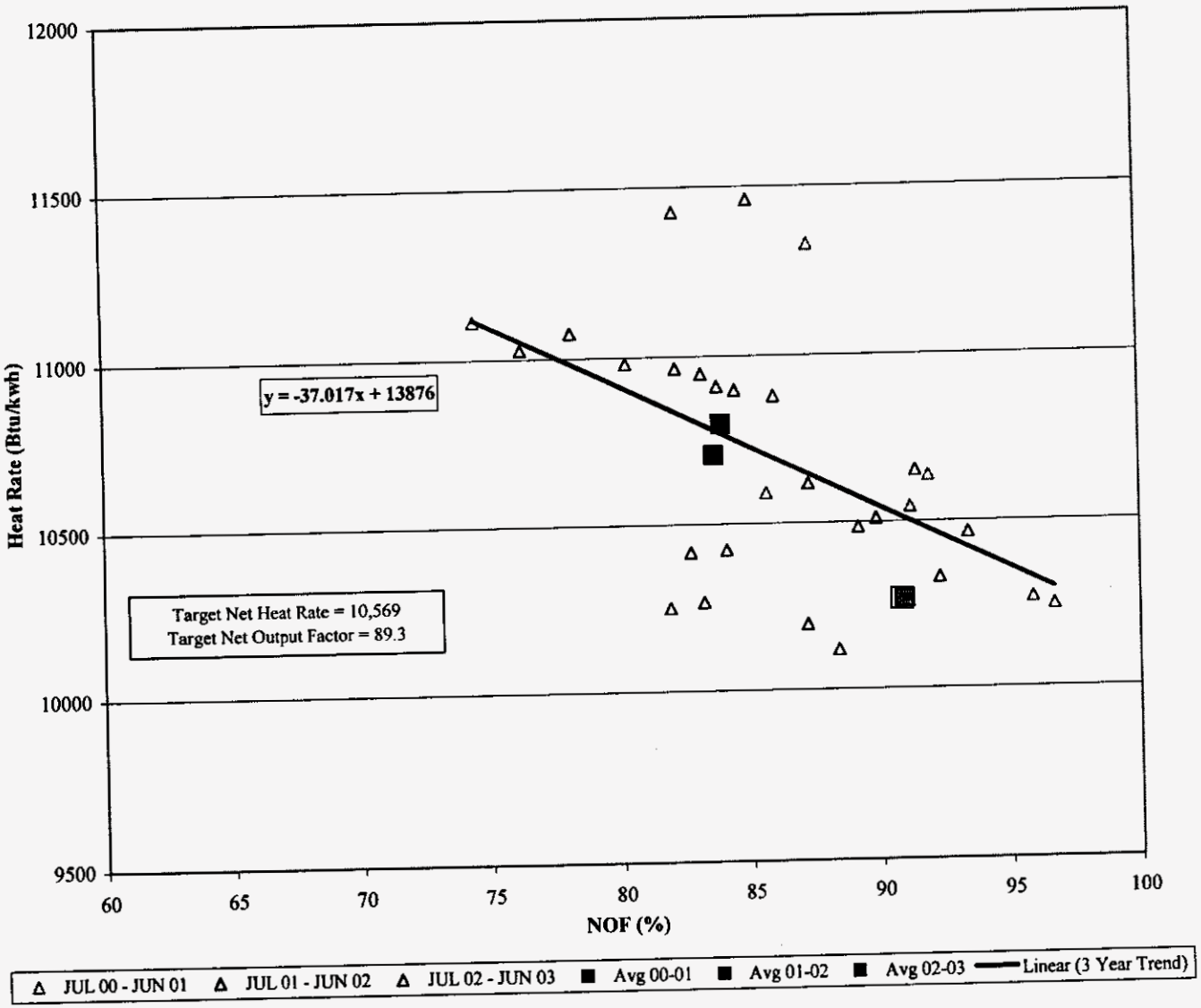
Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #3



Tampa Electric Company
Heat Rate vs Net Output Factor
Big Bend Unit #4



Tampa Electric Company
Heat Rate vs Net Output Factor
Polk Unit #1



TAMPA ELECTRIC COMPANY
GENERATING UNITS IN GPIF
TABLE 4.2
JANUARY 2004 - DECEMBER 2004

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
BIG BEND 1		447	425
BIG BEND 2		452	422
BIG BEND 3		455	433
BIG BEND 4		488	456
POLK 1		325	258
	GPIF TOTAL	2,167	1,993
	SYSTEM TOTAL	**4,547**	**4,222**
	% OF SYSTEM TOTAL	**47.66%**	**47.21%**

TAMPA ELECTRIC COMPANY
UNIT RATINGS
JANUARY 2004 - DECEMBER 2004

PLANT / UNIT		ANNUAL GROSS MDC (MW)	ANNUAL NET NDC (MW)
GANNON 1		0	0
GANNON 2		0	0
GANNON 3		0	0
GANNON 4		0	0
GANNON 5		0	0
GANNON 6		0	0
	GANNON TOTAL	0	0
BIG BEND 1		447	425
BIG BEND 2		452	422
BIG BEND 3		455	433
BIG BEND 4		488	456
	BIG BEND TOTAL	1,842	1,736
BIG BEND CT1		15	15
BIG BEND CT2		80	73
BIG BEND CT3		70	65
	CT TOTAL	165	153
PHILLIPS 1		18	17
PHILLIPS 2		18	17
	PHILLIPS TOTAL	36	34
POLK 1		325	258
POLK 2		180	170
POLK 3		180	173
	POLK TOTAL	685	600
BAYSIDE 1		787	735
BAYSIDE 2		1,032	965
	BAYSIDE TOTAL	1,819	1,700
	SYSTEM TOTAL	**4,547**	**4,222**

TAMPA ELECTRIC COMPANY
PERCENT GENERATION BY UNIT
JANUARY 2004 - DECEMBER 2004

PLANT	UNIT	NET OUTPUT MWH	PERCENT OF PROJECTED OUTPUT	PERCENT CUMULATIVE PROJECTED OUTPUT
BAYSIDE	2	4,984,242	25.90%	25.90%
BIG BEND	4	2,798,348	14.54%	40.44%
BAYSIDE	1	2,890,112	15.02%	55.46%
BIG BEND	3	2,263,934	11.76%	67.22%
BIG BEND	2	2,286,905	11.88%	79.11%
BIG BEND	1	2,149,249	11.17%	90.27%
POLK	1	1,728,783	8.98%	99.26%
POLK	2	40,157	0.21%	99.47%
PHILLIPS	1	35,275	0.18%	99.65%
PHILLIPS	2	34,067	0.18%	99.83%
POLK	3	33,156	0.17%	100.00%
BIG BEND CT	3	64	0.00%	100.00%
BIG BEND CT	1	58	0.00%	100.00%
BIG BEND CT	2	-	0.00%	100.00%
GANNON	1	-	0.00%	100.00%
GANNON	2	-	0.00%	100.00%
GANNON	3	-	0.00%	100.00%
GANNON	4	-	0.00%	100.00%
GANNON	5	-	0.00%	100.00%
GANNON	6	-	0.00%	100.00%
TOTAL GENERATION		19,244,350	100.00%	

GENERATION BY COAL UNITS: 14,117,331 MWH
% GENERATION BY COAL UNITS 73.36%

GENERATION BY NATURAL GAS UNITS: 7,947,667 MWH
% GENERATION BY NATURAL GAS UNITS 41.30%

GENERATION BY OIL UNITS: 69,464 MWH
% GENERATION BY OIL UNITS: 0.36%

GENERATION BY GPIF UNITS: 11,227,219 MWH
% GENERATION BY GPIF UNITS: 58.34%

EXHIBITS TO THE TESTIMONY OF

WILLIAM A. SMOTHERMAN

DOCKET NO. 030001-EI

GENERATING PERFORMANCE INCENTIVE FACTOR

JANUARY 2004 - DECEMBER 2004

DOCUMENT NO. 2

SUMMARY OF GPIF TARGETS

EXHIBIT NO. ___
TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
(WAS-2)
DOCUMENT NO. 2
PAGE 1 OF 1
FILED: 9/12/03

TAMPA ELECTRIC COMPANY
SUMMARY OF GPIF TARGETS
JANUARY 2004 - DECEMBER 2004

	Availability			Net
Unit	EAF	POF	EUOF	Heat Rate
Big Bend 1 [1]	67.2	5.74	27.11	10,708
Big Bend 2 [2]	66.7	5.74	27.57	10,384
Big Bend 3 [3]	67.6	5.74	26.66	10,278
Big Bend 4 [4]	78.2	5.74	16.09	10,272
Polk 1 [5]	85.6	4.37	10.03	10,569

1/ Original Sheet 8.401.04E, Page 12

2/ Original Sheet 8.401.04E, Page 13

3/ Original Sheet 8.401.04E, Page 14

4/ Original Sheet 8.401.04E, Page 15

5/ Original Sheet 8.401.04E, Page 16

FLORIDA PUBLIC SERVICE COMMISSION

DIVISION OF AUDITING AND SAFETY
BUREAU OF AUDITING

Tallahassee District Office

GULF POWER COMPANY

BASE YEAR HEDGING COSTS AUDIT

PROJECTED TEST YEAR ENDED MAY 31, 2003

DOCKET NUMBER 030001-EI

AUDIT CONTROL NO. 02-340-1-1

Michael Buckley

Michael Buckley, Audit Manager

Lynn M Deamer

Lynn M. Deamer, Audit Supervisor

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 9
COMPANY/ FPSC Staff
WITNESS: MEB-1 & MF-B-2
DATE: 11-12-03

TABLE OF CONTENTS

		PAGE
I.	**AUDITOR'S REPORT**	
	PURPOSE	1
	SCOPE LIMITATION	1
	DISCLAIM PUBLIC USE	1
	SUMMARY OF SIGNIFICANT FINDINGS	2
	SUMMARY OF SIGNIFICANT PROCEDURES	2
II.	**DISCLOSURE**	
	1. HEDGING	3

DIVISION OF AUDITING AND SAFETY
AUDITOR'S REPORT

June 10, 2003

TO: FLORIDA PUBLIC SERVICE COMMISSION AND OTHER INTERESTED PARTIES

We have applied the procedures described later in this report to audit base year hedging costs to be considered in the Fuel and Capacity Cost Recovery clause proceedings before this Commission.

This is an internal accounting report prepared after performing a limited scope audit. Accordingly, this report should not be relied upon for any purpose except to assist the Commission staff in the performance of their duties. Substantial additional work would have to be performed to satisfy generally accepted auditing standards and produce audited financial statements for public use.

SUMMARY OF SIGNIFICANT FINDINGS

The audit found that Gulf Power Company did not include any administrative financial hedging costs for the projected test year ended 5/31/03 as filed in Docket No. 010949-EI. The audit also did not find any actual administrative charges for financial hedging made before November 2002.

SUMMARY OF SIGNIFICANT PROCEDURES

Our audit was performed by examining certain transactions and account balances which we believe are sufficient to base our opinion. Our examination did not entail a complete review of all financial transactions of the utility. Our more important audit procedures are summarized below. The following definitions apply when used in this report:

Scanned - The documents or accounts were read quickly looking for obvious errors.

Verify - The item was tested for accuracy, and substantiating documentation was examined.

Obtained organization charts of Southern Company Services, Inc. to show what departments are involved in the physical and financial hedging process for the time period 1999 to 2003.

Obtained employee count for these departments from 1999 to 2003.

Obtained charges and percentage allocations for these departments from 1999 to 2003.

Verified actual FERC Account #501 (Fuel Handling Expense) and FERC Account #547 (Other Fuel Handling Expense) to estimated for the year 2002.

Verified actual account FERC Account #501 (Fuel Handling Expense) and FERC Account #547 (Other Fuel Handling Expense) to estimated for the first three months 2003.

II. DISCLOSURE

Disclosure No. 1

Subject: *Hedging*

Statement of Fact: Southern Company Services, Inc.(SCS), a subsidiary of Southern Company, charges its Fuel Services and Risk Management groups for financial hedging and other gas related activities. The Gas Procurement section in the SCS Fuel Services Organization procures physical gas, gas transportation, and gas storage, develops gas financial hedging strategy and executes financial hedging deals with counter parties. The Fuel Accounting group in the SCS Fuel Services Organization provides accounting services for gas procurement and gas financial hedging deals. The SCS Risk Management group confirms financial hedging deals with the counter parties, performs credit analysis on counter parties, performs overall risk analysis on financial hedging deals, and produces daily gas financial hedging reports.

These charges are then allocated to affiliates. In 1999, 2000, 2001 and 2002, the methodology for allocations were determined by each affiliates' percent ownership of total installed fossil fuel fired capacity for fossil fuel related charges. For 2003, the methodology for allocations were determined by each affiliates' percent ownership of gas fired capacity for charges related to gas supply activities and each affiliates' percent ownership of coal fired capacity for charges related to coal supply activities. Gulf Power Company experienced increasing charges each year up to 2002. For 2003, in spite of increased gas usage and additional administrative financial hedging costs, Gulf Power Company's expected allocation is lower. This is because of the new allocation method and several affiliates having new gas fired plants.

The estimated monthly administrative financial hedging charge for 2003 is $6,600. Gulf Power Company did not include any administrative financial hedging costs for the projected test year ended 5/31/03 as filed in Docket No. 010949-EI.

The only other hedging activity Gulf Power uses is physical, which has been used for many years. This is done through long term coal contracts. Costs are not kept separate. All physical hedging costs are included in base year costs.

DOCKET NO. 030001-EI: Fuel and purchased power cost recovery clause and generating performance incentive factor.

WITNESS: **Direct Testimony Of Michael E. Buckley,** Appearing On Behalf Of Staff

EXHIBIT: [redacted] 2002 Fuel Cost Recovery Clause Audit

FLORIDA PUBLIC SERVICE COMMISSION

DIVISION OF AUDITING AND SAFETY
BUREAU OF AUDITING

Tallahassee District Office

GULF POWER COMPANY

FUEL ADJUSTMENT AUDIT

TWELVE MONTH PERIOD ENDED DECEMBER 31, 2002

DOCKET NO. 030001-EI

AUDIT CONTROL NO. 03-034-1-1

Gennarro Jackson II, Audit Manager

Michael Buckley, Audit Staff

Lynn M. Deamer, Audit Supervisor

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DIVISION OF AUDITING AND SAFETY
AUDITOR'S REPORT

July 7, 2003

TO: FLORIDA PUBLIC SERVICE COMMISSION AND OTHER INTERESTED PARTIES

We have applied the procedures described later in this report to audit the accompanying fuel adjustment schedules for the twelve month period ended December 31, 2002, for Gulf Power Company. These schedules were prepared by the utility as part of its petition filed in Docket No. 030001-EI.

This is an internal accounting report prepared after performing a limited scope audit. Accordingly, this report should not be relied upon for any purpose except to assist the Commission staff in the performance of their duties. Substantial additional work would have to be performed to satisfy generally accepted auditing standards and produce audited financial statements for public use.

SUMMARY OF SIGNIFICANT PROCEDURES

Our audit was performed by examining, on a test basis, certain transactions and account balances which we believe are sufficient to base our opinion. Our examination did not entail a complete review of all financial transactions of the company. Our more important audit procedures are summarized below. The following definitions apply when used in this report:

Scanned - The documents or accounts were read quickly looking for obvious errors.

Compiled - The exhibit amounts were reconciled with the general ledger, and accounts were scanned for error or inconsistency.

Reviewed - The exhibit amounts were reconciled with the general ledger. The general ledger account balances were traced to subsidiary ledgers, and selective analytical review procedures were applied.

Verify - The item was tested for accuracy, and substantiating documentation was examined.

FUEL REVENUE: Revenue was audited in Review of Billing, Audit Control Number 02-183-1-1. No exceptions were found.

FUEL EXPENSE: Compiled the fuel cost of system net generation. Scanned and recomputed energy payments and fuel cost purchased power. Verified Other Generation (Gas). Recomputed net purchases/sales. Verified that Gains derived from non-separated, non-energy broker network, wholesale energy sales were credited to the fuel clause and separated between retail and wholesale customers based on the appropriate separation factor. Judgmentally sampled inventory Account 151 - Fuel Stock - Coal. Verified that the adjustment to coal inventory due to differences between the per book inventory quantities and the semi-annual coal inventory survey quantities were performed per Commission Order NO. PSC - 97-0359-FOF-EI. Recomputed and traced on a test basis coal and oil purchases filed in FPSC Form 423 to Company filings and the general ledger.

OTHER: Recalculated true-up and interest provision. Verified Commercial Paper rates in calculation of interest provision. Verified both the hours shown on annual GPIF filing and heat rate filed in schedule A4. Verified prior year accounts to determine the accounting methodologies and procedures used by the Company to account for incremental hedging costs, costs that are not included in base rates. Determined that the hedging program is consistent with Company's risk management plan for 2002.

DISCLOSURES

Disclosure No. 1

Subject: (Gain)/Loss on Hedging Settlements

Statement of Fact: Gulf Power Company recorded settlement costs of $38,750 to FERC Account # 547-4 (Hedging Settlement) for November 2002. In December 2002, Gulf recorded a settlement gain for gas hedging costs of ($277,500) to FERC Account # 547-4. November and December 2002 net to ($238,750) which is shown on the Company filed Schedule A-2, page 1 of 3, of the Fuel filing for December 2002. No administrative cost were charged for hedging in November or December 2002.

SCHEDULE A-2
PAGE 1 OF 3

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY

FOR THE MONTH OF: DECEMBER 2002

		CURRENT MONTH				PERIOD - TO - DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	$ ESTIMATED	AMOUNT ($)	%	ACTUAL	$ ESTIMATED	AMOUNT ($)	%
A.	*Fuel Cost & Net Power Transactions*								
1	Fuel Cost of System Net Generation	25,817,210.60	23,982,370	1,834,840.60	8.17	267,193,510.89	309,530,586.00	(36,337,075.11)	(11.97)
1a	Other Generation	208,047.59	425	207,622.59	48,852.37	2,275,474.19	217,158.00	2,058,316.19	947.84
1b	(Gain)/Loss of Hedging Settlement	(277,500.00)	0	(277,500.00)	#N/A	(236,750.00)	0.00	(236,750.00)	#N/A
2	Fuel Cost of Power Sold	(7,286,449.25)	(7,001,000)	(284,449.25)	3.78	(62,984,977.09)	(105,918,000.00)	42,933,022.91	(40.53)
3	Fuel Cost - Purchased Power	416,173.24	569,000	(152,826.76)	(26.86)	38,453,884.27	21,398,000.00	17,055,884.27	79.71
3a	Demand & Non-Fuel Cost Purchased Power	0.00	0	0.00	#N/A	0.00	0.00	0.00	#N/A
3b	Energy Payments to Qualifying Facilities	30,239.00	0	30,239.00	#N/A	5,019,154.46	312,882.00	4,706,322.46	1,504.42
4	Energy Cost-Economy Purchases	0.00	0	0.00	#N/A	0.00	0.00	0.00	#N/A
5	Total Fuel & Net Power Transactions	18,728,721.18	17,250,795	1,477,926.18	8.57	249,718,276.72	219,540,576	30,177,700.72	13.75
6	AdjustmentsTo Fuel Cost	10,069.14	0	10,069.14	#N/A	(1,611,150.68)	0	(1,611,150.68)	#N/A
7	Adj. Total Fuel & Net Power Transactions	18,738,790.32	17,250,795	1,487,995.32	8.63	248,107,126.04	219,540,576	28,566,550.04	13.01
B.	*KWH Sales*								
1	Jurisdictional Sales	767,122,522	806,488,000	(49,365,478)	(5.90)	10,771,897,002	10,265,886,000	506,011,002	4.93
2	Non-Jurisdictional Sales	31,376,354	29,309,000	2,067,354	7.05	371,528,951	356,845,000	14,683,951	4.11
3	Total Territorial Sales	818,498,876	865,797,000	(47,298,124)	(5.46)	11,143,425,953	10,622,731,000	520,694,953	4.90
4	Juris. Sales as % of Total Terr. Sales	96.1686	96.6148	(0.4462)	(0.46)	96.6659	96.6407	0.0252	0.03

Note: Line 6 - (Gain)/Loss on Sales of Natural Gas

EXHIBIT
Fuel Audit Report
Exhibit MEB-1 (Page 6 of 7)
Docket No. 030001-EI

CALCULATION OF TRUE-UP AND INTEREST PROVISION
GULF POWER COMPANY
FOR THE MONTH OF: DECEMBER 2002

	CURRENT MONTH				PERIOD - TO - DATE			
	$ ACTUAL	ESTIMATED	DIFFERENCE AMOUNT (#)	%	$ ACTUAL	ESTIMATED	DIFFERENCE AMOUNT (#)	%
C. *True-up Calculation*								
1 Jurisdictional Fuel Revenue	17,598,202.99	18,212,243	(616,039.99)	(3.38)	235,612,786.16	18,699,991	216,963,386.59	1,162.70
2 Fuel Adj. Revs. Not Applicable to Period:								
2a True-Up Provision	(991,807.59)	(991,803)	(4.59)	0.00	(10,701,890.96)	(10,701,891)	0.04	0.00
2b Incentive Provision	(31,148.92)	(31,147)	0.08	0.00	(373,764.04)	(373,764)	0.96	0.00
3 Juris. Fuel Revenue Applicable to Period	16,575,246.49	17,289,293	(616,044.51)	(3.56)	224,537,512.16	7,588,336	216,963,386.16	2,860.70
4 Adjusted Total Fuel & Net Power Transactions (Line A7)	18,736,790.32	17,250,795	1,487,995.32	8.63	248,107,126.04	219,540,576	28,566,550.04	13.01
5 Juris. Sales % of Total KWH Sales (Line B4)	98.1998	98.6148	(0.4152)	(0.46)	98.6859	98.6407	0.0252	0.03
6 Juris. Total Fuel & Net Power Transactions Adj. for Line Losses (C4 *C5*1.0007)	18,393,071.85	16,990,155	1,342,916.85	8.05	240,977,290.95	212,467,068	27,810,222.95	13.09
7 True-Up Provision for the Month Over/(Under) Collection (C3-C6)	(1,358,823.36)	599,138	(1,958,961.36)	(326.86)	(15,530,042.90)	(30,579)	(15,499,463.90)	50,686.63
8 Interest Provision for the Month	(29,942.60)	(685)	(29,057.60)	3,268.54	(373,985.49)	(44,624)	(329,364.49)	738.09
9 Beginning True-Up & Interest Provision*	(27,516,320.30)	(1,585,259)	(25,951,061.30)	1,657.94	(23,099,814.80)	(10,701,891)	(12,398,123.80)	115.87
10 True-Up Collected / (Refunded)	991,807.59	991,803	4.59	0.00	10,701,890.96	10,701,891	(0.04)	0.00
11 End of Period - Total Net True-Up, Before Adjustment (C7+C8+C9+C10)	(28,014,278.68)	(75,203)	(27,939,075.68)	37,151.54	(28,272,155.23)	(75,203)	(28,196,952.23)	37,494.45
12 2001 Revenue Sharing Refund True-Up		0	0.00	#N/A	257,876.55	0	257,876.55	#N/A
13 End of Period - Total Net True-Up (C11 + C12)	(28,014,278.68)	(75,203)	(27,939,075.68)	37,151.54	(28,014,278.68)	(75,203)	(27,939,075.68)	37,151.54

EXHIBIT
Exhibit MEB-1 (Page 7 of 7)
Fuel Audit Report

DOCKET NO. 030001-EI: Fuel and purchased power cost recovery clause and generating performance incentive factor.

WITNESS: **Direct Testimony Of Jocelyn Y. Stephens,** Appearing On Behalf Of Staff

EXHIBIT: JYS-1 - Audit of Base Year Costs For Security and Hedging

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. Comp. Exh. 1B
COMPANY/ FPSC - Staff
WITNESS: JYS-1 + JYS-2
DATE: 11-12-03

FLORIDA PUBLIC SERVICE COMMISSION

DIVISION OF AUDITING AND SAFETY
BUREAU OF AUDITING

TAMPA DISTRICT OFFICE

TAMPA ELECTRIC COMPANY

BASE YEAR SECURITY AND HEDGING COST AUDIT

FOR THE TWELVE MONTH PERIODS ENDED
DECEMBER 31, 2001 AND DECEMBER 31, 2002

DOCKET NO. 030001-EI

AUDIT CONTROL NO. 02-340-2-1

Jocelyn Y. Stephens, Audit Manager

James A. McPherson, Tampa District Supervisor

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DIVISION OF AUDITING AND SAFETY
AUDITOR'S REPORT

March 17, 2003

TO: FLORIDA PUBLIC SERVICE COMMISSION AND OTHER INTERESTED PARTIES

We have applied the procedures described later in this report to audit the base year security and hedging costs to be used in the fuel and capacity cost recovery clause proceedings for the historical twelve month periods ended December 31, 2001 and 2002 for Tampa Electric Company. There is no confidential information associated with this audit.

This is an internal accounting report prepared after performing a limited scope audit. Accordingly, this report should not be relied upon for any purpose except to assist the Commission staff in the performance of their duties. Substantial additional work would have to be performed to satisfy generally accepted auditing standards and produce audited financial statements for public use.

SUMMARY OF SIGNIFICANT PROCEDURES

Our audit was performed by examining, on a test basis, certain transactions and account balances which we believe are sufficient to base our opinion. Our examination did not entail a complete review of all financial transactions of the company. Our more important audit procedures are summarized below. The following definitions apply when used in this report:

Compiled - The exhibit amounts were reconciled with the general ledger, and accounts were scanned for error or inconsistency.

Verify - The item was tested for accuracy, and substantiating documentation was examined.

SECURITY: Obtained total security costs for the years 2000 through 2003 (projected). Determined total recorded security costs (including incremental costs), for calendar years 2000, 2001 and 2002 totaled $2,731,227, $3,508,664, and $3,619,633, respectively. Projected 2003 security costs totaled $3,283,370. Tested a randomly selected sample of security charges to supporting documentation.

HEDGING: Obtained total and incremental hedging costs for the years 2001, 2002 and for the projected year 2003. Determined the Company's distinction between financial hedging and physical hedging. Obtained the percentage of time employees devoted to hedging activities and recomputed hedging expense using the employees' annual salaries.

AUDIT DISCLOSURE NO. 1

SUBJECT: SECURITY COSTS

STATEMENT OF FACT:

The company was requested to provide plant security costs by function (i.e. generation, transmission and distribution). In its response to this request, the company spokesperson stated that for the period January 2000 through December 2002 security costs cannot be segregated between functions because these costs were not tracked by function, when incurred. The security costs specific to a location and to generation are distinguishable to a limited extent, as per FERC rules. These would include costs for security personnel who normally sign personnel and visitors in and out of a specified plant. Also, security costs pertaining to transmission and distribution cannot be segregated. These amounts are recorded as Administrative and General (A&G), along with actual A&G security costs. Any segregation of security costs would have to be done on some sort of arbitrary allocation methodology, which would not depict a true reflection of incurred security costs.

However, the Company was able to provide security by function for incremental costs incurred as a result of the 9/11 event.

AUDITOR OPINION:

Base year security costs per the company calculation for 2001 totals $3,108,013; and, for 2002 totals $3,225,684.

We prepared schedules for the years 2001, 2002 and projected 2003, by account, by month, for security costs recorded in the general ledger. In order to determine the amount of normal and recurring security costs, we removed those costs identified by the company as incremental. The resulting amount equals actual security costs on a consistent basis. Staff then calculated average security cost based upon 2001 and 2002 security costs. Average costs, per staff calculation, totaled $3,166,848. Staff believes that the average amount better represents a base amount for security costs when determining incremental security costs to be used in future years.. See table below:

	2001	2002	Projected 2003	Average 2001-2002
Balance PER G/L (Inc Incremental)	3,508,664	3,619,633	3,283,370	3,564,149
Incremental Costs	(400,651)	(393,949)	(228,970)	
BALANCE PER G/L (Exc Incremental)	3,108,013	3,225,684	3,054,400	3,166,848

AUDIT DISCLOSURE NO. 2

SUBJECT: HEDGING

STATEMENT OF FACT:

For the year ended December 31, 2001, Tampa Electric Company determined that it had incurred total hedging expense of $169,153. This total consisted of $159,723 of payroll and related fringe benefits determined by the percentage of time each employee in the Fuels department devoted to physical hedging activities. Additionally, $2,500 was spent for travel costs to the coal mine for contract negotiations and $6,930 for training on hedging. The payroll costs were not recorded in a separate account, rather the percentage of time devoted to hedging was multiplied by the fully loaded labor costs for each employee's position. As a result, these hedging expenses cannot be traced directly to the general ledger.

Effective in May 2002, the Fuels department and the Wholesale Marketing department merged to create the Wholesale Marketing and Fuels Department. We were told that in addition to physical and financial hedging activities this department also performs daily activities, planning, and regulatory activities. A breakdown between physical and financial hedging cannot be determined. This department currently consists of five positions that devote time to hedging (risk management):

1. Director
2. Fuels Strategist
3. Forecast Analysis
4. Contract Administrator
5. Manager of Natural Gas

Prior to May 2002, the procurement of natural gas for Tampa Electric's use was performed by Peoples Gas System (PGS). PGS arranged for the purchase and delivery of the gas and billed Tampa Electric its actual cost plus a small administration fee based on the time spent arranging the purchase. The total amount paid was included as cost of gas and recovered in the fuel clause.

For the calendar year 2002, Tampa Electric determined total hedging costs to be $252,939 with the incremental portion being $83,786. The percentage of time employees spent on hedging activities ranged from 30% to 80%. Any gains or losses on hedging activities are included in fuel costs and are recovered in the fuel clause.

DOCKET NO. 030001-EI: Fuel and purchased power cost recovery clause and generating performance incentive factor.

WITNESS: **Direct Testimony Of Jocelyn Y. Stephens,** Appearing On Behalf Of Staff

EXHIBIT: JYS-2 - 2002 Capacity Cost Recovery Clause Audit

FLORIDA PUBLIC SERVICE COMMISSION

DIVISION OF AUDITING AND SAFETY
BUREAU OF AUDITING

TAMPA DISTRICT OFFICE

TAMPA ELECTRIC COMPANY

CAPACITY COST RECOVERY AUDIT

FOR THE TWELVE MONTH PERIOD ENDED DECEMBER 31, 2002

DOCKET NO. 030001-EI

AUDIT CONTROL NO. 03-036-2-1

Jocelyn Y. Stephens, Audit Staff

Simon Ojada, Audit Manager

James A. McPherson, Tampa District Supervisor

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DIVISION OF AUDITING AND SAFETY
AUDITOR'S REPORT

April 8, 2003

TO: FLORIDA PUBLIC SERVICE COMMISSION AND OTHER INTERESTED PARTIES

We have applied the procedures described later in this report to audit the accompanying Capacity Cost Recovery True-up schedules for the historical twelve month period ended December 31, 2002 for Tampa Electric Company. These schedules were prepared by the utility as part of its petition for a Fuel Cost Factor Adjustment in Docket 030001-EI. There is no confidential information associated with this audit and there are no staff minority opinions.

This is an internal accounting report prepared after performing a limited scope audit. Accordingly, this report should not be relied upon for any purpose except to assist the Commission staff in the performance of their duties. Substantial additional work would have to be performed to satisfy generally accepted auditing standards and produce audited financial statements for public use.

SUMMARY OF SIGNIFICANT FINDINGS

During the period November 2001 through August 2002, the Company included an amount for Incremental Security Costs totaling $794,598.

In December 2002, the Company included an amount for a 1993 Capacity Price Adjustment totaling $170,300.

Revenues recorded in the general ledger were understated approximately $7,500 due to a refund being issued, in error, to optional provision customers.

SUMMARY OF SIGNIFICANT PROCEDURES

Our audit was performed by examining, on a test basis, certain transactions and account balances which we believe are sufficient to base our opinion. Our examination did not entail a complete review of all financial transactions of the company. Our more important audit procedures are summarized below. The following definitions apply when used in this report:

Compiled - The exhibit amounts were reconciled with the general ledger, and accounts were scanned for error or inconsistency.

Verify - The item was tested for accuracy, and substantiating documentation was examined.

REVENUE: Compiled Capacity Cost Recovery (CCR) revenue and agreed to the filing. Recomputed CCR revenues using approved FPSC rate factors and company provided KWH sales.

EXPENSES: Recomputed capacity costs. Agreed capacity costs to Tampa Electric billing statements. Identified costs by vendor. Performed audit test work of capacity cost payments to verify that vendors were paid capacity charges according to contract terms for electric power supplied by the vendors. Verified that incremental security costs were transferred from the fuel clause in accordance with Commission directive.

TRUE-UP: Recomputed CCR true-up and interest using FPSC approved amounts and interest rates.

Disclosure No. 1

Subject: Incremental Security Costs

Statement of Fact: In accordance with Commission Orders PSC-01-2516-FOF-EI and PSC-02-1761-FOF-EI, the company has recorded an amount for incremental security costs in its 2002 Capacity Filing of $794,598. These incremental costs were incurred by the company during the period November 2001 through August 2002.

Tampa Electric has interpreted incremental security costs to be any costs that occurred subsequent to the 9/11 event, that would not have occurred if not for the heightened level of alert. The company's computation of incremental security costs is shown below:

	Gen'l Ledger Balance	Incremental	Net Security
2001	$3,508,733	$400,650	$3,108,083
2002	3,619,633	393,948	3,225,685
			$6,333,768
Total 2002 Capacity Clause		$794,598	
Average Net Security			$3,166,884

Recommendation: Based upon the security costs audit performed by the PSC staff, a two-year average of net security costs was determined to be the most appropriate amount to use in calculating a base amount for incremental security costs. The two-year average was calculated using the general ledger balances less company recorded incremental costs for the years 2001 and 2002. Staff's average base amount for 2001 and 2002 equals $3,166,884. In future years, we believe any costs greater than this amount could be considered incremental.

Using the average balance per staff computation, incremental costs for 2002 should not exceed $452,785. This is greater than the amount recorded by the company, therefore the company's computed balance for incremental costs for 2002 appears to be reasonable.

Disclosure No. 2

Subject: Capacity Price Adjustment

Statement of Fact: The company included an adjustment for $170,300 increasing its capacity charges from Hardee Power Partners (HPP) in December 2002. The company states that the adjustment was the net effect of several omissions to the filings occurring during 1993 and 1994. First, a December 1993 invoice from Hardee Power Partners for Capacity Price Adjustments, approved by FERC which totaled $209,820 was never booked to an expense account. Per the company spokesperson, the December 2002 adjustment was the result of an internal reconciliation of balance sheet accounts performed last year. In doing the reconciliation it was discovered that an invoice for capacity price adjustment was paid in December 1993 and booked to account 234.21 (an interchange payable account). Additionally, in 1994 several adjustments [credits totaling $39,520] were made to interchange customers reducing their original capacity bills. These adjustment credits were not picked up in the capacity filing since the booked capacity expenses exceeded the amount booked as a payable. To make sure the ratepayers were not negatively impacted the company offset those credits against the original invoice amount and made an adjustment in December 2002 to record the balance of $170,300.

Recommendation: This adjustment is for activity that occurred eight and nine years ago. We did not have the time to verify whether or not these amounts had been included in any of the prior filings, but we did review the adjusting entry crediting the liability and debiting the capacity expense accounts in December 2002.

Disclosure No. 3

Subject: Erroneous Billing for Optional Provision Customers

Statement of Fact: The company was ordered to make refunds associated with the 1999 earnings settlement totaling $6.1 million plus interest over the period June through August 2002. During the process the company erroneously calculated and made refunds to its optional provision customers. This error results in differences of approximately $7,500 between the revenues per CCR Filing and revenues per the general ledger.

The company is currently working to resolve this situation.

Recommendation: Because of the overall immateriality of the refund amounts, company should be allowed to correct the error and PSC staff then perform an analysis of the correction in a subsequent audit.

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY ADJUSTMENT
For Months January 2002 through December 2002

Description	REVISED 2/5/02 REVISED 3/28/02 2001 DEC	2002 JAN	2002 FEB	2002 MAR	2002 APR	2002 MAY	2002 JUN	2002 JUL	2002 AUG	2002 SEP	2002 OCT	2002 NOV	2002 DEC	
Recovery Revenues	$2,442,049	$4,231,917	$3,557,714	$3,514,105	$4,056,855	$4,668,632	$4,817,528	$4,765,906	$4,980,801	$5,010,618	$5,007,012	$4,020,593	$3,775,360	$52,367,041
-up	164,770	(463,342)	(463,342)	(463,342)	(463,342)	(463,342)	(463,342)	(463,342)	(463,342)	(463,342)	(463,342)	(463,342)	(463,341)	(5,560,103)
Revenue Applicable to Period	2,606,819	3,768,575	3,094,372	3,050,763	3,593,513	4,205,290	4,354,186	4,302,564	4,497,459	4,547,276	4,543,670	3,557,251	3,312,019	46,806,938
Recovery Expense	2,425,900	4,422,147	3,969,637	3,807,725	3,824,815	3,831,192	4,668,981	4,525,624	4,507,015	3,599,294	4,616,759	3,797,508	5,453,384	51,024,061
This Period	180,919	(653,572)	(875,265)	(756,962)	(231,302)	374,098	(314,775)	(223,060)	(9,556)	947,982	(73,089)	(240,257)	(2,141,365)	(4,197,123)
rovision This Period	(5,003)	(4,793)	(5,210)	(5,775)	(5,829)	(5,012)	(4,295)	(3,961)	(3,416)	(2,116)	(796)	(314)	(1,061)	(42,576)
l Interest Provision ng of Month	(3,154,317)	(3,143,171)	(3,338,194)	(3,755,327)	(4,054,722)	(3,828,511)	(2,998,083)	(2,851,811)	(2,615,490)	(2,185,120)	(755,912)	(366,455)	(143,684)	(3,143,171)
-up Collected/(Refunded)	(164,770)	463,342	463,342	463,342	463,342	463,342	463,342	463,342	463,342	463,342	463,342	463,342	463,341	5,560,103
riod Total Net True-up	(3,143,171)	(3,338,194)	(3,755,327)	(4,054,722)	(3,828,511)	(2,998,083)	(2,851,811)	(2,615,490)	(2,185,120)	(755,912)	(366,455)	(143,684)	(1,822,769)	(1,822,769)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY ADJUSTMENT

ary 2002 through December 2002
REVISED 2/5/02
REVISED 3/26/02

nterest Provision	2001 DEC	2002 JAN	2002 FEB	2002 MAR	2002 APR	2002 MAY	2002 JUN	2002 JUL	2002 AUG	2002 SEP	2002 OCT	2002 NOV	2002 DEC	Total
rue-up	($4,770,478)	($3,143,171)	($3,338,194)	($3,755,327)	($4,054,722)	($3,628,511)	($2,998,083)	($2,851,811)	($2,615,490)	($2,185,120)	($755,912)	($368,455)	($143,684)	($1,822,769)
-up Amount Before Interest	(3,138,188)	(3,333,401)	(3,759,117)	(4,048,947)	(3,822,882)	(2,991,071)	(2,847,516)	(2,811,529)	(2,161,704)	(753,788)	(365,659)	(143,370)	(1,821,709)	
ning & Ending True-up	($7,908,666)	($6,476,572)	($7,098,311)	($7,804,274)	($7,877,604)	($6,619,582)	($5,843,599)	($5,663,340)	($4,777,194)	($2,918,918)	($1,121,571)	($509,825)	($1,965,392)	
ue-up Amount	($3,954,333)	($3,238,286)	($3,544,156)	($3,902,137)	($3,938,702)	($3,409,791)	($2,921,800)	($2,731,670)	($2,388,597)	($1,459,459)	($560,786)	($254,913)	($982,696)	
te - Last Day of Prior Month	2.040%	1.780%	1.770%	1.780%	1.800%	1.750%	1.770%	1.750%	1.730%	1.710%	1.780%	1.650%	1.300%	
te - Last Day of Current Month	1.780%	1.770%	1.750%	1.800%	1.750%	1.770%	1.750%	1.730%	1.710%	1.780%	1.650%	1.300%	1.280%	
	3.820%	3.550%	3.520%	3.580%	3.550%	3.520%	3.520%	3.480%	3.440%	3.470%	3.410%	2.950%	2.580%	
erest Rate	1.910%	1.775%	1.760%	1.775%	1.775%	1.760%	1.760%	1.740%	1.720%	1.735%	1.705%	1.475%	1.290%	
erage Interest Rate	0.159%	0.148%	0.147%	0.148%	0.148%	0.147%	0.147%	0.145%	0.143%	0.145%	0.142%	0.123%	0.108%	
vision	($6,287)	($4,793)	($5,210)	($5,775)	($5,829)	($5,012)	($4,295)	($3,961)	($3,416)	($2,116)	($798)	($314)	($1,061)	($42,578)

Exhibit GJY-1
2002 Hedging Activity

FPL NATURAL GAS PROCUREMENT

Instrument	Volume Purchases	Sales	Option Premiums	Savings
2002 Hedging Activity Totals:	[redacted]			
FIXED PRICE TRANSACTIONS				
STORAGE				
PHYSICAL POWER OPTIONS				
SWAPS				
SWING SWAPS				
OVER-THE-COUNTER OPTIONS				
GAS OPTIONS				
FUTURES				
BROKER FEES				
AVERAGE PERIOD OF HEDGE (Days) - PHYSICAL				
AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL				

DOCUMENT NUMBER-DATE
03022 APR-1 03
FPSC-COMMISSION CLERK
FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 11
COMPANY/ FL Natural Gas Procurement
WITNESS: GJY-1 & GJY-2
DATE: 11-12-03

Exhibit GJY-1
2002 Hedging Activity

FPL HEAVY FUEL OIL PROCUREMENT

Instrument	Volume Purchases	Sales	Option Premiums	Savings
2002 Hedging Activity Totals:	[redacted]			
FIXED PRICE TRANSACTIONS				
STORAGE				
PHYSICAL POWER OPTIONS				
SWAPS				
SWING SWAPS				
OVER-THE-COUNTER OPTIONS				
GAS OPTIONS				
FUTURES				
BROKER FEES				
AVERAGE PERIOD OF HEDGE (Days) - PHYSICAL				
AVERAGE PERIOD OF HEDGE (Days) - FINANCIAL				

Exhibit GJY-1
2002 Hedging Activity

Instrument	ELECTRICITY - Premiums Only Volume Purchases	Sales	Savings
FIXED PRICE TRANSACTIONS	[redacted]		
STORAGE			
PHYSICAL POWER OPTIONS			
SWAPS			
SWING SWAPS			
OVER-THE-COUNTER OPTIONS			
GAS OPTIONS			
FUTURES			
BROKER FEES			
AVERAGE PERIOD OF HEDGE (Days) - PHYSICAL			

Exhibit GJY-1
2002 Hedging Activity

FPL NATURAL GAS PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Jan-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	FUTURES				
	BROKER FEES				

Exhibit GJY-1
2002 Hedging Activity

FPL HEAVY FUEL OIL PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Jan-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	FUTURES				
	BROKER FEES				

Exhibit GJY-1
2002 Hedging Activity

		ELECTRICITY - Premiums Only		
		Volume		
	Instrument	Purchases	Sales	Savings
Jan-02	FIXED PRICE TRANSACTIONS	[redacted]		
	STORAGE			
	PHYSICAL POWER OPTIONS			
	SWAPS			
	SWING SWAPS			
	OVER-THE-COUNTER OPTIONS			
	FUTURES			
	BROKER FEES			

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2002 Hedging Activity

FPL NATURAL GAS PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Feb-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
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	SWING SWAPS				
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	FUTURES				
	BROKER FEES				

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2002 Hedging Activity

FPL HEAVY FUEL OIL PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Feb-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
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	SWING SWAPS				
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	FUTURES				
	BROKER FEES				

Exhibit GJY-1
2002 Hedging Activity

		ELECTRICITY - Premiums Only		
		Volume		
	Instrument	Purchases	Sales	Savings
Feb-02	FIXED PRICE TRANSACTIONS	[redacted]		
	STORAGE			
	PHYSICAL POWER OPTIONS			
	SWAPS			
	SWING SWAPS			
	OVER-THE-COUNTER OPTIONS			
	FUTURES			
	BROKER FEES			

Exhibit GJY-1
2002 Hedging Activity

FPL NATURAL GAS PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Mar-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
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	SWING SWAPS				
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	FUTURES				
	BROKER FEES				

Exhibit GJY-1
2002 Hedging Activity

FPL HEAVY FUEL OIL PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Mar-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
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	SWING SWAPS				
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	FUTURES				
	BROKER FEES				

Exhibit GJY-1
2002 Hedging Activity

		ELECTRICITY - Premiums Only		
		Volume		
	Instrument	Purchases	Sales	Savings
Mar-02	FIXED PRICE TRANSACTIONS	[redacted]		
	STORAGE			
	PHYSICAL POWER OPTIONS			
	SWAPS			
	SWING SWAPS			
	OVER-THE-COUNTER OPTIONS			
	FUTURES			
	BROKER FEES			

Exhibit GJY-1
2002 Hedging Activity

FPL NATURAL GAS PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Apr-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	FUTURES				
	BROKER FEES				

Exhibit GJY-1
2002 Hedging Activity

FPL HEAVY FUEL OIL PROCUREMENT

	Instrument	Volume Purchases	Volume Sales	Option Premiums	Savings
Apr-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	FUTURES				
	BROKER FEES				

Exhibit GJY-1
2002 Hedging Activity

		ELECTRICITY - Premiums Only		
		Volume		
	Instrument	Purchases	Sales	Savings
Apr-02	FIXED PRICE TRANSACTIONS	[redacted]		
	STORAGE			
	PHYSICAL POWER OPTIONS			
	SWAPS			
	SWING SWAPS			
	OVER-THE-COUNTER OPTIONS			
	FUTURES			
	BROKER FEES			

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2002 Hedging Activity

FPL NATURAL GAS PROCUREMENT

	Instrument	Volume Purchases	Volume Sales	Option Premiums	Savings
May-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	FUTURES				
	BROKER FEES				

Exhibit GJY-1
2002 Hedging Activity

FPL HEAVY FUEL OIL PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
May-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	FUTURES				
	BROKER FEES				

Exhibit GJY-1
2002 Hedging Activity

		ELECTRICITY - Premiums Only		
		Volume		
	Instrument	Purchases	Sales	Savings
May-02	FIXED PRICE TRANSACTIONS	[redacted]		
	STORAGE			
	PHYSICAL POWER OPTIONS			
	SWAPS			
	SWING SWAPS			
	OVER-THE-COUNTER OPTIONS			
	FUTURES			
	BROKER FEES			

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2002 Hedging Activity

FPL NATURAL GAS PROCUREMENT

	Instrument	Volume Purchases	Volume Sales	Option Premiums	Savings
Jun-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	FUTURES				
	BROKER FEES				

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2002 Hedging Activity

FPL HEAVY FUEL OIL PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Jun-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	FUTURES				
	BROKER FEES				

Exhibit GJY-1
2002 Hedging Activity

		ELECTRICITY - Premiums Only		
		Volume		
	Instrument	Purchases	Sales	Savings
Jun-02	FIXED PRICE TRANSACTIONS	[redacted]		
	STORAGE			
	PHYSICAL POWER OPTIONS			
	SWAPS			
	SWING SWAPS			
	OVER-THE-COUNTER OPTIONS			
	FUTURES			
	BROKER FEES			

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2002 Hedging Activity

FPL NATURAL GAS PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Jul-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	FUTURES				
	BROKER FEES				

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2002 Hedging Activity

FPL HEAVY FUEL OIL PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Jul-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	FUTURES				
	BROKER FEES				

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2002 Hedging Activity

ELECTRICITY - Premiums Only

	Instrument	Volume Purchases	Sales	Savings
Jul-02	FIXED PRICE TRANSACTIONS	[redacted]		
	STORAGE			
	PHYSICAL POWER OPTIONS			
	SWAPS			
	SWING SWAPS			
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2002 Hedging Activity

FPL NATURAL GAS PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Aug-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
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2002 Hedging Activity

FPL HEAVY FUEL OIL PROCUREMENT

	Instrument	Volume Purchases	Volume Sales	Option Premiums	Savings
Aug-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	FUTURES				
	BROKER FEES				

Exhibit GJY-1
2002 Hedging Activity

		ELECTRICITY - Premiums Only		
		Volume		
	Instrument	Purchases	Sales	Savings
Aug-02	FIXED PRICE TRANSACTIONS	[redacted]		
	STORAGE			
	PHYSICAL POWER OPTIONS			
	SWAPS			
	SWING SWAPS			
	OVER-THE-COUNTER OPTIONS			
	FUTURES			
	BROKER FEES			

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2002 Hedging Activity

FPL NATURAL GAS PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Sep-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	FUTURES				
	BROKER FEES				

Exhibit GJY-1
2002 Hedging Activity

FPL HEAVY FUEL OIL PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Sep-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	FUTURES				
	BROKER FEES				

Exhibit GJY-1
2002 Hedging Activity

		ELECTRICITY - Premiums Only		
		Volume		
	Instrument	Purchases	Sales	Savings
Sep-02	FIXED PRICE TRANSACTIONS	[redacted]		
	STORAGE			
	PHYSICAL POWER OPTIONS			
	SWAPS			
	SWING SWAPS			
	OVER-THE-COUNTER OPTIONS			
	FUTURES			
	BROKER FEES			

Exhibit GJY-1
2002 Hedging *Activity*

FPL NATURAL GAS PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Oct-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	FUTURES				
	BROKER FEES				

Exhibit GJY-1
2002 Hedging Activity

FPL HEAVY FUEL OIL PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Oct-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	FUTURES				
	BROKER FEES				

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2002 Hedging Activity

		ELECTRICITY - Premiums Only		
		Volume		
	Instrument	Purchases	Sales	Savings
Oct-02	FIXED PRICE TRANSACTIONS	[redacted]		
	STORAGE			
	PHYSICAL POWER OPTIONS			
	SWAPS			
	SWING SWAPS			
	OVER-THE-COUNTER OPTIONS			
	FUTURES			
	BROKER FEES			

Exhibit GJY-1
2002 Hedging Activity

FPL NATURAL GAS PROCUREMENT

	Instrument	Volume Purchases	Volume Sales	Option Premiums	Savings
Nov-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
	GAS OPTIONS				
	FUTURES				
	BROKER FEES				

Exhibit GJY-1
2002 Hedging Activity

FPL HEAVY FUEL OIL PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Nov-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
	OVER-THE-COUNTER OPTIONS				
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	BROKER FEES				

Exhibit GJY-1
2002 Hedging Activity

		ELECTRICITY - Premiums Only		
		Volume		
	Instrument	Purchases	Sales	Savings
Nov-02	FIXED PRICE TRANSACTIONS	[redacted]		
	STORAGE			
	PHYSICAL POWER OPTIONS			
	SWAPS			
	SWING SWAPS			
	OVER-THE-COUNTER OPTIONS			
	GAS OPTIONS			
	FUTURES			
	BROKER FEES			

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2002 Hedging Activity

FPL NATURAL GAS PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Dec-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
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	GAS OPTIONS				
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2002 Hedging Activity

FPL HEAVY FUEL OIL PROCUREMENT

	Instrument	Volume Purchases	Sales	Option Premiums	Savings
Dec-02	FIXED PRICE TRANSACTIONS	[redacted]			
	STORAGE				
	PHYSICAL POWER OPTIONS				
	SWAPS				
	SWING SWAPS				
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Exhibit GJY-1
2002 Hedging Activity

		ELECTRICITY - Premiums Only		
		Volume		
	Instrument	Purchases	Sales	Savings
Dec-02	FIXED PRICE TRANSACTIONS	[redacted]		
	STORAGE			
	PHYSICAL POWER OPTIONS			
	SWAPS			
	SWING SWAPS			
	OVER-THE-COUNTER OPTIONS			
	GAS OPTIONS			
	FUTURES			
	BROKER FEES			

APPENDIX I

FUEL COST RECOVERY

GJY-2

DOCKET NO. 030001-EI

EXHIBIT_____

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SEPTEMBER 12, 2003

APPENDIX 1

FUEL COST RECOVERY

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PAGE	DESCRIPTION	SPONSOR
3	Projected Dispatch Costs	G. Yupp
3	Projected Availability of Natural Gas	G. Yupp
4	Projected Unit Availabilities and Outage Schedules	G. Yupp
5,6	2004 Risk Management Plan	G. Yupp

Florida Power and Light Company
Projected Dispatch Costs and Projected Availability of Natural Gas
January Through December 2004

Heavy Oil	January	February	March	April	May	June	July	August	September	October	November	December
0.7% Sulfur Grade ($/Bbl)	25.60	24.32	24.90	25.86	26.82	27.07	27.46	28.22	29.25	29.44	29.06	27.52
0.7% Sulfur Grade ($/mmBtu)	4.00	3.80	3.89	4.04	4.19	4.23	4.29	4.41	4.57	4.60	4.54	4.30
1.0% Sulfur Grade ($/Bbl)	24.58	23.55	24.19	25.22	26.11	26.37	26.75	27.58	28.54	28.61	28.10	26.37
1.0% Sulfur Grade ($/mmBtu)	3.84	3.68	3.78	3.94	4.08	4.12	4.18	4.31	4.46	4.47	4.39	4.12

Light Oil	January	February	March	April	May	June	July	August	September	October	November	December
0.05% Sulfur Grade ($/Bbl)	34.34	33.52	33.70	34.16	34.57	34.81	35.50	37.08	38.19	38.24	37.43	36.15
0.05% Sulfur Grade ($/mmBtu)	5.89	5.75	5.78	5.86	5.93	5.97	6.09	6.36	6.55	6.56	6.42	6.20

Natural Gas Transportation	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT (mmBtu/Day)	750,000	750,000	750,000	839,000	874,000	874,000	874,000	874,000	874,000	839,000	750,000	750,000
Non-Firm FGT (mmBtu/Day)	160,000	160,000	160,000	130,000	70,000	70,000	70,000	70,000	70,000	130,000	160,000	160,000
Non-Firm Gulfstream (mmBtu/Day)	488,000	488,000	488,000	463,000	438,000	438,000	438,000	438,000	438,000	463,000	488,000	488,000
Total Projected Daily Availability (mmBtu/Day)	1,398,000	1,398,000	1,398,000	1,432,000	1,382,000	1,382,000	1,382,000	1,382,000	1,382,000	1,432,000	1,398,000	1,398,000

Natural Gas Dispatch Price	January	February	March	April	May	June	July	August	September	October	November	December
Firm FGT ($/mmBtu)	5.83	5.73	5.53	5.15	4.94	4.94	4.87	4.93	4.86	4.87	5.09	5.41
Non-Firm FGT ($/mmBtu)	6.05	5.95	5.75	5.42	5.27	5.27	5.20	5.26	5.19	5.14	5.31	5.64
Non-Firm Gulfstream ($/mmBtu)	5.85	5.75	5.55	5.19	5.01	5.01	4.93	4.99	4.92	4.92	5.12	5.44

Solid Fuel	January	February	March	April	May	June	July	August	September	October	November	December
Scherer ($/mmBtu)	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57	1.57
SJRPP ($/mmBtu)	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38	1.38

FLORIDA POWER & LIGHT
PROJECTED UNIT AVAILABILITIES & OUTAGE SCHEDULES
PERIOD OF: JANUARY THROUGH DECEMBER, 2004

PLANT/UNIT	PROJECTED FORCED OUTAGE FACTOR (%)	PROJECTED MAINTENANCE OUTAGE FACTOR (%)	PLANNED OUTAGE FACTOR (%)	OVERHAUL DATES	OVERHAUL DATES	OVERHAUL DATES	OVERHAUL DATES
Cape Canaveral 1	1.3	3.3	0.0	NONE			
Cape Canaveral 2	1.2	3.6	0.0	NONE			
Cutler 5	0.9	1.2	0.0	NONE			
Cutler 6	1.3	1.7	0.0	NONE			
Lauderdale 4	0.9	4.0	15.3	02/20/04 - 04/15/04			
Lauderdale 5	0.9	4.0	4.6	10/16/04 - 11/08/04 **			
Lauderdale GTs	1.0	7.2	0.0	NONE			
Fort Myers 2 CC	0.9	4.3	2.8	01/15/04 - 02/11/04 **	11/06/04 - 11/16/04 **	11/20/04 - 11/30/04 **	12/06/04 - 12/16/04 **
Ft. Myers 3	1.1	1.7	0.0	NONE			
Ft. Myers GTs	0.3	1.3	1.9	04/01/04 - 04/28/04 **	05/01/04 - 05/28/04 **	11/01/04 - 11/28/04 **	
Manatee 1	1.0	3.2	0.0	NONE			
Manatee 2	1.0	3.3	20.5	02/14/04 - 04/28/04			
Martin 1	0.9	3.0	0.0	NONE			
Martin 2	0.9	2.8	0.0	NONE			
Martin 3	1.0	4.3	1.4	10/23/04 - 11/01/04 **			
Martin 4	1.0	4.3	4.0	01/01/04 - 01/29/04 **			
Martin 8	0.3	2.4	21.3	10/15/04 - 05/15/05			
Port Everglades 1	1.7	2.3	0.0	NONE			
Port Everglades 2	1.6	2.0	13.7	02/23/04 - 04/12/04			
Port Everglades 3	1.3	3.3	0.0	NONE			
Port Everglades 4	1.2	3.3	3.8	12/04/04 - 12/17/04			
Port Everglades GTs	1.9	9.7	0.0	NONE			
Putnam 1	1.1	3.2	1.4	02/23/04 - 02/27/04			
Putnam 2	1.0	3.4	1.4	02/23/04 - 02/27/04			
Riviera 3	2.6	3.7	0.0	NONE			
Riviera 4	2.7	3.8	5.5	11/20/04 - 12/09/04			
Sanford 3	1.5	2.1	20.5	03/20/04 - 06/02/04			
Sanford 4 CC	2.0	3.2	1.6	11/22/04 - 11/27/04 **	11/29/04 - 12/04/04 **	12/06/04 - 12/11/04 **	12/13/04 - 12/18/04 **
Sanford 5 CC	1.0	3.7	0.8	03/01/04 - 03/06/04 **	03/08/04 - 03/13/04 **		
Turkey Point 1	1.4	3.4	0.0	NONE			
Turkey Point 2	1.4	3.3	5.7	04/24/04 - 05/14/04			
Turkey Point 3	1.0	1.0	17.8	09/25/04 - 11/29/04			
Turkey Point 4	1.2	1.3	0.0	NONE			
St. Lucie 1	1.2	1.2	6.8	03/22/04 - 04/16/04			
St. Lucie 2	1.1	1.1	8.2	11/22/04 - 12/22/04			
St. Johns River 1	2.0	4.4	0.0	NONE			
St. Johns River 2	1.6	3.6	15.8	02/28/04 - 04/25/04			
Scherer 4	1.8	3.9	12.0	02/28/04 - 04/11/04			

** Partial Planned Outage

2004 Risk Management Plan

1. Identify overall quantitative and qualitative risk management objectives.
   A. FPL's risk management objectives are to effectively execute a well-disciplined and independently controlled fuel procurement strategy to achieve the goals of fuel price stability (volatility minimization), to potentially achieve fuel cost minimization, and to achieve asset optimization. FPL's fuel procurement strategy aims to mitigate fuel price increases and reduce fuel price volatility, while maintaining the opportunity to benefit from price decreases in the marketplace for FPL's customers.

      FPL plans to hedge a percentage of its residual fuel oil and natural gas purchases with a combination of fixed price transactions and options. This hedging plan is consistent with the strategies that were presented to the parties on June 30, 2003 in Tallahassee.

3. Identify and quantify each risk, general and specific, that the utility may encounter with its fuel procurement.
   A. The potential risks that FPL encounters with its fuel procurement are supplier credit, fuel supply and transportation availability, product quality, delivery timing, weather, environmental and supplier failure to deliver. The utility determines acceptable levels of risk for fuel procurement by performing various analyses that include forecasted/expected levels of activity, forecasted price levels and price changes, price volatility, and Value-at-Risk (VaR) calculations. The analyses are then presented to the Exposure Management Committee for review and approval. Approval is given to remain within specified VaR limits. These VaR limits are specified in FPL's policies and procedures that were filed on a confidential basis with the Commission on June 24, 2002 as part of FPL's response to Staff's Second Request for Production of Documents in Docket No. 011605-EI.

4. Describe the utility's oversight of its fuel procurement activities.
   A. The utility has a separate and independent middle office risk management department that provides oversight of fuel procurement activities at the deal level. In addition, an executive-level, Exposure Management Committee meets monthly to review performance and discuss current procurement/hedging activities and monitors daily results of procurement activity.

5. Verify that the utility provides its fuel procurement activities with independent and unavoidable oversight.
   A. *Please see response to No. 4.*

6. Describe the utility's corporate risk policy regarding fuel procurement activities.
   A. The utility has a written policy and procedures that define VaR, stop -loss, and duration limits for all forward activity by portfolio. FPL's policies and procedures were filed on a confidential basis with the Commission on June 24, 2002 as part of FPL's response to Staff's Second Request for Production of Documents in Docket No. 011605-EI. In addition, individual procurement strategies must be documented and approved by front and middle office management prior to deal execution.

7. Verify that the utility's corporate risk policy clearly delineates individual and group transaction limits and authorizations for all fuel procurement activities.
   A. Please see response to No. 6.

8. Describe the utility's strategy to fulfill its risk management objectives.
   A. Please see response to No. 1.

9. Verify that the utility has sufficient policies and procedures to implement its strategy.
   A. Please see response to No. 6.

13. Describe the utility's reporting system for fuel procurement activities.
   A. The utility has sufficient systems capability for identifying, measuring, and monitoring all types of risk associated with fuel procurement activities. These systems include: deal capture, a database for maintaining current and historical pricing, deal information, and valuation models, and a reporting system that utilizes the information in the trade capture system and the database.

14. Verify that the utility's reporting system consistently and comprehensively identifies, measures, and monitors all forms of risk associated with fuel procurement activities.
   A. Please see response to No. 13.

15. If the utility has current limitations in implementing certain hedging techniques that would provide a net benefit to ratepayers, provide the details of a plan for developing the resources, policies, and procedures for acquiring the ability to use effectively the hedging techniques.
   A. FPL does not believe that there are any such limitations currently.

Florida Public Service Commission
Docket No. 030001-EI
GULF POWER COMPANY
Witness: T. A. Davis
Exhibit No. 12 (TAD-1)
Schedule 1

GULF POWER COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP
January 2002 - December 2002

1.	Estimated over/(under) - recovery for the period January 2002 - December 2002 (Schedule E1-A approved in Order No. PSC-02-1761-FOF-EI dated December 13, 2002)	$ (16,703,076)
2.	Actual over/(under)-recovery for the period January 2002 - December 2002 (DECEMBER 2002 Schedule A-2, Pg. 2 of 3, "Period-to-Date", Lines 7, 8 and 12)	(15,646,155)
3.	Amount to be refunded/(recovered) in the JANUARY 2004 - DECEMBER 2004 projection period (Line 2 - Line 1)	$ 1,056,921

FLORIDA PUBLIC SERVICE COMMISSION Comp Exh.
DOCKET NO. 030001-EI EXHIBIT NO 12
COMPANY/ Gulf Power
WITNESS: TAD-1, TAD-2 + TAD-3
DATE: 11-12-03

DOCUMENT NUMBER-DATE
03033 APR-1 8
FPSC-COMMISSION CLERK

Florida Public Service Commission
Docket No. 030001-EI
GULF POWER COMPANY
Witness: T. A. Davis
Exhibit No. ____ (TAD -1)
SCHEDULE CCA-1

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
JANUARY 2002 - DECEMBER 2002

1. Estimated over/(under)-recovery for the period JANUARY 2002 - DECEMBER 2002 (Schedule CCE-1a approved in Order No. PSC-02-1761-FOF-EI dated December 13, 2002)	$	353,333
2. Actual over/(under)-recovery for the period JANUARY 2002 - DECEMBER 2002 (Schedule CCA-2 Line 12+13 in the Total column)		547,029
3. Amount to be refunded/(recovered) in the JANUARY 2004 - DECEMBER 2004 projection period (Line 2 - Line 1)	$	193,696

SCHEDULE CCA-2

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP AND INTEREST PROVISION
FOR THE PERIOD JANUARY 2002 - DECEMBER 2002

	ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	ACTUAL JULY	ACTUAL AUGUST	ACTUAL SEPTEMBER	ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	ACTUAL TOTAL
1. IIC Payments / (Receipts) ($)	1,779,853	589,191	562,056	206,628	(222,830)	(288,616)	(53,638)	(204,405)	472,523	(46,522)	(56,062)	2,576	2,740,754
2. Transmission Revenue ($)	(7,179)	(5,956)	(8,590)	(22,368)	(14,271)	(20,840)	(31,540)	(20,755)	(24,234)	(34,348)	(56,301)	(54,984)	(301,366)
3. Capacity Payments to Solutia ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
4. Total Capacity Payments/(Receipts) (Line 1 + 2 + 3) ($)	1,834,876	645,437	615,668	246,462	(174,899)	(247,254)	(22,976)	(162,958)	510,491	(18,668)	(50,161)	9,794	3,185,812
5. Jurisdictional %	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747	0.9650747
6. Jurisdictional Capacity Payments / (Receipts) (Line 3 x 4) ($)	1,770,792	622,894	594,166	237,854	(168,790)	(238,619)	(22,173)	(157,265)	492,662	(18,016)	(48,409)	9,453	3,074,549
7. Amount Included in Retail Base Rate Revenues ($)	(137,666)	(137,666)	(137,666)	(137,667)	(137,667)	(17,728)							(706,060)
8. Total Jurisdictional Recovery Amount (Line 5 - 6) ($)	1,908,458	760,560	731,832	375,521	(31,123)	(220,891)	(22,173)	(157,265)	492,662	(18,016)	(48,409)	9,453	3,780,609
9. Jurisdictional Capacity Cost Recovery Revenue Net of Taxes ($)	53,654	165,620	175,156	176,597	212,302	231,884	258,216	247,899	232,587	204,556	164,159	368,808	2,491,438
10. True-Up Provision ($)	154,687	154,687	154,687	154,687	154,687	154,687	154,687	154,687	154,687	154,688	154,688	154,688	1,856,247
11. Jurisdictional Capacity Cost Recovery Revenue (Line 9 + 10) ($)	208,341	320,307	329,843	331,284	366,989	386,571	412,903	402,586	387,274	359,244	318,847	523,496	4,347,685
12. Over/(Under) Recovery (Line 11 - 8) ($)	(1,700,117)	(440,253)	(401,989)	(44,237)	398,112	607,462	435,076	559,851	(105,388)	377,260	367,256	514,043	567,076
13. Interest Provision ($)	162	(1,636)	(2,504)	(3,066)	(3,012)	(2,506)	(1,950)	(1,439)	(1,349)	(1,354)	(906)	(487)	(20,047)
14. Beginning Balance True-Up & Interest Provision ($)	1,036,739	(817,903)	(1,414,479)	(1,973,659)	(2,175,649)	(1,935,236)	(1,484,967)	(1,206,528)	(802,803)	(1,064,227)	(843,009)	(631,347)	1,036,739
15. True-Up Collected/(Refunded) ($)	(154,687)	(154,687)	(154,687)	(154,687)	(154,687)	(154,687)	(154,687)	(154,687)	(154,687)	(154,688)	(154,688)	(154,688)	(1,856,247)
16. End Of Period Total Net True-Up (Lines 12 + 13 + 14 + 15) ($)	(817,903)	(1,414,479)	(1,973,659)	(2,175,649)	(1,935,236)	(1,484,967)	(1,206,528)	(802,803)	(1,064,227)	(843,009)	(631,347)	(272,479)	

SCHEDULE CCA-3

GULF POWER COMPANY
PURCHASED POWER CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD JANUARY 2002 - DECEMBER 2002

	ACTUAL JANUARY	ACTUAL FEBRUARY	ACTUAL MARCH	ACTUAL APRIL	ACTUAL MAY	ACTUAL JUNE	ACTUAL JULY	ACTUAL AUGUST	ACTUAL SEPTEMBER	ACTUAL OCTOBER	ACTUAL NOVEMBER	ACTUAL DECEMBER	TOTAL
1. Beginning True-Up Amount ($)	1,036,739	(817,903)	(1,414,479)	(1,973,659)	(2,175,649)	(1,935,236)	(1,484,967)	(1,206,528)	(802,803)	(1,064,227)	(843,009)	(631,347)	
2. Ending True-Up Amount Before Interest ($)	(818,065)	(1,412,843)	(1,971,155)	(2,172,583)	(1,932,224)	(1,482,461)	(1,204,578)	(801,364)	(1,062,878)	(841,655)	(630,441)	(272,965)	
3. Total Beginning & Ending True-Up Amount ($) (Lines 1 + 2)	218,674	(2,230,746)	(3,385,634)	(4,146,242)	(4,107,873)	(3,417,697)	(2,689,545)	(2,007,892)	(1,865,681)	(1,905,882)	(1,473,450)	(904,312)	
4. Average True-Up Amount ($)	109,337	(1,115,373)	(1,692,817)	(2,073,121)	(2,053,937)	(1,708,849)	(1,344,773)	(1,003,946)	(932,841)	(952,941)	(736,725)	(452,156)	
5. Interest Rate - First Day of Reporting Business Month	0.017800	0.017700	0.017500	0.018000	0.017500	0.017700	0.017500	0.017300	0.017100	0.017600	0.016500	0.013000	
6. Interest Rate - First Day of Subsequent Business Month	0.017700	0.017500	0.018000	0.017500	0.017700	0.017500	0.017300	0.017100	0.017600	0.016500	0.013000	0.012900	
7. Total Interest Rate (Lines 5 + 6)	0.035500	0.035200	0.035500	0.035500	0.035200	0.035200	0.034800	0.034400	0.034700	0.034100	0.029500	0.025900	
8. Average Interest Rate	0.017750	0.017600	0.017750	0.017750	0.017600	0.017600	0.017400	0.017200	0.017350	0.017050	0.014750	0.012950	
9. Monthly Average Interest Rate (1/12 Of Line 8)	0.001479	0.001467	0.001479	0.001479	0.001467	0.001467	0.001450	0.001433	0.001446	0.001421	0.001229	0.001079	
10. Interest Provision For the Month (Lines 4 X 9) ($)	162	(1,636)	(2,504)	(3,066)	(3,012)	(2,506)	(1,950)	(1,439)	(1,349)	(1,354)	(906)	(487)	(20,047)

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FUEL COST AND PURCHASED POWER COST RECOVERY CLAUSE

DOCKET NO. 030001-EI

PREPARED DIRECT TESTIMONY AND EXHIBIT OF TERRY A. DAVIS

ESTIMATED TRUE-UP FOR THE PERIOD:

JANUARY - DECEMBER 2003 (Fuel)

JANUARY – DECEMBER 2003 (Capacity)

AUGUST 12, 2003

GULF POWER

A SOUTHERN COMPANY

DOCUMENT NUMBER-DATE
07368 AUG 12 8
FPSC-COMMISSION CLERK

GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Terry A. Davis
Docket No. 030001-EI
Fuel and Purchased Power Capacity Cost Recovery
Date of Filing: August 12, 2003

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

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from Mississippi College in Clinton, Mississippi in 1979 with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for a seismic survey firm, Geophysical Field Surveys, in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf in Accounts

Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I have participated in activities related to the cost recovery clauses, budgeting, a retail rate case, and other regulatory functions. In 1998, I was promoted to my current position, which includes preparation and/or coordination of the Company's Fuel, Capacity and Environmental Cost Recovery Clause filings, administration of Gulf's retail tariff, and review of other regulatory filings submitted by the Company.

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

A. Yes, I have.

Counsel: We ask that Ms. Davis' Exhibit consisting of five schedules be marked as Exhibit No. _____ (TAD-2).

Q. Are you familiar with the Fuel and Purchased Power (Energy) estimated true-up calculations for the period of January 2003 through December 2003 and the Purchased Power Capacity Cost estimated true-up calculations for the period of January 2003 through December 2003 set forth in your exhibit?

A. Yes, these documents were prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have.

Q. How were the estimated true-ups for the current period calculated for both fuel and purchased power capacity?

A. In each case the estimated true-up calculations include seven months of actual data and five months of estimated data.

Q. Ms. Davis, what has Gulf calculated as the fuel cost recovery true-up to be applied in the period January 2004 through December 2004?

A. The fuel cost recovery true-up for this period is an increase of .1877¢/kwh. As shown on Schedule E-1A, this includes an estimated under-recovery for the January through December 2003 period of $20,963,299, plus a final over-recovery for the January through December 2002 period of $1,056,921 (see Schedule 1 of Exhibit TAD-1 in this docket filed on April 1, 2003). The resulting net under-recovery is $19,906,378.

Q. Ms. Davis, you stated earlier that you are responsible for the Purchased Power Capacity Cost true-up calculation. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedules CCE-1a and CCE-1b of my exhibit relate to the Purchased Power Capacity Cost true-up calculation to be applied in the January 2004 through December 2004 period.

Q. What has Gulf calculated as the purchased power capacity factor true-up to be applied in the period January 2004 through December 2004?

A. The true-up for this period is a decrease of .0118¢ as shown on Schedule CCE-1a. This includes an estimated over-recovery of $1,058,876 for January 2003 through December 2003. It also includes a final true-up over-recovery of $193,696 for the period of January 2002 through December 2002 (see Schedule CCA-1 filed April 1, 2003). The resulting over-recovery is $1,252,572.

Q. Ms. Davis, does this complete your testimony?

A. Yes, it does.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 030001-EI

Before me the undersigned authority, personally appeared Terry A. Davis, who being first duly sworn, deposes, and says that she is the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company, a Maine corporation, that the foregoing is true and correct to the best of her knowledge, information, and belief. She is personally known to me.

Terry A. Davis
Staff Accountant

Sworn to and subscribed before me this 11 day of August, 2003.

Notary Public, State of Florida at Large

LINDA C. WEBB
Notary Public-State of FL
Comm. Exp: May 31, 2006
Comm. No: DD 110088

TAD-2

SCHEDULE E-1A

FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004

1.	Estimated over/(under)-recovery, JANUARY - DECEMBER 2003 (Sch. E-1B, page 2, line 11)	($20,963,299)
2.	Final over/(under)-recovery JANUARY - DECEMBER 2002 (EXHIBIT No.____(TAD-1), filed April 1, 2003	1,056,921
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in JANUARY 2004 - DECEMBER 2004 (Schedule E1, Line 28)	($19,906,378)
4.	Jurisdictional KWH sales FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004	10,605,379,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / KWH)	0.1877

SCHEDULE E-1B
Page 1 of 2

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2003 - DECEMBER 2003

			JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation	27,554,223.35	21,410,151.71	12,967,537.34	25,600,518.50	24,815,374.82	29,513,288.56	$141,861,094.28
	1a	Fuel Cost of Hedging Settlement	(387,350.00)			(885,000.00)	(1,491,945.00)	(1,510,000.00)	(4,274,295.00)
	1b	Fuel Cost of Hedging Support	8,562.62	5,428.85	6,115.14	5,036.05	11,585.32	5,883.33	42,711.31
	2	Fuel Cost of Power Sold	(6,095,066.95)	(4,875,252.88)	(4,069,348.48)	(7,851,576.21)	(5,112,624.90)	(5,516,962.93)	(33,520,832.35)
	3	Fuel Cost of Purchased Power	3,442,760.23	2,345,275.27	7,025,817.70	1,809,525.07	2,649,893.75	2,181,588.98	19,454,861.00
	3a	Demand & Non-Fuel Cost Of Purchased Power							0.00
	3b	Energy Payments to Qualified Facilities	455,431.00	82,124.00	11,539.42	3,671.00	34,178.00	30,838.00	617,781.42
	4	Energy Cost of Economy Purchases							0.00
	5	Other Generation	227,666.38	196,832.03	169,328.66	220,653.14	207,930.07	151,262.56	1,173,672.84
	6	Adjustment to Fuel Cost	(110,944.19)	5,770.91	(67,806.81)	63,224.88	(64,651.73)	(69,176.77)	(243,583.71)
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	$25,095,282.44	$19,170,329.89	$16,043,182.97	$18,966,052.43	$21,049,840.33	$24,786,721.73	$125,111,409.79
B	1	Jurisdictional KWH Sales	923,547,083	720,706,809	758,267,158	796,465,421	992,431,467	1,037,729,151	5,229,147,089
	2	Non-Jurisdictional KWH Sales	34,735,915	24,952,504	24,712,164	25,039,305	31,781,148	33,463,171	174,684,207
	3	TOTAL SALES (Lines B1 + B2)	958,282,998	745,659,313	782,979,322	821,504,726	1,024,212,615	1,071,192,322	5,403,831,296
	4	Jurisdictional % Of Total Sales (Line B1/B3)	96.3752%	96.6536%	96.8438%	96.9520%	96.8970%	96.8761%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	$21,855,316.40	$16,843,791.78	$17,688,692.64	$18,622,561.45	$23,204,478.23	$24,270,197.44	$122,485,037.94
	2	True-Up Provision	(2,422,599.83)	(2,422,599.83)	(2,422,599.83)	(2,422,599.83)	(2,422,599.83)	(2,422,599.83)	(14,535,598.98)
	2a	Incentive Provision	30,769.35	30,769.35	30,769.35	30,769.35	30,769.35	30,769.35	184,616.10
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$19,463,485.92	$14,451,961.30	$15,296,862.16	$16,230,730.97	$20,812,647.75	$21,878,366.96	$108,134,055.06
	4	Fuel & Net Power Transactions (Line A7)	$25,095,282.44	$19,170,329.89	$16,043,182.97	$18,966,052.43	$21,049,840.33	$24,786,721.73	$125,111,409.79
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7x Line B4 x 1.0007)	24,202,558.58	18,541,784.14	15,547,703.81	18,400,838.73	20,410,941.45	24,029,218.02	$121,133,044.73
	6	Over/(Under) Recovery (Line C3-C5)	(4,739,072.66)	(4,089,822.84)	(250,841.65)	(2,170,107.76)	401,706.30	(2,150,851.06)	($12,998,989.67)
	7	Interest Provision	(31,127.07)	(32,755.26)	(31,378.67)	(29,437.69)	(28,286.27)	(24,651.97)	($177,636.93)
	8	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2003 - JUNE 2003**							($13,176,626.60)

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2003 - DECEMBER 2003

			JULY ACTUAL	AUGUST ESTIMATED	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL PERIOD
			(a)	(b)	(c)				(d)
A	1	Fuel Cost of System Generation	34,065,059.72	36,790,000.00	33,080,000.00	28,792,000.00	22,869,000.00	24,876,000.00	$322,333,154.00
	1a	Fuel Cost of Hedging Settlement	(1,287,710.00)						($5,562,005.00)
	1b	Fuel Cost of Hedging Support	0.00	6,603.00	6,604.00	6,604.00	6,604.00	6,604.00	$75,730.31
	2	Fuel Cost of Power Sold	(7,638,485.98)	(12,153,000.00)	(12,221,000.00)	(12,472,000.00)	(9,049,000.00)	(7,345,000.00)	($94,399,318.33)
	3	Fuel Cost of Purchased Power	1,474,952.15	536,000.00	387,000.00	622,000.00	708,000.00	759,000.00	$23,941,813.15
	3a	Demand & Non-Fuel Cost Of Purchased Power							$0.00
	3b	Energy Payments to Qualified Facilities	205,439.85	16,051.00	845.00				$840,117.27
	4	Energy Cost of Economy Purchases							$0.00
	5	Other Generation	152,811.65	6,809.00	939.00				$1,334,232.49
	6	Adjustment to Fuel Cost	(38,523.39)						($282,107.04)
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	$26,933,544.06	$25,202,463.00	$21,254,388.00	$16,948,604.00	$14,534,604.00	$18,296,604.00	$248,281,616.85
B	1	Jurisdictional KWH Sales	1,091,270,631	1,105,129,000	919,954,000	755,145,000	680,394,000	812,109,000	10,593,148,720
	2	Non-Jurisdictional KWH Sales	34,375,042	37,217,000	32,570,000	27,658,000	26,104,000	29,950,000	362,558,249
	3	TOTAL SALES (Lines B1 + B2)	1,125,645,673	1,142,346,000	952,524,000	782,803,000	706,498,000	842,059,000	10,955,706,969
	4	Jurisdictional % Of Total Sales (Line B1/B3)	96.9462%	96.7421%	96.5807%	96.4668%	96.3052%	96.4432%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes) (1)	$25,533,527.25	$25,929,759.49	$21,584,978.74	$17,718,047.61	$15,964,156.93	$19,054,600.01	$248,270,107.97
	2	True-Up Provision	(2,422,599.83)	(2,422,599.83)	(2,422,599.83)	(2,422,599.83)	(2,422,599.83)	(2,422,599.87)	($29,071,198.00)
	2a	Incentive Provision	30,769.35	30,769.35	30,769.35	30,769.35	30,769.35	30,769.30	$369,232.15
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$23,141,696.77	$23,537,929.01	$19,193,148.26	$15,326,217.13	$13,572,326.45	$16,662,769.44	$219,568,142.12
	4	Fuel & Net Power Transactions (Line A7)	$26,933,544.06	$25,202,463.00	$21,254,388.00	$16,948,604.00	$14,534,604.00	$18,296,604.00	$248,281,616.85
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0007)	26,129,325.22	24,398,458.93	20,542,006.06	16,361,220.77	14,007,377.76	17,658,182.47	$240,229,616.94
	6	Over/(Under) Recovery (Line C3-C5)	(2,987,628.45)	(860,529.92)	(1,348,857.80)	(1,035,003.64)	(435,051.31)	(995,413.03)	($20,661,474.82)
	7	Interest Provision (2)	(23,004.90)	(22,598.81)	(21,492.62)	(20,459.98)	(19,036.27)	(17,594.43)	($301,823.94)
	11	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2003 - DECEMBER 2003**							($20,963,298.76)

Note 1: Estimated Revenues based on the 2003 Fuel Factor excluding revenue taxes of 2.3463 ¢/KWH
Note 2: Interest Calculated for August through December at July's rate of 0.0854

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2003 - DECEMBER 2003

		DOLLARS				KWH				¢/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMT.	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	322,333,154	312,745,343	9,587,811	3 07	15,450,540,000	15,925,270,000	(474,730,000)	(2.98)	2.0862	1 9638	0.1224	6.23
1a	Fuel Cost of Hedging Settlement	(5,582,005)											
2	Hedging Support Costs	75,730	79,240	(3,510)	(4.43)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Other Generation	1,334,232	19,253	1,314,979	6,830.00	59,402,000	820,000	58,582,000	7,144.15	2.2461	2.3479	(0.1018)	(4.34)
5	Adjustment to Fuel Cost	(282,107)											
5	TOTAL COST OF GENERATED POWER	317,899,004	312,843,836	5,055,168	1.62	15,509,942,000	15,926,090,000	(416,148,000)	(2.61)	2.0496	1.9643	0.0853	4.34
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
7	Energy Cost of Schedule C&X Econ Purchases (Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Other Economy Purchases (Nonbroker) (A9)	23,941,813	6,877,000	17,064,813	248.14	1,066,949,843	283,895,000	783,054,843	275.83	2.2439	2 4224	(0.1785)	(7 37)
9	Energy Cost of Schedule E Economy Purchases (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Energy Payments to Qualifying Facilities (A9a)	840,117	35,775	804,342	2,248 34	23,989,968	1,710,000	22,279,968	1,302.92	3.502	2 0921	1.4099	67.39
12	TOTAL COST OF PURCHASED POWER	24,781,930	6,912,775	17,869,155	258.49	1,090,939,811	285,605,000	805,334,811	281.98	2.2718	2.4204	(0.1488)	(6.15)
13	Total Available KWH (Lines 4 + Line 12)	342,680,934	319,756,611	22,924,323	7 17	16,600,881,811	16,211,695,000	389,186,811	2.40				
14	Fuel Cost of Economy Sales (A6)	(6,005,429)	(2,915,000)	(3,090,429)	(106.02)	(258,141,230)	(84,492,000)	(173,649,230)	(205.52)	(2.3264)	(3.4500)	1.1236	32.57
15	Gain on Economy Sales (A6)	(2,599,343)	(527,000)	(2,072,343)	(393 23)			0	#N/A	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Unit Power Sales (A6)	(26,613,044)	(22,465,000)	(4,148,044)	(18 46)	(1,410,733,978)	(1,234,807,000)	(175,926,978)	(14.25)	(1.8865)	(1.8193)	(0 0672)	(3.69)
17	Fuel Cost of Other Power Sales (A6)	(59,181,501)	(72,677,000)	13,495,499	18 57	(3,273,190,586)	(3,503,612,000)	230,421,414	6.58	(1.8081)	(2.0743)	0 2662	12.83
18	TOTAL FUEL COST AND GAINS ON POWER SALES (LINES 14+15+16+17)	(94,399,317)	(98,584,000)	4,184,683	4.24	(4,942,065,794)	(4,822,911,000)	(119,154,794)	(2.47)	(1.9101)	(2.0441)	0 1340	6 56
19	Net Inadvertent Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
20	**TOTAL FUEL & NET POWER TRANSACTIONS** (LINES 5+12+18+19)	248,281,617	221,172,611	27,109,006	12.26	11,658,816,017	11,398,784,000	270,032,017	2 37	2.1296	1.942	0.1876	9.66
21	Net Unbilled Sales	0	0	0	#N/A	0		0	#N/A	#N/A	#N/A	#N/A	#N/A
22	Company Use *	507,436	426,463	80,953	18 96	23,827,777	21,961,000	1,866,777	8.50	2.1296	1.942	0 1876	9.66
23	T & D Losses *	14,465,974	12,958,112	1,507,862	11.64	679,281,271	667,256,000	12,025,271	1.80	2.1296	1.942	0.1876	9 66
24	TERRITORIAL (SYSTEM) SALES	248,281,617	221,172,611	27,109,006	12.26	10,955,706,969	10,699,567,000	256,139,969	2.39	2.2662	2 0671	0 1991	9 63
25	Wholesale Sales	8,291,990	7,492,741	799,249	10.67	362,558,249	362,476,000	82,249	0.02	2.2871	2 0671	0 2200	10.64
26	Jurisdictional Sales	239,989,627	213,679,870	26,309,757	12.31	10,593,148,720	10,337,091,000	256,057,720	2.48	2.2655	2.0671	0.1984	9.60
26a	Jurisdictional Loss Multiplier**	1 0010	1 0007										
27	Jurisdictional Sales Adj. for Line Losses (Line 26 x 1 0007)	240,229,617	213,829,446	26,400,171	12.35	10,593,148,720	10,337,091,000	256,057,720	2.48	2.2678	2 0686	0 1992	9.63
28	TRUE-UP **	29,071,198	29,071,198	0	0.00	10,593,148,720	10,337,091,000	256,057,720	2.48	0.2744	0.2812	(0 0068)	(2 42)
29	TOTAL JURISDICTIONAL FUEL COST	269,300,815	242,900,644	26,400,171	10.87	10,593,148,720	10,337,091,000	256,057,720	2 48	2.5422	2 3498	0.1924	8 19
30	Revenue Tax Factor									1.00072	1 00072		
31	Fuel Factor Adjusted for Revenue Taxes									2.5440	2.3515	0 1925	8.19
32	GPIF Reward / (Penalty) **	(369,498)	(369,498)	0	0.00	10,593,148,720	10,337,091,000	256,057,720	2.48	(0.0035)	(0.0036)	0 0001	(2 78)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									2.5405	2.3479	0.1926	8.20
34	**FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)**									2.541	2.348	0.193	8.22

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

Note. Amounts Included in the Estimated/Actual Column represent 7 months actual and 5 months estimate

Schedule CCE-1a

Purchased Power Capacity Cost Recovery Clause
Calculation of True-up
Gulf Power Company
January 2004 - December 2004

1	Estimated over/(under)-recovery, January 2003 - December 2003 (Schedule CCE-1b-1, Line 18)	$1,058,876
2	Final True-Up, January 2002 - December 2002 (Exhibit No.____(TAD-1), filed April 1, 2003	193,696
3	Total Over/(Under)-Recovery (Line 1 & 2) (To be included in January 2004 - December 2004)	$1,252,572
4	Jurisdictional KWH sales, January 2004 - December 2004	10,605,379,000
5	True-up Factor (Line 3 / Line 4) x 100 (Cents/KWH)	(0.0118)

Schedule CCE-1b

Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
For the Period January 2003 - December 2003

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	IIC Payments/(Receipts) ($)	575,317	4,193	192,099	(9,415)	(102,417)	374,563	1,404,821	2,470,074	1,941,890	52,536	(10,668)	64,888	6,958,961
2	Projected Capacity Payments to Solutia ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
3	Transmission Revenue ($)	(51,592)	(78,086)	(31,701)	(44,371)	(39,430)	(22,413)	(31,968)	(9,000)	(13,000)	(8,000)	(10,000)	(9,000)	(348,561)
5	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3 + 4) ($)	585,927	(11,691)	222,600	8,416	(79,645)	414,352	1,435,155	2,523,276	1,991,092	106,738	41,534	118,090	7,356,844
6	Jurisdictional %	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	
7	Jurisdictional Capacity Payments/(Receipts) (Line 5 x Line 6) ($)	566,396	(11,282)	214,813	8,122	(76,858)	399,857	1,384,952	2,435,009	1,921,441	103,004	40,081	113,959	7,099,493
8	Retail KWH Sales								1,105,129,000	919,954,000	755,145,000	680,394,000	812,109,000	
9	Purchased Power Capacity Cost Recovery Factor (¢/KWH)								0.061	0.061	0.061	0.061	0.061	
10	Capacity Cost Recovery Revenues (Line 10 x Line 11/100) ($)	832,686	588,899	501,144	634,147	805,054	850,861	896,948	895,154	745,163	611,667	551,119	657,808	8,670,650
11	Revenue Taxes (Line 12 x .00072) ($)*	600	424	433	457	580	613	646	14,072	11,714	9,615	8,664	10,341	58,159
12	True-Up Provision ($)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(466,176)
13	Capacity Cost Recovery Revenues net of Revenue Taxes (Line 10 - Line 11 + Line 12) ($)	793,238	549,627	561,863	594,842	765,626	811,400	857,454	842,234	694,601	563,204	503,607	608,619	8,146,315
14	Over/(Under) Recovery (Line 13b - Line 7) ($)	226,842	560,909	347,050	586,720	842,484	411,543	(527,498)	(1,592,775)	(1,226,840)	460,200	463,526	494,660	1,046,822
15	Interest Provision ($)	(121)	308	796	1,277	2,047	2,500	2,305	1,434	265	(29)	399	841	12,022
16	Prior Period Adjustment Including Interest	32												32
17	Total Estimated True-Up for the Period January 2003 - December 2003 (Lines 14 + 15 +16) ($)													1,058,876

NOTE. Interest is Calculated for Aug - Dec at July's rate of 0.0854 %
Actual IIC Payments for January through July include Market Capacity Payments

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FUEL COST AND PURCHASED POWER COST RECOVERY CLAUSE

DOCKET NO. 030001-EI

PREPARED AMENDED DIRECT TESTIMONY AND EXHIBIT OF

TERRY A. DAVIS

SEPTEMBER 12, 2003

GULF POWER

A SOUTHERN COMPANY

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GULF POWER COMPANY

Before the Florida Public Service Commission
Prepared Direct Testimony and Exhibit of
Terry A. Davis
Docket No. 030001-EI
Fuel and Purchased Power Cost Recovery
Date of Filing: September 12, 2003

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

A. My name is Terry Davis. My business address is One Energy Place, Pensacola, Florida 32520-0780. I am the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company.

Q. Please briefly describe your educational background and business experience.

A. I graduated from Mississippi College in Clinton, Mississippi in 1979 with a Bachelor of Science Degree in Business Administration and a major in Accounting. Prior to joining Gulf Power, I was an accountant for seven years with a seismic survey firm, Geophysical Field Surveys, in Jackson, Mississippi. In that capacity, I was responsible for accounts receivable, accounts payable, sales, use, and fuel tax returns, and various other accounting activities. In 1986, I joined Gulf Power as an Associate Accountant in the Plant Accounting Department. Since then, I have held various positions of increasing responsibility with Gulf in

Accounts Payable, Financial Reporting, and Cost Accounting. In 1993, I joined the Rates and Regulatory Matters area, where I have participated in activities related to the cost recovery clauses, the rate case, budgeting, and other regulatory functions. In 1998, I was promoted to my current position, which includes preparation and/or coordination of the Company's Fuel, Capacity and Environmental Cost Recovery Clause filings, administration of Gulf's retail tariff, and review of other regulatory filings submitted by the Company.

Q. Have you previously filed testimony before this Commission in this on-going docket?

A. Yes, I have.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss the calculation of Gulf Power's fuel cost recovery factors for the period January 2004 through December 2004. I will also discuss the calculation of the purchased power capacity cost recovery factors for the period January 2004 through December 2004.

Q. Are you familiar with the Fuel and Purchased Power Cost Recovery Clause Calculation for the period of January 2004 through December 2004?

A. Yes, these documents were prepared under my supervision.

Q. Have you verified that to the best of your knowledge and belief, the information contained in these documents is correct?

A. Yes, I have.

Counsel: We ask that Ms. Davis's Exhibit consisting of fourteen schedules, be marked as Exhibit No. _____(TAD-3).

Q. What has been included in this filing to reflect the GPIF reward/penalty for the period of January 2002 through December 2002?

A. The GPIF result is shown on Line 33 of Schedule E-1 as an increase of .0041¢/kwh, thereby rewarding Gulf $431,920.

Q. Has there been any change that would affect the estimated true-up for 2003 filed by Gulf on August 12, 2003?

A. Yes. The actual fuel over/under recovery calculation for August 2003 resulted in an under-recovery of

$3,806,123.03 as shown on revised Schedule E-1b, page 2, of my exhibit. This amount is $2,945,593.11 more than projected on the original version of this schedule filed on August 12, 2003. I have revised this schedule and included the new estimated true-up amount on Schedule E-1b and in the resulting calculations on the other schedules in the E-1 series.

Q. What is the appropriate revenue tax factor to be applied in calculating the levelized fuel factor?

A. A revenue tax factor of 1.00072 has been applied to all jurisdictional fuel costs as shown on Line 31 of Schedule E-1.

Q. Ms. Davis, what is the levelized projected fuel factor for the period January 2003 through December 2003?

A. Gulf has proposed a levelized fuel factor of 2.459¢/kwh. It includes projected fuel and purchased power energy expenses for January 2004 through December 2004 and projected kwh sales for the same period, as well as the true-up and GPIF amount. The levelized fuel factor has not been adjusted for line losses.

Q. How does the levelized fuel factor for the projection period compare with the levelized fuel factor for the current period?

A. The projected levelized fuel factor for 2004 is .111 cents/kwh more or 4.7 percent higher than the levelized fuel factor for 2003 upon which current fuel factors are based.

Q. Ms. Davis, how were the line loss multipliers used on Schedule E-1E calculated?

A. They were calculated in accordance with procedures approved in prior filings and were based on Gulf's latest mwh Load Flow Allocators.

Q. Ms. Davis, what fuel factor does Gulf propose for its largest group of customers (Group A), those on Rate Schedules RS, GS, GSD, OSIII, and OSIV?

A. Gulf proposes a standard fuel factor, adjusted for line losses, of 2.472¢/kwh for Group A. Fuel factors for Groups A, B, C, and D are shown on Schedule E-1E. These factors have all been adjusted for line losses.

Q. Ms. Davis, how were the time-of-use fuel factors calculated?

A. These were calculated based on projected loads and system lambdas for the period January 2004 through December 2004. These factors included the GPIF and true-up, and were adjusted for line losses. These time-of-use fuel factors are also shown on Schedule E-1E.

Q. How does the proposed fuel factor for Rate Schedule RS compare with the factor applicable to December 2003 and how would the change affect the cost of 1000 kwh on Gulf's residential rate RS?

A. The current fuel factor for Rate Schedule RS applicable through December 2003 is 2.359¢/kwh compared with the proposed factor of 2.472¢/kwh. For a residential customer who uses 1000 kwh in January 2004, the fuel portion of the bill would increase from $23.59 to $24.72.

Q. Has Gulf updated its estimates of the as-available avoided energy costs to be shown on COG1 as required by Order No. 13247 issued May 1, 1984, in Docket No. 830377-EI and Order No. 19548 issued June 21, 1988, in Docket No. 880001-EI?

A. Yes. A tabulation of these costs is set forth in Schedule E-11 of my Exhibit TAD-3. These costs

represent the estimated averages for the period from January 2004 through December 2005.

Q. What amount have you calculated to be the appropriate benchmark level for calendar year 2004 gains on non-separated wholesale energy sales eligible for a shareholder incentive?

A. In accordance with Order No. PSC-00-1744-AAA-EI, a benchmark level of $2,016,185 has been calculated for 2004. The actual gains for 2001, 2002, and the estimated gains for 2003 on all non-separated sales have been averaged to determine the minimum projected threshold for 2004 that must be achieved before shareholders may receive any incentive. As demonstrated on Schedule E-6, page 2 of 2, Gulf's projection reflects a credit to customers of 100 percent of the gains on non-separated sales for 2003. The estimated gains on all non-separated sales are projected to be $383,000, whereas the threshold is estimated at $2,016,185.

Q. You stated earlier that you are responsible for the calculation of the purchased power capacity cost (PPCC) recovery factors. Which schedules of your exhibit relate to the calculation of these factors?

A. Schedule CCE-1, including CCE-1a and CCE-1b, and Schedule CCE-2 of my exhibit relate to the calculation of the PPCC recovery factors for the period January 2004 through December 2004.

Q. Please describe Schedule CCE-1 of your exhibit.

A. Schedule CCE-1 shows the calculation of the amount of capacity payments to be recovered through the PPCC Recovery Clause. Mr. Bell has provided me with Gulf's projected purchased power capacity transactions. Gulf's total projected net capacity expense which includes a credit for transmission revenue for the period January 2004 through December 2004 is $19,542,907. The jurisdictional amount is $18,859,271. This amount is added to the total true-up amount to determine the total purchased power capacity transactions that would be recovered in the period.

Q. What methodology was used to allocate the capacity payments to rate class?

A. As required by Commission Order No. 25773 in Docket No. 910794-EQ, the revenue requirements have been allocated using the cost of service methodology used in Gulf's last full requirements rate case and approved by the Commission in Order No. PSC-02-0787-FOF-EI issued

June 10, 2002, in Docket No. 010949-EI. For purposes of the PPCC Recovery Clause, Gulf has allocated the net purchased power capacity costs to rate class with 12/13th on demand and 1/13th on energy. This allocation is consistent with the treatment accorded to production plant in the cost of service study used in Gulf's last rate case.

Q. How were the allocation factors calculated for use in the PPCC Recovery Clause?

A. The allocation factors used in the PPCC Recovery Clause have been calculated using the 2001 load data filed with the Commission in accordance with FPSC Rule 25-6.0437. The calculations of the allocation factors are shown in columns A through I on Page 1 of Schedule CCE-2.

Q. Please describe the calculation of the cents/kwh factors by rate class used to recover purchased power capacity costs.

A. As shown in columns A through D on page 2 of Schedule CCE-2, the 12/13th of the jurisdictional capacity cost to be recovered is allocated to rate class based on the demand allocator, with the remaining 1/13th allocated based on energy. The total revenue requirement assigned to each rate class shown in column E is then divided by

that class's projected kwh sales for the twelve-month period to calculate the PPCC recovery factor. This factor would be applied to each customer's total kwh to calculate the amount to be billed each month.

Q. What is the amount related to purchased power capacity costs recovered through this factor that will be included on a residential customer's bill for 1000 kwh?

A. The purchased power capacity costs recovered through the clause for a residential customer who uses 1000 kwh will be $1.94.

Q. When does Gulf propose to collect these new fuel charges and purchased power capacity charges?

A. The fuel and capacity factors will be effective beginning with the first Bill Group for January 2004 and continuing through the last Bill Group for December 2004.

Q. Ms. Davis, does this complete your testimony?

A. Yes, it does.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 030001-EI

Before me the undersigned authority, personally appeared Terry A. Davis, who being first duly sworn, deposes, and says that she is the senior Staff Accountant in the Rates and Regulatory Matters Department of Gulf Power Company, a Maine corporation, that the foregoing is true and correct to the best of her knowledge, information, and belief. She is personally known to me.

Terry A. Davis
Staff Accountant

Sworn to and subscribed before me this 11th day of September, 2003.

Linda C. Webb
Notary Public, State of Florida at Large

LINDA C. WEBB
Notary Public-State of FL
Comm. Exp: May 31, 2006
Comm. No: DD 110088

SCHEDULE E-1

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004

Line				(a) $	(b) KWH	(c) ¢ / KWH
1	Fuel Cost of System Net Generation		E-3	340,226,335	16,251,250,000	2.0935
2	Nuclear Fuel Disposal Costs		E-2			#N/A
3	Coal Car Investment					#N/A
4	Other Generation		E-3	19,205	790,000	2.4310
5	Hedging Administration Costs		E-2	33,086		#N/A
6	**Total Cost of Generated Power**	(Line 1 - 5)		340,278,626	16,252,040,000	2.0938
7	Fuel Cost of Purchased Power (Exclusive of Economy)		E-7			#N/A
8	Energy Cost of Schedule C & X Econ. Purch.		E-9			#N/A
9	Energy Cost of Other Econ. Purch. (Nonbroker)		E-9	12,776,000	477,038,000	2.6782
10	Energy Cost of Schedule E Economy Purch.		E-9			#N/A
11	Capacity Cost of Schedule E Economy Purchases		E-2			#N/A
12	Energy Payments to Qualifying Facilities		E-8			#N/A
13	**Total Cost of Purchased Power**	(Line 6 - 12)		12,776,000	477,038,000	2.6782
14	**Total Available KWH**	(Line 5 + 13)			16,729,078,000	
15	Fuel Cost of Economy Sales		E-6	(2,289,000)	(74,677,000)	3.0652
16	Gain on Economy Sales		E-6	(383,000)		#N/A
17	Fuel Cost of Unit Power Sales		E-6	(26,458,000)	(1,561,911,000)	1.6940
18	Fuel Cost of Other Power Sales			(79,395,000)	(3,440,414,000)	2.3077
19	**Total Fuel Cost & Gains on Power Sales**	(Line 15 -18)		(108,525,000)	(5,077,002,000)	2.1376
20	Net Inadvertant Interchange			0	0	#N/A
21	**Total Fuel & Net Power Trans.**	(Line 6+13+19+20)		244,529,626	11,652,076,000	2.0986
22	Net Unbilled Sales *			0	0	#N/A
23	Company Use *			545,195	25,979,000	2.0986
24	T & D Losses *			14,395,200	685,943,000	2.0986
25	**System KWH Sales**			244,529,626	10,940,154,000	2.2352
26	Wholesale KWH Sales			8,348,785	373,514,000	2.2352
27	Jurisdictional KWH Sales			236,180,841	10,566,640,000	2.2352
27a	Jurisdictional Line Loss Multiplier			1.0007		1.0007
28	Jurisdictional KWH Sales Adjusted for Line Losses			236,346,168	10,566,640,000	2.2367
29	**True-Up** **			22,866,584	10,566,640,000	0.2164
30	**Total Jurisdictional Fuel Cost**			259,212,752	10,566,640,000	2.4531
31	Revenue Tax Factor					1.00072
32	Fuel Factor Adjusted For Revenue Taxes					2.4549
33	GPIF Reward/(Penalty) **			431,920	10,566,640,000	0.0041
34	Fuel Factor Adjusted for GPIF					2.4590
35	**Fuel Factor Rounded to Nearest .001(¢ / KWH)**					**2.459**

*For informational purposes only
** Calculation Based on Jurisdictional KWH Sales

SCHEDULE E-1A

FUEL COST RECOVERY CLAUSE
CALCULATION OF TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004

TAD-3

1.	Estimated over/(under)-recovery, JANUARY - DECEMBER 2003 (Sch. E-1B, page 2, line 11)	($23,923,505)
2.	Final over/(under)-recovery JANUARY - DECEMBER 2002 (EXHIBIT No.____(TAD-1), filed April 1, 2003	1,056,921
3.	Total over/(under)-recovery (Lines 1 + 2) To be included in JANUARY 2004 - DECEMBER 2004 (Schedule E1, Line 28)	($22,866,584)
4.	Jurisdictional KWH sales FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004	10,566,640,000
5.	True-up Factor (Line 3 / Line 4) x 100 (¢ / KWH)	0.2164

Note: Projected KWH sales for 2004 have been updated since the estimated true-up filing.

SCHEDULE E-1B
Page 1 of 2

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2003 - DECEMBER 2003

			JANUARY ACTUAL	FEBRUARY ACTUAL	MARCH ACTUAL	APRIL ACTUAL	MAY ACTUAL	JUNE ACTUAL	TOTAL SIX MONTHS
			(a)	(b)	(c)	(d)	(e)	(f)	(g)
A	1	Fuel Cost of System Generation	27,554,223.35	21,410,151.71	12,967,537.34	25,600,518.50	24,815,374.82	29,513,288.56	$141,861,094.28
	1a	Fuel Cost of Hedging Settlement	(387,350.00)			(885,000.00)	(1,491,945.00)	(1,510,000.00)	(4,274,295.00)
	1b	Fuel Cost of Hedging Support	8,562.62	5,428.85	6,115.14	5,036.05	11,685.32	5,883.33	42,711.31
	2	Fuel Cost of Power Sold	(6,095,066.95)	(4,875,252.88)	(4,069,348.48)	(7,851,576.21)	(5,112,624.90)	(5,516,962.93)	(33,520,832.35)
	3	Fuel Cost of Purchased Power	3,442,760.23	2,345,275.27	7,025,817.70	1,809,525.07	2,649,893.75	2,181,588.98	19,454,861.00
	3a	Demand & Non-Fuel Cost Of Purchased Power							0.00
	3b	Energy Payments to Qualified Facilities	455,431.00	82,124.00	11,539.42	3,671.00	34,176.00	30,838.00	617,781.42
	4	Energy Cost of Economy Purchases							0.00
	5	Other Generation	227,666.38	196,832.03	169,328.66	220,653.14	207,930.07	151,262.56	1,173,672.84
	6	Adjustment to Fuel Cost	(110,944.19)	5,770.91	(67,806.81)	63,224.88	(64,651.73)	(69,176.77)	(243,583.71)
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)	$25,095,282.44	$19,170,329.89	$16,043,182.97	$18,966,052.43	$21,049,840.33	$24,786,721.73	$125,111,409.79
B	1	Jurisdictional KWH Sales	923,547,083	720,706,809	758,267,158	796,465,421	992,431,467	1,037,729,151	5,229,147,089
	2	Non-Jurisdictional KWH Sales	34,735,915	24,952,504	24,712,164	25,039,305	31,781,148	33,463,171	174,684,207
	3	TOTAL SALES (Lines B1 + B2)	958,282,998	745,659,313	782,979,322	821,504,726	1,024,212,615	1,071,192,322	5,403,831,296
	4	Jurisdictional % Of Total Sales (Line B1/B3)	96.3752%	96.6536%	96.8438%	96.9520%	96.8970%	96.8761%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	$21,855,316.40	$16,843,791.78	$17,688,692.64	$18,622,561.45	$23,204,478.23	$24,270,197.44	$122,485,037.94
	2	True-Up Provision	(2,422,599.83)	(2,422,599.83)	(2,422,599.83)	(2,422,599.83)	(2,422,599.83)	(2,422,599.83)	(14,535,598.98)
	2a	Incentive Provision	30,769.35	30,769.35	30,769.35	30,769.35	30,769.35	30,769.35	184,616.10
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)	$19,463,485.92	$14,451,961.30	$15,296,862.16	$16,230,730.97	$20,812,647.75	$21,878,366.96	$108,134,055.06
	4	Fuel & Net Power Transactions (Line A7)	$25,095,282.44	$19,170,329.89	$16,043,182.97	$18,966,052.43	$21,049,840.33	$24,786,721.73	$125,111,409.79
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7x Line B4 x 1.0007)	24,202,558.58	18,541,784.14	15,547,703.81	18,400,838.73	20,410,941.45	24,029,218.02	$121,133,044.73
	6	Over/(Under) Recovery (Line C3-C5)	(4,739,072.66)	(4,089,822.84)	(250,841.65)	(2,170,107.76)	401,706.30	(2,150,851.06)	($12,998,989.67)
	7	Interest Provision	(31,127.07)	(32,755.26)	(31,378.67)	(29,437.69)	(28,286.27)	(24,651.97)	($177,636.93)
	8	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2003 - JUNE 2003**							($13,176,626.60)

CALCULATION OF ESTIMATED TRUE-UP
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2003 - DECEMBER 2003

				JULY ACTUAL	AUGUST ACTUAL	SEPTEMBER ESTIMATED	OCTOBER ESTIMATED	NOVEMBER ESTIMATED	DECEMBER ESTIMATED	TOTAL PERIOD
				(a)	(b)	(c)				(d)
A	1	Fuel Cost of System Generation		34,065,059.72	33,709,942.08	33,080,000 00	28,792,000.00	22,869,000.00	24,876,000.00	$319,253,096.08
	1a	Fuel Cost of Hedging Settlement		(1,287,710.00)	881,898.00					($4,680,107.00)
	1b	Fuel Cost of Hedging Support		0.00	(32,911.96)	6,604.00	6,604.00	6,604.00	6,604.00	$36,215.35
	2	Fuel Cost of Power Sold		(7,638,485.98)	(8,492,922.05)	(12,221,000.00)	(12,472,000.00)	(9,049,000 00)	(7,345,000.00)	($90,739,240.38)
	3	Fuel Cost of Purchased Power		1,474,952.15	1,771,017.59	387,000.00	622,000.00	708,000.00	759,000 00	$25,176,830.74
	3a	Demand & Non-Fuel Cost Of Purchased Power								$0 00
	3b	Energy Payments to Qualified Facilities		205,439.85	189,580.22	845.00				$1,013,646.49
	4	Energy Cost of Economy Purchases								$0.00
	5	Other Generation		152,811 65		939.00				$1,327,423.49
	6	Adjustment to Fuel Cost		(38,523.33)						($282,107.04)
	7	TOTAL FUEL & NET POWER TRANSACTIONS (Sum of Lines A1 Thru A6)		$26,933,544.06	$28,026,603.88	$21,254,388.00	$16,948,604.00	$14,534,604.00	$18,296,604.00	$251,105,757.73
B	1	Jurisdictional KWH Sales		1,091,270,631	1,099,060,271	919,954,000	755,145,000	680,394,000	812,110,000	10,587,080,991
	2	Non-Jurisdictional KWH Sales		34,375,042	36,033,658	32,570,000	27,658,000	26,104,000	29,950,000	361,374,907
	3	TOTAL SALES (Lines B1 + B2)		1,125,645,673	1,135,093,929	952,524,000	782,803,000	706,498,000	842,060,000	10,948,455,898
	4	Jurisdictional % Of Total Sales (Line B1/B3)		96.9462%	96.8255%	96.5807%	96.4668%	96.3052%	96 4432%	
C	1	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	(1)	$25,533,527.25	$25,741,602.62	$21,584,978.74	$17,718,047 61	$15,964,156 93	$19,054,623 47	$248,081,974.56
	2	True-Up Provision		(2,422,599.83)	(2,422,599.83)	(2,422,599.83)	(2,422,599.83)	(2,422,599.83)	(2,422,599 87)	($29,071,198.00)
	2a	Incentive Provision		30,769.35	30,769.35	30,769.35	30,769 35	30,769.35	30,769.30	$369,232 15
	3	FUEL REVENUE APPLICABLE TO PERIOD (Sum of Lines C1 Thru C2a)		$23,141,696.77	$23,349,772 14	$19,193,148.26	$15,326,217 13	$13,572,326.45	$16,662,792 90	$219,380,008.71
	4	Fuel & Net Power Transactions (Line A7)		$26,933,544.06	$28,026,603.88	$21,254,388.00	$16,948,604.00	$14,534,604.00	$18,296,604.00	$251,105,757.73
	5	Jurisdictional Fuel Cost Adj. for Line Losses (Line A7 x Line B4 x 1.0007)		26,129,325.22	27,155,895.17	20,542,006.06	16,361,220.77	14,007,377.76	17,658,182.47	$242,987,053 18
	6	Over/(Under) Recovery (Line C3-C5)		(2,987,628.45)	(3,806,123 03)	(1,348,857.80)	(1,035,003 64)	(435,051.31)	(995,389 57)	($23,607,044.47)
	7	Interest Provision	(2)	(23,004.90)	(24,554.95)	(24,712.69)	(23,652.65)	(22,190.07)	(20,708.78)	($316,460.97)
	11	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD JANUARY 2003 - DECEMBER 2003**								($23,923,505.44)

Note 1: Estimated Revenues based on the 2003 Fuel Factor excluding revenue taxes of 2.3463 ¢/KWH
Note 2: Interest Calculated for September through December at August's rate 0.0879

SCHEDULE E-1B-1

COMPARISON OF ESTIMATED/ACTUAL VERSUS ORIGINAL PROJECTIONS
OF THE FUEL AND PURCHASED POWER COST RECOVERY FACTOR
GULF POWER COMPANY
FOR THE PERIOD JANUARY 2003 - DECEMBER 2003

		DOLLARS				KWH				¢/KWH			
		ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMOUNT	%	ESTIMATED/ ACTUAL	ESTIMATED/ ORIGINAL	DIFFERENCE AMT	%
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Fuel Cost of System Net Generation (A3)	319,253,096	312,745,343	6,507,753	2 08	15,258,135,000	15,925,270,000	(667,135,000)	(4 19)	2 0923	1 9638	0 1285	6 54
1a	Fuel Cost of Hedging Settlement	(4,680,107)											
2	Hedging Support Costs	36,215	79,240	(43,025)	(54 30)	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
3	Coal Car Investment	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
4	Other Generation	1,327,423	19,253	1,308,170	6,794 63	67,376,000	820,000	66,556,000	8,116 59	1 9702	2 3479	(0 3777)	(16 09)
5	Adjustment to Fuel Cost	(282,107)											
5	TOTAL COST OF GENERATED POWER	315,654,520	312,843,836	2,810,684	0 90	15,325,511,000	15,926,090,000	(600,579,000)	(3 77)	2 0597	1 9643	0 0954	4 86
6	Fuel Cost of Purchased Power (Exclusive of Economy) (A8)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
7	Energy Cost of Schedule C&X Econ. Purchases (Broker) (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
8	Energy Cost of Other Economy Purchases (Nonbroker) (A9)	25,176,831	6,877,000	18,299,831	266 10	1,145,080,148	283,895,000	861,185,148	303 36	2 1987	2 4224	(0 2237)	(9 23)
9	Energy Cost of Schedule E Economy Purchases (A9)	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
10	Capacity Cost of Schedule E Economy Purchases	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
11	Energy Payments to Qualifying Facilities (A9a)	1,013,646	35,775	977,871	2,733 39	30,780,789	1,710,000	29,070,789	1,700 05	3 2931	2 0921	1 2010	57 41
12	TOTAL COST OF PURCHASED POWER	26,190,477	6,912,775	19,277,702	278 87	1,175,860,937	285,605,000	890,255,937	311 71	2 2273	2 4204	(0 1931)	(7 98)
13	Total Available KWH (Lines 4 + Line 12)	341,844,997	319,756,611	22,088,386	6 91	16,501,371,937	16,211,695,000	289,676,937	1 79				
14	Fuel Cost of Economy Sales (A6)	(13,985,859)	(2,915,000)	(11,070,859)	(379 79)	(285,780,733)	(84,492,000)	(201,288,733)	(238 23)	(4 8939)	(3 4500)	(1 4439)	(41 85)
15	Gain on Economy Sales (A6)	(2,792,836)	(527,000)	(2,265,836)	(429 95)			0	#N/A	#N/A	#N/A	#N/A	#N/A
16	Fuel Cost of Unit Power Sales (A6)	(24,433,044)	(22,485,000)	(1,968,044)	(8 76)	(1,413,266,108)	(1,234,807,000)	(178,459,108)	(14 45)	(1 7288)	(1 8193)	0 0905	4 97
17	Fuel Cost of Other Power Sales (A6)	(49,527,501)	(72,677,000)	23,149,499	31 85	(3,153,594,492)	(3,503,612,000)	350,017,508	9 99	(1 5705)	(2 0743)	0 5038	24 29
18	TOTAL FUEL COST AND GAINS ON POWER SALES (LINES 14+15+16+17)	(90,739,240)	(98,584,000)	7,844,760	7 96	(4,852,641,333)	(4,822,911,000)	(29,730,333)	(0 62)	(1 8699)	(2 0441)	0 1742	8 52
19	Net Inadvertent Interchange	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
20	**TOTAL FUEL & NET POWER TRANSACTIONS** (LINES 5+12+18+19)	251,105,757	221,172,611	29,933,146	13 53	11,648,730,804	11,388,784,000	259,946,804	2 28	2 1566	1 942	0 2136	11 00
21	Net Unbilled Sales	0	0	0	#N/A	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A
22	Company Use *	511,026	426,483	84,542	19 82	23,706,840	21,961,000	1,745,840	7 95	2 1556	1 942	0 2136	11 00
23	T & D Losses *	14,584,097	12,958,112	1,625,985	12 55	676,567,867	667,256,000	9,311,867	1 40	2 1556	1 942	0 2136	11 00
24	TERRITORIAL (SYSTEM) SALES	251,105,757	221,172,611	29,933,146	13 53	10,948,455,897	10,699,567,000	248,888,897	2 33	2 2935	2 0671	0 2264	10 95
25	Wholesale Sales	8,288,876	7,492,741	795,935	10 62	361,375,907	362,476,000	(1,100,093)	(0 30)	2 2936	2 0671	0 2265	10 96
26	Jurisdictional Sales	242,817,081	213,679,870	29,137,211	13 64	10,587,079,990	10,337,091,000	249,988,990	2 42	2 2935	2 0671	0 2264	10 95
26a	Jurisdictional Loss Multiplier***	1 0007	1 0007										
27	Jurisdictional Sales Adj for Line Losses (Line 26 x 1 0007)	242,987,053	213,829,446	29,157,607	13 64	10,587,079,990	10,337,091,000	249,988,990	2 42	2 2951	2 0686	0 2265	10 95
28	TRUE-UP **	29,071,198	29,071,198	0	0 00	10,587,079,990	10,337,091,000	249,988,990	2 42	0 2746	0 2812	(0 0066)	(2 35)
29	TOTAL JURISDICTIONAL FUEL COST	272,058,251	242,900,644	29,157,607	12.00	10,587,079,990	10,337,091,000	249,988,990	2 42	2 5697	2 3498	0 2199	9 36
30	Revenue Tax Factor									1 00072	1 00072		
31	Fuel Factor Adjusted for Revenue Taxes									2 5716	2 3515	0 2201	9 36
32	GPIF Reward / (Penalty) **	(369,498)	(369,498)	0	0 00	10,587,079,990	10,337,091,000	249,988,990	2 42	(0 0035)	(0 0036)	0 0001	(2 78)
33	Fuel Factor Adjusted for GPIF Reward / (Penalty)									2 5681	2 3479	0 2202	9 38
34	**FUEL FACTOR ROUNDED TO NEAREST .001(CENTS/KWH)**									2 568	2 348	0 220	9 37

* Included for Informational Purposes Only

** Calculation Based on Jurisdictional KWH Sales

Note Amounts Included in the Estimated/Actual Column represent 8 months actual and 4 months estimate

SCHEDULE E-1C

CALCULATION OF GENERATING PERFORMANCE INCENTIVE FACTOR AND TRUE-UP FACTOR GULF POWER COMPANY FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004

1.	TOTAL AMOUNT OF ADJUSTMENTS:		
	A. Generating Performance Incentive Reward/(Penalty)	$	431,920
	B. True-Up (Over)/Under Recovered	$	22,866,584
2.	TOTAL SALES (KWH)		10,566,640,000
3.	ADJUSTMENT FACTORS:		
	A. Generating Performance Incentive Factor		0.0041
	B. True-Up Factor		0.2164

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004

		NET ENERGY FOR LOAD %
	On-Peak	29.83
	Off-Peak	70.17
		100.00

	AVERAGE	ON-PEAK	OFF-PEAK
Cost per KWH Sold	2.2352	2.6271	2.0686
Jurisdictional Loss Factor	1.0007	1.0007	1.0007
Jurisdictional Fuel Factor	2.2368	2.6289	2.0700
GPIF	0.0041	0.0041	0.0041
True-Up	0.2164	0.2164	0.2164
TOTAL	2.4573	2.8494	2.2905
Revenue Tax Factor	1.00072	1.00072	1.00072
Recovery Factor	2.4590	2.8515	2.2921
Recovery Factor Rounded to the Nearest .001 ¢/KWH	2.459	2.851	2.292

HOURS:	ON-PEAK	25.59%
	OFF-PEAK	74.41%
		100.00%

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004

Group	Rate Schedules	Average Factor	Fuel Recovery Loss Multipliers	Standard Fuel Recovery Factor
A	RS, GS, GSD, OSIII, OSIV, SBS (1)	2.459	1.00526	2.472
B	LP/LPT, SBS (2)	2.459	0.98890	2.432
C	PX, RTP, CSA	2.459	0.98063	2.411
D	OS-I/II	2.459	1.00529	2.449 *

		TOU
A	On-Peak	2.866
	Off-Peak	2.304
B	On-Peak	2.820
	Off-Peak	2.267
C	On-Peak	2.796
	Off-Peak	2.248
D	On-Peak	N/A
	Off-Peak	N/A

Group D Calculation

* D	On-Peak	2.851 ¢ / KWH	x	0.2559	=	0.730	¢ / KWH
	Off-Peak	2.292 ¢ / KWH	x	0.7441	=	1.706	¢ / KWH
						2.436	¢ / KWH
			Line Loss Multiplier		x	1.00529	
						2.449	¢ / KWH

(1) Includes SBS customers with a Contract Demand in the range of 100 to 499 KW
(2) Includes SBS customers with a Contract Demand in the range of 500 to 7,499 KW

SCHEDULE E-2

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: *JANUARY 2004 - DECEMBER 2004*

LINE	LINE DESCRIPTION	(a) JANUARY	(b) FEBRUARY	(c) MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) JULY	(h) AUGUST	(i) SEPTEMBER	(j) OCTOBER	(k) NOVEMBER	(l) DECEMBER	(m) TOTAL
	$													
1	Fuel Cost of System Generation	29,072,303	24,315,394	25,566,584	22,619,302	25,164,736	34,300,418	37,258,383	37,233,070	33,761,003	26,519,384	22,051,119	22,364,640	340,226,335
1a	Other Generation	0	0	0	0	0	1,945	7,779	6,078	3,403	0	0	0	19,205
2	Fuel Cost of Power Sold	(8,639,000)	(6,961,000)	(7,068,000)	(5,893,000)	(5,282,000)	(11,109,000)	(13,793,000)	(13,489,000)	(13,235,000)	(9,303,000)	(8,055,000)	(5,698,000)	(108,525,000)
3	Fuel Cost of Purchased Power	1,021,000	1,186,000	1,234,000	1,644,000	1,770,000	787,000	1,071,000	1,126,000	346,000	851,000	695,000	1,045,000	12,776,000
3a	Demand & Non-Fuel Cost of Pur Power													0
3b	Qualifying Facilities	0	0	0	0	0	0	0	0	0	0	0	0	0
4	Energy Cost of Economy Purchases													0
5	Hedging Administrative Cost	2,757	2,757	2,757	2,757	2,757	2,757	2,757	2,757	2,757	2,757	2,757	2,759	33,086
6	**Total Fuel & Net Power Trans.** (Sum of Lines 1 -4)	21,457,060	18,543,151	19,735,341	18,373,059	21,655,493	23,983,120	24,546,919	24,878,904	20,878,163	18,070,141	14,693,876	17,714,399	244,529,626
6	System KWH Sold	891,992,000	761,289,000	811,822,000	773,893,000	962,513,000	1,082,122,000	1,127,950,000	1,161,236,000	967,819,000	806,886,000	718,907,000	873,725,000	10,940,154,000
6a	Jurisdictional % of Total Sales	96.3579	96.3476	96 7214	96.6082	96.7024	96.8627	96.5734	96 7492	96 6186	96 5120	96 3108	96 4662	96 5858
7	Cost per KWH Sold (¢/KWH)	2 4055	2.4358	2.4310	2 3741	2 2499	2 2163	2.1762	2 1425	2.1572	2 2395	2 0439	2 0275	2 2352
7a	Jurisdictional Loss Multiplier	1.0007	1 0007	1.0007	1.0007	1 0007	1 0007	1 0007	1 0007	1.0007	1 0007	1 0007	1 0007	1 0007
7b	Jurisdictional Cost (¢/KWH)	2.4072	2 4375	2 4327	2 3758	2 2515	2 2179	2 1777	2 1440	2 1587	2 2411	2 0453	2 0289	2 2368
8	GPIF (¢ / KWH) *	0.0042	0 0049	0 0046	0 0048	0 0039	0 0034	0 0033	0 0032	0 0038	0 0046	0 0052	0 0043	0 0041
9	True-Up (¢/KWH) *	0.2217	0 2598	0 2427	0 2549	0 2047	0.1818	0 1749	0 1696	0 2038	0.2447	0 2752	0 2261	0 2164
10	TOTAL	2.6331	2 7022	2 6800	2 6355	2 4601	2.4031	2 3559	2 3168	2 3663	2 4904	2 3257	2 2593	2 4573
11	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
12	Recovery Factor Adjusted for Taxes	2 6350	2 7041	2.6819	2 6374	2.4619	2 4048	2 3576	2 3185	2 3680	2 4922	2 3274	2 2609	2 4590
13	**Recovery Factor Rounded to the *Nearest .001 ¢/KWH***	2.635	2.704	2 682	2 637	2 462	2 405	2 358	2 319	2 368	2 492	2 327	2 261	2 459

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2003 - DECEMBER 2003

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	FUEL COST - NET GEN. ($)													
2	LIGHTER OIL (B.L.)	38,002	37,303	34,190	33,883	36,240	36,017	35,829	35,668	35,528	35,403	30,989	34,708	423,760
3	COAL excluding Scherer	16,825,877	12,896,768	13,715,864	12,500,757	15,929,470	20,885,564	22,235,070	22,156,798	21,213,095	17,328,178	16,629,466	17,214,335	209,531,242
3a	COAL at Scherer	2,482,405	2,319,313	2,483,773	2,360,007	2,194,040	2,419,279	2,531,367	2,526,868	2,461,013	2,444,350	304,086	950,393	25,476,894
4	GAS - Generation	9,699,362	9,035,888	9,319,486	7,713,337	6,984,459	10,939,236	12,433,119	12,493,454	10,031,169	6,691,172	5,065,722	4,143,689	104,550,093
4a	GAS (B.L.)	26,657	26,122	13,271	11,318	20,527	20,322	20,322	20,281	20,198	20,281	20,856	21,515	241,670
6	OTHER - C.T.	0	0	0	0	0	0	2,676	0	0	0	0	0	2,676
6a	OTHER GENERATION	0	0	0	0	0	1,945	7,779	6,078	3,403				19,205
7	TOTAL ($)	29,072,303	24,315,394	25,566,584	22,619,302	25,164,736	34,302,363	37,266,162	37,239,147	33,764,406	26,519,384	22,051,119	22,364,640	340,245,540
	SYSTEM NET GEN. (MWH)													
10	COAL	1,171,670	920,490	972,860	888,140	1,085,890	1,392,670	1,470,010	1,466,950	1,413,290	1,181,350	1,013,740	1,093,620	14,070,680
11	GAS	183,190	173,000	188,770	148,640	128,270	246,650	284,720	287,980	221,720	123,140	111,200	83,260	2,180,540
13	OTHER - C.T.	0	0	0	0	0	0	30	0	0	0	0	0	30
13a	OTHER GENERATION	0	0	0	0	0	80	320	250	140	0	0	0	790
14	TOTAL (MWH)	1,354,860	1,093,490	1,161,630	1,036,780	1,214,160	1,639,400	1,755,080	1,755,180	1,635,150	1,304,490	1,124,940	1,176,880	16,252,040
	UNITS OF FUEL BURNED													
16	LIGHTER OIL (BBL)	1,187	1,187	1,104	1,104	1,186	1,186	1,186	1,186	1,186	1,185	1,038	1,169	13,904
17	COAL excl Scherer (TON)	437,895	333,198	353,929	322,047	412,134	538,163	572,436	570,194	546,295	445,976	427,732	445,167	5,405,166
18	GAS-all (MCF)	1,302,034	1,238,988	1,332,803	1,032,989	918,308	1,697,195	1,971,105	1,986,173	1,532,349	872,876	798,997	604,577	15,288,394
20	OTHER - C.T. (BBL)	0	0	0	0	0	0	77	0	0	0	0	0	77
	BTU'S BURNED (MMBTU)													
23	COAL + GAS B.L. + OIL B.L.	11,962,451	9,367,011	9,956,221	9,122,819	11,150,680	14,272,157	15,145,503	15,085,271	14,473,280	12,089,876	10,351,409	11,156,935	144,133,613
24	GAS-Generation	1,336,982	1,272,044	1,370,594	1,061,785	941,743	1,743,997	2,026,125	2,041,644	1,574,206	894,948	818,853	618,601	15,701,522
26	OTHER - C.T.	0	0	0	0	0	0	450	0	0	0	0	0	450
27	TOTAL (MMBTU)	13,299,433	10,639,055	11,326,815	10,184,604	12,092,423	16,016,154	17,172,078	17,126,915	16,047,486	12,984,824	11,170,262	11,775,536	159,835,585

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	GENERATION MIX (% MWH)													
30	COAL	86.48	84.18	83 75	85 66	89 44	84 95	83.76	83 58	86 43	90 56	90 12	92 93	86 58
31	GAS-Generation	13 52	15 82	16 25	14.34	10.56	15.05	16.22	16.41	13 56	9 44	9 88	7 07	13.42
33	OTHER - C T	0 00	0.00	0 00	0 00	0.00	0.00	0.00	0.00	0 00	0.00	0 00	0.00	0 00
34	TOTAL (% MWH)	100 00	100.00	100.00	100.00	100 00	100.00	100 00	100.00	100.00	100.00	100 00	100 00	100 00
	FUEL COST $ / UNIT													
36	LIGHTER OIL ($/BBL)	32.01	31.43	30 96	30.69	30 55	30 37	30.21	30 08	29 97	29.87	29 86	29 69	30 48
37	COAL ($/TON)*	38.42	38.71	38 75	38 82	38.65	38 81	38.84	38 86	38 83	38 85	38.88	38.67	38 76
38	GAS + B.L. ($/MCF)	7.47	7.31	7.00	7.48	7 63	6 46	6.32	6 30	6 56	7.69	6 37	6 89	6 85
40	OTHER - C.T	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	34 79	#N/A	#N/A	#N/A	#N/A	#N/A	34.79
	FUEL COST $ / MMBTU													
43	COAL + GAS B.L. - OIL B L	1.62	1.63	1.63	1 63	1 63	1 63	1.64	1.64	1 64	1 64	1 64	1 63	1 63
44	GAS-Generation	7.25	7.10	6 80	7 26	7 42	6 27	6 14	6 12	6 37	7 48	6 19	6 70	6 66
46	OTHER - C.T.	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	5.95	#N/A	#N/A	#N/A	#N/A	#N/A	5 95
47	TOTAL ($/MMBTU)	2.19	2.29	2.26	2.22	2.08	2 14	2.17	2 17	2.10	2.04	1 97	1 90	2.13
	BTU BURNED BTU / KWH													
50	COAL + GAS B L + OIL B L	10,210	10,176	10,234	10,272	10,269	10,248	10,303	10,283	10,241	10,234	10,211	10,202	10,244
51	GAS-Generation	7,298	7,353	7,261	7,143	7,342	7,071	7,116	7,090	7,100	7,268	7,364	7,430	7,201
53	OTHER - C T	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	15,000	#N/A	#N/A	#N/A	#N/A	#N/A	15,000
	TOTAL (BTU/KWH)	9,816	9,729	9,751	9,823	9,959	9,770	9,786	9,759	9,815	9,954	9,930	10,006	9,835
	FUEL COST CENTS / KWH													
57	COAL + GAS B.L + OIL B L	1.65	1.66	1.67	1 68	1.67	1.68	1 69	1.69	1 68	1.68	1 68	1 67	1 67
58	GAS-Generation	5 29	5 22	4 94	5.19	5.45	4.44	4 37	4 34	4 52	5 43	4 56	4 98	4 79
60	OTHER - C.T.	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	8.92	#N/A	#N/A	#N/A	#N/A	#N/A	8 92
61	TOTAL (¢/KWH)	2.15	2.22	2 20	2.18	2.07	2 09	2.12	2 12	2.06	2.03	1 96	1 90	2.09

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JANUARY 2004

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	98.6	#N/A	#N/A	Gas - G					#N/A	#N/A
2	Crist 3	35.0	0	0.0	98.9	#N/A	#N/A	Gas - G					#N/A	#N/A
3	Crist 4	78.0	54,650	94.2	99.1	95.0	10,385	Coal	23,962	11,842	567,525	893,156	1.63	37.27
4	4							Gas - G						
5	Crist 5	80.0	54,370	91.3	98.0	93.2	10,236	Coal	23,496	11,842	556,506	875,815	1.61	37.28
6	5							Gas - G						
7	Crist 6	302.0	171,090	76.1	78.4	97.1	10,484	Coal	75,731	11,842	1,793,673	2,822,837	1.65	37.27
8	6							Gas - G						
9	Crist 7	477.0	329,910	93.0	93.0	100.0	10,124	Coal	141,022	11,842	3,340,043	5,256,475	1.59	37.27
10	7							Gas - G						
11	Scherer 3 (2)	211.3	148,880	94.7	95.6	99.1	10,238	Coal	86,719	8,788	1,524,181	2,482,405	1.67	28.63
12	Scholz 1	46.0	17,620	51.5	96.9	53.1	12,234	Coal	8,660	12,446	215,558	413,466	2.35	47.74
13	Scholz 2	46.0	17,730	51.8	96.4	53.7	12,492	Coal	8,898	12,446	221,487	424,838	2.40	47.75
14	Smith 1	162.0	116,280	96.5	98.5	97.9	9,970	Coal	48,334	11,993	1,159,333	1,945,960	1.67	40.26
15	Smith 2	189.0	127,320	90.5	93.7	96.6	9,841	Coal	52,236	11,993	1,252,926	2,103,058	1.65	40.26
16	Smith 3	584.0	183,190	42.2	91.2	46.2	7,298	Gas - G	1,298,041	1,030	1,336,982	9,699,362	5.29	7.47
17	Smith A (CT)	40.0	0	0.0	99.6	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		0										#N/A	#N/A
19	Daniel 1 (1)	253.5	85,710	45.4	48.8	93.1	9,984	Coal	36,012	11,881	855,717	1,354,946	1.58	37.62
20	Daniel 2 (1)	257.0	48,110	25.2	27.3	92.2	9,653	Coal	19,544	11,881	464,396	735,326	1.53	37.62
21	Gas,BL							Gas	3,993	1,030	4,113	26,657	#N/A	6.68
22	Ltr. Oil							Oil	1,187	140,241	6,993	38,002	#N/A	32.01
23		2,784.8	1,354,860	65.4	82.2	79.6	9,816				13,299,433	29,072,303	2.15	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : FEBRUARY 2004

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	98.6	#N/A	#N/A	Gas - G					#N/A	#N/A
2	Crist 3	35.0	0	0.0	98.9	#N/A	#N/A	Gas - G					#N/A	#N/A
3	Crist 4	78.0	51,270	94.4	98.7	95.7	10,382	Coal	22,477	11,841	532,290	841,327	1.64	37.43
4	4							Gas - G						
5	Crist 5	80.0	50,960	91.5	97.6	93.8	10,231	Coal	22,016	11,841	521,363	824,056	1.62	37.43
6	5							Gas - G						
7	Crist 6	302.0	47,640	22.7	23.6	96.0	10,483	Coal	21,088	11,841	499,395	789,333	1.66	37.43
8	6							Gas - G						
9	Crist 7	477.0	222,190	66.9	67.4	99.3	10,129	Coal	95,038	11,841	2,250,580	3,557,220	1.60	37.43
10	7							Gas - G						
11	Scherer 3 (2)	211.3	139,520	94.9	94.6	100.3	10,237	Coal	81,294	8,784	1,428,220	2,319,313	1.66	28.53
12	Scholz 1	46.0	17,190	53.7	96.9	55.4	12,216	Coal	8,563	12,261	209,991	417,872	2.43	48.80
13	Scholz 2	46.0	16,700	52.2	96.4	54.1	12,471	Coal	8,493	12,261	208,258	414,425	2.48	48.80
14	Smith 1	162.0	74,810	66.3	67.8	97.9	9,943	Coal	31,008	11,994	743,840	1,249,190	1.67	40.29
15	Smith 2	189.0	106,470	80.9	83.8	96.6	9,819	Coal	43,582	11,994	1,045,472	1,755,745	1.65	40.29
16	Smith 3	584.0	173,000	42.6	91.3	46.6	7,353	Gas - G	1,234,994	1,030	1,272,044	9,035,888	5.22	7.32
17	Smith A (CT	40.0	0	0.0	99.6	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		0				#N/A						#N/A	#N/A
19	Daniel 1 (1)	253.5	155,120	87.9	91.5	96.1	9,943	Coal	65,133	11,840	1,542,346	2,452,629	1.58	37.66
20	Daniel 2 (1)	257.0	38,620	21.6	22.7	95.1	9,688	Coal	15,800	11,840	374,150	594,971	1.54	37.66
21	Gas,BL							Gas	3,994	1,030	4,113	26,122	#N/A	6.54
22	Ltr. Oil							Oil	1,187	140,278	6,993	37,303	#N/A	31.43
23		2,784.8	1,093,490	56.4	72.8	77.5	9,729				10,639,055	24,315,394	2.22	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : MARCH 2004

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	98.6	#N/A	#N/A	Gas - G					#N/A	#N/A
2	Crist 3	35.0	0	0.0	98.9	#N/A	#N/A	Gas - G					#N/A	#N/A
3	Crist 4	78.0	51,230	88.3	92.3	95.6	10,518	Coal	22,707	11,865	538,839	857,043	1.67	37.74
4	4							Gas - G						
5	Crist 5	80.0	51,180	86.0	91.3	94.2	10,219	Coal	22,040	11,865	523,014	831,873	1.63	37.74
6	5							Gas - G						
7	Crist 6	302.0	215,980	96.1	96.8	99.3	10,638	Coal	96,826	11,865	2,297,635	3,654,472	1.69	37.74
8	6							Gas - G						
9	Crist 7	477.0	0	0.0	0.0	#N/A	#N/A	Coal	0	0	0	0	#N/A	#N/A
10	7							Gas - G						
11	Scherer 3 (2)	211.3	149,920	95.4	95.6	99.8	10,234	Coal	87,343	8,783	1,534,295	2,483,773	1.66	28.44
12	Scholz 1	46.0	19,560	57.2	96.9	59.0	12,168	Coal	9,791	12,154	238,010	483,790	2.47	49.41
13	Scholz 2	46.0	19,100	55.8	96.4	57.9	12,425	Coal	9,763	12,154	237,309	482,365	2.53	49.41
14	Smith 1	162.0	37,760	31.3	32.0	97.9	10,112	Coal	15,916	11,995	381,829	641,385	1.70	40.30
15	Smith 2	189.0	95,770	68.1	69.5	98.0	9,813	Coal	39,175	11,995	939,795	1,578,640	1.65	40.30
16	Smith 3	584.0	188,770	43.4	91.2	47.6	7,261	Gas - G	1,330,674	1,030	1,370,594	9,319,486	4.94	7.00
17	Smith A (CT	40.0	0	0.0	99.6	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		0										#N/A	#N/A
19	Daniel 1 (1)	253.5	174,190	92.4	94.8	97.4	9,925	Coal	73,103	11,825	1,728,859	2,753,130	1.58	37.66
20	Daniel 2 (1)	257.0	158,170	82.7	84.1	98.4	9,660	Coal	64,608	11,825	1,527,934	2,433,166	1.54	37.66
21	Gas,BL							Gas	2,129	1,030	2,193	13,271	#N/A	6.23
22	Ltr. Oil							Oil	1,104	140,344	6,509	34,190	#N/A	30.96
23		2,784.8	1,161,630	56.1	71.8	78.1	9,751				11,326,815	25,566,584	2.20	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : APRIL 2004

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	290	1.7	98.6	1.7	17,941	Gas - G	5,051	1,030	5,203	26,846	9.26	5.31
2	Crist 3	35.0	0	0.0	98.9	#N/A	#N/A	Gas - G					#N/A	#N/A
3	Crist 4	78.0	51,660	92.0	99.0	92.9	10,407	Coal	22,600	11,895	537,643	860,466	1.67	38.07
4	4							Gas - G						
5	Crist 5	80.0	51,230	88.9	97.9	90.8	10,303	Coal	22,187	11,895	527,809	844,727	1.65	38.07
6	5							Gas - G						
7	Crist 6	302.0	184,480	84.8	87.2	97.3	10,484	Coal	81,300	11,895	1,934,109	3,095,427	1.68	38.07
8	6							Gas - G						
9	Crist 7	477.0	0	0.0	0.0	#N/A	#N/A	Coal	0	0	0	0	#N/A	#N/A
10	7							Gas - G						
11	Scherer 3 (2)	211.3	142,370	93.6	94.7	98.8	10,243	Coal	83,028	8,782	1,458,321	2,360,007	1.66	28.42
12	Scholz 1	46.0	15,840	47.8	96.9	49.4	12,141	Coal	7,947	12,099	192,316	395,163	2.49	49.72
13	Scholz 2	46.0	13,910	42.0	96.4	43.6	12,358	Coal	7,104	12,099	171,904	353,222	2.54	49.72
14	Smith 1	162.0	101,890	87.4	92.2	94.7	10,252	Coal	43,541	11,995	1,044,563	1,755,257	1.72	40.31
15	Smith 2	189.0	19,560	14.4	15.6	92.1	10,087	Coal	8,224	11,995	197,300	331,538	1.69	40.31
16	Smith 3	566.0	148,350	36.4	91.2	39.9	7,122	Gas - G	1,025,808	1,030	1,056,582	7,686,491	5.18	7.49
17	Smith A (CT)	32.0	0	0.0	99.6	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		0										#N/A	#N/A
19	Daniel 1 (1)	253.5	143,880	78.8	85.5	92.2	9,989	Coal	60,850	11,809	1,437,175	2,292,278	1.59	37.67
20	Daniel 2 (1)	257.0	163,320	88.3	93.7	94.2	9,876	Coal	68,294	11,809	1,612,976	2,572,679	1.58	37.67
21	Gas,BL							Gas	2,130	1,030	2,193	11,318	#N/A	5.31
22	Ltr. Oil							Oil	1,104	140,365	6,510	33,883	#N/A	30.69
23		2,758.8	1,036,780	52.2	70.7	73.8	9,823				10,184,604	22,619,302	2.18	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : MAY 2004

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	98.6	#N/A	#N/A	Gas - G					#N/A	#N/A
2	Crist 3	35.0	0	0.0	98.9	#N/A	#N/A	Gas - G					#N/A	#N/A
3	Crist 4	78.0	48,900	84.3	99.1	85.0	10,538	Coal	21,740	11,852	515,319	820,086	1.68	37.72
4	4							Gas - G						
5	Crist 5	80.0	48,580	81.6	98.0	83.3	10,542	Coal	21,605	11,852	512,128	815,008	1.68	37.72
6	5							Gas - G						
7	Crist 6	302.0	187,210	83.3	97.2	85.7	10,370	Coal	81,898	11,852	1,941,325	3,089,453	1.65	37.72
8	6							Gas - G						
9	Crist 7	477.0	148,450	41.8	45.0	93.0	10,177	Coal	63,737	11,852	1,510,822	2,404,344	1.62	37.72
10	7							Gas - G						
11	Scherer 3 (2)	211.3	132,580	84.4	95.6	88.2	10,220	Coal	77,156	8,781	1,355,025	2,194,040	1.65	28.44
12	Scholz 1	46.0	12,950	37.8	96.9	39.0	12,188	Coal	6,538	12,070	157,832	326,200	2.52	49.89
13	Scholz 2	46.0	12,500	36.5	96.4	37.9	12,451	Coal	6,447	12,070	155,639	321,667	2.57	49.89
14	Smith 1	162.0	99,890	82.9	98.8	83.9	10,230	Coal	42,593	11,996	1,021,843	1,717,671	1.72	40.33
15	Smith 2	189.0	107,240	76.3	93.3	81.7	10,091	Coal	45,107	11,996	1,082,162	1,819,065	1.70	40.33
16	Smith 3	566.0	128,270	30.5	91.3	33.4	7,342	Gas - G	914,314	1,030	941,743	6,984,459	5.45	7.64
17	Smith A (CT)	32.0	0	0.0	99.6	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		0										#N/A	#N/A
19	Daniel 1 (1)	253.5	142,590	75.6	94.8	79.7	10,008	Coal	60,525	11,789	1,427,018	2,281,257	1.60	37.69
20	Daniel 2 (1)	257.0	145,000	75.8	93.4	81.2	10,072	Coal	61,944	11,789	1,460,461	2,334,719	1.61	37.69
21	Gas,BL							Gas	3,994	1,030	4,113	20,527	#N/A	5.14
22	Ltr. Oil							Oil	1,186	140,357	6,993	36,240	#N/A	30.55
23		2,758.8	1,214,160	59.2	86.2	68.6	9,959				12,092,423	25,164,736	2.07	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JUNE 2004

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	89.7	#N/A	#N/A	Gas - G					#N/A	#N/A
2	Crist 3	35.0	0	0.0	93.3	#N/A	#N/A	Gas - G					#N/A	#N/A
3	Crist 4	78.0	52,970	94.3	99.0	95.3	10,382	Coal	23,215	11,844	549,925	879,082	1.66	37.87
4	4							Gas - G						
5	Crist 5	80.0	52,870	91.8	97.9	93.8	10,221	Coal	22,812	11,844	540,375	863,816	1.63	37.87
6	5							Gas - G						
7	Crist 6	302.0	206,670	95.0	97.2	97.8	10,486	Coal	91,485	11,844	2,167,109	3,464,230	1.68	37.87
8	6							Gas - G						
9	Crist 7	477.0	318,740	92.8	93.3	99.5	10,254	Coal	137,975	11,844	3,268,337	5,224,598	1.64	37.87
10	7							Gas - G						
11	Scherer 3 (2)	211.3	145,870	95.9	97.1	98.8	10,237	Coal	85,038	8,780	1,493,313	2,419,279	1.66	28.45
12	Scholz 1	46.0	23,280	70.3	96.3	73.0	12,081	Coal	11,677	12,042	281,245	584,433	2.51	50.05
13	Scholz 2	46.0	22,950	69.3	96.2	72.0	12,329	Coal	11,748	12,042	282,945	587,966	2.56	50.05
14	Smith 1	162.0	112,060	96.1	98.9	97.1	10,118	Coal	47,261	11,996	1,133,851	1,906,352	1.70	40.34
15	Smith 2	189.0	123,310	90.6	93.6	96.8	10,052	Coal	51,666	11,996	1,239,550	2,084,065	1.69	40.34
16	Smith 3	566.0	246,650	60.5	95.1	63.6	7,071	Gas - G	1,693,201	1,030	1,743,997	10,939,236	4.44	6.46
17	Smith A (CT)	32.0	0	0.0	99.2	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		80										0.00	#N/A
19	Daniel 1 (1)	253.5	166,280	91.1	95.1	95.8	9,943	Coal	70,211	11,774	1,653,343	2,647,341	1.59	37.71
20	Daniel 2 (1)	257.0	167,670	90.6	93.8	96.6	9,847	Coal	70,113	11,774	1,651,057	2,643,681	1.58	37.71
21	Gas,BL							Gas	3,994	1,030	4,113	20,322	#N/A	5.09
22	Ltr. Oil							Oil	1,186	140,382	6,994	36,017	#N/A	30.37
23		2,758.8	1,639,400	82.5	95.4	86.5	9,770				16,016,154	34,300,418	2.09	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : JULY 2004

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	320	1.8	89.7	2.0	17,519	Gas - G	5,442	1,030	5,606	27,692	8.65	5.09
2	Crist 3	35.0	690	2.6	93.3	2.8	14,925	Gas - G	9,998	1,030	10,298	50,874	7.37	5.09
3	Crist 4	78.0	56,400	97.2	99.1	98.1	10,356	Coal	24,683	11,832	584,093	934,191	1.66	37.85
4	4							Gas - G						
5	Crist 5	80.0	56,550	95.0	98.0	96.9	10,125	Coal	24,196	11,832	572,546	915,723	1.62	37.85
6	5							Gas - G						
7	Crist 6	302.0	217,650	96.9	97.2	99.7	10,491	Coal	96,494	11,832	2,283,369	3,651,992	1.68	37.85
8	6							Gas - G						
9	Crist 7	477.0	330,700	93.2	93.4	99.8	10,364	Coal	144,840	11,832	3,427,414	5,481,763	1.66	37.85
10	7							Gas - G						
11	Scherer 3 (2)	211.3	152,590	97.1	97.0	100.1	10,235	Coal	88,940	8,780	1,561,818	2,531,367	1.66	28.46
12	Scholz 1	46.0	25,370	74.1	96.3	77.0	12,059	Coal	12,721	12,025	305,943	637,949	2.51	50.15
13	Scholz 2	46.0	25,190	73.6	96.2	76.5	12,309	Coal	12,893	12,025	310,067	646,549	2.57	50.15
14	Smith 1	162.0	118,600	98.4	98.8	99.6	10,100	Coal	49,927	11,996	1,197,830	2,014,845	1.70	40.36
15	Smith 2	189.0	130,630	92.9	93.7	99.1	10,180	Coal	55,430	11,996	1,329,849	2,236,911	1.71	40.36
16	Smith 3	566.0	283,710	67.4	95.1	70.8	7,085	Gas - G	1,951,671	1,030	2,010,221	12,354,553	4.35	6.33
17	Smith A (CT)	32.0	30	0.1	99.2	0.1	15,000	Oil - G	77	139,298	450	2,676	8.92	34.79
18	Other Generation		320										0.00	#N/A
19	Daniel 1 (1)	253.5	177,870	94.3	95.2	99.1	10,175	Coal	76,863	11,773	1,809,863	2,904,317	1.63	37.79
20	Daniel 2 (1)	257.0	178,460	93.3	93.8	99.5	9,815	Coal	74,389	11,773	1,751,605	2,810,830	1.58	37.79
21	Gas,BL							Gas	3,994	1,030	4,113	20,322	#N/A	5.09
22	Ltr. Oil							Oil	1,186	140,404	6,993	35,829	#N/A	30.21
23		2,758.8	1,755,080	85.5	95.4	89.6	9,786				17,172,078	37,258,383	2.12	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : AUGUST 2004

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	89.7	#N/A	#N/A	Gas - G					#N/A	#N/A
2	Crist 3	35.0	0	0.0	93.3	#N/A	#N/A	Gas - G					#N/A	#N/A
3	Crist 4	78.0	56,460	97.3	99.1	98.2	10,356	Coal	24,722	11,826	584,727	935,342	1.66	37.83
4	4							Gas - G						
5	Crist 5	80.0	56,840	95.5	98.0	97.4	10,109	Coal	24,295	11,826	574,615	919,167	1.62	37.83
6	5							Gas - G						
7	Crist 6	302.0	216,910	96.5	97.2	99.3	10,593	Coal	97,148	11,826	2,297,753	3,675,537	1.69	37.83
8	6							Gas - G						
9	Crist 7	477.0	330,610	93.2	93.4	99.7	10,287	Coal	143,794	11,826	3,401,024	5,440,356	1.65	37.83
10	7							Gas - G						
11	Scherer 3 (2)	211.3	152,260	96.9	97.0	99.9	10,236	Coal	88,757	8,780	1,558,599	2,526,868	1.66	28.47
12	Scholz 1	46.0	25,480	74.5	96.3	77.3	12,055	Coal	12,783	12,014	307,157	641,827	2.52	50.21
13	Scholz 2	46.0	25,260	73.8	96.2	76.7	12,312	Coal	12,943	12,014	310,993	649,843	2.57	50.21
14	Smith 1	162.0	118,070	98.0	98.8	99.2	10,104	Coal	49,726	11,996	1,193,018	2,007,245	1.70	40.37
15	Smith 2	189.0	130,350	92.7	93.7	98.9	10,138	Coal	55,083	11,996	1,321,533	2,223,471	1.71	40.37
16	Smith 3	566.0	287,980	68.4	95.1	71.9	7,090	Gas - G	1,982,179	1,030	2,041,644	12,493,454	4.34	6.30
17	Smith A (CT	32.0	0	0.0	99.2	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		250										0.00	#N/A
19	Daniel 1 (1)	253.5	177,120	93.9	95.2	98.6	10,054	Coal	75,633	11,773	1,780,805	2,861,624	1.62	37.84
20	Daniel 2 (1)	257.0	177,590	92.9	93.8	99.0	9,820	Coal	74,067	11,773	1,743,941	2,802,386	1.58	37.84
21	Gas,BL							Gas	3,994	1,030	4,113	20,281	#N/A	5.08
22	Ltr. Oil							Oil	1,186	140,423	6,993	35,668	#N/A	30.08
23		2,758.8	1,755,180	85.5	95.4	89.6	9,759				17,126,915	37,233,069	2.12	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : SEPTEMBER 2004

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	89.7	#N/A	#N/A	Gas - G					#N/A	#N/A
2	Crist 3	35.0	0	0.0	93.3	#N/A	#N/A	Gas - G					#N/A	#N/A
3	Crist 4	78.0	54,070	96.3	99.0	97.3	10,364	Coal	23,687	11,829	560,374	897,335	1.66	37.88
4	4							Gas - G						
5	Crist 5	80.0	53,670	93.2	97.9	95.2	10,181	Coal	23,097	11,829	546,407	874,969	1.63	37.88
6	5							Gas - G						
7	Crist 6	302.0	210,400	96.8	96.8	100.0	10,490	Coal	93,294	11,829	2,207,095	3,534,252	1.68	37.88
8	6							Gas - G						
9	Crist 7	477.0	319,830	93.1	93.3	99.8	10,312	Coal	139,410	11,829	3,298,075	5,281,253	1.65	37.88
10	7							Gas - G						
11	Scherer 3 (2)	211.3	147,730	97.1	97.1	100.0	10,235	Coal	86,133	8,777	1,512,031	2,461,013	1.67	28.57
12	Scholz 1	46.0	21,210	64.0	96.3	66.5	12,084	Coal	10,672	12,008	256,307	536,171	2.53	50.24
13	Scholz 2	46.0	21,620	65.3	96.2	67.9	12,340	Coal	11,109	12,009	266,796	558,114	2.58	50.24
14	Smith 1	162.0	114,630	98.3	98.5	99.8	10,102	Coal	48,264	11,996	1,157,951	1,948,498	1.70	40.37
15	Smith 2	189.0	126,410	92.9	93.2	99.7	10,033	Coal	52,863	11,996	1,268,272	2,134,137	1.69	40.37
16	Smith 3	566.0	221,720	54.4	95.1	57.2	7,100	Gas - G	1,528,355	1,030	1,574,206	10,031,169	4.52	6.56
17	Smith A (CT	32.0	0	0.0	99.2	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		140										0.00	#N/A
19	Daniel 1 (1)	253.5	171,460	93.9	95.1	98.8	9,902	Coal	72,094	11,775	1,697,831	2,729,646	1.59	37.86
20	Daniel 2 (1)	257.0	172,260	93.1	93.8	99.2	9,817	Coal	71,805	11,775	1,691,035	2,718,720	1.58	37.86
21	Gas,BL							Gas	3,994	1,030	4,113	20,198	#N/A	5.06
22	Ltr. Oil							Oil	1,186	140,441	6,993	35,528	#N/A	29.96
23		2,758.8	1,635,150	82.3	95.3	86.4	9,815				16,047,486	33,761,003	2.06	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : OCTOBER 2004

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	98.6	#N/A	#N/A	Gas - G					#N/A	#N/A
2	Crist 3	35.0	0	0.0	98.9	#N/A	#N/A	Gas - G					#N/A	#N/A
3	Crist 4	78.0	52,360	90.2	98.7	91.4	10,436	Coal	23,075	11,840	546,410	877,350	1.68	38.02
4	4							Gas - G						
5	Crist 5	80.0	51,710	86.9	97.6	89.0	10,192	Coal	22,256	11,840	527,019	846,215	1.64	38.02
6	5							Gas - G						
7	Crist 6	302.0	187,960	83.7	87.8	95.3	10,481	Coal	83,196	11,840	1,970,036	3,163,213	1.68	38.02
8	6							Gas - G						
9	Crist 7	477.0	296,710	83.6	84.0	99.5	10,129	Coal	126,918	11,840	3,005,352	4,825,580	1.63	38.02
10	7							Gas - G						
11	Scherer 3 (2)	211.3	145,980	92.9	95.6	97.2	10,244	Coal	85,213	8,775	1,495,456	2,444,350	1.67	28.69
12	Scholz 1	46.0	14,930	43.6	96.9	45.0	12,232	Coal	7,606	12,006	182,624	382,241	2.56	50.26
13	Scholz 2	46.0	10,830	31.6	96.4	32.8	12,475	Coal	5,627	12,006	135,105	282,782	2.61	50.25
14	Smith 1	162.0	111,780	92.7	98.8	93.9	10,144	Coal	47,260	11,996	1,133,856	1,908,665	1.71	40.39
15	Smith 2	189.0	110,490	78.6	84.6	92.9	10,085	Coal	46,443	11,996	1,114,266	1,875,689	1.70	40.39
16	Smith 3	566.0	123,140	29.2	91.3	32.0	7,268	Gas - G	868,882	1,030	894,948	6,691,172	5.43	7.70
17	Smith A (CT	32.0	0	0.0	99.6	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		0										#N/A	#N/A
19	Daniel 1 (1)	253.5	31,760	16.8	18.5	91.0	10,010	Coal	13,499	11,775	317,903	511,327	1.61	37.88
20	Daniel 2 (1)	257.0	166,840	87.3	93.8	93.0	9,894	Coal	70,096	11,775	1,650,742	2,655,116	1.59	37.88
21	Gas,BL							Gas	3,994	1,030	4,113	20,281	#N/A	5.08
22	Ltr. Oil							Oil	1,185	140,457	6,994	35,403	#N/A	29.87
23		2,758.8	1,304,490	63.6	84.3	75.4	9,954				12,984,824	26,519,384	2.03	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : NOVEMBER, 2004

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	98.6	#N/A	#N/A	Gas - G					#N/A	#N/A
2	Crist 3	35.0	0	0.0	98.9	#N/A	#N/A	Gas - G					#N/A	#N/A
3	Crist 4	78.0	47,950	85.4	92.5	92.3	10,096	Coal	20,431	11,847	484,107	778,562	1.62	38.11
4	4							Gas - G						
5	Crist 5	80.0	47,540	82.5	91.4	90.3	10,025	Coal	20,113	11,848	476,578	766,453	1.61	38.11
6	5							Gas - G						
7	Crist 6	302.0	181,320	83.4	87.1	95.7	10,482	Coal	80,213	11,848	1,900,636	3,056,685	1.69	38.11
8	6							Gas - G						
9	Crist 7	477.0	318,500	92.7	93.1	99.6	10,260	Coal	137,909	11,848	3,267,772	5,255,374	1.65	38.11
10	7							Gas - G						
11	Scherer 3 (2)	211.3	18,210	12.0	8.1	147.8	10,186	Coal	10,572	8,773	185,496	304,086	1.67	28.76
12	Scholz 1	46.0	9,260	28.0	84.0	33.3	12,253	Coal	4,726	12,004	113,461	237,551	2.57	50.26
13	Scholz 2	46.0	10,080	30.4	96.4	31.6	12,491	Coal	5,244	12,004	125,908	263,611	2.62	50.27
14	Smith 1	162.0	109,050	93.5	98.5	94.9	10,137	Coal	46,077	11,996	1,105,477	1,861,277	1.71	40.39
15	Smith 2	189.0	120,400	88.5	93.3	94.8	10,071	Coal	50,542	11,996	1,212,589	2,041,620	1.70	40.39
16	Smith 3	584.0	111,200	26.4	91.2	29.0	7,364	Gas - G	795,003	1,030	818,853	5,065,722	4.56	6.37
17	Smith A (CT	40.0	0	0.0	99.6	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		0										#N/A	#N/A
19	Daniel 1 (1)	253.5	0	0.0	0.0	#N/A	#N/A	Coal	0	0	0	0	#N/A	#N/A
20	Daniel 2 (1)	257.0	151,430	81.8	87.1	94.0	9,702	Coal	62,477	11,757	1,469,149	2,368,333	1.56	37.91
21	Gas,BL							Gas	3,994	1,030	4,113	20,856	#N/A	5.22
22	Ltr. Oil							Oil	1,038	140,451	6,123	30,989	#N/A	29.86
23		2,784.8	1,124,940	56.1	77.0	72.9	9,930				11,170,262	22,051,119	1.96	

Notes:

(1) Represents Gulf's 50% Ownership

(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE MONTH OF : DECEMBER 2004

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned MMBTU	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	0	0.0	98.6	0.0	#N/A	Gas - G					#N/A	#N/A
2	Crist 3	35.0	0	0.0	98.9	0.0	#N/A	Gas - G					#N/A	#N/A
3	Crist 4	78.0	52,730	90.9	99.1	91.7	10,424	Coal	23,198	11,847	549,655	883,984	1.68	38.11
4	4							Gas - G						
5	Crist 5	80.0	51,300	86.2	97.7	88.2	10,394	Coal	22,503	11,847	533,204	857,526	1.67	38.11
6	5							Gas - G						
7	Crist 6	302.0	195,940	87.2	90.9	95.9	10,482	Coal	86,679	11,847	2,053,817	3,303,055	1.69	38.11
8	6							Gas - G						
9	Crist 7	477.0	297,170	83.7	84.4	99.2	10,126	Coal	126,995	11,847	3,009,101	4,839,391	1.63	38.11
10	7							Gas - G						
11	Scherer 3 (2)	211.3	56,700	36.1	24.9	144.9	10,213	Coal	33,005	8,772	579,076	950,393	1.68	28.80
12	Scholz 1	46.0	0	0.0	15.6	0.0	#N/A	Coal	0	0	0	0	#N/A	#N/A
13	Scholz 2	46.0	8,320	24.3	96.4	25.2	12,535	Coal	4,344	12,003	104,294	218,403	2.63	50.28
14	Smith 1	162.0	113,010	93.8	98.8	94.9	10,134	Coal	47,736	11,996	1,145,279	1,928,550	1.71	40.40
15	Smith 2	189.0	112,290	79.9	84.5	94.5	10,071	Coal	47,136	11,996	1,130,891	1,904,321	1.70	40.40
16	Smith 3	584.0	83,260	19.2	91.2	21.0	7,430	Gas - G	600,583	1,030	618,601	4,143,689	4.98	6.90
17	Smith A (CT	40.0	0	0.0	99.6	0.0	#N/A	Oil - G	0	0	0	0	#N/A	#N/A
18	Other Generation		0										#N/A	#N/A
19	Daniel 1 (1)	253.5	36,280	19.2	21.5	89.5	10,026	Coal	15,432	11,785	363,738	584,500	1.61	37.88
20	Daniel 2 (1)	257.0	169,880	88.8	93.4	95.1	9,871	Coal	71,144	11,785	1,676,869	2,694,605	1.59	37.88
21	Gas,BL							Gas	3,994	1,030	4,113	21,515	#N/A	5.39
22	Ltr. Oil							Oil	1,169	140,487	6,898	34,708	#N/A	29.69
23		2,784.8	1,176,880	56.8	78.3	72.5	10,006				11,775,536	22,364,640	1.90	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM NET GENERATION AND FUEL COST
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD : JANUARY 2004 - DECEMBER 2004

Line	(a) Plant/Unit	(b) Net Cap. (MW)	(c) Net Gen. (MWH)	(d) Cap. Factor (%)	(e) Equiv. Avail. Factor (%)	(f) Net Output Factor (%)	(g) Avg. Net Heat Rate (BTU/KWH)	(h) Fuel Type	(i) Fuel Burned (Units) Tons/MCF/Bbl	(j) Fuel Heat Value (BTU/Unit) Lbs/CF/Gal	(k) Fuel Burned (MMBTU)	(l) As Burned Fuel Cost ($)	(m) Fuel Cost/ KWH (¢/KWH)	(n) Fuel Cost/ Unit ($/Unit)
1	Crist 2	24.0	610	0.3	95.7	0.3	17,720	Gas - G	10,493	1,030	10,809	54,538	8.94	5.20
2	Crist 3	35.0	690	0.2	97.0	0.2	14,925	Gas - G	9,998	1,030	10,298	50,874	7.37	5.09
3	Crist 4	78.0	630,650	92.0	97.9	94.0	10,388	Coal	276,497	11,846	6,550,907	10,457,924	1.66	37.82
4	4							Gas - G						
5	Crist 5	80.0	626,800	89.2	96.8	92.1	10,229	Coal	270,616	11,846	6,411,564	10,235,348	1.63	37.82
6	5							Gas - G						
7	Crist 6	302.0	2,223,250	83.8	86.7	96.7	10,501	Coal	985,352	11,847	23,345,952	37,300,487	1.68	37.85
8	6							Gas - G						
9	Crist 7	477.0	2,912,810	69.5	70.1	99.2	10,223	Coal	1,257,638	11,839	29,778,520	47,566,353	1.63	37.82
10	7							Gas - G						
11	Scherer 3 (2)	211.3	1,532,610	82.6	82.8	99.7	10,235	Coal	893,198	8,781	15,685,831	25,476,894	1.66	28.52
12	Scholz 1	46.0	202,690	50.2	88.8	56.5	12,139	Coal	101,684	12,098	2,460,444	5,056,663	2.49	49.73
13	Scholz 2	46.0	204,190	50.5	96.4	52.4	12,394	Coal	104,613	12,096	2,530,705	5,203,785	2.55	49.74
14	Smith 1	162.0	1,227,830	86.3	90.1	95.8	10,114	Coal	517,643	11,995	12,418,670	20,884,895	1.70	40.35
15	Smith 2	189.0	1,310,240	78.9	82.8	95.3	10,025	Coal	547,487	11,995	13,134,605	22,088,260	1.69	40.34
16	Smith 3	574.0	2,179,240	43.2	92.5	46.7	7,195	Gas - G	15,223,705	1,030	15,680,415	104,444,681	4.79	6.86
17	Smith A (CT)	35.0	30	0.0	99.5	0.0	15,000	Oil - G	77	139,298	450	2,676	8.92	34.79
18	Other Generation		790										0.00	#N/A
19	Daniel 1 (1)	253.5	1,462,260	65.7	69.6	94.4	9,995	Coal	619,355	11,798	14,614,598	23,372,995	1.60	37.74
20	Daniel 2 (1)	257.0	1,737,350	77.0	81.1	94.9	9,828	Coal	724,281	11,787	17,074,315	27,364,532	1.58	37.78
21	Gas,BL							Gas	44,198	1,030	45,516	241,670	#N/A	5.47
22	Ltr. Oil							Oil	13,904	140,385	81,986	423,760	#N/A	30.48
23		2,769.8	16,252,040	66.8	83.8	79.7	9,835				159,835,585	340,226,335	2.09	

Notes:
(1) Represents Gulf's 50% Ownership
(2) Represents Gulf's 25% Ownership

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2004 - DECEMBER 2004

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	LIGHT OIL													
1	*PURCHASES :*													
2	UNITS (BBL)	1,109	1,108	1,026	1,025	1,107	1,107	1,107	1,107	1,107	1,106	959	1,090	12,958
3	UNIT COST ($/BBL)	28 66	28.66	28 66	28 66	28 66	28.66	28.66	28 66	28 66	28 66	28 70	28 66	28 66
4	AMOUNT ($)	31,769	31,758	29,408	29,388	31,724	31,730	31,724	31,719	31,714	31,710	27,518	31,240	371,402
5	*BURNED :*													
6	UNITS (BBL)	1,187	1,187	1,104	1,104	1,186	1,186	1,186	1,186	1,186	1,185	1,038	1,169	13,904
7	UNIT COST ($/BBL)	32.01	31.43	30 96	30.69	30.55	30.37	30 21	30 08	29 97	29 87	29 86	29 69	30 48
8	AMOUNT ($)	38,002	37,303	34,190	33,883	36,240	36,017	35,829	35,668	35,528	35,403	30,989	34,708	423,760
9	*ENDING INVENTORY :*													
10	UNITS (BBL)	8,671	8,593	8,514	8,435	8,356	8,277	8,198	8,119	8,040	7,961	7,882	7,803	
11	UNIT COST ($/BBL)	32 21	31 86	31.59	31.36	31 11	30 89	30.69	30 50	30 33	30 16	30 03	29 89	
12	AMOUNT ($)	279,321	273,776	268,994	264,499	259,983	255,696	251,591	247,642	243,828	240,135	236,664	233,196	
13	DAYS SUPPLY:	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
	COAL EXCLUDING PLANT SCHERER													
14	*PURCHASES :*													
15	UNITS (TONS)	408,593	366,369	347,215	325,023	418,073	533,367	557,309	558,026	536,945	486,237	445,251	438,752	5,421,160
16	UNIT COST ($/TON)	38.61	38 94	39 12	39 16	38 54	38 89	38.88	38 88	38 86	38.89	38.89	38.86	38 87
17	AMOUNT ($)	15,773,897	14,265,576	13,583,137	12,728,259	16,113,122	20,741,167	21,668,200	21,696,776	20,865,024	18,908,437	17,316,961	17,050,918	210,711,474
18	*BURNED*													
19	UNITS (TONS)	437,895	333,198	353,929	322,047	412,134	538,163	572,436	570,194	546,295	445,976	427,732	445,167	5,405,166
20	UNIT COST ($/TON)	38 42	38.71	38.75	38.82	38 65	38.81	38 84	38.86	38 83	38 85	38 88	38 67	38 76
21	AMOUNT ($)	16,825,877	12,896,768	13,715,864	12,500,757	15,929,470	20,885,564	22,235,070	22,156,798	21,213,095	17,328,178	16,629,466	17,214,335	209,531,242
22	*ENDING INVENTORY*													
23	UNITS (TONS)	542,058	575,229	568,515	571,491	577,430	572,634	557,507	545,339	535,989	576,250	593,769	587.354	
24	UNIT COST ($/TON)	38.53	38.69	38 91	39 10	39 02	39 09	39 14	39 17	39 20	39 21	39 21	39.36	
25	AMOUNT ($)	20,884,031	22,252,839	22,120,112	22,347,614	22,531,266	22,386,869	21,819,999	21,359,977	21,011,906	22,592,165	23,279,660	23,116,243	
26	DAYS SUPPLY:	28	29	29	29	30	29	29	28	27	29	30	30	

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2004 - DECEMBER 2004

		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
	COAL AT PLANT SCHERER													
27	*PURCHASES :*													
28	UNITS (MMBTU)	2,286,598	1,424,288	1,615,330	1,531,486	1,430,412	1,398,444	1,466,874	1,463,730	1,058,275	1,018,832	1,018,832	1,018,832	16,731,933
29	UNIT COST ($/MMBTU	1 60	1.62	1.61	1.62	1.62	1.62	1.62	1.62	1 64	1.64	1 64	1 64	1 62
30	AMOUNT ($)	3,664,783	2,304,169	2,605,608	2,477,379	2,317,898	2,267,456	2,378,914	2,373,955	1,734,199	1,675,448	1,675,448	1,675,448	27,150,704
31	*BURNED*													
32	UNITS (MMBTU)	1,524,181	1,428,220	1,534,295	1,458,321	1,355,025	1,493,313	1,561,818	1,558,599	1,512,031	1,495,456	185,496	579,076	15,685,831
33	UNIT COST ($/MMBTU	1 63	1.62	1 62	1 62	1 62	1 62	1 62	1.62	1 63	1 63	1 64	1 64	1 62
34	AMOUNT ($)	2,482,405	2,319,313	2,483,773	2,360,007	2,194,040	2,419,279	2,531,367	2,526,868	2,461,013	2,444,350	304,086	950,393	25,476,894
35	*ENDING INVENTORY*													
36	UNITS (MMBTU)	1,751,733	1,747,800	1,828,835	1,902,000	1,977,387	1,882,518	1,787,574	1,692,705	1,238,949	762,325	1,595,661	2,035,417	
37	UNIT COST ($/MMBTU	1 63	1 62	1 62	1 62	1 62	1 62	1 62	1 62	1 62	1 63	1 64	1 64	
38	AMOUNT ($)	2,849,141	2,833,997	2,955,832	3,073,204	3,197,062	3,045,239	2,892,786	2,739,873	2,013,059	1,244,157	2,615,518	3,340,573	
39	DAYS SUPPLY	34	34	35	36	38	36	34	32	24	15	31	39	
	GAS													
44	*BURNED :*													
45	UNITS (MCF)	1,302,034	1,238,988	1,332,803	1,032,989	918,308	1,697,195	1,971,105	1,986,173	1,532,349	872,876	798,997	604,577	15,288,394
46	UNIT COST ($/MCF)	7 47	7.31	7.00	7 48	7 63	6 46	6.32	6 30	6 56	7 69	6 37	6 89	6 85
47	AMOUNT ($)	9,726,019	9,062,010	9,332,757	7,724,655	7,004,986	10,959,558	12,453,441	12,513,735	10,051,367	6,711,453	5,086,578	4,165,204	104,791,763
	OTHER - C.T. OIL													
53	*PURCHASES :*													
54	UNITS (BBL)	0	0	0	0	0	0	76	1	0	0	0	0	77
55	UNIT COST ($/BBL)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	28 70	29.40	#N/A	#N/A	#N/A	#N/A	28 68
56	AMOUNT ($)	0	0	0	0	0	0	2,187	21	0	0	0	0	2,208
57	*BURNED :*													
58	UNITS (BBL)	0	0	0	0	0	0	77	0	0	0	0	0	77
59	UNIT COST ($/BBL)	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	34.79	#N/A	#N/A	#N/A	#N/A	#N/A	34 75
60	AMOUNT ($)	0	0	0	0	0	0	2,676	0	0	0	0	0	2,676
61	*ENDING INVENTORY :*													
62	UNITS (BBL)	12,857	12,857	12,857	12,857	12,857	12,857	12,856	12,857	12,857	12,857	12,857	12,857	
63	UNIT COST ($/BBL)	34 81	34 81	34.81	34.81	34 81	34 81	34 78	34 78	34 78	34 78	34.78	34 78	
64	AMOUNT ($)	447,608	447,608	447,608	447,608	447,608	447,608	447,119	447,140	447,140	447,140	447,140	447,140	
65	DAYS SUPPLY	7	7	7	7	7	7	7	7	7	7	7	7	

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2004 - DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
			KWH		(A)	(B)	(6) x (7)(A)	(6) x (7)(B)
		TOTAL	WHEELED	KWH	¢ / KWH		TOTAL $	
MONTH		KWH	FROM OTHER	FROM OWN	FUEL	TOTAL	FOR FUEL	TOTAL COST
LINE	TYPE & SCHEDULE	SOLD	SYSTEMS	GENERATION	COST	COST	ADJUSTMENT	$
JANUARY								
1	Southern Co Interchange	277,758,000	0	277,758,000	2.06	2.29	5,720,000	6,357,000
2	Unit Power Sales	154,866,000	0	154,866,000	1.71	1.86	2,651,000	2,886,000
3	Economy Sales	7,761,000	0	7,761,000	3.00	2.99	233,000	232,000
4	Gain on Economy Sales						35,000	35,000
5	TOTAL ESTIMATED SALES	440,385,000	0	440,385,000	1.96	2.16	8,639,000	9,510,000
FEBRUARY								
1	Southern Co Interchange	195,727,000	0	195,727,000	2.28	2.53	4,470,000	4,960,000
2	Unit Power Sales	135,886,000	0	135,886,000	1.73	1.87	2,345,000	2,547,000
3	Economy Sales	4,291,000	0	4,291,000	2.96	2.91	127,000	125,000
4	Gain on Economy Sales						19,000	19,000
5	TOTAL ESTIMATED SALES	335,904,000	0	335,904,000	2.07	2.28	6,961,000	7,651,000
MARCH								
1	Southern Co. Interchange	188,478,000	0	188,478,000	2.17	2.41	4,095,000	4,536,000
2	Unit Power Sales	154,062,000	0	154,062,000	1.74	1.89	2,678,000	2,906,000
3	Economy Sales	8,607,000	0	8,607,000	2.99	2.97	257,000	256,000
4	Gain on Economy Sales						38,000	38,000
5	TOTAL ESTIMATED SALES	351,147,000	0	351,147,000	2.01	2.20	7,068,000	7,736,000
APRIL								
1	Southern Co. Interchange	140,840,000	0	140,840,000	2.35	2.59	3,304,000	3,644,000
2	Unit Power Sales	144,395,000	0	144,395,000	1.69	1.84	2,439,000	2,663,000
3	Economy Sales	4,675,000	0	4,675,000	2.78	2.78	130,000	130,000
4	Gain on Economy Sales						20,000	20,000
5	TOTAL ESTIMATED SALES	289,910,000	0	289,910,000	2.03	2.23	5,893,000	6,457,000
MAY								
1	Southern Co Interchange	140,526,000	0	140,526,000	2.13	2.36	2,992,000	3,319,000
2	Unit Power Sales	128,737,000	0	128,737,000	1.67	1.83	2,152,000	2,351,000
3	Economy Sales	4,865,000	0	4,865,000	2.47	2.53	120,000	123,000
4	Gain on Economy Sales						18,000	18,000
5	TOTAL ESTIMATED SALES	274,128,000	0	274,128,000	1.93	2.12	5,282,000	5,811,000
JUNE								
1	Southern Co. Interchange	343,083,000	0	343,083,000	2.43	2.64	8,352,000	9,068,000
2	Unit Power Sales	146,719,000	0	146,719,000	1.65	1.81	2,416,000	2,658,000
3	Economy Sales	8,928,000	0	8,928,000	3.18	3.21	284,000	287,000
4	Gain on Economy Sales						57,000	57,000
5	TOTAL ESTIMATED SALES	498,730,000	0	498,730,000	2.23	2.42	11,109,000	12,070,000

POWER SOLD
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2004 - DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)		(7)	(8)
			KWH		(A)	(B)	(6) x (7)(A)	(6) x (7)(B)
		TOTAL	WHEELED	KWH	¢ / KWH		TOTAL $	
MONTH		KWH	FROM OTHER	FROM OWN	FUEL	TOTAL	FOR FUEL	TOTAL COST
LINE	TYPE & SCHEDULE	SOLD	SYSTEMS	GENERATION	COST	COST	ADJUSTMENT	$
JULY								
1	Southern Co Interchange	397,846,000	0	397,846,000	2.72	2.95	10,811,000	11,731,000
2	Unit Power Sales	155,733,000	0	155,733,000	1.66	1.82	2,584,000	2,841,000
3	Economy Sales	8,529,000	0	8,529,000	3.89	3.88	332,000	331,000
4	Gain on Economy Sales						66,000	66,000
5	TOTAL ESTIMATED SALES	562,108,000	0	562,108,000	2.45	2.66	13,793,000	14,969,000
AUGUST								
1	Southern Co Interchange	363,822,000	0	363,822,000	2.93	3.19	10,666,000	11,617,000
2	Unit Power Sales	155,296,000	0	155,296,000	1.66	1.83	2,580,000	2,835,000
3	Economy Sales	4,656,000	0	4,656,000	4.36	4.34	203,000	202,000
4	Gain on Economy Sales						40,000	40,000
5	TOTAL ESTIMATED SALES	523,774,000	0	523,774,000	2.58	2.81	13,489,000	14,694,000
SEPTEMBER								
1	Southern Co Interchange	458,215,000	0	458,215,000	2.30	2.53	10,536,000	11,614,000
2	Unit Power Sales	148,520,000	0	148,520,000	1.64	1.81	2,439,000	2,684,000
3	Economy Sales	7,206,000	0	7,206,000	3.14	3.14	226,000	226,000
4	Gain on Economy Sales						34,000	34,000
5	TOTAL ESTIMATED SALES	613,941,000	0	613,941,000	2.16	2.37	13,235,000	14,558,000
OCTOBER								
1	Southern Co. Interchange	344,500,000	0	344,500,000	1.98	2.21	6,817,000	7,621,000
2	Unit Power Sales	140,932,000	0	140,932,000	1.67	1.82	2,356,000	2,570,000
3	Economy Sales	4,507,000	0	4,507,000	2.51	2.49	113,000	112,000
4	Gain on Economy Sales						17,000	17,000
5	TOTAL ESTIMATED SALES	489,939,000	0	489,939,000	1.90	2.11	9,303,000	10,320,000
NOVEMBER								
1	Southern Co Interchange	353,865,000	0	353,865,000	1.99	2.22	7,045,000	7,864,000
2	Unit Power Sales	41,374,000	0	41,374,000	2.03	2.11	840,000	874,000
3	Economy Sales	5,825,000	0	5,825,000	2.54	2.54	148,000	148,000
4	Gain on Economy Sales						22,000	22,000
5	TOTAL ESTIMATED SALES	401,064,000	0	401,064,000	2.01	2.22	8,055,000	8,908,000
DECEMBER								
1	Southern Co. Interchange	235,754,000	0	235,754,000	1.95	2.16	4,587,000	5,097,000
2	Unit Power Sales	55,391,000	0	55,391,000	1.77	1.90	978,000	1,053,000
3	Economy Sales	4,827,000	0	4,827,000	2.40	2.40	116,000	116,000
4	Gain on Economy Sales						17,000	17,000
5	TOTAL ESTIMATED SALES	295,972,000	0	295,972,000	1.93	2.12	5,698,000	6,283,000
TOTAL								
1	Southern Co Interchange	3,440,414,000	0	3,440,414,000	2.31	2.54	79,395,000	87,428,000
2	Unit Power Sales	1,561,911,000	0	1,561,911,000	1.69	1.85	26,458,000	28,868,000
3	Economy Sales	74,677,000	0	74,677,000	3.07	3.06	2,289,000	2,288,000
4	Gain on Economy Sales						383,000	383,000
5	TOTAL ESTIMATED SALES	5,077,002,000	0	5,077,002,000	2.14	2.34	108,525,000	118,967,000

SCHEDULE E-7

PURCHASED POWER
GULF POWER COMPANY
(EXCLUSIVE OF ECONOMY ENERGY PURCHASES)

ESTIMATED FOR THE PERIOD OF: JANUARY 2004 - DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8) ¢ / KWH		(9)
MONTH	PURCHASED FROM	TYPE & SCHED	TOTAL KWH PURCH	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7)x(8)(a)
January	NONE								
February	NONE								
March	NONE								
April	NONE								
May	NONE								
June	NONE								
July	NONE								
August	NONE								
September	NONE								
October	NONE								
November	NONE								
December	NONE								
Total	NONE								

SCHEDULE E-8

ENERGY PAYMENT TO QUALIFYING FACILITIES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2004 - DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				KWH			¢/KWH		
MONTH	PURCHASED FROM.	TYPE AND SCHEDULE	TOTAL KWH PURCHASED	FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJ.
JANUARY	Solutia	COG-1				None			
FEBRUARY	Solutia	COG-1				None			
MARCH	Solutia	COG-1				None			
APRIL	Solutia	COG-1				None			
MAY	Solutia	COG-1				None			
JUNE	Solutia	COG-1				None			
JULY	Solutia	COG-1				None			
AUGUST	Solutia	COG-1				None			
SEPTEMBER	Solutia	COG-1				None			
OCTOBER	Solutia	COG-1				None			
NOVEMBER	Solutia	COG-1				None			
DECEMBER	Solutia	COG-1				None			
TOTAL			0			-			0

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2004- DECEMBER 2004

(1)	(2)	(3)	(4)	(5)
LINE	MONTH TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL S FOR FUEL ADJ.
	JANUARY			
1	Southern Co. Interchange	15,458,000	3.53	545,000
2	Unit Power Sales	9,480,000	2.59	246,000
3	Economy Energy	6,005,000	2.95	177,000
4	Other Purchases	1,930,000	2.75	53,000
5	TOTAL ESTIMATED PURCHASES	32,873,000	3.11	1,021,000
	FEBRUARY			
1	Southern Co. Interchange	28,122,000	2.79	786,000
2	Unit Power Sales	8,677,000	2.41	209,000
3	Economy Energy	3,201,000	2.75	88,000
4	Other Purchases	3,740,000	2.75	103,000
5	TOTAL ESTIMATED PURCHASES	43,740,000	2.71	1,186,000
	MARCH			
1	Southern Co. Interchange	22,202,000	2.63	583,000
2	Unit Power Sales	10,273,000	2.40	247,000
3	Economy Energy	5,943,000	2.76	164,000
4	Other Purchases	8,220,000	2.92	240,000
5	TOTAL ESTIMATED PURCHASES	46,638,000	2.65	1,234,000
	APRIL			
1	Southern Co. Interchange	53,000,000	2.33	1,233,000
2	Unit Power Sales	5,542,000	2.45	136,000
3	Economy Energy	3,508,000	2.68	94,000
4	Other Purchases	5,990,000	2.68	181,000
5	TOTAL ESTIMATED PURCHASES	68,040,000	2.42	1,644,000
	MAY			
1	Southern Co. Interchange	73,466,000	1.96	1,438,000
2	Unit Power Sales	4,383,000	2.21	97,000
3	Economy Energy	2,700,000	2.44	66,000
4	Other Purchases	6,360,000	2.66	169,000
5	TOTAL ESTIMATED PURCHASES	86,909,000	2.04	1,770,000
	JUNE			
1	Southern Co. Interchange	4,978,000	4.04	201,000
2	Unit Power Sales	1,765,000	2.89	51,000
3	Economy Energy	5,545,000	3.17	176,000
4	Other Purchases	10,910,000	3.29	359,000
5	TOTAL ESTIMATED PURCHASES	23,198,000	3.39	787,000

ECONOMY ENERGY PURCHASES
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2004 - DECEMBER 2004

(1)	(2)	(3)	(4)	(5)
LINE	MONTH TYPE & SCHEDULE	TOTAL KWH PURCHASED	TRANSACTION COST ¢ / KWH	TOTAL $ FOR FUEL ADJ.
	JULY			
1	Southern Co. Interchange	8,685,000	5.45	473,000
2	Unit Power Sales	2,320,000	3.79	88,000
3	Economy Energy	6,607,000	3.83	253,000
4	Other Purchases	7,470,000	3.44	257,000
5	TOTAL ESTIMATED PURCHASES	25,082,000	4.27	1,071,000
	AUGUST			
1	Southern Co. Interchange	11,431,000	5.28	603,000
2	Unit Power Sales	2,218,000	3.92	87,000
3	Economy Energy	3,801,000	4.45	169,000
4	Other Purchases	7,780,000	3.43	267,000
5	TOTAL ESTIMATED PURCHASES	25,230,000	4.46	1,126,000
	SEPTEMBER			
1	Southern Co. Interchange	301,000	2.99	9,000
2	Unit Power Sales	1,404,000	2.99	42,000
3	Economy Energy	4,603,000	3.08	142,000
4	Other Purchases	5,180,000	2.95	153,000
5	TOTAL ESTIMATED PURCHASES	11,488,000	3.01	346,000
	OCTOBER			
1	Southern Co. Interchange	23,836,000	2.28	544,000
2	Unit Power Sales	5,608,000	2.26	127,000
3	Economy Energy	3,432,000	2.36	81,000
4	Other Purchases	4,000,000	2.48	99,000
5	TOTAL ESTIMATED PURCHASES	36,876,000	2.31	851,000
	NOVEMBER			
1	Southern Co. Interchange	4,919,000	2.13	105,000
2	Unit Power Sales	16,350,000	2.20	359,000
3	Economy Energy	4,483,000	2.43	109,000
4	Other Purchases	5,070,000	2.41	122,000
5	TOTAL ESTIMATED PURCHASES	30,822,000	2.25	695,000
	DECEMBER			
1	Southern Co. Interchange	28,471,000	2.28	648,000
2	Unit Power Sales	9,253,000	2.18	202,000
3	Economy Energy	3,998,000	2.33	93,000
4	Other Purchases	4,420,000	2.31	102,000
5	TOTAL ESTIMATED PURCHASES	46,142,000	2.26	1,045,000
	TOTAL FOR PERIOD			
1	Southern Co. Interchange	274,869,000	2.61	7,168,000
2	Unit Power Sales	77,273,000	2.45	1,891,000
3	Economy Energy	53,826,000	2.99	1,612,000
4	Other Purchases	71,070,000	2.96	2,105,000
5	TOTAL ESTIMATED PURCHASES	477,038,000	2.68	12,776,000

Schedule E-10

RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1000 KWH
GULF POWER COMPANY
ESTIMATED FOR THE PERIOD OF: JANUARY 2004 - DECEMBER 2004

	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
Customer Charge	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10 00	10.00	10.00	10.00	120 00
Energy Charge	39.30	39.30	39.30	39.30	39.30	39.30	39.30	39.30	39.30	39.30	39 30	39.30	471.60
Conservation Cost Recovery	0.63	0.61	0.61	0.61	0 61	0.61	0.61	0.61	0.61	0.61	0.61	0 61	7 34
Environmental Cost Recovery	1.05	1.36	1.36	1.36	1.36	1.36	1.36	1.36	1.36	1.36	1.36	1.36	16 01
Capacity Cost Recovery	0.75	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1.94	1 94	22.09
Subtotal Base	51.73	53.21	53.21	53.21	53.21	53.21	53.21	53.21	53.21	53 21	53.21	53.21	637 04
Fuel Cost (Schedule E2)	26.35	27.04	26.82	26.37	24.62	24 05	23.58	23.19	23.68	24.92	23.27	22.61	296.50
Group Line Loss Multiplier	1.0526	1.0526	1.0526	1.0526	1.0526	1.0526	1.0526	1.0526	1.0526	1.0526	1.0526	1.0526	1.0526
Fuel Cost Recovery	27.74	28.46	28.23	27.76	25.92	25.32	24.82	24.41	24.93	26 23	24 49	23.80	312.10
Gross Receipts	2.04	2.09	2.09	2.08	2.03	2.01	2.00	1.99	2.00	2.04	1.99	1.98	24.35
Total	81.51	83.76	83.53	83.05	81.16	80.54	80.03	79.60	80.14	81 48	79.68	78.99	973.50

Note: ECCR is current 2003 factor because the projected 2004 factor has not been filed. Fuel, PPCC & ECRC are projected 2004 factors.
*Monthly and cumulative twelve month estimated data

SCHEDULE E-11

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST
GULF POWER COMPANY

		TOTAL ¢ / KWH
2004	JANUARY	1.946
	FEBRUARY	1.946
	MARCH	1.946
	APRIL	2.149
	MAY	2.149
	JUNE	2.149
	JULY	2.149
	AUGUST	2.149
	SEPTEMBER	2.149
	OCTOBER	2.149
	NOVEMBER	1.978
	DECEMBER	1.978
2005	JANUARY	1.978
	FEBRUARY	1.978
	MARCH	1.978
	APRIL	2.180
	MAY	2.180
	JUNE	2.180
	JULY	2.180
	AUGUST	2.180
	SEPTEMBER	2.180
	OCTOBER	2.180
	NOVEMBER	1.965
	DECEMBER	1.965

SCHEDULE H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
GULF POWER COMPANY
FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004

LINE	LINE DESCRIPTION	YEAR 2001	2002	2003	2004	DIFFERENCE (%) FROM PRIOR PERIOD 2001 to 2002	2002 to 2003	2003 to 2004
	FUEL COST OF SYSTEM NET GENERATION ($)							
2	LIGHTER OIL (B.L.)	604,951	595,280	387,045	423,760	(1 60)	(34 98)	9 49
3	COAL	175,540,970	200,532,553	184,938,103	209,531,242	14.24	(7 78)	13 30
3a	COAL at Scherer	16,932,117	24,868,993	27,665,239	25,476,894	46 87	11 24	(7 91)
4	GAS	2,098,156	76,046,394	99,393,351	104,550,093	3,524 44	30.70	5.19
4a	GAS (B.L.)	569,786	393,420	279,368	241,670	(30 95)	(28.99)	(13.49)
6	OTHER - C T	2,406,188	1,093,946	82,237	2,676	(54 54)	(92.48)	(96.75)
6a	OTHER GENERATION	1,795,125	217,158	19,253	19,205	(87 90)	(91.13)	(0 25)
7	TOTAL ($)	196,934,163	303,747,744	312,764,596	340,245,540	54 24	2.97	8 79
	SYSTEM NET GENERATION (MWH)							
8	COAL	12,508,400	13,141,770	13,087,710	14,070,680	5 06	(0 41)	7 51
9	GAS	26,920	1,838,690	2,836,540	2,180,540	6,730.20	54 27	(23 13)
10	OTHER - C T	31,750	15,210	1,020	30	(52.09)	(93.29)	(97 06)
10a	OTHER GENERATION	102,520	10,200	820	790	(90.05)	(91 96)	(3 66)
11	TOTAL (MWH)	12,669,590	15,005,870	15,926,090	16,252,040	18 44	6.13	2.05
	UNITS OF FUEL BURNED							
12	LIGHTER OIL (BBL)	19,654	19,560	13,859	13,904	(0.48)	(29.15)	0 32
13	COAL excl Scherer (TON)	4,870,369	5,044,600	5,078,332	5,405,166	3 58	0 67	6.44
14	GAS (MCF)	508,404	14,594,108	20,528,086	15,288,394	2,770 57	40.66	(25.52)
15	OTHER - C.T. (BBL)	75,882	36,207	2,467	77	(52.29)	(93.19)	(96.88)
	BTU'S BURNED (MMBTU)							
16	COAL + GAS B.L. + OIL B.L.	127,790,405	134,479,733	135,130,195	144,133,613	5.23	0.48	6.66
17	GAS - Generation	424,512	14,936,020	21,067,944	15,701,522	3,418.40	41.05	(25 47)
18	OTHER - C T	447,667	213,809	14,404	450	(52 24)	(93 26)	(96 88)
19	TOTAL (MMBTU)	126,219,497	149,629,562	156,212,544	159,835,585	18 55	4 40	2 32
	GENERATION MIX (% MWH)							
30	COAL + GAS B.L. + OIL B.L.	98 73	87.58	82.17	86.57	(11.29)	(6 18)	5 35
31	GAS - Generation	0.21	12 25	17.81	13 42	5,733.33	45.39	(24 65)
33	OTHER - C T	0.25	0.10	0.01	0.00	(60 00)	(90 00)	(100 00)
33a	OTHER GENERATION	0.81	0 07	0.01	0 00	(91.36)	(85 71)	(100.00)
34	TOTAL (% MWH)	100.00	100 00	100.00	100 00	0.00	0 00	0 00
	FUEL COST PER UNIT							
36	LIGHTER OIL B L ($/BBL)	30 78	30 43	27 93	30 48	(1.14)	(8 22)	9 13
37	COAL ($/TON)	36.04	39 75	36.42	38 76	10 29	(8.38)	6 43
38	GAS +B L ($/MCF)	5.25	5.24	4.86	6.85	(0 19)	(7 25)	40.95
40	OTHER - C.T.	31.71	30.21	33.34	34.79	(4.73)	10 36	4 35
	FUEL COST ($) / MMBTU							
43	COAL + GAS B L + OIL B.L.	1.51	1 68	1.58	1 64	11 26	(5 95)	3 80
44	GAS - Generation	4 94	5 09	4 72	6 66	3 04	(7 27)	41 10
46	OTHER - C.T.	5 37	5 12	5 71	5 95	(4 66)	11 52	4 20
47	TOTAL ($/MMBTU)	1 57	2.03	2 00	2 13	29.30	(1 48)	6 50
	BTU BURNED / KWH							
50	COAL + GAS B.L. + OIL B.L.	10,216	10,233	10,325	10,244	0 17	0 90	(0.78)
51	GAS - Generation	15,769	8,123	7,427	7,201	(48 49)	(8 57)	(3.04)
53	OTHER - C T.	14,100	14,057	14,121	15,000	(0.30)	0 46	6.22
54	TOTAL (BTU/KWH)	9,962	9,978	9,809	9,835	0.16	(1.69)	0 27
	FUEL COST (¢ / KWH)							
57	COAL + GAS B L. + OIL B.L.	1.54	1 72	1 63	1 67	11.69	(5.23)	2 45
58	GAS - Generation	7 79	4.14	3.50	4 79	(46.85)	(15.46)	36.86
60	OTHER - C T.	7 58	7.19	8.06	8 92	(5.15)	12 10	10.67
60a	OTHER GENERATION	1 75	2.13	2 35	2.43	21.71	10 33	3.40
61	TOTAL (¢ / KWH)	1.55	2.02	1.96	2.09	30.32	(2 97)	6.63

Schedule CCE-1

Projected Purchased Power Capacity Payments/(Receipts)
Gulf Power Company
For January 2004 - December 2004

		January	February	March	April	May	June	July	August	September	October	November	December	Total
1	Projected IIC Payments/(Receipts) & Market Sales ($)	1,368,425	403,175	540,580	43,854	81,480	1,724,294	6,286,325	5,688,244	2,360,242	199,580	67,649	144,635	18,908,483
2	Projected Capacity Payments to Solutia ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
2a	Subtotal	1,430,627	465,377	602,782	106,056	143,682	1,786,496	6,348,527	5,750,446	2,422,444	261,782	129,851	206,837	19,654,907
3	Projected Transmission Revenue	(12,000)	(6,000)	(13,000)	(7,000)	(7,000)	(13,000)	(13,000)	(7,000)	(11,000)	(7,000)	(9,000)	(7,000)	(112,000)
4	Total Projected Capacity Payments/(Receipts) (Line 1 + 2a + 3) ($)	1,418,627	459,377	589,782	99,056	136,682	1,773,496	6,335,527	5,743,446	2,411,444	254,782	120,851	199,837	19,542,907
5	Jurisdictional %	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187
6	Projected Jurisdictional Capacity Payments/(Receipts) (Line 4 x Line 5) ($)	1,369,002	443,307	569,151	95,591	131,901	1,711,457	6,113,902	5,542,533	2,327,089	245,869	116,623	192,846	18,859,271
7	True-Up ($)													(1,252,572)
8	Total Jurisdictional Amount to be Recovered (Line 6 + Line 7) ($)													17,606,699
9	Revenue Tax Multiplier													1.00072
10	Total Recoverable Capacity Payments/(Receipts) (Line 8 x Line 9) ($)													17,619,376

Calculation of Jurisdictional % *

	12 CP KW	%
FPSC	1,662,910.86	96.50187%
FERC	60,279.39	3.49813%
Total	1,723,190.25	100.00000%

* Based on 2001 Actual Data

Schedule CCE-1a

Purchased Power Capacity Cost Recovery Clause
Calculation of True-up
Gulf Power Company
January 2004 - December 2004

1	Estimated over/(under)-recovery, January 2003 - December 2003 (Schedule CCE-1b-1, Line 18)	$1,058,876
2	Final True-Up, January 2002 - December 2002 (Exhibit No.____(TAD-1), filed April 1, 2003	193,696
3	Total Over/(Under)-Recovery (Line 1 & 2) (To be included in January 2004 - December 2004)	$1,252,572
4	Jurisdictional KWH sales, January 2004 - December 2004	10,566,640,000
5	True-up Factor (Line 3 / Line 4) x 100 (Cents/KWH)	(0.0119)

Note: Projected KWH sales for 2004 have been updated since the estimated true-up filing.

Schedule CCE-1b

Purchased Power Capacity Cost Recovery Clause
Calculation of Estimated True-Up Amount
Gulf Power Company
For the Period January 2003 - December 2003

		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	Total
1	IIC Payments/(Receipts) ($)	576,317	4,193	192,099	(9,415)	(102,417)	374,563	1,404,921	2,470,074	1,941,890	52,536	(10,668)	64,888	6,958,981
2	Projected Capacity Payments to Sokutsa ($)	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	62,202	746,424
3	Transmission Revenue ($)	(51,592)	(78,086)	(31,701)	(44,371)	(39,430)	(22,413)	(31,968)	(9,000)	(13,000)	(8,000)	(10,000)	(9,000)	(348,561)
5	Total Capacity Payments/(Receipts) (Line 1 + 2 + 3 + 4) ($)	586,927	(11,691)	222,600	8,416	(79,645)	414,352	1,435,155	2,523,276	1,991,092	106,738	41,534	118,090	7,356,844
6	Jurisdictional %	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	0.9650187	
7	Jurisdictional Capacity Payments/(Receipts) (Line 5 x Line 6) ($)	566,396	(11,282)	214,813	8,122	(76,858)	399,857	1,384,952	2,435,009	1,921,441	103,004	40,081	113,959	7,099,493
8	Retail KWH Sales								1,105,129,000	919,954,000	755,145,000	680,394,000	812,109,000	
9	Purchased Power Capacity Cost Recovery Factor (¢/KWH)								0.081	0.081	0.081	0.081	0.081	
10	Capacity Cost Recovery Revenues (Line 10 x Line 11/100) ($)	832,686	588,899	601,144	634,147	805,054	850,861	896,948	895,154	745,163	611,667	551,119	657,808	8,670,650
11	Revenue Taxes (Line 12 x .00072) ($)*	600	424	433	457	580	613	646	11,072	11,714	9,615	8,664	10,341	58,159
12	True-Up Provision ($)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(38,848)	(466,176)
13	Capacity Cost Recovery Revenues net of Revenue Taxes (Line 10 - Line 11 + Line 12) ($)	793,238	549,627	561,863	594,842	765,626	811,400	857,454	842,234	694,601	563,204	503,607	608,619	8,146,315
14	Over/(Under) Recovery (Line 136 - Line 7) ($)	226,842	560,909	347,050	586,720	842,484	411,543	(527,498)	(1,592,775)	(1,226,840)	460,200	463,526	494,660	1,046,822
15	Interest Provision ($)	(121)	308	796	1,277	2,047	2,500	2,305	1,434	265	(29)	399	841	12,022
16	Prior Period Adjustment Including Interest	32												32
17	Total Estimated True-Up for the Period January 2003 - December 2003 (Lines 14 + 15 +16) ($)													1,058,876

NOTE Interest is Calculated for Aug - Dec at July's rate of 0.0854 %
Actual IIC Payments for January through July include Market Capacity Payments

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
For January 2004 - December 2004

	A	B	C	D	E	F	G	H	I
Rate Class	Average 12 CP Load Factor at Meter	Jan - Dec 04 Projected KWH Sales at Meter	Projected Avg 12 CP KW at Meter Col B / (8,760 hours x Col A)	Demand Loss Expansion Factor	Energy Loss Expansion Factor	Jan - Dec 04 Projected KWH Sales at Generation Col B x Col E	Projected Avg 12 CP KW at Generation Col C x Col D	Percentage of KWH Sales at Generation Col F / Total Col F	Percentage of 12 CP KW Demand at Generation Col G / Total Col G
RS, RSVP	59.521838%	4,903,598,000	940,447.20	1.0048648	1.00530097	4,929,591,826	945,022.25	46.64256%	54.67725%
GS	61.623894%	294,062,000	54,473.55	1.0048589	1.00529775	295,619,867	54,738.23	2.79708%	3.16705%
GSD, GSDT, GSTOU	74.923957%	2,366,440,000	360,554.31	1.0047057	1.00516604	2,378,665,124	362,250.95	22.50634%	20.95917%
LP, LPT	86.403429%	2,055,355,000	271,551.22	0.9842260	0.98911989	2,032,992,512	267,267.76	19.23567%	15.46362%
PX, PXT, RTP, SBS	99.499138%	817,083,000	93,743.84	0.9744382	0.98057253	801,209,145	91,347.58	7.58084%	5.28520%
OS - I / II	247.068649%	101,916,000	4,708.91	1.0046893	1.00529485	102,455,630	4,730.99	0.96941%	0.27373%
OS-III	98.528325%	24,279,000	2,812.97	1.0051151	1.00526827	24,406,908	2,827.36	0.23093%	0.16359%
OS-IV	248.927520%	3,907,000	179.17	1.0024052	1.00541301	3,928,149	179.60	0.03717%	0.01039%
TOTAL		10,566,640,000	1,728,471.17			10,568,869,161	1,728,364.72	100.00000%	100.00000%

Notes:
Col A - Average 12 CP load factor based on actual 2001 load research data.
Col C - 8,760 is the number of hours in 12 months.

Calculation of Purchased Power Capacity Cost Recovery Factors
Gulf Power Company
For January 2004 - December 2004

Rate Class	A Jan - Dec 04 Percentage of KWH Sales at Generation Page 1, Col H	B Percentage of 12 CP KW Demand at Generation Page 1, Col I	C Energy-Related Costs ($)	D Demand-Related Costs ($)	E Total Capacity Costs ($) Col C + Col D	F Jan - Dec 04 Projected KWH Sales at Meter Page 1, Col B	G Capacity Cost Recovery Factors (¢ / KWH) Col E / Col F x 100
RS, RSVP	46.64256%	54.67725%	632,163	8,892,729	9,524,892	4,903,598,000	0.194
GS	2.79708%	3.16705%	37,910	515,090	553,000	294,062,000	0.188
GSD, GSDT, GSTOU	22.50634%	20.95917%	305,037	3,408,808	3,713,845	2,366,440,000	0.157
LP, LPT	19.23567%	15.46362%	260,708	2,515,009	2,775,717	2,055,355,000	0.135
PX, PXT, RTP, SBS	7.58084%	5.28520%	102,746	859,587	962,333	817,083,000	0.118
OS - I / II	0.96941%	0.27373%	13,139	44,520	57,659	101,916,000	0.057
OS-III	0.23093%	0.16359%	3,130	26,606	29,736	24,279,000	0.122
OS-IV	0.03717%	0.01039%	504	1,690	2,194	3,907,000	0.056
TOTAL	100.00000%	100.00000%	$1,355,337	$16,264,039	$17,619,376	10,566,640,000	0.167

Notes:
Col C - (Recoverable Amount from Schedule CCE-1, line 12) / 13 x Col A
Col D - (Recoverable Amount from Schedule CCE-1, line 12) x 12 / 13 x Col B

APPENDIX I

FUEL COST RECOVERY

TRUE UP CALCULATION

KMD-1
DOCKET NO. 030001-EI
FPL WITNESS: K.M. DUBIN
April 1, 2003

FLORIDA PUBLIC SERVICE COMMISSION Comp Exh.
DOCKET NO. 030001-EI EXHIBIT NO 13
COMPANY/ FPUC
WITNESS: KMD 1, 2, 3, 4, 5 & 6
DATE: 11-12-03

DOCUMENT NUMBER-DATE
03020 APR-1 8
FPSC-COMMISSION CLERK

APPENDIX I

FUEL COST RECOVERY

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3	SUMMARY OF NET TRUE UP AMOUNT
4	CALCULATION OF FINAL TRUE UP AMOUNT
5	CALCULATION OF FINAL TRUE UP VARIANCES

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP FOR THE
PERIOD JANUARY THROUGH DECEMBER 2002

1	End of Period True-up for the period January through December 2002 (from page 4, lines D7 & D8)	$ (79,514,964)
2	Less - Estimated/Actual True-up for the same period *	$ (7,047,788)
3	Net True-up for the period January through December 2002	$ (72,467,176)

( ) Reflects Underrecovery

* Approved in FPSC Order No. PSC-02-1761-FOF-EI dated December 13, 2002

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2002

LINE NO.			(1) JAN	(2) FEB	(3) MAR	(4) APR	(5) MAY	(6) JUN
A		**Fuel Costs & Net Power Transactions**						
	1	a Fuel Cost of System Net Generation	$ 119,974,068.25	$ 89,346,972.49	$ 138,814,883.44	$ 167,505,301.20	$ 195,936,128.14	$ 181,750,529.87
		b Cost of Repairing Leaking Nuclear Fuel Rods	0.00	0.00	0.00	0.00	0.00	0.00
		c Nuclear Fuel Disposal Costs	2,081,228.83	1,864,713.17	1,979,318.86	1,891,727.83	1,988,689.43	1,968,998.24
		d *Coal Cars Depreciation & Return*	301,618.26	299,885.64	298,153.03	296,420.41	294,687.80	292,955.19
		e Gas Pipelines Depreciation & Return	197,127.20	195,671.65	194,216.13	192,760.60	191,305.04	189,849.50
		f DOE D&D Fund Payment	0.00	0.00	0.00	0.00	0.00	0.00
	2	a Fuel Cost of Power Sold Transmission Reactive Fuel (Per A6)	(3,849,406.00)	(3,408,651.00)	(4,434,786.00)	(4,091,052.00)	(2,657,087.00)	(3,900,141.00)
		b Gains from Off-System Sales	(1,166,838.00)	(1,036,336.00)	(1,233,478.00)	(840,787.00)	(454,950.00)	(1,056,528.00)
	3	a Fuel Cost of Purchased Power (Per A7)	*10,829,821.00*	*13,048,269.00*	13,284,773.00	20,803,756.00	20,635,095.00	15,189,243.00
		b Energy Payments to Qualifying Facilities (Per A8)	8,968,182.00	10,322,866.00	12,292,058.00	9,710,032.00	8,260,614.00	10,882,076.00
		c Cypress Settlement Payment	0.00	0.00	0.00	1,108,358.00	0.00	0.00
		d Okeelanta Settlement Amortization including interest	68,538.11	1,624,316.75	844,797.73	843,649.08	842,140.25	840,998.08
	4	Energy Cost of Economy Purchases (Per A9)	2,902,470.00	1,682,472.00	5,231,159.00	12,208,207.00	10,492,065.00	5,117,485.00
	5	Total Fuel Costs & Net Power Transactions	$ 140,306,809.65	$ 113,940,179.70	$ 167,271,095.19	$ 209,628,373.12	$ 235,528,687.66	$ 211,275,465.88
	6	**Adjustments to Fuel Cost**						
		a Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(1,668,359.47)	(1,803,030.51)	(1,594,602.42)	(2,325,539.45)	(2,875,733.69)	(2,953,569.49)
		b Reactive and Voltage Control / Energy Imbalance Fuel Revenues	(38,886.74)	(112,856.74)	(62,140.56)	(47,054.46)	56,550.74	(20,377.06)
		c Inventory Adjustments	13,503.78	(12,980.17)	(56,061.30)	(62,494.92)	88,738.01	(1,099.73)
		d Non Recoverable Oil/Tank Bottoms	(48,494.70)	231,386.83	(209,559.78)	0.00	0.00	(34,674.55)
		e Incremental Plant Security Costs per Order No. PSC -01-2516	124,507.26	231,659.71	190,407.92	494,349.65	463,698.82	1,025,299.49
		f Incremental Hedging Implementation Costs	0.00	0.00	0.00	0.00	0.00	0.00
	7	Adjusted Total Fuel Costs & Net Power Transactions	$ 138,689,079.78	$ 112,474,358.82	$ 165,539,139.05	$ 207,687,633.94	$ 233,261,941.54	$ 209,291,044.55
B		**kWh Sales**						
	1	Jurisdictional kWh Sales (RTP @ CBL) (a)	7,536,411,301	6,792,202,174	6,468,512,323	7,206,304,174	8,075,468,188	8,526,048,757
	2	Sale for Resale (excluding FKEC & CKW)	595,255	603,523	454,158	422,978	507,980	453,295
	3	Sub-Total Sales (excluding FKEC & CKW)	7,537,006,556	6,792,805,697	6,468,966,481	7,206,727,152	8,075,976,168	8,526,502,052
	6	**Jurisdictional % of Total Sales (B1/B3)**	99.99210%	99.99112%	99.99298%	99.99413%	99.99371%	99.99468%
		See Footnotes on page 2.						
C		**True-up Calculation**						
	1	*Juris Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes*	$ 213,314,794.63	$ 191,080,079.34	$ 181,934,007.90	$ 194,695,686.62	$ 209,058,996.71	$ 220,750,206.22
	2	**Fuel Adjustment Revenues Not Applicable to Period**						
		a 1 Amortize 1/24 of $518,005,376 per Order PSC-00-2385-FOF	(21,583,557.33)	(21,583,557.33)	(21,583,557.33)	(21,583,557.33)	(21,583,557.33)	(21,583,557.33)
		a 2 Prior Period True-up (Collected)/Refunded This Period	1,149,505.58	1,149,505.58	1,149,505.58	1,149,505.58	1,149,505.58	1,149,505.58
		a 3 2001 Final True-up Refunded per Rate Case Order PSC-02-0501-AS-EI	0.00	0.00	0.00	6,104,092.37	12,112,808.30	12,112,808.30
		b GPIF, Net of Revenue Taxes (b)	(738,596.58)	(738,596.58)	(738,596.58)	(738,596.58)	(738,596.58)	(738,596.58)
		c Oil Backout Revenues, Net of revenue taxes	107.56	20.15	(3.68)	(15.73)	102.64	0.04
	3	Jurisdictional Fuel Revenues Applicable to Period	$ 192,142,253.87	$ 169,907,451.17	$ 160,761,355.90	$ 179,627,114.94	$ 199,999,259.33	$ 211,690,366.24
	4	a Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 138,689,079.78	$ 112,474,358.82	$ 165,539,139.05	$ 207,687,633.94	$ 233,261,941.54	$ 209,291,044.55
		b Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	0.00	0.00	0.00	0.00	0.00	0.00
		c RTP Incremental Fuel -100% Retail	(4,163.97)	(24,963.90)	(13,815.13)	(34,599.19)	(1,598.18)	45,903.62
		d D&D Fund Payments -100% Retail	0.00	0.00	0.00	0.00	0.00	0.00
		e Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	138,693,243.75	112,499,322.72	165,552,954.18	207,722,233.14	233,263,539.72	209,245,140.93
	5	Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.99210 %	99.99112 %	99.99298 %	99.99413 %	99.99371 %	99.99468 %
	6	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00052(c)) +(Lines C4b,c,d)	$ 138,750,238.03	$ 112,522,863.10	$ 165,613,598.87	$ 207,783,449.81	$ 233,368,558.82	$ 209,388,714.62
	7	True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ 53,392,015.84	$ 57,384,588.07	$ (4,852,242.98)	$ (28,156,334.87)	$ (33,369,299.50)	$ 2,301,651.62
	8	Interest Provision for the Month (Line D10)	211,410.05	289,485.64	328,597.90	298,541.47	237,134.24	195,246.75
	9	a True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	*13,794,067.00*	*66,247,987.30*	*122,772,555.43*	*117,099,404.77*	*81,988,013.42*	35,593,534.28
		b Deferred True-up Beginning of Period - Over/(Under) Recovery	103,006,558.76	103,006,558.76	103,006,558.76	103,006,558.76	103,006,558.76	103,006,558.76
	10	a Prior Period True-up Collected/(Refunded) This Period	(1,149,505.58)	(1,149,505.58)	(1,149,505.58)	(1,149,505.58)	(1,149,505.58)	(1,149,505.58)
		b 2001 Final True-up Refunded per Rate Case Order PSC-02-0501-AS-EI	0.00	0.00	0.00	(6,104,092.37)	(12,112,808.30)	(12,112,808.30)
	11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ 169,254,546.06	$ 225,779,114.19	$ 220,105,963.53	$ 184,994,572.18	$ 138,600,093.04	$ 127,834,677.52

NOTES

(a) Real Time Pricing (RTP) sales are shown at the Customer Base Load (CBL) KWH. The incremental/decremental kwh sales are excluded. The incremental/decremental RTP fuel revenues (net of revenue taxes) are included in jurisdictional fuel revenues.

(b) Generation Performance Incentive Factor is (($9,004,713/12) x 98.4280%) - See Order No. PSC-01-2516-FOF-EI.

(c) Per Estimated Schedule E-3, filed November 5, 2001.

CALCULATION OF ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2002

LINE NO.			(7) JUL	(8) AUG	(9) SEP	(10) OCT	(11) NOV	(12) DEC	(13) TOTAL PERIOD
A		**Fuel Costs & Net Power Transactions**							
1	a	Fuel Cost of System Net Generation	$ 193,534,022.83	$ 208,986,504.97	$ 211,490,286.40	$ 235,448,378.31	$ 159,497,158.04	162,804,161.26	$ 2,065,088,395.20
	b	Cost of Repairing Leaking Nuclear Fuel Rods	0.00	0.00	0.00	$ 314,598.00	$ 0.00	$ 0.00	314,598.00
	c	Nuclear Fuel Disposal Costs	2,084,842.33	2,024,429.73	2,022,409.59	1,469,889.42	2,071,206.04	2,021,757.46	23,469,210.93
	d	Coal Cars Depreciation & Return	291,222.57	289,489.95	287,757.36	286,024.74	284,292.12	282,559.52	3,505,066.59
	e	Gas Pipelines Depreciation & Return	188,393.95	186,938.41	185,482.85	*184,027.33*	*182,571.79*	*181,116.24*	*2,269,460.69*
	f	DOE D&D Fund Payment	0.00	0.00	0.00	0.00	6,004,645.48	0.00	6,004,645.48
2	a	Fuel Cost of Power Sold Transmission Reactive Fuel (Per A6)	(3,560,315.00)	(3,320,814.00)	(4,061,563.00)	(2,270,566.00)	(4,288,388.00)	(5,352,101.00)	(45,194,870.00)
	b	Gains from Off-System Sales	(672,676.00)	(541,245.00)	(706,122.00)	43,696.00	(713,018.00)	(1,348,205.00)	(9,726,487.00)
3	a	Fuel Cost of Purchased Power (Per A7)	19,297,242.00	21,459,370.00	26,403,701.00	31,722,327.00	15,695,125.00	14,447,716.00	222,816,438.00
	b	Energy Payments to Qualifying Facilities (Per A8)	*12,826,288.00*	*12,057,648.00*	*10,504,339.00*	*6,803,802.00*	8,121,807.00	11,513,247.00	122,262,959.00
	c	Cypress Settlement Payment	0.00	0.00	0.00	1,108,358.00	0.00	0.00	2,216,716.00
	d	Okeelanta Settlement Amortization including interest	839,161.53	837,350.94	836,736.05	834,626.93	826,132.07	819,509.45	10,057,956.98
4		Energy Cost of Economy Purchases (Per A9)	3,628,394.00	5,578,128.00	11,060,826.00	13,527,887.00	8,185,127.00	9,133,306.00	88,747,526.00
5		Total Fuel Costs & Net Power Transactions	$ 228,456,576.21	$ 247,557,801.00	$ 258,023,853.25	$ 289,473,048.73	$ 195,866,658.54	$ 194,503,066.93	$ 2,491,831,615.87
6		**Adjustments to Fuel Cost**							
	a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(2,570,298.33)	(2,825,337.83)	(2,891,004.48)	(2,901,870.49)	(3,457,638.89)	(2,260,380.10)	(30,127,365.14)
	b	Reactive and Voltage Control / Energy Imbalance Fuel Revenues	(24,050.91)	1,952.28	(56,367.18)	(51,680.29)	(39,556.79)	(103,878.32)	(498,346.03)
	c	Inventory Adjustments	(16,945.47)	60,540.74	(34,060.38)	(167,858.27)	(67,216.57)	(4,416.48)	(260,350.76)
	d	Non Recoverable Oil/Tank Bottoms	(35,112.68)	0.00	0.00	0.00	(30,698.46)	397,811.08	270,657.74
	e	*Incremental Plant Security Costs per Order No. PSC -01-2516*	627,611.67	911,987.30	517,064.49	367,883.48	1,165,895.84	(6,120,365.63)	0.00
	f	Incremental Hedging Implementation Costs	0.00	0.00	2,149,721.87	160,320.00	227,912.06	188,099.69	2,726,053.62
7		Adjusted Total Fuel Costs & Net Power Transactions	$ 226,437,780.50	$ 245,706,943.49	$ 257,709,207.57	$ 286,879,843.16	$ 193,665,355.73	$ 186,599,937.17	$ 2,463,942,265.30
B		**kWh Sales**							
1		Jurisdictional kWh Sales (RTP @ CBL) (a)	8,354,425,512	9,110,874,101	9,237,002,940	8,995,730,671	8,067,694,729	7,154,389,841	95,525,064,711
2		Sale for Resale (excluding FKEC & CKW)	32,447,470	35,005,970	37,025,235	39,391,847	48,868,221	35,428,225	231,204,157
3		Sub-Total Sales (excluding FKEC & CKW)	8,386,872,982	9,145,880,071	9,274,028,175	9,035,122,518	8,116,562,950	7,189,818,066	95,756,268,868
6		**Jurisdictional % of Total Sales (B1/B3)**	99.61312%	99.61725%	99.60076%	99.56401%	99.39792%	99.50724%	99.75855%
		See Footnotes on page 2.							
C		**True-up Calculation**							
1		Juris Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 216,200,699.88	$ 235,870,281.94	$ 239,132,162.38	$ 232,889,049.39	$ 208,830,663.69	$ 184,956,342.10	$ 2,528,712,970.80
2		**Fuel Adjustment Revenues Not Applicable to Period**							
	a 1	Amortize 1/24 of $518,005,376 per Order PSC-00-2385-FOF	(21,583,557.33)	(21,583,557.33)	(21,583,557.33)	(21,583,557.33)	(21,583,557.33)	(21,583,557.50)	(259,002,688.13)
	a 2	Prior Period True-up (Collected)/Refunded This Period	1,149,505.58	1,149,505.58	1,149,505.58	1,149,505.58	*1,149,505.58*	*1,149,505.58*	*13,794,067.00*
	a 3	2001 Final True-up Refunded per Rate Case Order PSC-02-0501-AS-EI	12,112,808.30	12,112,808.30	12,112,808.30	12,112,808.30	12,112,808.30	12,112,808.30	103,006,558.76
	b	GPIF, Net of Revenue Taxes (b)	(738,596.58)	(738,596.58)	(738,596.58)	(738,596.58)	(738,596.58)	(738,596.58)	(8,863,158.91)
	c	Oil Backout Revenues, Net of revenue taxes	(1.32)	3.12	(0.38)	91,354.35	(1.66)	1.02	91,566.11
3		Jurisdictional Fuel Revenues Applicable to Period	$ 207,140,858.54	$ 226,810,445.04	$ 230,072,321.97	$ 223,920,563.72	$ 199,770,822.00	$ 175,896,502.93	$ 2,377,739,315.63
4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 226,437,780.50	$ 245,706,943.49	$ 257,709,207.57	$ 286,879,843.16	$ 193,665,355.73	$ 186,599,937.17	$ 2,463,942,265.30
	b	Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	c	RTP Incremental Fuel -100% Retail	(43,082.00)	20,570.47	(51,105.78)	1,216.53	27,961.41	(2,612.71)	(80,288.83)
	d	D&D Fund Payments -100% Retail	0.00	0.00	0.00	0.00	6,004,645.48	0.00	6,004,645.48
	e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items *(C4a-C4b-C4c-C4d)*	226,480,862.50	245,686,373.02	257,760,313.35	286,878,626.63	187,632,748.85	186,602,549.88	2,458,017,908.66
5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.61312 %	99.61725 %	99.60076 %	99.56401 %	99.39792 %	99.50724 %	99.75855 %
6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00052(c)) +(Lines C4b,c,d)	$ 225,678,886.00	$ 244,893,846.47	$ 256,813,625.22	$ 285,777,607.53	$ 192,632,637.89	$ 185,776,989.29	$ 2,459,001,015.65
7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (18,538,027.46)	$ (18,083,401.43)	$ (26,741,303.25)	$ (61,857,043.81)	$ 7,138,184.12	$ (9,880,486.36)	$ (81,261,700.02)
8		Interest Provision for the Month (Line D10)	162,305.04	115,414.74	*65,009.72*	*(17,805.39)*	*(65,358.40)*	*(73,245.65)*	1,746,736.11
9	a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	24,828,118.76	(6,809,917.54)	(38,040,218.12)	(77,978,825.53)	(153,115,988.61)	(159,305,476.78)	13,794,067.00
	b	Deferred True-up Beginning of Period - Over/(Under) Recovery	103,006,558.76	103,006,558.76	103,006,558.76	103,006,558.76	103,006,558.76	103,006,558.76	103,006,558.76
10	a	Prior Period True-up Collected/(Refunded) This Period	(1,149,505.58)	(1,149,505.58)	(1,149,505.58)	(1,149,505.58)	(1,149,505.58)	(1,149,505.58)	(13,794,067.00)
	b	2001 Final True-up Refunded per Rate Case Order PSC-02-0501-AS-EI	(12,112,808.30)	(12,112,808.30)	(12,112,808.30)	(12,112,808.30)	(12,112,808.30)	(12,112,808.30)	(103,006,558.76)
11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ 96,196,641.22	$ 64,966,340.64	$ 25,027,733.23	$ (50,109,429.85)	$ (56,298,918.02)	$ (79,514,963.91)	$ (79,514,963.91)

NOTES

(a) Real Time Pricing (RTP) sales are shown at the Customer Base Load (CBL) KWH. The incremental/decremental kwh sales are excluded.
The incremental/decremental RTP fuel revenues (net of revenue taxes) are included in jurisdictional fuel revenues.
(b) Generation Performance Incentive Factor is (($9,004,713/12) x 98.4280%) - See Order No. PSC-01-2516-FOF-EI.
(c) Per Estimated Schedule E-2, filed November 5, 2001.

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - ACTUAL vs ESTIMATED/ACTUAL
FOR THE PERIOD JANUARY THROUGH DECEMBER 2002

	LINE NO.			(1) ACTUAL	(2) ESTIMATED / ACTUAL (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
A			**Fuel Costs & Net Power Transactions**				
	1	a	Fuel Cost of System Net Generation	$ 2,065,402,993	$ 2,004,603,135	$ 60,799,859	3.0 %
		b	Nuclear Fuel Disposal Costs	23,469,211	23,353,868	115,343	0.5 %
		c	*Coal Cars Depreciation & Return*	3,505,067	3,505,067	(0)	0.0 %
		d	Gas Pipelines Depreciation & Return	2,269,461	2,269,460	0	0.0 %
		e	DOE D&D Fund Payment	6,004,645	6,287,000	(282,355)	(4.5) %
	2	a	Fuel Cost of Power Sold Transmission Reactive Fuel (Per A6)	(45,194,870)	(42,231,063)	(2,963,807)	7.0 %
		b	Gains from Off-System Sales	(9,726,487)	(8,249,490)	(1,476,997)	17.9 %
	3	a	Fuel Cost of Purchased Power (Per A7)	222,816,438	203,766,737	19,049,701	9.3 %
		b	Energy Payments to Qualifying Facilities (Per A8)	122,262,959	118,157,963	4,104,996	3.5 %
		c	Cypress Settlement Payment	2,216,716	2,340,072	(123,356)	(5.3) %
		d	Okeelanta Settlement Amortization including interest	10,057,957	10,860,337	(802,380)	(7.4) %
	4		Energy Cost of Economy Purchases (Per A9)	88,747,526	83,621,741	5,125,785	6.1 %
	5		Total Fuel Costs & Net Power Transactions	$ 2,491,831,616	$ 2,408,284,828	$ 83,546,788	3.5 %
	6		**Adjustments to Fuel Cost**				
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (30,127,365)	$ (29,406,003)	$ (721,362)	2.5 %
		b	Reactive and Voltage Control Fuel Revenue	(498,346)	(303,231)	(195,115)	64.3 %
		c	Inventory Adjustments	(260,351)	(20,859)	(239,491)	1148.1 %
		d	Non Recoverable Oil/Tank Bottoms	270,658	(96,455)	367,113	(380.6) %
		e	Incremental Hedging Implementation Costs	2,726,054	2,784,784	(58,731)	(2.1) %
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 2,463,942,265	$ 2,381,243,064	$ 86,899,250	3.6 %
B	1		Jurisdictional kWh Sales	95,525,064,711	95,156,430,470	368,634,241	0.4 %
	2		Sale for Resale	231,204,157	200,247,864	30,956,293	15.5 %
	3		Total Sales (Excluding RTP Incremental)	95,756,268,868	95,356,678,334	399,590,534	0.4 %
	4		Jurisdictional Sales % of Total kWh Sales (Line B-6)	N/A	N/A	N/A	N/A
C			**True-up Calculation**				
	1		Juris Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 2,528,712,971	2,519,410,266	$ 9,302,705	0.4 %
	2		**Fuel Adjustment Revenues Not Applicable to Period**			0	N/A
		a 1	Amortize 1/2 of $518,005,376 per Order PSC-00-2385-FOF	(259,002,688)	(259,002,688)	(0)	0.0 %
		a 2	Prior Period True-up (Collected)/Refunded This Period	13,794,067	13,794,067	0	0.0 %
		a 3	2001 Final True-up Refunded per Rate Case Order PSC-02-0501-AS-EI	103,006,559	103,006,559	(0)	0.0 %
		b	*GPIF, Net of Revenue Taxes* (b)	(8,863,159)	(8,863,159)	0	0.0 %
		c	Oil Backout Revenues, Net of revenue taxes (c)	91,566	212	91,354	43010.2 %
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 2,377,739,316	$ 2,368,345,257	$ 9,394,058	0.4 %
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 2,463,942,265	$ 2,381,243,064	82,699,201	3.5 %
		b	Nuclear Fuel Expense - 100% Retail	-	-	0	N/A
		c	RTP Incremental Fuel -100% Retail	(80,289)	(106,854)	26,565	N/A
		d	D&D Fund Payments -100% Retail (Line A 1 e)	6,004,645	6,287,000	(282,355)	N/A
		e	Adj. Total Fuel Costs & Net Power Transactions - *Excluding 100% Retail Items* (D4a-D4b-D4c-D4d)	2,458,017,909	2,375,062,919	82,954,990	3.5 %
	5		Jurisdictional Sales % of Total kWh Sales	N/A	N/A	N/A	N/A
	6		Jurisdictional Total Fuel Costs & Net Power Transactions	$ 2,459,001,016	$ 2,377,320,574	$ 81,680,442	3.4 %
	7		True-up Provision for the Period- Over/(Under) Recovery (Line D3 - Line D6)	$ (81,261,700)	$ (8,975,317)	$ 91,354	(1.0) %
	8		Interest Provision for the Month	1,746,736	1,927,529	(180,793)	(9.4) %
	9	a	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	13,794,067	13,794,067	0	0.0 %
		b	Deferred True-up Beginning of Period - Over/(Under) Recovery	103,006,559	103,006,559	0	0.0 %
	10	a	Prior Period True-up Collected/(Refunded) This Period	(13,794,067)	(13,794,067)	0	0.0 %
		b	*2001 Final True-up Refunded per Rate Case Order* PSC-02-0501-AS-EI	(103,006,559)	(103,006,559)	0	0.0 %
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (79,514,964)	$ (7,047,788)	$ (72,467,176)	1028.2 %

NOTES

(a) Per Estimated/Actual, Appendix II, page 6, filed November 4, 2002.

(b) Generation Performance Incentive Factor is (($9,004,713/12) x 98.4280%) - See Order No. PSC-01-2516-FOF-EI.

(c) Period to Date includes under refund of $91,352.01 for third 12 month period per PSC Order No. 99-0519-AS-EI.

APPENDIX II

CAPACITY COST RECOVERY

TRUE UP CALCULATION

KMD-2
DOCKET NO. 030001-EI
FPL WITNESS: K.M. DUBIN
April 1, 2003

APPENDIX II

CAPACITY COST RECOVERY

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FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP FOR THE
PERIOD JANUARY THROUGH DECEMBER 2002

1.	End of Period True-up for the period January through December 2002 (from page 6, lines 17 & 18)	$ 56,420,197
2.	Less - Estimated/Actual True-up for the same period *	43,743,474
3.	Net True-up for the period January through December 2002	$ 12,676,723

( ) Reflects Underrecovery .

* Approved in FPSC Order No. PSC-02-1761-FOF-EI dated December 13, 2002

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2002

LINE NO.		(1) JAN 2002	(2) FEB 2002	(3) MAR 2002	(4) APR 2002	(5) MAY 2002	(6) JUN 2002
1.	UPS Capacity Charges	$ 4,509,711.00	$ 8,552,011.00	$ 8,397,229.00	$ 8,629,685.00	$ 7,969,793.00	$ 9,326,700.00
2.	Short Term Capacity Purchases CCR	961,500.00	961,500.00	961,500.00	2,161,724.00	3,714,286.00	15,755,560.00
3.	QF Capacity Charges	27,906,044.98	25,121,883.56	25,956,929.80	25,904,994.89	27,345,987.50	26,128,811.06
4.	SJRPP Capacity Charges	7,714,674.11	7,639,381.65	7,971,748.97	8,016,979.03	8,161,139.82	7,015,610.11
4a.	SJRPP Suspension Accrual	301,945.00	301,945.00	301,945.00	301,945.00	301,945.00	301,945.00
4b.	Return on SJRPP Suspension Liability	(192,579.53)	(195,552.16)	(198,524.79)	(201,497.43)	(204,470.05)	(207,442.69)
5.	SJRPP Deferred Interest Payment	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)
6a.	Cypress Settlement (Capacity)	0.00	0.00	0.00	1,530,589.14	0.00	0.00
6b.	Okeelanta Settlement (Capacity)	257,833.85	3,180,941.58	3,178,048.62	3,173,727.48	3,168,051.42	3,163,754.69
6c.	Incremental Plant Security Costs-Order No. PSC-02-1761	0.00	0.00	0.00	0.00	0.00	0.00
7.	Trans. of Electricity by Others - FPL Sales	10,446.59	14,911.82	44,084.03	588,710.00	497,594.61	557,356.98
8.	Revenues from Capacity Sales	(636,942.08)	(617,158.26)	(473,479.79)	(362,814.45)	(313,964.36)	(488,297.10)
9.	Total (Lines 1 through 8)	$ 40,522,088.05	$ 44,649,318.32	$ 45,828,934.97	$ 49,433,496.79	$ 50,329,817.07	$ 61,243,452.18
10.	Jurisdictional Separation Factor (a)	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%
11.	Jurisdictional Capacity Charges	40,131,447.02	44,218,889.96	45,387,134.87	48,956,948.00	49,844,627.56	60,653,053.06
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)
13.	Jurisdictional Capacity Charges Authorized	$ 35,385,981.02	$ 39,473,423.96	$ 40,641,668.87	$ 44,211,482.00	$ 45,099,161.56	$ 55,907,587.06
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 45,394,373.26	$ 42,156,895.36	$ 40,852,951.49	$ 44,915,305.42	$ 49,895,576.00	$ 52,232,678.36
15.	Prior Period True-up Provision	1,846,071.00	1,846,071.00	1,846,071.00	1,846,071.00	1,846,071.00	1,846,071.00
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 47,240,444.26	$ 44,002,966.36	$ 42,699,022.49	$ 46,761,376.42	$ 51,741,647.00	$ 54,078,749.36
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	11,854,463.24	4,529,542.40	2,057,353.62	2,549,894.42	6,642,485.43	(1,828,837.70)
18.	Interest Provision for Month	36,430.39	45,483.32	47,943.72	48,689.33	52,519.17	53,418.63
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	22,152,857.00	32,197,679.63	34,926,634.35	35,185,860.69	35,938,373.44	40,787,307.04
20.	Deferred True-up - Over/(Under) Recovery	(2,528,058.19)	(2,528,058.19)	(2,528,058.19)	(2,528,058.19)	(2,528,058.19)	(2,528,058.19)
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(1,846,071.00)	(1,846,071.00)	(1,846,071.00)	(1,846,071.00)	(1,846,071.00)	(1,846,071.00)
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ 29,669,621.44	$ 32,398,576.16	$ 32,657,802.50	$ 33,410,315.25	$ 38,259,248.85	$ 34,637,758.78

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 3, Docket No. 000001-EI, filed September 21, 2000.
(b) Per FPSC Order No. PSC-94-1092-POF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2002

LINE NO.		(7) JUL 2002	(8) AUG 2002	(9) SEP 2002	(10) OCT 2002	(11) NOV 2002	(12) DEC 2002	(13) TOTAL	LINE NO.
1.	UPS Capacity Charges	$ 7,349,526.00	$ 8,174,682.00	$ 8,549,968.00	$ 8,541,886.00	$ 8,593,291.00	$ 8,821,679.00	$ 97,416,161.00	1.
2.	Short Term Capacity Purchases CCR	9,039,990.00	21,884,322.00	9,432,163.00	3,269,085.00	3,367,082.94	3,497,470.00	75,006,182.94	2.
3.	QF Capacity Charges	26,015,757.41	26,176,563.57	26,641,829.34	26,915,700.41	26,778,493.57	26,988,814.96	317,881,811.05	3.
4.	SJRPP Capacity Charges	7,417,353.08	6,857,706.64	7,162,367.81	5,513,043.14	5,591,274.25	5,319,668.05	84,380,946.66	4.
4a.	SJRPP Suspension Accrual	301,945.00	301,945.00	301,945.00	301,945.00	301,945.00	301,945.00	3,623,340.00	4a.
4b.	*Return on SJRPP Suspension Liability*	(210,415.33)	(213,387.95)	(216,360.58)	(219,333.23)	(222,305.84)	(225,278.48)	(2,507,148.06)	4b.
5.	SJRPP Deferred Interest Payment	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)	(310,545.87)	(3,726,550.44)	5.
6a.	Cypress Settlement (Capacity)	0.00	0.00	0.00	1,530,589.14	0.00	0.00	3,061,178.28	6a.
6b.	Okeelanta Settlement (Capacity)	3,156,845.76	3,150,034.48	3,147,721.33	3,139,787.04	3,107,830.17	3,082,916.50	34,907,492.93	6b.
6c.	Incremental Plant Security Costs-Order No. PSC-02-1761	0.00	0.00	0.00	0.00	0.00	8,754,766.31	8,754,766.31	6c.
7.	Trans. of Electricity by Others - FPL Sales	532,912.00	482,761.00	388,451.00	508,496.00	493,476.78	503,680.00	4,622,880.81	7.
8.	Revenues from Capacity Sales	(543,947.83)	(300,352.10)	(394,560.94)	(268,611.54)	(334,185.32)	(494,061.93)	(5,228,375.70)	8.
9.	Total (Lines 1 through 8)	$ 52,749,420.22	$ 66,203,728.77	$ 54,702,978.09	$ 48,922,041.09	$ 47,366,356.68	$ 56,241,053.54	$ 618,192,685.78	9.
10.	Jurisdictional Separation Factor (a)	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%	99.03598%	N/A	10.
11.	Jurisdictional Capacity Charges	52,240,905.26	65,565,511.58	54,175,630.44	48,450,422.83	46,909,735.53	55,698,878.54	612,233,184.65	11.
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(4,745,466.00)	(56,945,592.00)	12.
13.	Jurisdictional Capacity Charges Authorized	$ 47,495,439.26	$ 60,820,045.58	$ 49,430,164.44	$ 43,704,956.83	$ 42,164,269.53	$ 50,953,412.54	$ 555,287,592.65	13.
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 51,348,287.19	$ 56,086,784.38	$ 56,481,506.65	$ 55,305,322.35	$ 49,972,588.27	$ 44,271,609.19	$ 588,913,877.91	14.
15.	Prior Period True-up Provision	1,846,071.00	1,846,071.00	1,846,071.00	1,846,071.00	1,846,071.00	1,846,071.00	22,152,857.00	15.
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 53,194,358.19	$ 57,932,855.38	$ 58,327,577.65	$ 57,151,393.35	$ 51,818,659.27	$ 46,117,680.19	$ 611,066,734.91	16.
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	5,698,918.93	(2,887,190.20)	8,897,413.21	13,446,436.52	9,654,389.74	(4,835,732.35)	55,779,142.26	17.
18.	Interest Provision for Month	53,018.06	51,853.69	54,056.66	66,449.25	69,495.35	61,697.41	641,054.98	18.
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	37,165,816.97	41,071,682.97	36,390,275.46	43,495,674.33	55,162,489.10	63,040,303.19	22,152,857.00	19.
20.	Deferred True-up - Over/(Under) Recovery	(2,528,058.19)	(2,528,058.19)	(2,528,058.19)	(2,528,058.19)	(2,528,058.19)	(2,528,058.19)	(2,528,058.19)	20.
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(1,846,071.00)	(1,846,071.00)	(1,846,071.00)	(1,846,071.00)	(1,846,071.00)	(1,846,071.00)	(22,152,857.00)	21.
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	$ 38,543,624.78	$ 33,862,217.27	$ 40,967,616.14	$ 52,634,430.91	$ 60,512,245.00	$ 53,892,139.05	$ 53,892,139.05	22.

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 3, Doc
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY THROUGH DECEMBER 2002

Line No.		(1) ACTUAL	(2) ESTIMATED / ACTUAL (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
1.	Payments to Non-cogenerators	$ 253,076,740	$ 259,322,616	$ (6,245,876)	(2.4) %
2	Payments to Cogenerators	317,881,811	321,751,679	(3,869,868)	(1.2) %
3.	SJRPP Suspension Accrual	3,623,340	3,623,340	0	0.0 %
4.	Return Requirements on SJRPP Suspension Liability	(2,507,148)	(2,507,148)	0	0.0 %
4b.	Cypress Settlement (Capacity)	3,061,178	3,231,528	(170,349)	(5.3) %
4c.	Okeelanta Settlement (Capacity)	34,907,493	35,000,147	(92,654)	(0.3) %
4d.	Incremental Plant Security Costs-Order No. PSC-02-1761	8,754,766	7,999,567	755,199	9.4 %
5.	Transmission of Electricity by Others - FPL Sales	4,622,881	4,715,976	(93,095)	(2.0) %
6.	Revenues from Capacity Sales	(5,228,376)	(5,237,440)	9,064	(0.2) %
7.	Total (Lines 1 through 6)	$ 618,192,686	$ 627,900,265	$ (9,707,579)	(1.5) %
8.	Jurisdictional Separation Factor	N/A	N/A	N/A	N/A
9.	Jurisdictional Capacity Charges	$ 612,233,185	$ 621,847,180	$ (9,613,996)	(1.5) %
10.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	$ (56,945,592)	(56,945,592)	0	N/A
11.	Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$ 555,287,593	$ 564,901,588	$ (9,613,996)	(1.7) %
12.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 588,913,878	$ 585,843,814	$ 3,070,064	0.5 %
13.	Prior Period True-up Provision	22,152,857	22,152,857	0	N/A
14.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 611,066,735	$ 607,996,671	$ 3,070,064	0.5 %
15.	True-up Provision for Period - Over/(Under) Recovery (Line 14 - Line 11)	$ 55,779,142	$ 43,095,083	$ 12,684,060	N/A
16.	Interest Provision for Period	641,055	648,392	(7,337)	N/A
17.	True-up & Interest Provision Beginning of Period - Over/(Under) Recovery	22,152,857	22,152,857	0	N/A
18.	Deferred True-up - Over/(Under) Recovery	(2,528,058)	(2,528,058)	0	N/A
19.	Prior Period True-up Provision - Collected/(Refunded) this Period	(22,152,857)	(22,152,857)	0	N/A
20.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 15 through 19)	$ 53,892,139	$ 41,215,416	$ 12,676,723	30.8 %

Notes:

(a) Per K. M. Dubin's Testimony Appendix III, Page 7, Docket No. 020001-EI, dated November 25, 2002.

(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

APPENDIX I

FUEL COST RECOVERY

ESTIMATED/ACTUAL TRUE UP CALCULATION

KMD-3
DOCKET NO. 030001-EI
FPL WITNESS: K.M. DUBIN
August 12, 2003

CALCULATION OF THE ESTIMATED/ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003
SIX MONTHS ACTUAL SIX MONTHS NEW ESTIMATES

LINE NO.		(1) ACTUAL JAN	(2) ACTUAL FEB	(3) ACTUAL MAR	(4) ACTUAL APR	(5) ACTUAL MAY	(6) ACTUAL JUN
A	**Fuel Costs & Net Power Transactions**						
1	Fuel Cost of System Net Generation	$ 202,082,274	$ 166,332,573	$ 338,352,856	$ 220,910,699	$ 290,580,370	$ 301,507,670
	Incremental Hedging Costs	38,985	(72,347)	80,832	37,832	25,080	64,444
	Nuclear Fuel Disposal Costs	2,045,325	1,810,224	1,585,058	1,830,109	1,438,413	1,705,778
	Coal Cars Depreciation & Return	280,827	279,094	277,362	275,629	273,896	272,164
	Gas Pipelines Depreciation & Return	179,661	178,205	169,743	168,535	170,561	169,139
	DOE D&D Fund Payment	-	-	-	-	-	-
2	Fuel Cost of Power Sold (Per A6)	(12,579,178)	(10,953,013)	(2,393,727)	(4,860,362)	(2,233,044)	(3,762,281)
	Revenues from Off-System Sales	(4,563,079)	(2,636,240)	(647,973)	(1,097,584)	(463,000)	(637,885)
3	Fuel Cost of Purchased Power (Per A7)	20,296,416	12,949,526	26,342,605	22,880,054	28,117,567	24,599,036
	Energy Payments to Qualifying Facilities (Per A8)	11,897,821	12,098,222	10,942,372	8,250,698	12,980,622	12,252,734
	Cypress Settlement Payment					255,797	
	Okeelanta Settlement Amortization including interest	818,207	816,772	814,626	812,971	812,626	809,227
4	Energy Cost of Economy Purchases (Per A9)	2,690,456	5,403,637	9,253,845	6,437,812	7,503,345	9,642,332
5	Total Fuel Costs & Net Power Transactions	223,187,714	186,206,654	384,777,599	255,646,393	339,462,234	346,622,358
6	**Adjustments to Fuel Cost**						
	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(2,649,558)	(2,656,228)	(2,619,112)	(4,890,322)	(3,333,364)	(3,919,200)
	Reactive and Voltage Control / Energy Imbalance Fuel Revenues	(109,305)	(104,038)	(106,100)	(64,303)	(73,782)	(1,513)
	Inventory Adjustments	(97,396)	(25,202)	(70,714)	(51,017)	67,936	(1,124,954)
	Non Recoverable Oil/Tank Bottoms	-	60,265	-	-	-	-
7	Adjusted Total Fuel Costs & Net Power Transactions	$ 220,331,455	$ 183,481,452	$ 381,981,674	$ 250,640,752	$ 336,123,023	$ 341,576,691
B	**kWh Sales**						
1	Jurisdictional kWh Sales (RTP @ CBL) (a)	7,569,038,419	7,463,818,224	7,510,229,964	7,396,486,620	7,999,797,862	9,047,332,704
2	Sale for Resale (excluding FKEC & CKW)	35,312,711	39,847,223	39,632,175	45,981,820	46,122,096	42,551,013
3	Sub-Total Sales (excluding FKEC & CKW)	7,604,351,130	7,503,665,447	7,549,862,139	7,442,468,440	8,045,919,958	9,089,883,717
6	**Jurisdictional % of Total Sales (B1/B3)**	99.53562%	99.46896%	99.47506%	99.38217%	99.42676%	99.53189%
	See Footnotes on page 2.						
C	**True-up Calculation**						
1	Juris Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 202,273,176	$ 200,127,330	$ 201,471,500	$ 228,902,315	$ 251,666,698	$ 284,778,187
2	**Fuel Adjustment Revenues Not Applicable to Period**						
	Prior Period True-up (Collected)/Refunded This Period	(587,316)	(587,316)	(587,316)	(587,316)	(587,316)	(587,316)
	2002 Final True-up Collected (Order PSC-03-0381-PCO-EI)	0	0	0	(8,051,908)	(8,051,908)	(8,051,908)
	GPIF, Net of Revenue Taxes (b)	(578,218)	(578,218)	(578,218)	(578,218)	(578,218)	(578,218)
	Oil Backout Revenues, Net of revenue taxes	(2)	(2)	(25)	(0)	(0)	(2)
	Jurisdictional Fuel Revenues Applicable to Period	$ 201,107,640	$ 198,961,795	$ 200,305,941	$ 219,684,873	$ 242,449,256	$ 275,560,743
3	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 220,331,455	$ 183,481,452	$ 381,981,674	$ 250,640,752	$ 336,123,023	$ 341,576,691
4	Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	0	0	0	0	0	0
	RTP Incremental Fuel -100% Retail	(43,241)	(46,853)	33,420	95,378	(28,433)	4,846
	D&D Fund Payments -100% Retail	0	0	0	0	0	0
	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	220,374,695	183,528,305	381,948,254	250,545,373	336,151,456	341,571,845
	Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.53562 %	99.46896 %	99.47506 %	99.38217 %	99.42676 %	99.53189 %
5	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00049(c)) +(Lines C4b,c,d)	$ 219,415,561	$ 182,596,295	$ 380,162,847	$ 249,214,815	$ 334,359,838	$ 340,144,346
6	True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (18,307,921)	$ 16,365,500	$ (179,856,906)	$ (29,529,943)	$ (91,910,582)	$ (64,583,603)
7	Interest Provision for the Month (Line D10)	(94,270)	(93,296)	(172,231)	(266,978)	(322,706)	(361,539)
8	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(7,047,788)	(24,862,663)	(8,003,144)	(187,444,965)	(208,602,661)	(292,196,725)
9	Deferred True-up Beginning of Period - Over/(Under) Recovery	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)
	Prior Period True-up Collected/(Refunded) This Period	587,316	587,316	587,316	587,316	587,316	587,316
10	2002 Final True-up Collected (Order PSC-03-0381-PCO-EI)				8,051,908	8,051,908	8,051,908
11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (97,329,839)	$ (80,470,320)	$ (259,912,141)	$ (281,069,837)	$ (364,663,901)	$ (420,969,820)

NOTES

(a) **Real Time Pricing (RTP) sales are shown at the Customer Base Load (CBL) KWH. The incremental/decremental kwh sales are excluded. The incremental/decremental RTP fuel revenues (net of revenue taxes) are included in jurisdictional fuel revenues.**

(b) **Generation Performance Incentive Factor is (($7,049,431) x 98.4280%) - See Order No. PSC-02-1761-FOF-EI.**

(c) **Per Estimated Schedule E-2, filed November 4, 2002.**

CALCULATION OF THE ESTIMATED/ACTUAL TRUE-UP AMOUNT
FLORIDA POWER & LIGHT COMPANY
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003
SIX MONTHS ACTUAL SIX MONTHS NEW ESTIMATES

LINE NO.		(7) NEW ESTIMATE JUL	(8) NEW ESTIMATE AUG	(9) NEW ESTIMATE SEP	(10) NEW ESTIMATE OCT	(11) NEW ESTIMATE NOV	(12) NEW ESTIMATE DEC	(13) TOTAL PERIOD
A	**Fuel Costs & Net Power Transactions**	$ 321,479,024	$ 306,518,187	$ 282,799,136	$ 266,934,711	$ 194,639,929	$ 206,228,316	$ 3,098,365,746
1	Fuel Cost of System Net Generation	96,026	21,026	21,026	21,026	31,038	21,026	385,994
	Incremental Hedging Costs	1,983,357	1,983,357	1,919,376	1,606,204	1,967,633	2,033,221	21,908,055
	Nuclear Fuel Disposal Costs	270,431	268,699	266,966	265,233	263,501	261,768	3,255,570
	Coal Cars Depreciation & Return	167,718	166,296	164,874	163,452	162,031	160,609	2,020,824
	Gas Pipelines Depreciation & Return	-	-	-	-	6,475,000	-	6,475,000
	DOE D&D Fund Payment	(8,879,282)	(7,927,779)	(5,842,389)	(6,991,893)	(5,286,806)	(6,299,706)	(78,009,460)
2	Fuel Cost of Power Sold (Per A6)	(804,220)	(1,297,960)	(321,000)	(150,000)	(168,300)	(303,870)	(13,091,111)
	Revenues from Off-System Sales	24,729,192	22,978,872	17,944,656	19,078,431	15,815,999	17,681,617	253,413,971
3	Fuel Cost of Purchased Power (Per A7)	12,989,208	12,989,208	12,736,208	13,012,350	10,659,350	12,882,350	143,691,143
	Energy Payments to Qualifying Facilities (Per A8)							255,797
	Cypress Settlement Payment	805,682	805,033	804,384	803,735	803,086	802,437	9,708,785
	Okeelanta Settlement Amortization including interest	6,660,620	6,524,620	6,119,620	5,889,181	4,372,604	4,438,104	74,936,176
4	Energy Cost of Economy Purchases (Per A9)	359,497,756	343,029,559	316,612,857	300,632,430	229,735,065	237,905,872	$ 3,523,316,489.9
5	Total Fuel Costs & Net Power Transactions							
6	**Adjustments to Fuel Cost**							
	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(2,936,133)	(3,046,357)	(3,094,818)	(2,950,323)	(2,766,173)	(2,527,957)	(37,389,545)
	Reactive and Voltage Control / Energy Imbalance Fuel Revenues							(459,042)
	Inventory Adjustments							(1,301,346)
	Non Recoverable Oil/Tank Bottoms							60,265
7	Adjusted Total Fuel Costs & Net Power Transactions	$ 356,561,622	$ 339,983,202	$ 313,518,039	$ 297,682,107	$ 226,968,891	$ 235,377,915	$ 3,484,226,822.8
B	**kWh Sales**							
1	Jurisdictional kWh Sales (RTP @ CBL) (a)	8,933,913,000	9,546,863,000	9,414,698,000	8,720,491,000	7,932,816,000	7,317,796,000	98,853,280,793
2	Sale for Resale (excluding FKEC & CKW)	34,651,000	33,546,000	34,616,000	34,569,000	33,549,000	34,614,000	454,992,038
3	Sub-Total Sales (excluding FKEC & CKW)	8,968,564,000	9,580,409,000	9,449,314,000	8,755,060,000	7,966,365,000	7,352,410,000	99,308,272,831
6	**Jurisdictional % of Total Sales (B1/B3)**	99.61364%	99.64985%	99.63367%	99.60515%	99.57887%	99.52922%	N/A
	See Footnotes on page 2.							
C	**True-up Calculation**							
1	Juris Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 281,127,296	$ 347,962,997	$ 343,145,862	$ 317,843,483	$ 289,134,392	$ 266,718,212	$ 3,215,151,449
2	**Fuel Adjustment Revenues Not Applicable to Period**							
	Prior Period True-up (Collected)/Refunded This Period	(587,316)	(587,316)	(587,316)	(587,316)	(587,316)	(587,316)	(7,047,788)
	2002 Final True-up Collected (Order PSC-03-0381-PCO-EI)	(8,051,908)	(8,051,908)	(8,051,908)	(8,051,908)	(8,051,908)	(8,051,908)	(72,467,176)
	GPIF, Net of Revenue Taxes (b)	(578,218)	(578,218)	(578,218)	(578,218)	(578,218)	(578,218)	(6,938,614)
	Oil Backout Revenues, Net of revenue taxes	0	0	0	0	0	0	(31)
	Jurisdictional Fuel Revenues Applicable to Period	$ 271,909,854	$ 338,745,555	$ 333,928,420	$ 308,626,041	$ 279,916,950	$ 257,500,770	$ 3,128,697,839
3	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 356,561,622	$ 339,983,202	$ 313,518,039	$ 297,682,107	$ 226,968,891	$ 235,377,915	$ 3,484,226,823
4	Nuclear Fuel Expense - 100% Retail (Acct. 518.111)	0	0	0	0	0	0	0.00
	RTP Incremental Fuel -100% Retail	0	0	0	0	0	0	15,118.40
	D&D Fund Payments -100% Retail	0	0	0	0	6,475,000	0	6,475,000
	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	356,561,622	339,983,202	313,518,039	297,682,107	220,493,891	235,377,915	3,477,736,704
5	Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.61364 %	99.64985 %	99.63367 %	99.60515 %	99.57887 %	99.52922 %	N/A
6	Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00049(c)) +(Lines C4b,c,d)	$ 355,358,051	$ 338,958,759	$ 312,522,590	$ 296,651,997	$ 226,147,913	$ 234,384,595	$ 3,469,917,608
7	True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (83,448,197)	$ (213,204)	$ 21,405,830	$ 11,974,044	$ 53,769,037	$ 23,116,175	$ (341,219,769)
8	Interest Provision for the Month (Line D10)	(381,963)	(409,940)	(394,253)	(373,474)	(339,195)	(300,244)	(3,510,090)
9	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(348,502,644)	(423,693,580)	(415,677,499)	(386,026,698)	(365,786,904)	(303,717,838)	(7,047,788)
	Deferred True-up Beginning of Period - Over/(Under) Recovery	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)	(72,467,176)
10	Prior Period True-up Collected/(Refunded) This Period	587,316	587,316	587,316	587,316	587,316	587,316	7,047,788
	2002 Final True-up Collected (Order PSC-03-0381-PCO-EI)	8,051,908	8,051,908	8,051,908	8,051,908	8,051,908	8,051,908	72,467,176
11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (496,160,756)	$ (488,144,675)	$ (458,493,874)	$ (438,254,080)	$ (376,185,014)	$ (344,729,859)	$ (344,729,859)

NOTES

(a) Real Time Pricing (RTP) sales are shown at the Customer Base Load (C
The incremental/decremental RTP fuel revenues (net of revenue taxes) a

(b) Generation Performance Incentive Factor is (($7,049,431) x 98.4280%)

(c) Per Estimated Schedule E-2, filed November 4, 2002.

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
CALCULATION OF VARIANCE - ESTIMATED/ACTUAL vs MIDCOURSE CORRECTION
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003

LINE NO.			(1) ESTIMATED / ACTUAL	(2) MIDCOURSE CORRECTION (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
A		**Fuel Costs & Net Power Transactions**				
	1 a	Fuel Cost of System Net Generation	$ 3,098,365,746	$ 2,794,640,361	$ 303,725,384	10.9 %
	b	Incremental Hedging Costs	385,994	419,548	(33,554)	(8.0) %
	c	Nuclear Fuel Disposal Costs	21,908,055	22,026,934	(118,879)	(0.5) %
	d	Coal Cars Depreciation & Return	3,255,570	3,255,570	(0)	0.0 %
	e	Gas Pipelines Depreciation & Return	2,020,824	2,042,819	(21,995)	(1.1) %
	f	DOE D&D Fund Payment	6,475,000	6,475,000	0	0.0 %
	2 a	Fuel Cost of Power Sold (Per A6)	(78,009,460)	(59,201,175)	(18,808,285)	31.8 %
	b	Revenues from Off-System Sales	(13,091,111)	(13,234,731)	143,620	(1.1) %
	3 a	Fuel Cost of Purchased Power (Per A7)	253,413,971	217,275,796	36,138,175	16.6 %
	b	Energy Payments to Qualifying Facilities (Per A8)	143,691,143	124,199,745	19,491,398	15.7 %
	c	Cypress Settlement Payment	255,797	255,797	0	0.0 %
	d	Okeelanta Settlement Amortization including interest	9,708,785	9,840,467	(131,682)	(1.3) %
	4	Energy Cost of Economy Purchases (Per A9)	74,936,176	58,014,095	16,922,081	29.2 %
	5	Total Fuel Costs & Net Power Transactions	$ 3,523,316,490	$ 3,166,010,227	$ 357,306,263	11.3 %
	6	**Adjustments to Fuel Cost**				
	a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (37,389,545)	$ (36,221,505)	$ (1,168,040)	3.2 %
	b	Reactive and Voltage Control Fuel Revenue	(459,042)	(457,528)	(1,513)	0.3 %
	c	Inventory Adjustments	(1,301,346)	(176,392)	(1,124,954)	637.8 %
	d	Non Recoverable Oil/Tank Bottoms	60,265	60,265	0	N/A
	7	Adjusted Total Fuel Costs & Net Power Transactions	$ 3,484,226,823	$ 3,129,215,067	$ 371,802,155	11.9 %
B	1	**Jurisdictional kWh Sales**				
	2	Jurisdictional kWh Sales (RTP @ CBL) (b)	98,853,280,793	98,572,098,089	281,182,704	0.3 %
	3	Sale for Resale	454,992,038	445,910,025	9,082,013	2.0 %
	4	Total Sales (Excluding RTP Incremental)	99,308,272,831	99,018,008,114	290,264,717	0.3 %
		Jurisdictional Sales % of Total kWh Sales (Line B-6)	N/A	N/A	N/A	N/A
C	1	Juris Fuel Revenues (Incl RTP @ CBL) Net of Revenue Taxes	$ 3,215,151,449	3,206,221,487	$ 8,929,961	0.3 %
	2	**Fuel Adjustment Revenues Not Applicable to Period**				
	a 1	Prior Period True-up (Collected)/Refunded This Period	(7,047,788)	(7,047,788)	0	0.0 %
	a 2	2002 Final True-up Collected	(72,467,176)	(72,467,176)	(0)	0.0 %
	b	GPIF, Net of Revenue Taxes (c)	(6,938,614)	(6,938,614)	0	0.0 %
	c	Oil Backout Revenues, Net of revenue taxes	(31)	(30)	(1)	4.0 %
	3	Jurisdictional Fuel Revenues Applicable to Period	$ 3,128,697,839	$ 3,119,767,880	$ 8,929,961	0.3 %
	4 a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 3,484,226,823	$ 3,129,215,067	$ 355,011,756	11.3 %
	b	Nuclear Fuel Expense - 100% Retail	-	0	0	N/A
	c	RTP Incremental Fuel -100% Retail	15,118	10,272	4,846	47.2 %
	d	D&D Fund Payments -100% Retail (Line A 1 f)	6,475,000	6,475,000	0	0.0 %
	e	Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (D4a-D4b-D4c-D4d)	3,477,736,704	3,122,729,795	355,006,910	11.4 %
	5	Jurisdictional Sales % of Total kWh Sales	N/A	N/A	N/A	N/A
	6	Jurisdictional Total Fuel Costs & Net Power Transactions	$ 3,469,917,608	$ 3,116,411,191	$ 353,506,417	11.3 %
	7	True-up Provision for the Period Over/(Under) Recovery (Line C3 - Line C6)	$ (341,219,769)	$ 3,356,689	$ (344,576,458)	N/A
	8	Interest Provision for the Period	(3,510,090)	(2,673,806)	(836,284)	31.3 %
	9	True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(7,047,788)	(7,047,788)	0	0.0 %
	a	Deferred True-up Beginning of Period - Over/(Under) Recovery	(72,467,176)	(72,467,176)	0	0.0 %
	10 a	Prior Period True-up Collected/(Refunded) This Period	7,047,788	7,047,788	0	0.0 %
	10 b	2002 Final True-up Refunded per Rate Case Order PSC-03-0000-AS-EI	72,467,176	72,467,176	(0)	0.0 %
	11	End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through D10b)	$ (344,729,859)	$ 682,883	$ (345,412,742)	N/A

NOTES

(a) **Per Midcourse Correction approved by the Commission on July 1, 2003.**

(b) **Real Time Pricing (RTP) sales are shown at the Customer Base Load (CBL) KWH. The incremental/decremental kwh sales are excluded. The incremental/decremental RTP fuel revenues (net of revenue taxes) are included in jurisdictional fuel revenues.**

(c) **Generation Performance Incentive Factor is (($7,049,431) x 98.4280%) - See Order No. PSC-02-1761-FOF-EI.**

APPENDIX II

CAPACITY COST RECOVERY

ESTIMATED/ACTUAL TRUE UP CALCULATION

KMD-4
DOCKET NO. 030001-EI
FPL WITNESS: K.M. DUBIN
August 12, 2003

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003
SIX MONTHS ACTUAL SIX MONTHS NEW ESTIMATES

LINE NO.		(1) JAN 2003 ACTUAL	(2) FEB 2003 ACTUAL	(3) MAR 2003 ACTUAL	(4) APR 2003 ACTUAL	(5) MAY 2003 ACTUAL	(6) JUN 2003 ACTUAL
1.	Payments to non-Cogenerators (UPS & SJRPP)	$ 15,596,426	$ 15,990,408	$ 14,684,403	$ 15,153,064	$ 14,649,614	$ 15,005,398
2.	Short Term Capacity Payments	$ 6,245,451	$ 6,245,451	$ 4,361,584	$ 4,490,250	$ 6,995,796	$ 15,128,009
3.	Payments to Cogenerators (QFs)	$ 27,481,162	$ 28,207,963	$ 28,961,670	$ 29,873,286	$ 34,695,552	$ 28,990,956
4a.	SJRPP Suspension Accrual	$ 586,656	$ 586,656	$ 586,656	$ 586,656	$ 586,656	$ 586,656
4b.	Return Requirements on SJRPP Suspension Liability	$ (229,653)	$ (235,428)	$ (241,204)	$ (246,979)	$ (252,755)	$ (258,531)
5a.	Cypress Settlement (Capacity)	$ -	$ -	$ -	$ -	$ 353,244	$ -
5b.	Okeelanta Settlement (Capacity)	$ 3,078,016	$ 3,072,620	$ 3,064,546	$ 3,058,320	$ 3,057,020	$ 3,044,234
6	Incremental Plant Security Costs (Order No. PSC-02-1761-EI)	$ 113,771	$ 832,709	$ 1,151,391	$ 787,976	$ 769,376	$ 709,694
7	Transmission of Electricity by Others	$ 708,540	$ 726,582	$ 967,321	$ 1,113,810	$ 744,916	$ 497,782
8	Revenues from Capacity Sales	$ (853,648)	$ (676,765)	$ (153,736)	$ (226,606)	$ (243,744)	$ (329,412)
9.	Total (Lines 1 through 8)	$ 52,726,720	$ 54,750,196	$ 53,382,631	$ 54,589,777	$ 61,355,676	$ 63,374,786
10.	Jurisdictional Separation Factor (a)	99.01742%	99.01742%	99.01742%	99.01742%	99.01742%	99.01742%
11.	Jurisdictional Capacity Charges	52,208,638	54,212,232	52,858,104	54,053,389	60,752,807	62,752,078
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)
13.	Jurisdictional Capacity Charges Authorized	47,463,172	49,466,766	48,112,638	49,307,923	56,007,341	58,006,612
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	45,289,301	44,889,661	44,494,357	44,357,710	47,550,317	52,878,607
15.	Prior Period True-up Provision	3,434,618	3,434,618	3,434,618	3,434,618	3,434,618	3,434,618
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	48,723,919	48,324,279	47,928,975	47,792,328	50,984,935	56,313,225
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	1,260,747	(1,142,487)	(183,663)	(1,515,596)	(5,022,407)	(1,693,387)
18.	Interest Provision for Month	56,326	51,960	46,008	40,687	34,539	25,582
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	41,215,416	39,097,870	34,572,726	31,000,453	26,090,927	17,668,441
20.	Deferred True-up - Over/(Under) Recovery	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	51,774,593	47,249,449	43,677,176	38,767,650	30,345,164	25,242,741

Notes: **(a) Per K. M. Dubin's Testimony Appendix III Page 5, filed November 4, 2002.**
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003
SIX MONTHS ACTUAL SIX MONTHS NEW ESTIMATES

LINE NO.		(7) JUL 2003 NEW ESTIMATE	(8) AUG 2003 NEW ESTIMATE	(9) SEP 2003 NEW ESTIMATE	(10) OCT 2003 NEW ESTIMATE	(11) NOV 2003 NEW ESTIMATE	(12) DEC 2003 NEW ESTIMATE	(13) TOTAL	LINE NO.
1.	Payments to non-Cogenerators (UPS & SJRPP)	$ 13,871,393	$ 13,871,393	$ 13,871,393	$ 13,871,393	$ 13,871,393	$ 13,871,393	$ 174,307,674	1.
2.	Short Term Capacity Payments	$ 14,516,860	$ 14,516,860	$ 8,289,080	$ 3,542,060	$ 3,885,560	$ 6,180,400	$ 94,397,361	2.
3.	Payments to Cogenerators (QFs)	$ 28,785,491	$ 28,785,491	$ 28,785,491	$ 28,785,491	$ 28,785,491	$ 28,785,491	$ 350,923,536	3.
4a.	SJRPP Suspension Accrual	$ 586,656	$ 586,656	$ 586,656	$ 586,656	$ 586,656	$ 586,656	$ 7,039,872	4a.
4b.	Return Requirements on SJRPP Suspension Liability	$ (264,306)	$ (270,082)	$ (275,857)	$ (281,633)	$ (287,409)	$ (293,184)	$ (3,137,021)	4b.
5a.	Cypress Settlement (Capacity)	$ -	$ -	$ -	$ -	$ -	$ -	$ 353,244	5a.
5b.	Okeelanta Settlement (Capacity)	$ 3,030,898	$ 3,028,457	$ 3,026,015	$ 3,023,574	$ 3,021,133	$ 3,018,691	$ 36,523,524	5b.
6	Incremental Plant Security Costs (Order No. PSC-02-1761-EI)	$ 929,747	$ 1,635,873	$ 1,226,931	$ 857,145	$ 618,230	$ 625,907	$ 10,258,750	6
7	Transmission of Electricity by Others	$ 553,979	$ 548,963	$ 559,522	$ 617,988	$ 664,739	$ 678,142	$ 8,382,284	7
8	Revenues from Capacity Sales	$ (546,680)	$ (512,080)	$ (370,220)	$ (415,200)	$ (380,600)	$ (470,720)	$ (5,179,411)	8
9.	Total (Lines 1 through 8)	$ 61,464,038	$ 62,191,532	$ 55,699,012	$ 50,587,475	$ 50,765,194	$ 52,982,777	$ 673,869,815	9.
10.	Jurisdictional Separation Factor (a)	99.01742%	99.01742%	99.01742%	99.01742%	99.01742%	99.01742%	N/A	10.
11.	Jurisdictional Capacity Charges	60,860,105	61,580,450	55,151,724	50,090,413	50,266,385	52,462,179	667,248,504	11.
12.	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(56,945,592)	12.
13.	Jurisdictional Capacity Charges Authorized	56,114,639	56,834,984	50,406,258	45,344,947	45,520,919	47,716,713	610,302,912	13.
14.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	52,584,962	56,192,782	55,414,860	51,328,761	46,692,511	43,072,506	584,746,334	14.
15.	Prior Period True-up Provision	3,434,618	3,434,618	3,434,618	3,434,618	3,434,618	3,434,618	41,215,416	15.
16.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	56,019,580	59,627,400	58,849,478	54,763,379	50,127,129	46,507,124	625,961,750	16.
17.	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(95,059)	2,792,416	8,443,219	9,418,432	4,606,209	(1,209,589)	15,658,838	17.
18.	Interest Provision for Month	19,565	17,843	19,677	24,274	27,275	25,851	389,587	18.
19.	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	12,566,018	9,055,906	8,431,547	13,459,826	19,467,914	20,666,781	41,215,416	19.
20.	Deferred True-up - Over/(Under) Recovery	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723	20.
21.	Prior Period True-up Provision - Collected/(Refunded) this Month	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(41,215,416)	21.
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	21,732,629	21,108,270	26,136,549	32,144,637	33,343,504	28,725,148	28,725,148	22.

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 5, filed Novemb
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-E
Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATE/ACTUAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003

Line No.		(1) ESTIMATED / ACTUAL	(2) ORIGINAL PROJECTIONS (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
1.	Payments to Non-cogenerators (UPS & SJRPP)	$ 174,307,675	$ 186,512,879	$ (12,205,204)	(6.5) %
2	Short Term Capacity Payments	$ 94,397,361	95,709,055	$ (1,311,694)	(1.4) %
3	Payments to Cogenerators (QFs)	350,923,536	344,845,248	6,078,288	1.8 %
4a	SJRPP Suspension Accrual	7,039,872	7,999,536	(959,664)	(12.0) %
4b	Return Requirements on SJRPP Suspension Liability	(3,137,021)	(3,193,708)	56,687	(1.8) %
5a	Cypress Settlement (Capacity)	353,244	0	353,244	N/A
5b	*Okeelanta Settlement* (Capacity)	36,523,524	37,308,244	(784,720)	(2.1) %
6	Incremental Power Plant Security Costs-Order No. PSC-02-1761	10,258,750	4,702,875	5,555,875	118.1 %
7	Transmission of Electricity by Others	8,382,284	6,213,511	2,168,773	34.9 %
8	Revenues from Capacity Sales	(5,179,411)	(4,064,426)	(1,114,985)	27.4 %
9	Total (Lines 1 through 8)	$ 673,869,815	$ 676,033,214	$ (2,163,399)	(0.3) %
10	Jurisdictional Separation Factor	99.01742%	99.01742%	0	0.0 %
11	Jurisdictional Capacity Charges	$ 667,248,505	$ 669,390,647	$ (2,142,142)	(0.3) %
12	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(56,945,592)	(56,945,592)	0	N/A
13	Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$ 610,302,913	$ 612,445,055	$ (2,142,142)	(0.3) %
14	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 584,746,334	$ 571,229,639	$ 13,516,695	2.4 %
15	Prior Period True-up Provision	41,215,416	41,215,416	0	N/A
16	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 625,961,750	$ 612,445,055	$ 13,516,695	2.2 %
17	True-up Provision for Period - Over/(Under) Recovery (Line 14 - Line 11)	$ 15,658,837	$0	$ 15,658,837	N/A
18	Interest Provision for Period	389,587	0	389,587	N/A
19	True-up & Interest Provision Beginning of Period - Over/(Under) Recovery	41,215,416	41,215,416	0	N/A
20	Deferred True-up - Over/(Under) Recovery	12,676,723	0	12,676,723	N/A
21	Prior Period True-up Provision - Collected/(Refunded) this Period	(41,215,416)	(41,215,416)	0	N/A
22	End of Period True-up - Over/(Under) Recovery (Sum of Lines 15 through 19)	$ 28,725,148	$0	$ 28,725,148	N/A

Notes: **(a) Per K. M. Dubin's Testimony Appendix III, Page 5, Docket No. 020001-EI, filed November 5, 2002.**
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. *930001-EI, filed July 8, 1993.*

APPENDIX II

CAPACITY COST RECOVERY

ESTIMATED/ACTUAL TRUE UP CALCULATION

KMD-4
DOCKET NO. 030001-EI
FPL WITNESS: K.M. DUBIN
August 12, 2003

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003
SIX MONTHS ACTUAL, SIX MONTHS NEW ESTIMATES

LINE NO.		(1) JAN 2003 ACTUAL	(2) FEB 2003 ACTUAL	(3) MAR 2003 ACTUAL	(4) APR 2003 ACTUAL	(5) MAY 2003 ACTUAL	(6) JUN 2003 ACTUAL
1	Payments to non-Cogenerators (UPS & SJRPP)	$ 15,595,426	$ 15,990,408	$ 14,684,403	$ 15,153,064	$ 14,649,614	$ 15,005,398
2	Short Term Capacity Payments	$ 6,245,451	$ 6,245,451	$ 4,361,584	$ 4,490,250	$ 6,995,796	$ 15,128,009
3	Payments to Cogenerators (QFs)	$ 27,481,162	$ 28,207,963	$ 28,961,670	$ 29,873,286	$ 34,695,552	$ 28,990,956
4a	SJRPP Suspension Accrual	$ 586,656	$ 586,656	$ 586,656	$ 586,656	$ 586,656	$ 586,656
4b.	Return Requirements on SJRPP Suspension Liability	$ (229,653)	$ (235,428)	$ (241,204)	$ (246,979)	$ (252,755)	$ (258,531)
5a	Cypress Settlement (Capacity)	$ -	$ -	$ -	$ -	$ 353,244	$ -
5b	Okeelanta Settlement (Capacity)	$ 3,078,016	$ 3,072,620	$ 3,064,546	$ 3,058,320	$ 3,057,020	$ 3,044,234
6	Incremental Plant Security Costs (Order No PSC-02-1761-EI)	$ 113,771	$ 832,709	$ 1,151,391	$ 787,976	$ 769,376	$ 709,694
7	Transmission of Electricity by Others	$ 708,540	$ 726,582	$ 967,321	$ 1,113,810	$ 744,916	$ 497,782
8	Revenues from Capacity Sales	$ (853,648)	$ (676,765)	$ (153,736)	$ (226,606)	$ (243,744)	$ (329,412)
9	Total (Lines 1 through 8)	$ 52,726,720	$ 54,750,196	$ 53,382,631	$ 54,589,777	$ 61,355,676	$ 63,374,786
10	Jurisdictional Separation Factor (a)	99.01742%	99.01742%	99.01742%	99.01742%	99.01742%	99.01742%
11	Jurisdictional Capacity Charges	52,208,638	54,212,232	52,858,104	54,053,389	60,752,807	62,752,078
12	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)
13	Jurisdictional Capacity Charges Authorized	47,463,172	49,466,766	48,112,638	49,307,923	56,007,341	58,006,612
14	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	45,289,301	44,889,661	44,494,357	44,357,710	47,550,317	52,878,607
15	Prior Period True-up Provision	3,434,618	3,434,618	3,434,618	3,434,618	3,434,618	3,434,618
16	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	48,723,919	48,324,279	47,928,975	47,792,328	50,984,935	56,313,225
17	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	1,260,747	(1,142,487)	(183,663)	(1,515,596)	(5,022,407)	(1,693,387)
18	Interest Provision for Month	56,326	51,960	46,008	40,687	34,539	25,582
19	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	41,215,416	39,097,870	34,572,726	31,000,453	26,090,927	17,668,441
20	Deferred True-up - Over/(Under) Recovery	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723
21	Prior Period True-up Provision - Collected/(Refunded) this Month	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)
22	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	51,774,593	47,249,449	43,677,176	38,767,650	30,345,164	25,242,741

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 5, filed November 4, 2002.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003
SIX MONTHS ACTUAL SIX MONTHS NEW ESTIMATES

LINE NO		(7) JUL 2003 NEW ESTIMATE	(8) AUG 2003 NEW ESTIMATE	(9) SEP 2003 NEW ESTIMATE	(10) OCT 2003 NEW ESTIMATE	(11) NOV 2003 NEW ESTIMATE	(12) DEC 2003 NEW ESTIMATE	(13) TOTAL	LINE NO
1	Payments to non-Cogenerators (UPS & SJRPP)	$ 13,871,393	$ 13,871,393	$ 13,871,393	$ 13,871,393	$ 13,871,393	$ 13,871,393	$ 174,307,674	1
2	Short Term Capacity Payments	$ 14,516,860	$ 14,516,860	$ 8,289,080	$ 3,542,060	$ 3,885,560	$ 6,180,400	$ 94,397,361	2
3	Payments to Cogenerators (QFs)	$ 28,785,491	$ 28,785,491	$ 28,785,491	$ 28,785,491	$ 28,785,491	$ 28,785,491	$ 350,923,536	3
4a.	SJRPP Suspension Accrual	$ 586,656	$ 586,656	$ 586,656	$ 586,656	$ 586,656	$ 586,656	$ 7,039,872	4a
4b	Return Requirements on SJRPP Suspension Liability	$ (264,305)	$ (270,082)	$ (275,857)	$ (281,633)	$ (287,409)	$ (293,184)	$ (3,137,021)	4b
5a	Cypress Settlement (Capacity)	$ -	$ -	$ -	$ -	$ -	$ -	$ 353,244	5a
5b	Okeelanta Settlement (Capacity)	$ 3,030,898	$ 3,028,457	$ 3,026,015	$ 3,023,574	$ 3,021,133	$ 3,018,691	$ 36,529,524	5b
6	Incremental Plant Security Costs (Order No PSC-02-1761-FI)	$ 929,747	$ 1,635,873	$ 1,226,931	$ 857,145	$ 618,230	$ 625,907	$ 10,258,750	6
7	Transmission of Electricity by Others	$ 553,979	$ 548,963	$ 559,522	$ 617,988	$ 664,739	$ 678,142	$ 8,382,284	7
8	Revenues from Capacity Sales	$ (546,580)	$ (512,080)	$ (370,220)	$ (415,200)	$ (380,600)	$ (470,720)	$ (5,179,411)	8
9	Total (Lines 1 through 8)	$ 61,464,038	$ 62,191,532	$ 55,699,012	$ 50,587,475	$ 50,765,194	$ 52,982,777	$ 673,869,815	9
10	Jurisdictional Separation Factor (a)	99.01742%	99.01742%	99.01742%	99.01742%	99.01742%	99.01742%	N/A	10.
11	Jurisdictional Capacity Charges	60,860,105	61,580,450	55,151,724	50,090,413	50,266,385	52,462,179	667,248,504	11
12	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(56,945,592)	12
13	Jurisdictional Capacity Charges Authorized	56,114,639	56,834,984	50,406,258	45,344,947	45,520,919	47,716,713	610,302,912	13
14	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	52,584,962	56,192,782	55,414,860	51,328,761	46,692,511	43,072,306	584,746,334	14
15	Prior Period True-up Provision	3,434,618	3,434,618	3,434,618	3,434,618	3,434,618	3,434,618	41,215,416	15
16	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	56,019,580	59,627,400	58,849,478	54,763,379	50,127,129	46,507,124	625,961,750	16
17	True-up Provision for Month - Over/(Under) Recovery (Line 16 - Line 13)	(95,059)	2,792,416	8,443,219	9,418,432	4,606,209	(1,209,589)	15,658,838	17
18	Interest Provision for Month	19,565	17,843	19,677	24,274	27,275	25,851	389,587	18
19	True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	12,566,018	9,055,906	8,431,547	13,459,826	19,467,914	20,666,781	41,215,416	19
20	Deferred True-up - Over/(Under) Recovery	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723	12,676,723	20
21	Prior Period True-up Provision - Collected/(Refunded) this Month	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(3,434,618)	(41,215,416)	21
22.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 17 through 21)	21,732,629	21,108,270	26,136,549	32,144,637	33,343,504	28,725,148	28,725,148	22

Notes: (a) Per K. M. Dubin's Testimony Appendix III Page 5, filed Novemb
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-E
Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATE/ACTUAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY THROUGH DECEMBER 2003

Line No.		(1) ESTIMATED / ACTUAL	(2) ORIGINAL PROJECTIONS (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
1	Payments to Non-cogenerators (UPS & SJRPP)	$ 174,307,675	$ 186,512,879	$ (12,205,204)	(6.5) %
2	Short Term Capacity Payments	$ 94,397,361	95,709,055	$ (1,311,694)	(1.4) %
3	Payments to Cogenerators (QFs)	350,923,536	344,845,248	6,078,288	1.8 %
4a	SJRPP Suspension Accrual	7,039,872	7,999,536	(959,664)	(12.0) %
4b	Return Requirements on SJRPP Suspension Liability	(3,137,021)	(3,193,708)	56,687	(1.8) %
5a	Cypress Settlement (Capacity)	353,244	0	353,244	N/A
5b	Okeelanta Settlement (Capacity)	36,523,524	37,308,244	(784,720)	(2.1) %
6	Incremental Power Plant Security Costs-Order No PSC-02-1761	10,258,750	4,702,875	5,555,875	118.1 %
7	Transmission of Electricity by Others	8,382,284	6,213,511	2,168,773	34.9 %
8	Revenues from Capacity Sales	(5,179,411)	(4,064,426)	(1,114,985)	27.4 %
9	Total (Lines 1 through 8)	$ 673,869,815	$ 676,033,214	$ (2,163,399)	(0.3) %
10	Jurisdictional Separation Factor	99.01742%	99.01742%	0	0.0 %
11	Jurisdictional Capacity Charges	$ 667,248,505	$ 669,390,647	$ (2,142,142)	(0.3) %
12	Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(56,945,592)	(56,945,592)	0	N/A
13	Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$ 610,302,913	$ 612,445,055	$ (2,142,142)	(0.3) %
14	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$ 584,746,334	$ 571,229,639	$ 13,516,695	2.4 %
15	Prior Period True-up Provision	41,215,416	41,215,416	0	N/A
16	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$ 625,961,750	$ 612,445,055	$ 13,516,695	2.2 %
17	True-up Provision for Period - Over/(Under) Recovery (Line 14 - Line 11)	$ 15,658,837	$0	$ 15,658,837	N/A
18	Interest Provision for Period	389,587	0	389,587	N/A
19	True-up & Interest Provision Beginning of Period - Over/(Under) Recovery	41,215,416	41,215,416	0	N/A
20	Deferred True-up - Over/(Under) Recovery	12,676,723	0	12,676,723	N/A
21	Prior Period True-up Provision - Collected/(Refunded) this Period	(41,215,416)	(41,215,416)	0	N/A
22	End of Period True-up - Over/(Under) Recovery (Sum of Lines 15 through 19)	$ 28,725,148	$0	$ 28,725,148	N/A

Notes: (a) Per K. M. Dubin's Testimony Appendix III, Page 5, Docket No. 020001-EI, filed November 5, 2002.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, Docket No. 940001-EI, as adjusted in August 1993, per E.L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES

KMD-5
DOCKET NO. 030001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT _____
PAGES 1-69
SEPTEMBER 12, 2003

APPENDIX II
FUEL COST RECOVERY
E SCHEDULES
January 2004 – December 2004

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SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004

		(a) DOLLARS	(b) MWH	(c) ¢/KWH
1	Fuel Cost of System Net Generation (E3)	$2,948,212,042	89,141,154	3.3074
2	Nuclear Fuel Disposal Costs (E2)	21,731,958	23,360,161	0.0930
3	Fuel Related Transactions (E2)	12,899,420	0	0.0000
3b	Incremental Hedging Costs (E2)	427,857	0	
4	Fuel Cost of Sales to FKEC / CKW (E2)	(41,152,955)	(1,057,012)	3.8933
5	TOTAL COST OF GENERATED POWER	$2,942,118,322	88,084,142	3.3401
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	288,786,758	12,872,405	2.2435
7	Energy Cost of Sched C & X Econ Purch (Florida) (E9)	18,665,303	557,300	3.3492
8	Energy Cost of Other Econ Purch (Non-Florida) (E9)	33,673,183	919,835	3.6608
9		0	0	0.0000
10		0	0	0.0000
11	Okeelanta/Osceola Settlement (E2)	$9,578,625	0	0.0000
12	Payments to Qualifying Facilities (E8)	148,266,648	7,115,665	2.0837
13	TOTAL COST OF PURCHASED POWER	$498,970,517	21,465,205	2.3246
14	TOTAL AVAILABLE KWH (LINE 5 + LINE 13)		109,549,347	
15	Fuel Cost of Economy Sales (E6)	(52,502,900)	(1,301,000)	4.0356
16	Gain on Economy Sales (E6A)	0	0	0.0000
17	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(1,435,065)	(502,068)	0.2858
18	Fuel Cost of Other Power Sales (E6)	0	0	0.0000
18a	Revenues from Off-System Sales	(7,048,624)	(1,803,068)	0.3909
19	TOTAL FUEL COST AND GAINS OF POWER SALES	($60,986,589)	(1,803,068)	3.3824
19a	Net Inadvertent Interchange	0	0	
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 13 + 19 + 19a)	$3,380,102,249	107,746,279	3.1371
21	Net Unbilled Sales	(31,807,177) **	(1,013,906)	(0.0314)
22	Company Use	10,140,307 **	323,239	0.0100
23	T & D Losses	219,706,646 **	7,003,508	0.2166
24	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$3,380,102,249	101,433,438	3.3323
25	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$17,322,348	519,832	3.3323
26	Jurisdictional MWH Sales	$3,362,779,901	100,913,607	3.3323
27	Jurisdictional Loss Multiplier	-	-	1.00059
28	Jurisdictional MWH Sales Adjusted for Line Losses	$3,364,763,941	100,913,607	3.3343
29	FINAL TRUE-UP JAN 02 - DEC 02 / EST/ACT TRUE-UP JAN 03 - DEC 03 $344,729,859 underrecovery	344,729,859	100,913,607	0.3416
30	TOTAL JURISDICTIONAL FUEL COST	$3,709,493,800	100,913,607	3.6759
31	Revenue Tax Factor			1.01597
32	Fuel Factor Adjusted for Taxes			3.7346
33	GPIF ***	$7,449,429	100,913,607	0.0074
34	Fuel Factor including GPIF (Line 32 + Line 33)			3.7420
35	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			3.742

** For Informational Purposes Only
*** Calculation Based on Jurisdictional KWH Sales

SCHEDULE E - 1A

CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004

1. Estimated/Actual over/(under) recovery (January 2003 - December 2003)	$ (344,729,859)
2.Over/(under) recovery from January 2002 - December 2002 $72,467,176 underrecovery included in Midcourse Correction June 13, 2003	$ -
3.Total over/(under) recovery to be included in the January 2004 - December 2004 projected period (Schedule E1, Line 29)	$ (344,729,859)
4. TOTAL JURISDICTIONAL SALES (MWH) (Projected period)	100,913,607
5. True-Up Factor (Lines 3/4) c/kWh:	(0.3416)

SCHEDULE E - 1C

CALCULATION OF GENERATING PERFORMANCE
INCENTIVE FACTOR AND TRUE - UP FACTOR
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: JANUARY 2004 - DECEMBER 2004

1. TOTAL AMOUNT OF ADJUSTMENTS:	352,179,288
A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY)	$7,449,429
B. TRUE-UP (OVER)/UNDER RECOVERED	$ 344,729,859
2. TOTAL JURISDICTIONAL SALES (MWH)	100,913,607
3. ADJUSTMENT FACTORS c/kWh:	0.3490
A. GENERATING PERFORMANCE INCENTIVE FACTOR	0.0074
B. TRUE-UP FACTOR	0.3416

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1D

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

JANUARY 2004 - DECEMBER 2004

NET ENERGY FOR LOAD (%)		FUEL COST (%)
ON PEAK	30.74	33.82
OFF PEAK	69.26	66.18
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS	$3,380,102,249	$1,143,150,581	$2,236,951,668
2	MWH SALES	101,433,438	31,180,639	70,252,799
3	COST PER KWH SOLD	3.3323	3.6662	3.1841
4	JURISDICTIONAL LOSS FACTOR	1.00059	1.00059	1.00059
5	JURISDICTIONAL FUEL FACTOR	3.3343	3.6684	3.1860
6	TRUE-UP	0.3416	0.3416	0.3416
7				
8	TOTAL	3.6759	4.0100	3.5276
9	REVENUE TAX FACTOR	1.01597	1.01597	1.01597
10	RECOVERY FACTOR	3.7346	4.0740	3.5839
11	GPIF	0.0074	0.0074	0.0074
12	RECOVERY FACTOR including GPIF	3.7420	4.0814	3.5913
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	3.742	4.081	3.591

HOURS:		
	ON-PEAK	24.75 %
	OFF-PEAK	75.25 %

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

JANUARY 2004 - DECEMBER 2004

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1, GS-1, SL-2		3.742	1.00206	3.750
A-1*	SL-1, OL-1, PL-1		3.670	1.00206	3.678
B	GSD-1		3.742	1.00199	3.749
C	GSLD-1 & CS-1		3.742	1.00093	3.745
D	GSLD-2, CS-2, OS-2 & MET		3.742	0.99366	3.718
E	GSLD-3 & CS-3		3.742	0.95529	3.575
A	RST-1, GST-1	ON-PEAK	4.081	1.00206	4.090
		OFF-PEAK	3.591	1.00206	3.599
B	GSDT-1	ON-PEAK	4.081	1.00199	4.090
	CILC-1(G)	OFF-PEAK	3.591	1.00199	3.598
C	GSLDT-1 &	ON-PEAK	4.081	1.00093	4.085
	CST-1	OFF-PEAK	3.591	1.00093	3.595
D	GSLDT-2 &	ON-PEAK	4.081	0.99497	4.061
	CST-2	OFF-PEAK	3.591	0.99497	3.573
E	GSLDT-3,CST-3,	ON-PEAK	4.081	0.95529	3.899
	CILC -1(T)	OFF-PEAK	3.591	0.95529	3.431
	& ISST-1(T)				
F	CILC -1(D) &	ON-PEAK	4.081	0.99317	4.054
	ISST-1(D)	OFF-PEAK	3.591	0.99317	3.567

* WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

Florida Power & Light Company
2002 Actual Energy Losses by Rate Class

Line No	Rate Class	Delivered MWH Sales	Expansion Factor	Delivered Energy at Generation	Delivered Efficiency	Losses	Fuel Cost Recovery Multiplier
1	RS-1 Sec	50,835,861	1.07375594	54,585,307	0.931310	3,749,447	1.00206
2							
3	GS-1 Sec	5,761,864	1.07375594	6,186,836	0.931310	424,972	1.00206
4							
5	GSD-1 Pri	62,884	1.04655264	65,811	0.955518	2,927	
6	GSD-1 Sec	21,554,173	1.07375594	23,143,921	0.931310	1,589,748	
7	Subtotal GSD-1	21,617,057	1.07367680	23,209,733	0.931379	1,592,676	1.00199
8							
9	OS-2 Pri	20,861	1.04655264	21,832	0.955518	971	
10	OS-2 Sec	-	1.07375594	-	0.000000	-	
11	Subtotal OS-2	20,861	1.04655264	21,832	0.955518	971	0.97668
12							
13	GSLD-1 Pri	388,040	1.04655264	406,105	0.955518	18,064	
14	GSLD-1 Sec	9,235,261	1.07375594	9,916,416	0.931310	681,155	
15	Subtotal GSLD-1	9,623,301	1.07265902	10,322,521	0.932263	699,220	1.00104
16							
17	CS-1 Pri	53,288	1.04655264	55,768	0.955518	2,481	
18	CS-1 Sec	173,144	1.07375594	185,914	0.931310	12,770	
19	Subtotal CS-1	226,431	1.06735400	241,682	0.936896	15,251	0.99609
20							
21	Subtotal GSLD-1 / CS-1	9,849,732	1.07253706	10,564,203	0.932369	714,471	1.00093
22							
23	GSLD-2 Pri	362,200	1.04655264	379,061	0.955518	16,861	
24	GSLD-2 Sec	977,069	1.07375594	1,049,133	0.931310	72,065	
25	Subt GSLD-2	1,339,268	1.06639892	1,428,194	0.937735	88,926	0.99520
26							
27	CS-2 Pri	36,040	1.04655264	37,718	0.955518	1,678	
28	CS-2 Sec	49,807	1.07375594	53,480	0.931310	3,674	
29	Subtotal CS-2	85,846	1.06233550	91,198	0.941322	5,351	0.99140
30							
31	Subtotal GSLD-2 / CS-2	1,425,115	1.06615414	1,519,392	0.937951	94,277	0.99497
32							
33	GSLD-3 Trn	170,488	1.02363751	174,518	0.976908	4,030	0.95529
34							
35	CS-3 Trn	0	1.02363751	0	0.000000	0	0.00000
36							
37	Subtotal GSLD-3 / CS-3	170,488	1.02363751	174,518	0.976908	4,030	0.95529
38							
39	ISST-1 Sec	0	1.07375594	0	0.000000	0	0.00000
40							
41	SST-1 Pri	41,655	1.04655264	43,594	0.955518	1,939	
42	SST-1 Sec	14,093	1.07375594	15,132	0.931310	1,039	
43	Subtotal SST-1 (D)	55,748	1.05342951	58,726	0.949280	2,979	0.98309
44							
45	SST-1 Trn	138,648	1.02363751	141,926	0.976908	3,277	0.95529
46							
47	CILC-1D Pri	1,063,122	1.04655264	1,112,614	0.955518	49,491	
48	CILC-1D Sec	1,971,890	1.07375594	2,117,329	0.931310	145,439	
49	Subtotal CILC-1D	3,035,013	1.06422700	3,229,942	0.939649	194,930	0.99317
50							
51	CILC-1G Pri	0	1.04655264	0	0.000000	0	

Florida Power & Light Company
2002 Actual Energy Losses by Rate Class

Line No	Rate Class	Delivered MWH Sales	Expansion Factor	Delivered Energy at *Generation*	Delivered *Efficiency*	Losses	Fuel Cost Recovery Multiplier
52	CILC-1G Sec	242,804	1.07375594	260,712	0.931310	17,908	
53	Subtotal CILC-1G	242,804	1.07375594	260,712	0.931310	17,908	1.00206
54							
55	Subtotal CILC-1D / CILC-1G	3,277,816	1.06493286	3,490,654	0.939026	212,838	0.99383
56							
57	Subtotal GSD-1 & CILC-1G	21,859,860	1.07367768	23,470,444	0.931378	1,610,584	1.00199
58							
59	CILC-1T Trn	1,506,310	1.02363751	1,541,916	0.976908	35,605	0.95529
60							
61	Subtotal ISST-D & CILC-1D	3,035,013	1.06422700	3,229,942	0.939649	194,930	0.99317
62							
63	MET Pri	88,733	1.04655264	92,863	0.955518	4,131	0.97668
64							
65	Subtotal OS-2, GSLD-2, CS-2, & MET	1,534,708	1.06475440	1,634,087	0.939184	99,379	0.99366
66							
67	OL-1 Sec	110,215	1.07375594	118,344	0.931310	8,129	1.00206
68							
69	SL-1 Sec	411,469	1.07375594	441,817	0.931310	30,348	1.00206
70							
71	Subtotal OL-1 / SL-1	521,684	1.07375594	560,161	0.931310	38,477	1.00206
72							
73	SL-2 Sec	72,877	1.07375594	78,252	0.931310	5,375	1.00206
74							
75	RTP-1 Pri	0	1.04655264	0	0.000000	0	
76	RTP-1 Sec	40,115	1.07375594	43,073	0.931310	2,959	
77	Subtotal RTP-1	40,115	1.07375594	43,073	0.931310	2,959	1.00206
78							
79	RTP-2 Pri	83,721	1.04655264	87,618	0.955518	3,897	
80	RTP-2 Sec	121,212	1.07375594	130,152	0.931310	8,940	
81	Subtotal RTP-2	204,933	1.06264263	217,771	0.941050	12,838	0.99169
82							
83	RTP-3 Trn	0	1.02363751	0	0.000000	0	0.00000
84							
85	Total FPSC	95,587,841	1.07217782	102,487,163	0.932681	6,899,322	1.00059
86							
87	Total FERC Sales	1,267,278	1.02363751	1,297,234	0.976908	29,955	
88							
89	Total Company	96,855,119	1.07154270	103,784,396	0.933234	6,929,277	
90							
91	Company Use	138,363	1.07375594	148,568	0.931310	10,205	
92							
93	Total FPL	96,993,482	1.07154586	103,932,964	0.933231	6,939,482	1.00000
94							
95	**Summary of Sales by Voltage:**						
96							
97	Transmission	3,082,725	1.02363751	3,155,593	0.976908	72,868	
98							
99	Primary	2,200,544	1.04655264	2,302,985	0.955518	102,441	
100							
101	Secondary	91,571,851	1.07375594	98,325,818	0.931310	6,753,968	
102							
103	Total	96,855,119	1.07154270	103,784,396	0.933234	6,929,277	

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

SCHEDULE E2
Page 1 of 2

LINE NO.		(a) JANUARY	(b) FEBRUARY	(c) ESTIMATED MARCH	(d) APRIL	(e) MAY	(f) JUNE	(g) 6 MONTH SUB-TOTAL	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$202,819,302	$186,215,676	$215,812,476	$227,290,470	$249,599,496	$270,742,086	$1,352,479,506	A1
1a	NUCLEAR FUEL DISPOSAL	2,033,221	1,902,046	1,847,534	1,645,411	1,983,357	1,919,376	11,330,945	1a
1b	COAL CAR INVESTMENT	322,496	382,978	380,756	378,533	376,310	374,088	2,215,161	1b
1d	GAS LATERAL ENHANCEMENTS	159,187	157,765	156,343	154,922	153,500	152,078	933,795	1d
1e	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	0	0	0	1e
1g	INCREMENTAL HEDGING COSTS	57,896	30,296	31,015	31,015	31,015	31,015	212,252	1g
2	FUEL COST OF POWER SOLD	(7,091,623)	(6,093,617)	(3,449,343)	(2,949,421)	(3,429,959)	(3,974,741)	(26,988,704)	2
2a	REVENUES FROM OFF-SYSTEM SALES	(810,110)	(848,796)	(393,382)	(470,140)	(642,100)	(620,450)	(3,784,978)	2a
3	FUEL COST OF PURCHASED POWER	24,078,877	21,456,163	20,943,576	24,085,346	22,369,914	24,802,933	137,736,809	3
3b	OKEELANTA/OSCEOLA SETTLEMENT	801,788	801,139	800,490	799,841	799,192	798,543	4,800,994	3b
3c	QUALIFYING FACILITIES	12,664,908	11,992,554	12,704,006	11,158,287	12,697,137	12,526,632	73,743,524	3c
4	ENERGY COST OF ECONOMY PURCHASES	5,546,519	5,069,774	5,607,472	3,434,738	3,512,922	3,611,779	26,783,204	4
4a	FUEL COST OF SALES TO FKEC / CKW	(2,931,990)	(2,974,848)	(2,985,732)	(3,206,958)	(3,382,615)	(3,520,717)	(19,002,859)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$237,650,471	$218,091,130	$251,455,211	$262,352,044	$284,068,169	$306,842,623	$1,560,459,648	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	8,167,344	7,386,655	7,215,692	7,314,645	7,897,858	9,143,897	47,126,091	6
7	COST PER KWH SOLD (¢/KWH)	2.9098	2.9525	3.4848	3.5867	3.5968	3.3557	3.3112	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00059	1.00059	1.00059	1.00059	1.00059	1.00059	1.00059	7a
7b	JURISDICTIONAL COST (¢/KWH)	2.9115	2.9542	3.4869	3.5888	3.5989	3.3577	3.3132	7b
9	TRUE-UP (¢/KWH)	0.3534	0.3909	0.4001	0.3948	0.3656	0.3157	0.3676	9
10	TOTAL	3.2649	3.3451	3.8870	3.9836	3.9645	3.6734	3.6808	10
11	REVENUE TAX FACTOR 0.01597	0.0521	0.0534	0.0621	0.0636	0.0633	0.0587	0.0588	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	3.3170	3.3985	3.9491	4.0472	4.0278	3.7321	3.7396	12
13	GPIF (¢/KWH)	0.0076	0.0084	0.0086	0.0085	0.0079	0.0068	0.0079	13
14	RECOVERY FACTOR including GPIF	3.3246	3.4069	3.9577	4.0557	4.0357	3.7389	3.7475	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	3.325	3.407	3.958	4.056	4.036	3.739	3.748	15

FLORIDA POWER & LIGHT COMPANY
FUEL & PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
FOR THE PERIOD JANUARY 2004 - DECEMBER 2004

LINE NO.		(h) JULY	(i) AUGUST	(j) ESTIMATED SEPTEMBER	(k) OCTOBER	(l) NOVEMBER	(m) DECEMBER	(n) 12 MONTH PERIOD	LINE NO.
A1	FUEL COST OF SYSTEM GENERATION	$297,674,518	$296,401,187	$274,406,529	$270,047,466	$231,203,441	$225,999,395	$2,948,212,042	A1
1a	NUCLEAR FUEL DISPOSAL	1,983,357	1,983,357	1,828,859	1,515,688	1,388,379	1,701,373	$21,731,958	1a
1b	COAL CAR INVESTMENT	371,865	369,643	367,420	365,197	362,975	360,752	$4,413,013	1b
1d	GAS LATERAL ENHANCEMENTS	150,656	149,235	147,813	146,391	144,969	143,548	$1,816,407	1d
1e	DOE DECONTAMINATION AND DECOMMISSIONING COSTS	0	0	0	0	6,670,000	0	$6,670,000 $0	1e
1g	INCREMENTAL HEDGING COSTS	45,773	31,015	31,015	31,015	31,015	45,773	$427,857	1g
2	FUEL COST OF POWER SOLD	(4,557,445)	(4,629,630)	(3,807,877)	(3,446,692)	(4,163,310)	(6,344,308)	($53,937,966)	2
2a	REVENUES FROM OFF-SYSTEM SALES	(877,400)	(807,300)	(478,500)	(278,600)	(241,700)	(580,146)	($7,048,624)	2a
3	FUEL COST OF PURCHASED POWER	31,083,905	29,158,629	27,352,946	22,792,197	17,517,064	23,145,208	$288,786,758	3
3b	OKEELANTA/OSCEOLA SETTLEMENT	797,894	797,245	796,596	795,947	795,298	794,649	$9,578,625	3b
3c	QUALIFYING FACILITIES	12,916,234	12,947,931	12,682,715	12,855,682	10,412,845	12,707,717	$148,266,648	3c
4	ENERGY COST OF ECONOMY PURCHASES	3,670,788	3,682,788	3,683,954	5,178,910	4,624,425	4,714,417	$52,338,486	4
4a	FUEL COST OF SALES TO FKEC / CKW	(3,753,544)	(3,892,284)	(3,953,281)	(3,771,405)	(3,539,694)	(3,239,889)	($41,152,955)	4a
5	TOTAL FUEL & NET POWER TRANSACTIONS (SUM OF LINES A-1 THRU A-4)	$339,506,601	$336,191,817	$313,058,189	$306,231,797	$265,205,708	$259,448,490	$3,380,102,249	5
6	SYSTEM KWH SOLD (MWH) (Excl sales to FKEC / CKW)	9,549,476	9,884,379	9,830,611	8,954,487	8,047,190	8,041,204	101,433,438	6
7	COST PER KWH SOLD (¢/KWH)	3.5552	3.4012	3.1845	3.4199	3.2956	3.2265	3.3323	7
7a	JURISDICTIONAL LOSS MULTIPLIER	1.00059	1.00059	1.00059	1.00059	1.00059	1.00059	1.00059	7a
7b	JURISDICTIONAL COST (¢/KWH)	3.5573	3.4033	3.1864	3.4219	3.2976	3.2284	3.3343	7b
9	TRUE-UP (¢/KWH)	0.3024	0.2921	0.2938	0.3226	0.3590	0.3591	0.3416	9
10	TOTAL	3.8597	3.6954	3.4802	3.7445	3.6566	3.5875	3.6759	10
11	REVENUE TAX FACTOR 0.01597	0.0616	0.0590	0.0556	0.0598	0.0584	0.0573	0.0587	11
12	RECOVERY FACTOR ADJUSTED FOR TAXES	3.9213	3.7544	3.5358	3.8043	3.7150	3.6448	3.7346	12
13	GPIF (¢/KWH)	0.0065	0.0063	0.0063	0.0070	0.0078	0.0078	0.0074	13
14	RECOVERY FACTOR including GPIF	3.9278	3.7607	3.5421	3.8113	3.7228	3.6526	3.7420	14
15	RECOVERY FACTOR ROUNDED TO NEAREST .001 ¢/KWH	3.928	3.761	3.542	3.811	3.723	3.653	3.742	15

Florida Power & Light Company
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Generating System Comparative Data by Fuel Type

		Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
	Fuel Cost of System Net Generation ($)						
1	Heavy Oil	$27,248,782	$26,646,686	$46,932,866	$44,607,040	$54,022,406	$71,217,656
2	Light Oil	$637,210	$231,700	$429,750	$3,853,940	$3,832,000	$4,288,040
3	Coal	$9,040,370	$7,554,680	$1,314,060	$4,838,700	$8,217,910	$8,054,420
4	Gas	$159,600,680	$145,915,370	$161,393,840	$168,690,230	$177,134,700	$181,015,020
5	Nuclear	$6,292,260	$5,867,240	$5,741,960	$5,300,560	$6,392,480	$6,166,950
6	***Total***	$202,819,302	$186,215,676	$215,812,476	$227,290,470	$249,599,496	$270,742,086
	System Net Generation (MWH)						
7	Heavy Oil	589,359	587,496	1,129,017	1,078,074	1,298,934	1,724,818
8	Light Oil	6,104	2,147	4,817	41,203	40,947	47,080
9	Coal	555,242	477,448	86,087	309,366	534,714	523,173
10	Gas	3,061,120	2,836,742	3,321,694	3,489,535	3,784,385	3,870,249
11	Nuclear	2,185,554	2,044,551	1,985,955	1,768,689	2,131,954	2,063,180
12	***Total***	6,397,379	5,948,384	6,527,570	6,686,867	7,790,934	8,228,501
	Units of Fuel Burned						
13	Heavy Oil (BBLS)	942,596	926,933	1,744,880	1,694,356	2,066,964	2,717,564
14	Light Oil (BBLS)	16,362	5,982	10,784	104,737	106,217	119,083
15	Coal (TONS)	282,116	242,077	33,936	159,545	274,243	268,336
16	Gas (MCF)	24,459,787	22,514,019	25,658,624	28,394,690	30,978,378	31,647,021
17	Nuclear (MBTU)	23,772,692	22,238,964	21,633,434	19,526,898	23,469,146	22,712,080
	BTU Burned (MMBTU)						
18	Heavy Oil	6,032,612	5,932,374	11,167,234	10,843,878	13,228,570	17,392,408
19	Light Oil	95,392	34,874	62,874	610,618	619,243	694,253
20	Coal	5,409,939	4,652,546	829,407	3,040,050	5,241,243	5,128,180
21	Gas	24,459,787	22,514,019	25,658,624	28,394,690	30,978,378	31,647,021
22	Nuclear	23,772,692	22,238,964	21,633,434	19,526,898	23,469,146	22,712,080
23	***Total***	59,770,422	55,372,777	59,351,573	62,416,134	73,536,580	77,573,943

Generating System Comparative Data by Fuel Type

		Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
	Generation Mix (%MWH)						
24	Heavy Oil	9.21%	9.88%	17.30%	16.12%	16.67%	20.96%
25	Light Oil	0.10%	0.04%	0.07%	0.62%	0.53%	0.57%
26	Coal	8.68%	8.03%	1.32%	4.63%	6.86%	6.36%
27	Gas	47.85%	47.69%	50.89%	52.18%	48.57%	47.03%
28	Nuclear	34.16%	34.37%	30.42%	26.45%	27.36%	25.07%
29	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit						
30	Heavy Oil ($/BBL)	28.9082	28.7472	26.8975	26.3268	26.1361	26.2064
31	Light Oil ($/BBL)	38.9436	38.7329	39.8503	36.7964	36.0771	36.0088
32	Coal ($/ton)	32.0449	31.2078	38.7217	30.3281	29.9658	30.0162
33	Gas ($/MCF)	6.5250	6.4811	6.2900	5.9409	5.7180	5.7198
34	Nuclear ($/MBTU)	0.2647	0.2638	0.2654	0.2714	0.2724	0.2715
	Fuel Cost per MMBTU ($/MMBTU)						
35	Heavy Oil	4.5169	4.4917	4.2027	4.1136	4.0838	4.0948
36	Light Oil	6.6799	6.6439	6.8351	6.3115	6.1882	6.1765
37	Coal	1.6711	1.6238	1.5843	1.5917	1.5679	1.5706
38	Gas	6.5250	6.4811	6.2900	5.9409	5.7180	5.7198
39	Nuclear	0.2647	0.2638	0.2654	0.2714	0.2724	0.2715
	BTU burned per KWH (BTU/KWH)						
40	Heavy Oil	10,236	10,098	9,891	10,059	10,184	10,084
41	Light Oil	15,629	16,243	13,053	14,820	15,123	14,746
42	Coal	9,743	9,745	9,635	9,827	9,802	9,802
43	Gas	7,990	7,937	7,725	8,137	8,186	8,177
44	Nuclear	10,877	10,877	10,893	11,040	11,008	11,008
	Generated Fuel Cost per KWH (cents/KWH)						
45	Heavy Oil	4.6235	4.5356	4.1570	4.1377	4.1590	4.1290
46	Light Oil	10.4399	10.7918	8.9219	9.3535	9.3584	9.1079
47	Coal	1.6282	1.5823	1.5264	1.5641	1.5369	1.5395
48	Gas	5.2138	5.1438	4.8588	4.8342	4.6807	4.6771
49	Nuclear	0.2879	0.2870	0.2891	0.2997	0.2998	0.2989
50	***Total***	3.1704	3.1305	3.3062	3.3991	3.2037	3.2903

Florida Power & Light Company
9/3/2003

Generating System Comparative Data by Fuel Type

		Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Total
	Fuel Cost of System Net Generation ($)							
1	Heavy Oil	$85,455,658	$83,382,297	$73,622,129	$75,193,416	$61,003,941	$38,409,085	$687,741,961
2	Light Oil	$4,962,290	$4,905,970	$4,857,980	$3,994,880	$362,810	$838,170	$33,194,740
3	Coal	$8,341,750	$8,281,880	$8,082,670	$8,230,650	$8,211,380	$8,430,870	$88,599,340
4	Gas	$192,558,560	$193,494,760	$182,017,640	$177,804,620	$157,270,190	$172,734,370	$2,069,629,980
5	Nuclear	$6,356,260	$6,336,280	$5,826,110	$4,823,900	$4,355,120	$5,586,900	$69,046,020
6	***Total***	$297,674,518	$296,401,187	$274,406,529	$270,047,466	$231,203,441	$225,999,395	$2,948,212,041
	System Net Generation (MWH)							
7	Heavy Oil	2,065,599	1,996,059	1,739,338	1,730,861	1,402,935	883,903	16,226,393
8	Light Oil	55,932	54,436	52,902	42,221	5,069	9,788	362,646
9	Coal	543,139	538,011	524,606	539,078	540,319	551,749	5,722,932
10	Gas	4,188,251	4,176,311	3,960,968	3,766,062	3,437,370	3,576,336	43,469,023
11	Nuclear	2,131,954	2,131,954	1,965,881	1,629,247	1,492,399	1,828,843	23,360,161
12	***Total***	8,984,875	8,896,770	8,243,696	7,707,468	6,878,092	6,850,620	89,141,154
	Units of Fuel Burned							
13	Heavy Oil (BBLS)	3,242,226	3,130,668	2,734,251	2,729,231	2,215,490	1,412,223	25,557,382
14	Light Oil (BBLS)	136,614	133,385	129,736	106,803	9,282	22,344	901,329
15	Coal (TONS)	278,711	276,104	269,133	276,401	274,696	280,383	2,915,681
16	Gas (MCF)	34,437,365	34,167,473	32,422,697	31,278,038	26,660,646	28,105,203	350,723,939
17	Nuclear (MBTU)	23,469,146	23,469,146	21,619,142	17,822,426	16,110,750	19,939,540	255,783,364
	BTU Burned (MMBTU)							
18	Heavy Oil	20,750,246	20,036,278	17,499,208	17,467,076	14,179,136	9,038,228	163,567,248
19	Light Oil	796,461	777,633	756,362	622,662	54,113	130,264	5,254,748
20	Coal	5,324,207	5,274,098	5,142,357	5,283,395	5,264,111	5,375,659	55,965,192
21	Gas	34,437,365	34,167,473	32,422,697	31,278,038	26,660,646	28,105,203	350,723,939
22	Nuclear	23,469,146	23,469,146	21,619,142	17,822,426	16,110,750	19,939,540	255,783,364
23	***Total***	84,777,426	83,724,627	77,439,766	72,473,597	62,268,756	62,588,894	831,294,491

Florida Power & Light Company
9/3/2003

Generating System Comparative Data by Fuel Type

		Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Total
	Generation Mix (%MWH)							
24	Heavy Oil	22.99%	22.44%	21.10%	22.46%	20.40%	12.90%	18.20%
25	Light Oil	0.62%	0.61%	0.64%	0.55%	0.07%	0.14%	0.41%
26	Coal	6.05%	6.05%	6.36%	6.99%	7.86%	8.05%	6.42%
27	Gas	46.61%	46.94%	48.05%	48.86%	49.98%	52.20%	48.76%
28	Nuclear	23.73%	23.96%	23.85%	21.14%	21.70%	26.70%	26.21%
29	***Total***	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
	Fuel Cost per Unit							
30	Heavy Oil ($/BBL)	26.3571	26.6340	26.9259	27.5511	27.5352	27.1976	26.9097
31	Light Oil ($/BBL)	36.3234	36.7806	37.4452	37.4042	39.0875	37.5121	36.8286
32	Coal ($/ton)	29.9297	29.9955	30.0323	29.7779	29.8926	30.0691	30.3872
33	Gas ($/MCF)	5.5916	5.6631	5.6139	5.6846	5.8990	6.1460	5.9010
34	Nuclear ($/MBTU)	0.2708	0.2700	0.2695	0.2707	0.2703	0.2802	0.2699
	Fuel Cost per MMBTU ($/MMBTU)							
35	Heavy Oil	4.1183	4.1616	4.2072	4.3049	4.3024	4.2496	4.2046
36	Light Oil	6.2304	6.3089	6.4228	6.4158	6.7047	6.4344	6.3171
37	Coal	1.5668	1.5703	1.5718	1.5578	1.5599	1.5683	1.5831
38	Gas	5.5916	5.6631	5.6139	5.6846	5.8990	6.1460	5.9010
39	Nuclear	0.2708	0.2700	0.2695	0.2707	0.2703	0.2802	0.2699
	BTU burned per KWH (BTU/KWH)							
40	Heavy Oil	10,046	10,038	10,061	10,092	10,107	10,225	10,080
41	Light Oil	14,240	14,285	14,297	14,748	10,675	13,308	14,490
42	Coal	9,803	9,803	9,802	9,801	9,743	9,743	9,779
43	Gas	8,222	8,181	8,186	8,305	7,756	7,859	8,068
44	Nuclear	11,008	11,008	10,997	10,939	10,795	10,903	10,950
	Generated Fuel Cost per KWH (cents/KWH)							
45	Heavy Oil	4.1371	4.1773	4.2328	4.3443	4.3483	4.3454	4.2384
46	Light Oil	8.8720	9.0124	9.1829	9.4619	7.1574	8.5629	9.1535
47	Coal	1.5358	1.5394	1.5407	1.5268	1.5197	1.5280	1.5481
48	Gas	4.5976	4.6332	4.5953	4.7212	4.5753	4.8299	4.7612
49	Nuclear	0.2981	0.2972	0.2964	0.2961	0.2918	0.3055	0.2956
50	***Total***	3.3131	3.3316	3.3287	3.5037	3.3614	3.2990	3.3074

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	398	25,030	11.8	95.2	46.6	11,080	Heavy Oil BBLS ->	37,697	6,399,993	241,260	1,113,228	4.4476
2			9,863					Gas MCF ->	145,357	1,000,000	145,357	949,397	9.6263
3													
4	TRKY O 2	398	17,140	9.4	95.0	44.5	11,656	Heavy Oil BBLS ->	26,282	6,399,989	168,206	776,153	4.5283
5			10,837					Gas MCF ->	157,893	1,000,000	157,893	1,032,038	9.5233
6													
7	TRKY N 3	717	520,110	97.5	97.5	100.0	11,180	Nuclear Othr ->	5,815,045	1,000,000	5,815,045	1,560,300	0.3000
8													
9	TRKY N 4	717	520,110	97.5	97.5	100.0	10,897	Nuclear Othr ->	5,667,426	1,000,000	5,667,426	1,561,700	0.3003
10													
11	FT LAUD4	440	265,291	81.0	94.3	85.8	8,136	Gas MCF ->	2,158,319	1,000,000	2,158,319	14,071,164	5.3041
12													
13	FT LAUD5	442	243,033	73.9	94.9	78.2	8,228	Gas MCF ->	1,999,652	1,000,000	1,999,652	13,036,692	5.3642
14													
15	PT EVER1	212	1,806	4.2	96.0	41.3	14,023	Heavy Oil BBLS ->	2,491	6,400,016	15,945	70,188	3.8855
16			4,769					Gas MCF ->	76,258	1,000,000	76,258	498,066	10.4445
17													
18	PT EVER2	212	2,711	5.6	95.8	43.0	12,617	Heavy Oil BBLS ->	3,286	6,400,073	21,033	92,495	3.4117
19			6,122					Gas MCF ->	90,417	1,000,000	90,417	590,426	9.6446
20													
21	PT EVER3	392	35,686	17.7	95.4	48.3	11,385	Heavy Oil BBLS ->	58,012	6,399,995	371,277	1,633,378	4.5771
22			16,037					Gas MCF ->	217,588	1,000,000	217,588	1,425,687	8.8899
23													
24	PT EVER4	398	77,988	32.0	95.3	63.0	10,342	Heavy Oil BBLS ->	120,481	6,400,002	771,078	3,392,196	4.3497
25			16,805					Gas MCF ->	209,268	1,000,000	209,268	1,369,252	8.1479
26													
27	RIV 3	284	9,728	8.1	93.7	46.8	10,673	Heavy Oil BBLS ->	10,551	6,400,032	67,526	300,025	3.0841
28			7,313					Gas MCF ->	114,356	1,000,000	114,356	746,427	10.2064
29													
30	RIV 4	286	44,577	51.8	93.1	57.9	10,817	Heavy Oil BBLS ->	72,846	6,399,996	466,217	2,071,533	4.6471
31			65,726					Gas MCF ->	726,931	1,000,000	726,931	4,779,785	7.2723
32													
33	ST LUC 1	853	618,763	97.5	97.5	100.0	10,718	Nuclear Othr ->	6,631,784	1,000,000	6,631,784	1,590,100	0.2570
34													

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
35	ST LUC 2	726	526,572	97.5	97.5	100.0	10,746	Nuclear Othr ->	5,658,438	1,000,000	5,658,438	1,580,200	0.3001
37	CAP CN 1	398	20,210	13.4	95.4	40.1	11,723	Heavy Oil BBLS ->	32,650	6,400,006	208,960	935,412	4.6286
38			19,323					Gas MCF ->	254,481	1,000,000	254,481	1,664,818	8.6159
40	CAP CN 2	398	57,603	23.7	95.2	53.1	10,446	Heavy Oil BBLS ->	88,300	6,400,001	565,121	2,529,784	4.3917
41			12,504					Gas MCF ->	167,245	1,000,000	167,245	1,093,485	8.7452
43	SANFRD 3	142	1,136	5.1	95.4	51.9	12,520	Heavy Oil BBLS ->	1,591	6,399,862	10,184	47,814	4.2105
44			4,240					Gas MCF ->	57,113	1,000,000	57,113	373,369	8.8069
46	PUTNAM 1	250	234	7.6	95.7	51.6	10,652	Light Oil BBLS ->	407	5,830,305	2,374	17,300	7.3995
47			13,915					Gas MCF ->	148,343	1,000,000	148,343	970,655	6.9757
49	PUTNAM 2	250	115	5.1	95.5	42.7	11,250	Light Oil BBLS ->	211	5,830,171	1,229	9,000	7.8534
50			9,411					Gas MCF ->	105,936	1,000,000	105,936	694,123	7.3757
52	MANATE 1	802	75,133	15.3	95.8	46.3	10,862	Heavy Oil BBLS ->	127,824	6,400,001	818,076	3,789,377	5.0435
53			15,917					Gas MCF ->	170,910	1,000,000	170,910	1,103,611	6.9337
55	MANATE 2	802	82,543	17.3	94.6	46.8	10,602	Heavy Oil BBLS ->	137,087	6,399,998	877,354	4,063,981	4.9235
56			20,470					Gas MCF ->	214,772	1,000,000	214,772	1,386,846	6.7750
58	CUTLER 5	70	2,842	5.5	97.8	60.1	14,126	Gas MCF ->	40,152	1,000,000	40,152	262,077	9.2206
60	CUTLER 6	142	4,714	4.5	97.1	46.8	12,496	Gas MCF ->	58,911	1,000,000	58,911	384,608	8.1583
62	MARTIN 1	813	59,925	16.1	96.2	52.6	10,782	Heavy Oil BBLS ->	98,102	6,400,002	627,850	2,823,831	4.7122
63			37,474					Gas MCF ->	422,325	1,000,000	422,325	2,780,315	7.4194
65	MARTIN 2	795	78,143	23.6	96.3	49.6	10,553	Heavy Oil BBLS ->	125,395	6,399,998	802,525	3,609,428	4.6190
66			61,176					Gas MCF ->	667,701	1,000,000	667,701	4,385,457	7.1686
68	MARTIN 3	465	219,169	63.4	94.7	76.2	7,380	Gas MCF ->	1,617,515	1,000,000	1,617,515	10,545,379	4.8115

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
69													
70	MARTIN 4	466	156,606	45.2	50.3	50.8	7,638	Gas MCF ->	1,196,197	1,000,000	1,196,197	7,798,558	4.9797
71													
72	FM GT	624	4,891	1.0	98.4	59.1	16,526	Light Oil BBLS ->	13,865	5,830,007	80,831	536,600	10.9712
73													
74	FL GT	768	3	1.9	91.8	63.4	16,358	Light Oil BBLS ->	7	5,797,297	43	300	10.7143
75			11,079					Gas MCF ->	181,239	1,000,000	181,239	1,184,931	10.6951
76													
77	PE GT	384	322	2.4	88.4	56.8	17,576	Light Oil BBLS ->	925	5,830,289	5,394	35,100	10.9176
78			6,553					Gas MCF ->	115,432	1,000,000	115,432	753,269	11.4950
79													
80	SJRPP 1O	130	85,962	88.9	93.7	97.5	9,633	Coal TONS ->	33,800	24,499,985	828,109	1,281,000	1.4902
81													
82	SJRPP 2O	130	87,111	90.1	93.9	98.4	9,495	Coal TONS ->	33,758	24,500,006	827,076	1,279,400	1.4687
83													
84	SCHER #4	648	382,170	79.3	93.5	86.9	9,825	Coal TONS ->	214,557	17,500,002	3,754,753	6,480,000	1.6956
85													
86	FMREP 1	1,467	751,558	68.9	85.9	78.5	7,152	Gas MCF ->	5,374,896	1,000,000	5,374,896	35,041,502	4.6625
87													
88	SNREP4	950	531,053	75.1	94.7	85.4	6,957	Gas MCF ->	3,694,610	1,000,000	3,694,610	24,086,954	4.5357
89													
90	SNREP5	950	470,236	66.5	95.2	76.2	7,129	Gas MCF ->	3,352,105	1,000,000	3,352,105	21,864,159	4.6496
91													
92	FM SC	326	319	12.7	97.2	74.8	10,593	Light Oil BBLS ->	553	5,830,407	3,221	21,400	6.7064
93			30,427					Gas MCF ->	322,476	1,000,000	322,476	2,106,188	6.9222
94													
95	MR SC	326	221	15.2	96.6	75.2	10,946	Light Oil BBLS ->	394	5,830,629	2,300	17,500	7.9365
96			36,659					Gas MCF ->	401,391	1,000,000	401,391	2,621,085	7.1499
97													
98	TOTAL	18,971	6,397,378				9,343				59,770,420	202,819,044	3.1703

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Feb-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	398	30,915	14.8	95.2	49.6	10,802	Heavy Oil BBLS ->	46,132	6,399,997	295,244	1,385,885	4.4829
2			10,104					Gas MCF ->	147,847	1,000,000	147,847	958,344	9.4852
3													
4	TRKY O 2	398	18,419	10.6	95.0	44.8	11,619	Heavy Oil BBLS ->	28,185	6,400,011	180,381	846,671	4.5966
5			10,865					Gas MCF ->	159,873	1,000,000	159,873	1,036,912	9.5434
6													
7	TRKY N 3	717	486,554	97.5	97.5	100.0	11,180	Nuclear Othr ->	5,439,881	1,000,000	5,439,881	1,454,900	0.2990
8													
9	TRKY N 4	717	486,554	97.5	97.5	100.0	10,897	Nuclear Othr ->	5,301,778	1,000,000	5,301,778	1,456,300	0.2993
10													
11	FT LAUD4	440	159,754	52.2	61.4	84.3	8,169	Gas MCF ->	1,304,968	1,000,000	1,304,968	8,450,073	5.2894
12													
13	FT LAUD5	442	230,272	74.9	94.9	79.2	8,206	Gas MCF ->	1,889,639	1,000,000	1,889,639	12,235,943	5.3137
14													
15	PT EVER1	212	2,632	5.3	96.0	43.2	13,522	Heavy Oil BBLS ->	3,610	6,399,934	23,104	100,746	3.8279
16			5,205					Gas MCF ->	82,871	1,000,000	82,871	537,494	10.3259
17													
18	PT EVER2	212	3,213	5.2	72.7	46.7	11,757	Heavy Oil BBLS ->	3,861	6,399,974	24,707	107,734	3.3530
19			4,389					Gas MCF ->	64,667	1,000,000	64,667	419,620	9.5616
20													
21	PT EVER3	392	49,089	22.8	95.4	53.7	10,973	Heavy Oil BBLS ->	78,662	6,399,999	503,435	2,194,547	4.4706
22			13,141					Gas MCF ->	179,389	1,000,000	179,389	1,168,765	8.8942
23													
24	PT EVER4	398	94,613	39.4	95.3	70.3	10,159	Heavy Oil BBLS ->	144,876	6,399,999	927,207	4,041,797	4.2719
25			14,630					Gas MCF ->	182,605	1,000,000	182,605	1,184,963	8.0995
26													
27	RIV 3	284	49,521	54.9	93.7	61.4	10,855	Heavy Oil BBLS ->	81,409	6,400,003	521,017	2,320,502	4.6859
28			58,951					Gas MCF ->	656,443	1,000,000	656,443	4,292,489	7.2814
29													
30	RIV 4	286	9,814	8.7	93.1	45.5	11,313	Heavy Oil BBLS ->	11,394	6,399,982	72,918	324,786	3.3095
31			7,488					Gas MCF ->	122,822	1,000,000	122,822	796,185	10.6324
32													
33	ST LUC 1	853	578,843	97.5	97.5	100.0	10,718	Nuclear Othr ->	6,203,932	1,000,000	6,203,932	1,482,600	0.2561
34													

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Feb-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
35	ST LUC 2	726	492,599	97.5	97.5	100.0	10,746	Nuclear Othr ->	5,293,375	1,000,000	5,293,375	1,473,500	0.2991
37	CAP CN 1	398	34,090	16.4	95.3	48.4	10,868	Heavy Oil BBLS ->	53,552	6,399,996	342,729	1,513,306	4.4391
38			11,238					Gas MCF ->	149,924	1,000,000	149,924	972,694	8.6551
40	CAP CN 2	398	71,061	29.3	95.1	58.8	10,176	Heavy Oil BBLS ->	107,671	6,400,003	689,097	3,042,666	4.2818
41			10,104					Gas MCF ->	136,856	1,000,000	136,856	887,649	8.7849
43	SANFRD 3	142	1,036	5.5	95.4	50.1	12,624	Heavy Oil BBLS ->	1,452	6,399,821	9,295	44,468	4.2944
44			4,357					Gas MCF ->	58,783	1,000,000	58,783	382,033	8.7680
46	PUTNAM 1	250	158	7.2	79.2	46.3	11,147	Light Oil BBLS ->	288	5,829,920	1,680	12,200	7.7166
47			12,363					Gas MCF ->	137,888	1,000,000	137,888	893,719	7.2293
49	PUTNAM 2	250	9	4.6	79.1	37.0	11,982	Light Oil BBLS ->	17	5,823,529	99	700	8.0460
50			8,080					Gas MCF ->	96,821	1,000,000	96,821	628,396	7.7773
52	MANATE 1	802	57,885	12.1	95.8	47.1	10,874	Heavy Oil BBLS ->	98,637	6,400,003	631,276	2,942,389	5.0832
53			9,493					Gas MCF ->	101,409	1,000,000	101,409	650,518	6.8525
55	MANATE 2	802	37,180	7.7	42.4	47.8	10,518	Heavy Oil BBLS ->	61,210	6,400,003	391,745	1,825,903	4.9110
56			5,992					Gas MCF ->	62,356	1,000,000	62,356	399,997	6.6752
58	CUTLER 5	70	2,932	6.0	97.8	58.7	14,269	Gas MCF ->	41,838	1,000,000	41,838	270,897	9.2387
60	CUTLER 6	142	4,732	4.8	97.0	45.2	12,574	Gas MCF ->	59,504	1,000,000	59,504	385,271	8.1415
62	MARTIN 1	813	49,401	14.2	96.2	52.5	10,785	Heavy Oil BBLS ->	80,597	6,399,999	515,823	2,326,870	4.7102
63			30,717					Gas MCF ->	348,287	1,000,000	348,287	2,281,506	7.4275
65	MARTIN 2	795	78,629	24.3	96.3	49.0	10,502	Heavy Oil BBLS ->	125,687	6,400,000	804,395	3,628,657	4.6149
66			55,902					Gas MCF ->	608,498	1,000,000	608,498	3,969,637	7.1011
68	MARTIN 3	465	196,654	60.8	94.7	74.2	7,415	Gas MCF ->	1,458,120	1,000,000	1,458,120	9,441,773	4.8012

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Feb-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
69													
70	MARTIN 4	466	215,373	66.4	94.5	75.9	7,293	Gas MCF ->	1,570,669	1,000,000	1,570,669	10,170,498	4.7223
71													
72	FM GT	624	1,980	0.5	98.4	57.4	16,715	Light Oil BBLS ->	5,677	5,830,007	33,095	218,700	11.0455
73													
74	FL GT	768	0	1.6	91.8	62.7	16,385	Light Oil BBLS ->	0		0	0	
75			8,400					Gas MCF ->	137,638	1,000,000	137,638	897,132	10.6800
76													
77	PE GT	384	0	2.6	88.4	54.9	17,863	Light Oil BBLS ->	0	8,000,000	1	0	
78			6,948					Gas MCF ->	124,115	1,000,000	124,115	807,649	11.6239
79													
80	SJRPP 1O	130	78,790	87.1	93.6	96.8	9,636	Coal TONS ->	31,040	24,459,997	759,233	1,196,000	1.5180
81													
82	SJRPP 2O	130	74,064	81.9	87.4	97.6	9,498	Coal TONS ->	28,759	24,459,986	703,433	1,108,100	1.4961
83													
84	SCHER #4	648	324,594	72.0	87.1	86.3	9,827	Coal TONS ->	182,279	17,500,004	3,189,880	5,250,700	1.6176
85													
86	FMREP 1	1,467	773,299	75.7	88.6	83.1	7,111	Gas MCF ->	5,498,777	1,000,000	5,498,777	35,606,162	4.6045
87													
88	SNREP4	950	487,432	73.7	94.7	84.0	7,009	Gas MCF ->	3,416,324	1,000,000	3,416,324	22,121,644	4.5384
89													
90	SNREP5	950	407,025	61.6	95.2	71.8	7,247	Gas MCF ->	2,949,510	1,000,000	2,949,510	19,106,355	4.6941
91													
92	FM SC	326	0	13.5	97.1	74.2	10,599	Light Oil BBLS ->	0		0	0	
93			30,580					Gas MCF ->	324,100	1,000,000	324,100	2,098,671	6.8630
94													
95	MR SC	326	0	17.8	96.6	74.3	10,949	Light Oil BBLS ->	0		0	0	
96			40,320					Gas MCF ->	441,479	1,000,000	441,479	2,862,496	7.0995
97													
98	TOTAL	18,971	5,948,382				9,309				55,372,779	186,216,109	3.1305

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Mar-04

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Plant Unit	Net Capb (MW)	Net Gen (MWH)	Capac FAC (%)	Equiv Avail FAC (%)	Net Out FAC (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Type	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (C/KWH)
1	TRKY O 1	398	80,789	31.2	95.2	68.7	9,850	Heavy Oil BBLS ->	117,917	6,400,000	754,669	3,295,736	4.0794
2			11,461					Gas MCF ->	153,992	1,000,000	153,992	967,931	8.4455
3													
4	TRKY O 2	398	70,318	27.9	95.0	69.5	9,962	Heavy Oil BBLS ->	103,177	6,400,003	660,334	2,883,831	4.1011
5			12,419					Gas MCF ->	163,862	1,000,000	163,862	1,030,217	8.2956
6													
7	TRKY N 3	717	520,110	97.5	97.5	100.0	11,180	Nuclear Othr ->	5,815,045	1,000,000	5,815,045	1,550,200	0.2981
8													
9	TRKY N 4	717	520,110	97.5	97.5	100.0	10,897	Nuclear Othr ->	5,667,426	1,000,000	5,667,426	1,551,700	0.2983
10													
11	FT LAUD4	440		0.0	0.0		0						
12													
13	FT LAUD5	442	280,697	85.4	94.9	90.3	7,971	Gas MCF ->	2,237,467	1,000,000	2,237,467	14,042,977	5.0029
14													
15	PT EVER1	212	16,248	14.0	96.0	66.3	10,173	Heavy Oil BBLS ->	21,414	6,400,002	137,049	557,650	3.4322
16			5,771					Gas MCF ->	86,944	1,000,000	86,944	546,660	9.4729
17													
18	PT EVER2	212		0.0	0.0		0						
19													
20	PT EVER3	392	108,796	41.0	95.4	70.4	10,332	Heavy Oil BBLS ->	170,644	6,400,002	1,092,124	4,443,603	4.0843
21			10,706					Gas MCF ->	142,610	1,000,000	142,610	908,914	8.4897
22													
23	PT EVER4	398	146,791	54.2	95.3	82.2	9,923	Heavy Oil BBLS ->	222,579	6,400,001	1,424,506	5,795,922	3.9484
24			13,839					Gas MCF ->	169,407	1,000,000	169,407	1,067,265	7.7121
25													
26	RIV 3	284	26,842	16.5	93.7	65.9	10,432	Heavy Oil BBLS ->	36,455	6,399,993	233,312	981,387	3.6562
27			8,016					Gas MCF ->	130,314	1,000,000	130,314	819,013	10.2174
28													
29	RIV 4	286	66,865	67.0	93.1	75.4	10,456	Heavy Oil BBLS ->	138,600	6,399,999	887,037	3,731,262	4.2955
30			55,717					Gas MCF ->	603,850	1,000,000	603,850	3,848,856	6.9079
31													
32	ST LUC 1	853	419,163	66.0	66.0	100.0	10,718	Nuclear Othr ->	4,492,526	1,000,000	4,492,526	1,070,000	0.2553
33													
34	ST LUC 2	726	526,572	97.5	97.5	100.0	10,746	Nuclear Othr ->	5,658,438	1,000,000	5,658,438	1,570,000	0.2982

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Mar-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
35													
36	CAP CN 1	398	91,866	35.1	95.4	65.3	10,165	Heavy Oil BBLS ->	140,640	6,400,001	900,094	3,684,663	4.0109
37			12,187					Gas MCF ->	157,567	1,000,000	157,567	992,406	8.1429
38													
39	CAP CN 2	398	125,938	45.7	95.2	73.6	9,804	Heavy Oil BBLS ->	188,231	6,399,999	1,204,678	4,931,464	3.9158
40			9,354					Gas MCF ->	121,662	1,000,000	121,662	766,039	8.1896
41													
42	SANFRD 3	142	2,824	6.5	58.5	55.5	11,477	Heavy Oil BBLS ->	3,918	6,400,082	25,074	117,029	4.1448
43			4,096					Gas MCF ->	54,347	1,000,000	54,347	342,768	8.3675
44													
45	PUTNAM 1	250	1,675	21.6	95.7	68.0	9,522	Light Oil BBLS ->	2,611	5,829,969	15,220	109,600	6.5429
46			38,557					Gas MCF ->	367,863	1,000,000	367,863	2,326,869	6.0349
47													
48	PUTNAM 2	250	486	10.0	95.5	52.3	10,303	Light Oil BBLS ->	819	5,829,691	4,775	34,400	7.0782
49			18,038					Gas MCF ->	186,077	1,000,000	186,077	1,177,840	6.5297
50													
51	MANATE 1	802	58,627	10.7	95.8	54.6	10,758	Heavy Oil BBLS ->	98,682	6,399,998	631,567	2,873,947	4.9021
52			4,921					Gas MCF ->	52,064	1,000,000	52,064	323,759	6.5789
53													
54	MANATE 2	802		0.0	0.0		0						
55													
56	CUTLER 5	70	3,351	6.4	97.8	59.8	13,467	Gas MCF ->	45,130	1,000,000	45,130	283,270	8.4528
57													
58	CUTLER 6	142	6,808	6.4	97.1	46.5	11,883	Gas MCF ->	80,901	1,000,000	80,901	507,737	7.4581
59													
60	MARTIN 1	813	150,860	38.4	96.2	59.1	10,587	Heavy Oil BBLS ->	244,698	6,399,999	1,566,065	6,638,682	4.4006
61			81,166					Gas MCF ->	890,461	1,000,000	890,461	5,729,525	7.0590
62													
63	MARTIN 2	795	162,255	43.9	96.3	59.7	10,380	Heavy Oil BBLS ->	257,926	6,399,999	1,650,726	6,997,620	4.3127
64			97,490					Gas MCF ->	1,045,428	1,000,000	1,045,428	6,604,685	6.7747
65													
66	MARTIN 3	465	273,244	79.0	94.7	87.9	7,195	Gas MCF ->	1,965,950	1,000,000	1,965,950	12,338,804	4.5157
67													
68	MARTIN 4	466	270,401	78.0	94.5	89.5	7,088	Gas MCF ->	1,916,678	1,000,000	1,916,678	12,029,634	4.4488

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Mar-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
69													
70	FM GT	624	2,323	0.5	98.4	57.5	16,699	Light Oil BBLS ->	6,655	5,829,977	38,799	256,400	11.0360
71													
72	FL GT	768	35	1.4	91.8	63.0	16,370	Light Oil BBLS ->	93	5,831,545	544	3,700	10.6017
73			7,787					Gas MCF ->	127,502	1,000,000	127,502	801,709	10.2955
74													
75	PE GT	384	66	2.4	88.4	55.4	17,781	Light Oil BBLS ->	193	5,829,610	1,122	7,300	11.0272
76			6,644					Gas MCF ->	118,191	1,000,000	118,191	742,041	11.1689
77													
78	SJRPP 1O	130	86,087	89.0	93.7	99.1	9,635	Coal TONS ->	33,937	24,439,978	829,407	1,314,100	1.5265
79													
80	SJRPP 2O	130		0.0	0.0		0						
81													
82	SCHER #4	648		0.0	0.0		0						
83													
84	FMREP 1	1,467	904,133	82.8	94.7	91.9	7,025	Gas MCF ->	6,351,963	1,000,000	6,351,963	39,866,619	4.4094
85													
86	SNREP4	950	589,805	83.4	94.7	94.1	6,833	Gas MCF ->	4,029,863	1,000,000	4,029,863	25,294,812	4.2887
87													
88	SNREP5	950	516,140	73.0	86.0	82.6	6,984	Gas MCF ->	3,604,538	1,000,000	3,604,538	22,673,644	4.3929
89													
90	FM SC	326	4	12.2	97.2	74.3	10,598	Light Oil BBLS ->	7	5,819,444	42	300	7.3171
91			29,696					Gas MCF ->	314,737	1,000,000	314,737	1,975,415	6.6520
92													
93	MR SC	326	228	20.4	96.6	75.6	10,947	Light Oil BBLS ->	408	5,830,184	2,376	18,100	7.9456
94			49,250					Gas MCF ->	539,258	1,000,000	539,258	3,384,522	6.8721
95													
96	TOTAL	18,971	6,527,571				9,092				59,351,578	215,812,524	3.3062
		=======	=======				=======				=======	=======	=======

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Apr-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	63,365	25.6	95.2	58.8	10,381	Heavy Oil BBLS ->	98,513	6,400,001	630,486	2,658,432	4.1954
2			9,134					Gas MCF ->	122,153	1,000,000	122,153	724,672	7.9342
3													
4	TRKY O 2	394	71,283	28.1	72.9	66.0	10,149	Heavy Oil BBLS ->	109,366	6,400,000	699,941	2,951,341	4.1403
5			8,293					Gas MCF ->	107,647	1,000,000	107,647	638,193	7.6959
6													
7	TRKY N 3	693	486,491	97.5	97.5	100.0	11,233	Nuclear Othr ->	5,464,564	1,000,000	5,464,564	1,452,300	0.2985
8													
9	TRKY N 4	693	486,491	97.5	97.5	100.0	11,244	Nuclear Othr ->	5,470,288	1,000,000	5,470,288	1,493,300	0.3070
10													
11	FT LAUD4	422	110,468	36.4	46.6	88.8	8,052	Gas MCF ->	889,470	1,000,000	889,470	5,268,147	4.7689
12													
13	FT LAUD5	424	264,675	86.7	94.9	91.8	7,811	Gas MCF ->	2,067,269	1,000,000	2,067,269	12,244,063	4.6261
14													
15	PT EVER1	211	17,171	17.1	96.0	53.0	11,826	Heavy Oil BBLS ->	28,235	6,400,002	180,702	721,868	4.2040
16			8,848					Gas MCF ->	127,000	1,000,000	127,000	772,040	8.7259
17													
18	PT EVER2	211	2,479	4.4	57.5	42.4	12,856	Heavy Oil BBLS ->	3,975	6,400,075	25,440	101,599	4.0987
19			4,165					Gas MCF ->	59,973	1,000,000	59,973	362,328	8.6989
20													
21	PT EVER3	390	114,243	47.0	95.4	75.9	10,129	Heavy Oil BBLS ->	176,207	6,399,999	1,127,721	4,505,301	3.9436
22			17,710					Gas MCF ->	208,820	1,000,000	208,820	1,261,854	7.1250
23													
24	PT EVER4	394	95,444	39.2	95.3	70.4	10,399	Heavy Oil BBLS ->	150,211	6,400,000	961,350	3,840,628	4.0240
25			15,822					Gas MCF ->	195,733	1,000,000	195,733	1,186,779	7.5007
26													
27	RIV 3	282	64,464	57.5	93.7	76.1	10,527	Heavy Oil BBLS ->	103,270	6,400,000	660,930	2,708,069	4.2009
28			52,328					Gas MCF ->	568,525	1,000,000	568,525	3,434,918	6.5642
29													
30	RIV 4	284	42,763	24.2	93.1	69.3	10,256	Heavy Oil BBLS ->	62,016	6,400,000	396,901	1,626,211	3.8029
31			6,687					Gas MCF ->	110,246	1,000,000	110,246	653,814	9.7777
32													
33	ST LUC 1	839	294,489	48.7	48.7	100.0	10,816	Nuclear Othr ->	3,185,243	1,000,000	3,185,243	859,300	0.2918
34													

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Apr-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
35	ST LUC 2	714	501,219	97.5	97.5	100.0	10,787	Nuclear Othr ->	5,406,805	1,000,000	5,406,805	1,495,600	0.2984
37	CAP CN 1	394	75,441	31.9	95.4	60.7	10,226	Heavy Oil BBLS ->	115,967	6,400,002	742,191	2,978,603	3.9483
38			15,128					Gas MCF ->	183,985	1,000,000	183,985	1,109,345	7.3331
40	CAP CN 2	394	94,268	36.6	95.2	63.5	10,018	Heavy Oil BBLS ->	143,089	6,400,001	915,772	3,675,275	3.8987
41			9,605					Gas MCF ->	124,797	1,000,000	124,797	740,628	7.7105
43	SANFRD 3	138		0.0	0.0		0						
45	PUTNAM 1	239	1,364	24.6	95.7	68.7	10,857	Light Oil BBLS ->	2,423	5,830,038	14,126	100,200	7.3460
46			40,995					Gas MCF ->	445,764	1,000,000	445,764	2,693,773	6.5709
48	PUTNAM 2	239	1,335	25.0	95.5	64.5	10,498	Light Oil BBLS ->	2,292	5,829,879	13,362	94,800	7.1038
49			41,730					Gas MCF ->	438,712	1,000,000	438,712	2,642,890	6.3333
51	MANATE 1	795	133,769	26.8	95.8	50.8	10,598	Heavy Oil BBLS ->	221,664	6,399,999	1,418,646	6,157,899	4.6034
52			19,356					Gas MCF ->	204,104	1,000,000	204,104	1,198,087	6.1898
54	MANATE 2	795		0.0	6.3		0						
56	CUTLER 5	68	7,973	16.3	97.8	62.3	14,147	Gas MCF ->	112,799	1,000,000	112,799	668,099	8.3792
58	CUTLER 6	138	13,714	13.8	97.0	49.4	12,870	Gas MCF ->	176,499	1,000,000	176,499	1,045,425	7.6233
60	MARTIN 1	807	152,928	43.2	96.2	54.8	10,378	Heavy Oil BBLS ->	243,103	6,399,999	1,555,857	6,398,171	4.1838
61			97,806					Gas MCF ->	1,046,243	1,000,000	1,046,243	6,216,735	6.3562
63	MARTIN 2	792	150,456	46.8	96.3	48.9	10,377	Heavy Oil BBLS ->	238,741	6,400,000	1,527,942	6,283,403	4.1762
64			116,238					Gas MCF ->	1,239,465	1,000,000	1,239,465	7,390,261	6.3579
66	MARTIN 3	443	260,061	81.5	94.7	91.2	7,230	Gas MCF ->	1,880,230	1,000,000	1,880,230	11,136,244	4.2822
68	MARTIN 4	443	266,239	83.5	94.5	91.7	7,196	Gas MCF ->	1,915,959	1,000,000	1,915,959	11,347,923	4.2623

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Apr-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
69													
70	FM GT	552	38,002	9.6	90.8	65.6	15,146	Light Oil BBLS ->	98,727	5,829,998	575,579	3,608,900	9.4966
71													
72	FL GT	684	83	12.2	91.8	70.7	17,462	Light Oil BBLS ->	237	5,830,165	1,380	9,400	11.3253
73			59,838					Gas MCF ->	1,044,975	1,000,000	1,044,975	6,189,248	10.3433
74													
75	PE GT	348	244	11.7	88.4	62.4	18,959	Light Oil BBLS ->	757	5,830,184	4,412	28,600	11.7117
76			28,617					Gas MCF ->	542,759	1,000,000	542,759	3,219,685	11.2511
77													
78	SJRPP 1O	127	81,417	89.0	93.7	99.0	9,456	Coal TONS ->	31,513	24,430,004	769,855	1,180,800	1.4503
79													
80	SJRPP 2O	127	11,197	12.2	15.6	97.8	9,326	Coal TONS ->	4,274	24,430,012	104,421	160,100	1.4298
81													
82	SCHER #4	643	216,753	46.8	59.2	86.5	9,992	Coal TONS ->	123,759	17,499,994	2,165,773	3,497,800	1.6137
83													
84	FMREP 1	1,423	861,186	84.1	94.6	93.2	7,131	Gas MCF ->	6,140,900	1,000,000	6,140,900	36,371,536	4.2234
85													
86	SNREP4	888	533,445	83.4	94.7	93.8	6,937	Gas MCF ->	3,700,343	1,000,000	3,700,343	21,930,848	4.1112
87													
88	SNREP5	888	507,890	79.4	95.2	91.0	7,019	Gas MCF ->	3,564,855	1,000,000	3,564,855	21,280,509	4.1900
89													
90	FM SC	298	107	22.3	97.2	81.2	10,544	Light Oil BBLS ->	184	5,829,718	1,075	6,700	6.2617
91			47,663					Gas MCF ->	502,605	1,000,000	502,605	2,976,966	6.2458
92													
93	MR SC	298	68	29.8	96.6	81.4	10,526	Light Oil BBLS ->	117	5,830,494	685	5,200	7.6135
94			63,922					Gas MCF ->	672,862	1,000,000	672,862	3,985,238	6.2346
95													
96	TOTAL	18,306	6,686,867				9,334				62,416,132	227,290,046	3.3991

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : May-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	86,996	33.7	95.2	57.1	10,321	Heavy Oil BBLS ->	135,271	6,399,998	865,736	3,605,479	4.1444
2			11,652					Gas MCF ->	152,441	1,000,000	152,441	869,231	7.4600
3													
4	TRKY O 2	394	51,686	19.6	52.1	65.3	10,111	Heavy Oil BBLS ->	79,227	6,399,996	507,051	2,111,684	4.0856
5			5,815					Gas MCF ->	74,345	1,000,000	74,345	423,846	7.2888
6													
7	TRKY N 3	693	502,707	97.5	97.5	100.0	11,233	Nuclear Othr ->	5,646,720	1,000,000	5,646,720	1,495,800	0.2975
8													
9	TRKY N 4	693	502,707	97.5	97.5	100.0	11,244	Nuclear Othr ->	5,652,632	1,000,000	5,652,632	1,538,100	0.3060
10													
11	FT LAUD4	422	277,439	88.4	94.3	93.6	7,956	Gas MCF ->	2,207,291	1,000,000	2,207,291	12,584,947	4.5361
12													
13	FT LAUD5	424	270,181	85.6	94.9	90.7	7,834	Gas MCF ->	2,116,497	1,000,000	2,116,497	12,067,256	4.4664
14													
15	PT EVER1	211	5,437	10.4	96.0	40.4	12,588	Heavy Oil BBLS ->	9,209	6,400,024	58,939	236,185	4.3441
16			10,889					Gas MCF ->	146,572	1,000,000	146,572	863,291	7.9284
17													
18	PT EVER2	211	19,760	18.2	95.8	55.8	11,069	Heavy Oil BBLS ->	30,851	6,399,992	197,444	791,093	4.0034
19			8,868					Gas MCF ->	119,445	1,000,000	119,445	696,967	7.8592
20													
21	PT EVER3	390	139,217	57.2	95.4	68.8	10,149	Heavy Oil BBLS ->	216,421	6,400,000	1,385,095	5,549,788	3.9864
22			26,880					Gas MCF ->	300,643	1,000,000	300,643	1,725,554	6.4196
23													
24	PT EVER4	394	127,045	49.4	95.3	67.4	10,366	Heavy Oil BBLS ->	200,649	6,400,000	1,284,151	5,145,340	4.0500
25			17,847					Gas MCF ->	217,808	1,000,000	217,808	1,255,885	7.0370
26													
27	RIV 3	282	39,735	24.7	93.7	54.4	10,976	Heavy Oil BBLS ->	62,742	6,400,000	401,551	1,633,238	4.1103
28			12,089					Gas MCF ->	167,242	1,000,000	167,242	954,928	7.8995
29													
30	RIV 4	284	81,454	67.3	93.1	74.6	10,259	Heavy Oil BBLS ->	127,389	6,399,999	815,290	3,316,104	4.0711
31			60,723					Gas MCF ->	643,329	1,000,000	643,329	3,735,717	6.1521
32													
33	ST LUC 1	839	608,613	97.5	97.5	100.0	10,816	Nuclear Othr ->	6,582,768	1,000,000	6,582,768	1,818,100	0.2987
34													

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : May-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
35	ST LUC 2	714	517,926	97.5	97.5	100.0	10,787	Nuclear Othr ->	5,587,028	1,000,000	5,587,028	1,540,400	0.2974
37	CAP CN 1	394	61,250	26.8	95.4	58.9	10,322	Heavy Oil BBLS ->	94,366	6,400,001	603,941	2,415,921	3.9444
38			17,273					Gas MCF ->	206,541	1,000,000	206,541	1,201,160	6.9542
40	CAP CN 2	394	82,054	32.1	95.2	65.1	10,052	Heavy Oil BBLS ->	124,301	6,400,001	795,525	3,182,346	3.8784
41			11,969					Gas MCF ->	149,560	1,000,000	149,560	858,351	7.1713
43	SANFRD 3	138		0.0	0.0		0						
45	PUTNAM 1	239	117	27.6	95.7	81.6	10,281	Light Oil BBLS ->	197	5,828,673	1,147	8,100	6.9172
46			48,932					Gas MCF ->	503,129	1,000,000	503,129	2,931,447	5.9909
48	PUTNAM 2	239	117	28.9	95.5	80.9	9,838	Light Oil BBLS ->	188	5,830,679	1,099	7,800	6.6553
49			51,204					Gas MCF ->	503,792	1,000,000	503,792	2,931,648	5.7255
51	MANATE 1	795	179,005	38.3	95.8	43.1	10,698	Heavy Oil BBLS ->	299,209	6,400,000	1,914,934	7,976,663	4.4561
52			47,394					Gas MCF ->	507,006	1,000,000	507,006	2,863,780	6.0425
54	MANATE 2	795	143,741	38.4	94.6	40.8	10,596	Heavy Oil BBLS ->	238,083	6,400,001	1,523,728	6,347,094	4.4157
55			83,170					Gas MCF ->	880,716	1,000,000	880,716	4,974,614	5.9812
57	CUTLER 5	68	6,744	13.3	97.8	60.9	13,580	Gas MCF ->	91,589	1,000,000	91,589	522,192	7.7426
59	CUTLER 6	138	11,367	11.1	97.1	47.3	12,696	Gas MCF ->	144,316	1,000,000	144,316	822,783	7.2382
61	MARTIN 1	807	172,433	49.5	96.2	51.8	10,433	Heavy Oil BBLS ->	275,317	6,400,000	1,762,027	7,177,175	4.1623
62			125,006					Gas MCF ->	1,341,264	1,000,000	1,341,264	7,658,046	6.1261
64	MARTIN 2	792	109,122	35.0	96.3	44.3	10,448	Heavy Oil BBLS ->	173,931	6,400,001	1,113,158	4,534,157	4.1551
65			97,083					Gas MCF ->	1,041,203	1,000,000	1,041,203	5,988,932	6.1689
67	MARTIN 3	443	258,093	78.3	94.7	90.4	7,244	Gas MCF ->	1,869,528	1,000,000	1,869,528	10,659,109	4.1299

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : May-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
69	MARTIN 4	443	262,066	79.5	94.5	90.4	7,216	Gas MCF ->	1,891,019	1,000,000	1,891,019	10,781,669	4.1141
71	FM GT	552	40,442	9.8	91.0	65.2	15,184	Light Oil BBLS ->	105,328	5,830,002	614,061	3,797,300	9.3895
73	FL GT	684	4	11.3	91.8	70.2	17,482	Light Oil BBLS ->	12	5,852,459	71	500	11.6279
74			57,571					Gas MCF ->	1,006,448	1,000,000	1,006,448	5,738,238	9.9672
76	PE GT	348	24	10.1	88.4	61.4	19,084	Light Oil BBLS ->	74	5,830,393	430	2,800	11.8644
77			25,708					Gas MCF ->	490,636	1,000,000	490,636	2,797,395	10.8813
79	SJRPP 1O	127	82,317	87.1	93.7	98.3	9,457	Coal TONS ->	31,826	24,460,000	778,466	1,176,500	1.4292
81	SJRPP 2O	127	83,157	88.0	93.9	98.5	9,318	Coal TONS ->	31,679	24,459,986	774,868	1,171,100	1.4083
83	SCHER #4	643	369,241	77.2	93.5	86.8	9,988	Coal TONS ->	210,738	17,500,003	3,687,909	5,870,200	1.5898
85	FMREP 1	1,423	854,428	80.7	94.7	92.2	7,146	Gas MCF ->	6,105,446	1,000,000	6,105,446	34,810,333	4.0741
87	SNREP4	888	544,501	82.4	94.7	93.7	6,937	Gas MCF ->	3,777,155	1,000,000	3,777,155	21,553,543	3.9584
89	SNREP5	888	510,670	77.3	95.2	89.3	7,047	Gas MCF ->	3,598,437	1,000,000	3,598,437	20,730,032	4.0594
91	FM SC	298	208	14.3	97.2	80.6	10,541	Light Oil BBLS ->	358	5,830,215	2,088	12,900	6.2049
92			31,569					Gas MCF ->	332,869	1,000,000	332,869	1,897,935	6.0121
94	MR SC	298	35	16.8	96.6	80.7	10,525	Light Oil BBLS ->	60	5,832,215	348	2,600	7.4928
95			37,254					Gas MCF ->	392,120	1,000,000	392,120	2,235,662	6.0011
97	TOTAL	18,306	7,790,934				9,439				73,536,586	249,598,960	3.2037

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jun-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	105,048	39.9	95.2	65.0	10,167	Heavy Oil BBLS ->	161,985	6,400,000	1,036,703	4,330,305	4.1222
2			8,265					Gas MCF ->	115,348	1,000,000	115,348	656,022	7.9371
3													
4	TRKY O 2	394	129,487	49.3	95.0	72.1	9,993	Heavy Oil BBLS ->	197,408	6,400,000	1,263,410	5,277,170	4.0754
5			10,374					Gas MCF ->	134,203	1,000,000	134,203	763,352	7.3586
6													
7	TRKY N 3	693	486,491	97.5	97.5	100.0	11,233	Nuclear Othr ->	5,464,564	1,000,000	5,464,564	1,443,000	0.2966
8													
9	TRKY N 4	693	486,491	97.5	97.5	100.0	11,244	Nuclear Othr ->	5,470,288	1,000,000	5,470,288	1,483,900	0.3050
10													
11	FT LAUD4	422	274,439	90.3	94.3	95.6	7,916	Gas MCF ->	2,172,398	1,000,000	2,172,398	12,355,035	4.5019
12													
13	FT LAUD5	424	270,153	88.5	94.9	93.7	7,774	Gas MCF ->	2,100,253	1,000,000	2,100,253	11,944,757	4.4215
14													
15	PT EVER1	211	24,918	23.6	96.0	54.3	11,411	Heavy Oil BBLS ->	40,833	6,400,000	261,328	1,058,744	4.2489
16			10,869					Gas MCF ->	147,029	1,000,000	147,029	862,795	7.9384
17													
18	PT EVER2	211	43,186	33.2	95.8	69.9	10,439	Heavy Oil BBLS ->	66,308	6,400,005	424,372	1,719,204	3.9809
19			7,207					Gas MCF ->	101,703	1,000,000	101,703	588,570	8.1672
20													
21	PT EVER3	390	165,528	66.9	95.4	72.3	10,000	Heavy Oil BBLS ->	256,493	6,400,001	1,641,553	6,650,405	4.0177
22			22,298					Gas MCF ->	236,693	1,000,000	236,693	1,360,507	6.1016
23													
24	PT EVER4	394	147,765	57.1	95.3	73.5	10,250	Heavy Oil BBLS ->	231,852	6,400,000	1,483,852	6,011,503	4.0683
25			14,102					Gas MCF ->	175,259	1,000,000	175,259	1,009,299	7.1570
26													
27	RIV 3	282	87,197	71.9	93.7	78.6	10,462	Heavy Oil BBLS ->	139,368	6,400,001	891,957	3,650,858	4.1869
28			58,726					Gas MCF ->	634,655	1,000,000	634,655	3,696,204	6.2940
29													
30	RIV 4	284	63,834	34.6	93.1	68.4	10,324	Heavy Oil BBLS ->	97,233	6,400,001	622,293	2,547,136	3.9903
31			6,853					Gas MCF ->	107,496	1,000,000	107,496	613,181	8.9480
32													
33	ST LUC 1	839	588,980	97.5	97.5	100.0	10,816	Nuclear Othr ->	6,370,424	1,000,000	6,370,424	1,754,100	0.2978
34													

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jun-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
35	ST LUC 2	714	501,219	97.5	97.5	100.0	10,787	Nuclear Othr ->	5,406,805	1,000,000	5,406,805	1,486,000	0.2965
36													
37	CAP CN 1	394	90,303	36.9	95.4	69.0	10,066	Heavy Oil BBLS ->	137,478	6,399,998	879,858	3,544,180	3.9248
38			14,316					Gas MCF ->	173,283	1,000,000	173,283	1,001,328	6.9944
39													
40	CAP CN 2	394	105,120	40.8	95.2	73.4	9,894	Heavy Oil BBLS ->	157,967	6,399,999	1,010,989	4,072,389	3.8740
41			10,744					Gas MCF ->	135,312	1,000,000	135,312	770,676	7.1734
42													
43	SANFRD 3	138	7,681	18.1	89.0	53.3	11,299	Heavy Oil BBLS ->	12,339	6,399,979	78,969	360,098	4.6882
44			10,336					Gas MCF ->	124,606	1,000,000	124,606	739,311	7.1527
45													
46	PUTNAM 1	239	1,361	40.4	95.7	87.9	10,058	Light Oil BBLS ->	2,238	5,829,989	13,045	91,300	6.7108
47			68,237					Gas MCF ->	686,977	1,000,000	686,977	4,079,033	5.9777
48													
49	PUTNAM 2	239	1,448	42.2	95.5	88.8	9,606	Light Oil BBLS ->	2,274	5,829,954	13,254	92,800	6.4111
50			71,193					Gas MCF ->	684,497	1,000,000	684,497	4,054,288	5.6948
51													
52	MANATE 1	795	221,094	45.0	95.8	47.7	10,557	Heavy Oil BBLS ->	364,733	6,400,000	2,334,289	9,605,965	4.3448
53			36,488					Gas MCF ->	384,973	1,000,000	384,973	2,169,033	5.9445
54													
55	MANATE 2	795	180,983	43.4	94.6	45.5	10,472	Heavy Oil BBLS ->	296,143	6,399,999	1,895,318	7,799,550	4.3095
56			67,491					Gas MCF ->	706,787	1,000,000	706,787	3,982,173	5.9003
57													
58	CUTLER 5	68	10,457	21.4	97.8	61.5	13,570	Gas MCF ->	141,902	1,000,000	141,902	806,980	7.7168
59													
60	CUTLER 6	138	17,974	18.1	97.0	48.1	12,651	Gas MCF ->	227,402	1,000,000	227,402	1,293,295	7.1952
61													
62	MARTIN 1	807	196,034	54.8	96.2	57.3	10,312	Heavy Oil BBLS ->	309,886	6,400,000	1,983,272	8,111,009	4.1376
63			122,527					Gas MCF ->	1,301,586	1,000,000	1,301,586	7,422,922	6.0582
64													
65	MARTIN 2	792	156,640	47.2	96.3	49.3	10,326	Heavy Oil BBLS ->	247,539	6,400,000	1,584,249	6,479,130	4.1363
66			112,647					Gas MCF ->	1,196,275	1,000,000	1,196,275	6,853,468	6.0840
67													
68	MARTIN 3	443	256,468	80.4	94.7	92.0	7,222	Gas MCF ->	1,852,136	1,000,000	1,852,136	10,533,650	4.1072

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jun-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
70	MARTIN 4	443	262,558	82.3	94.5	91.4	7,202	Gas MCF ->	1,891,007	1,000,000	1,891,007	10,754,671	4.0961
72	FM GT	552	43,087	10.8	98.4	65.2	15,183	Light Oil BBLS ->	112,214	5,829,998	654,209	4,017,400	9.3239
74	FL GT	684	41	12.1	91.8	70.2	17,480	Light Oil BBLS ->	116	5,831,752	676	4,600	11.3300
75			59,577					Gas MCF ->	1,041,438	1,000,000	1,041,438	5,922,964	9.9416
77	PE GT	348	194	10.9	88.4	61.6	19,053	Light Oil BBLS ->	605	5,829,780	3,528	22,800	11.7344
78			26,537					Gas MCF ->	505,767	1,000,000	505,767	2,876,407	10.8394
80	SJRPP 1O	127	80,442	88.0	93.7	97.8	9,455	Coal TONS ->	31,084	24,469,994	760,616	1,175,400	1.4612
82	SJRPP 2O	127	81,259	88.9	93.9	98.1	9,317	Coal TONS ->	30,939	24,470,034	757,069	1,170,000	1.4398
84	SCHER #4	643	361,472	78.1	93.5	86.7	9,988	Coal TONS ->	206,314	17,499,997	3,610,496	5,709,100	1.5794
86	FMREP 1	1,423	876,357	85.5	94.6	94.2	7,123	Gas MCF ->	6,242,103	1,000,000	6,242,103	35,500,728	4.0509
88	SNREP4	888	544,237	85.1	94.7	96.3	6,892	Gas MCF ->	3,751,077	1,000,000	3,751,077	21,356,024	3.9240
90	SNREP5	888	517,478	80.9	95.2	93.2	6,971	Gas MCF ->	3,607,461	1,000,000	3,607,461	20,977,569	4.0538
92	FM SC	298	912	17.4	97.2	80.8	10,533	Light Oil BBLS ->	1,572	5,829,971	9,162	56,300	6.1712
93			36,477					Gas MCF ->	384,648	1,000,000	384,648	2,187,991	5.9982
95	MR SC	298	38	30.2	96.6	81.0	10,526	Light Oil BBLS ->	65	5,825,153	380	2,900	7.6517
96			64,864					Gas MCF ->	682,746	1,000,000	682,746	3,883,086	5.9865
98	TOTAL	18,306	8,228,501				9,427				77,573,942	270,742,561	3.2903

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jul-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	108,229	46.0	95.2	69.4	10,159	Heavy Oil BBLS ->	166,304	6,400,000	1,064,348	4,476,025	4.1357
2			26,589					Gas MCF ->	305,244	1,000,000	305,244	1,702,117	6.4017
3													
4	TRKY O 2	394	131,137	55.6	95.0	77.0	9,991	Heavy Oil BBLS ->	199,016	6,399,999	1,273,700	5,356,355	4.0846
5			31,812					Gas MCF ->	354,289	1,000,000	354,289	1,972,488	6.2004
6													
7	TRKY N 3	693	502,707	97.5	97.5	100.0	11,233	Nuclear Othr ->	5,646,720	1,000,000	5,646,720	1,486,200	0.2956
8													
9	TRKY N 4	693	502,707	97.5	97.5	100.0	11,244	Nuclear Othr ->	5,652,632	1,000,000	5,652,632	1,528,400	0.3040
10													
11	FT LAUD4	422	287,958	91.7	94.3	97.1	7,889	Gas MCF ->	2,271,835	1,000,000	2,271,835	12,648,220	4.3924
12													
13	FT LAUD5	424	285,976	90.7	94.9	96.0	7,734	Gas MCF ->	2,211,610	1,000,000	2,211,610	12,312,915	4.3056
14													
15	PT EVER1	211	44,004	33.3	96.0	61.0	11,016	Heavy Oil BBLS ->	71,334	6,399,996	456,534	1,871,611	4.2533
16			8,278					Gas MCF ->	119,410	1,000,000	119,410	685,684	8.2833
17													
18	PT EVER2	211	65,776	44.8	95.8	80.4	10,184	Heavy Oil BBLS ->	100,071	6,399,999	640,457	2,625,649	3.9918
19			4,555					Gas MCF ->	75,803	1,000,000	75,803	425,324	9.3373
20													
21	PT EVER3	390	193,543	73.9	95.4	78.0	9,918	Heavy Oil BBLS ->	298,351	6,400,001	1,909,449	7,828,172	4.0447
22			20,955					Gas MCF ->	217,974	1,000,000	217,974	1,236,258	5.8996
23													
24	PT EVER4	394	171,613	63.8	95.3	78.0	10,165	Heavy Oil BBLS ->	268,174	6,400,001	1,716,313	7,036,363	4.1001
25			15,443					Gas MCF ->	185,068	1,000,000	185,068	1,048,097	6.7869
26													
27	RIV 3	282	52,090	29.7	93.7	52.5	11,252	Heavy Oil BBLS ->	85,623	6,400,002	547,986	2,260,548	4.3397
28			10,285					Gas MCF ->	153,874	1,000,000	153,874	879,136	8.5480
29													
30	RIV 4	284	118,471	76.2	93.1	83.5	10,186	Heavy Oil BBLS ->	185,662	6,400,001	1,188,236	4,901,605	4.1374
31			42,480					Gas MCF ->	451,231	1,000,000	451,231	2,540,027	5.9793
32													
33	ST LUC 1	839	608,613	97.5	97.5	100.0	10,816	Nuclear Othr ->	6,582,768	1,000,000	6,582,768	1,811,200	0.2976
34													

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jul-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
35	ST LUC 2	714	517,926	97.5	97.5	100.0	10,787	Nuclear Othr ->	5,587,028	1,000,000	5,587,028	1,530,500	0.2955
36													
37	CAP CN 1	394	123,866	45.5	95.4	76.4	9,911	Heavy Oil BBLS ->	187,119	6,400,000	1,197,564	4,874,072	3.9350
38			9,610					Gas MCF ->	125,269	1,000,000	125,269	704,990	7.3361
39													
40	CAP CN 2	394	131,629	48.3	95.2	77.6	9,820	Heavy Oil BBLS ->	197,251	6,400,001	1,262,406	5,138,058	3.9034
41			9,944					Gas MCF ->	127,849	1,000,000	127,849	718,097	7.2216
42													
43	SANFRD 3	138	17,326	28.6	95.4	55.4	10,991	Heavy Oil BBLS ->	27,697	6,399,998	177,263	804,875	4.6456
44			12,008					Gas MCF ->	145,149	1,000,000	145,149	845,022	7.0373
45													
46	PUTNAM 1	239	4,333	51.6	95.7	91.0	9,954	Light Oil BBLS ->	7,062	5,830,010	41,169	279,500	6.4503
47			87,352					Gas MCF ->	871,438	1,000,000	871,438	5,101,111	5.8397
48													
49	PUTNAM 2	239	4,591	54.0	95.5	93.7	9,485	Light Oil BBLS ->	7,129	5,829,990	41,562	282,100	6.1450
50			91,461					Gas MCF ->	869,448	1,000,000	869,448	5,042,916	5.5137
51													
52	MANATE 1	795	255,201	48.2	95.8	50.5	10,489	Heavy Oil BBLS ->	418,253	6,400,000	2,676,820	10,987,193	4.3053
53			30,173					Gas MCF ->	316,484	1,000,000	316,484	1,745,495	5.7850
54													
55	MANATE 2	795	235,001	47.0	94.6	49.3	10,396	Heavy Oil BBLS ->	381,719	6,400,000	2,443,004	10,027,436	4.2670
56			43,211					Gas MCF ->	449,213	1,000,000	449,213	2,477,512	5.7335
57													
58	CUTLER 5	68	14,599	28.9	97.8	61.7	13,423	Gas MCF ->	195,955	1,000,000	195,955	1,090,927	7.4726
59													
60	CUTLER 6	138	24,081	23.5	97.1	48.4	12,542	Gas MCF ->	302,027	1,000,000	302,027	1,681,563	6.9831
61													
62	MARTIN 1	807	228,167	59.6	96.2	62.3	10,225	Heavy Oil BBLS ->	358,036	6,400,000	2,291,431	9,429,444	4.1327
63			129,759					Gas MCF ->	1,368,301	1,000,000	1,368,301	7,679,016	5.9179
64													
65	MARTIN 2	792	189,547	51.8	96.3	54.1	10,239	Heavy Oil BBLS ->	297,614	6,400,000	1,904,730	7,838,141	4.1352
66			115,829					Gas MCF ->	1,222,144	1,000,000	1,222,144	6,855,788	5.9189
67													
68	MARTIN 3	443	276,229	83.8	94.7	94.2	7,192	Gas MCF ->	1,986,638	1,000,000	1,986,638	11,060,352	4.0041

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jul-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
69													
70	MARTIN 4	443	276,939	84.0	94.5	93.5	7,174	Gas MCF ->	1,986,771	1,000,000	1,986,771	11,061,145	3.9941
71													
72	FM GT	552	45,851	11.2	98.4	65.3	15,173	Light Oil BBLS ->	119,326	5,829,998	695,670	4,282,600	9.3403
73													
74	FL GT	684	402	13.3	91.8	70.6	17,458	Light Oil BBLS ->	1,146	5,829,756	6,681	45,600	11.3518
75			67,152					Gas MCF ->	1,172,673	1,000,000	1,172,673	6,528,719	9.7223
76													
77	PE GT	348	473	16.7	88.4	62.5	18,940	Light Oil BBLS ->	1,463	5,829,917	8,532	54,900	11.6141
78			42,125					Gas MCF ->	798,260	1,000,000	798,260	4,444,227	10.5502
79													
80	SJRPP 1O	127	83,706	88.6	93.7	97.3	9,455	Coal TONS ->	32,395	24,429,980	791,414	1,220,700	1.4583
81													
82	SJRPP 2O	127	84,104	89.0	93.9	97.4	9,316	Coal TONS ->	32,072	24,430,021	783,517	1,208,500	1.4369
83													
84	SCHER #4	643	375,330	78.5	93.5	86.5	9,989	Coal TONS ->	214,244	17,500,002	3,749,276	5,912,700	1.5753
85													
86	FMREP 1	1,423	920,303	86.9	94.7	96.2	7,103	Gas MCF ->	6,536,648	1,000,000	6,536,648	36,392,036	3.9544
87													
88	SNREP4	888	573,139	86.8	94.7	97.7	6,871	Gas MCF ->	3,938,307	1,000,000	3,938,307	21,926,098	3.8256
89													
90	SNREP5	888	558,522	84.5	95.2	95.5	6,932	Gas MCF ->	3,871,872	1,000,000	3,871,872	21,695,439	3.8844
91													
92	FM SC	298	275	36.4	97.2	81.1	10,543	Light Oil BBLS ->	474	5,830,591	2,764	17,000	6.1773
93			80,438					Gas MCF ->	848,211	1,000,000	848,211	4,722,333	5.8707
94													
95	MR SC	298	8	41.1	96.6	81.2	10,526	Light Oil BBLS ->	14	5,818,182	83	600	7.2289
96			91,049					Gas MCF ->	958,380	1,000,000	958,380	5,335,640	5.8602
97													
98	TOTAL	18,306	8,984,876				9,436				84,777,431	297,674,741	3.3131

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Aug-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	101,744	43.4	95.2	67.9	10,179	Heavy Oil BBLS ->	156,423	6,399,999	1,001,106	4,257,473	4.1845
2			25,543					Gas MCF ->	294,590	1,000,000	294,590	1,662,589	6.5089
3													
4	TRKY O 2	394	127,838	54.4	95.0	75.3	10,008	Heavy Oil BBLS ->	194,242	6,400,002	1,243,146	5,286,855	4.1356
5			31,657					Gas MCF ->	353,088	1,000,000	353,088	1,989,890	6.2858
6													
7	TRKY N 3	693	502,707	97.5	97.5	100.0	11,233	Nuclear Othr ->	5,646,720	1,000,000	5,646,720	1,481,400	0.2947
8													
9	TRKY N 4	693	502,707	97.5	97.5	100.0	11,244	Nuclear Othr ->	5,652,632	1,000,000	5,652,632	1,523,600	0.3031
10													
11	FT LAUD4	422	288,396	91.9	94.3	97.2	7,886	Gas MCF ->	2,274,363	1,000,000	2,274,363	12,817,627	4.4444
12													
13	FT LAUD5	424	286,780	90.9	94.9	96.2	7,728	Gas MCF ->	2,216,370	1,000,000	2,216,370	12,490,783	4.3555
14													
15	PT EVER1	211	38,537	29.3	96.0	60.1	11,105	Heavy Oil BBLS ->	62,536	6,400,000	400,229	1,667,002	4.3258
16			7,518					Gas MCF ->	111,218	1,000,000	111,218	642,712	8.5489
17													
18	PT EVER2	211	60,168	41.3	95.8	79.7	10,229	Heavy Oil BBLS ->	91,596	6,400,003	586,217	2,441,586	4.0579
19			4,597					Gas MCF ->	76,256	1,000,000	76,256	434,168	9.4454
20													
21	PT EVER3	390	186,524	72.0	95.4	77.1	9,935	Heavy Oil BBLS ->	287,647	6,399,999	1,840,941	7,667,618	4.1108
22			22,311					Gas MCF ->	233,919	1,000,000	233,919	1,341,051	6.0107
23													
24	PT EVER4	394	172,485	64.4	95.3	75.9	10,158	Heavy Oil BBLS ->	269,986	6,399,999	1,727,912	7,196,877	4.1725
25			16,261					Gas MCF ->	189,359	1,000,000	189,359	1,085,015	6.6727
26													
27	RIV 3	282	97,458	74.8	93.7	81.9	10,426	Heavy Oil BBLS ->	155,316	6,399,998	994,023	4,151,215	4.2595
28			59,473					Gas MCF ->	642,123	1,000,000	642,123	3,671,547	6.1735
29													
30	RIV 4	284	80,105	40.3	93.1	75.0	10,226	Heavy Oil BBLS ->	121,760	6,400,001	779,264	3,254,328	4.0626
31			4,996					Gas MCF ->	90,964	1,000,000	90,964	512,678	10.2609
32													
33	ST LUC 1	839	608,613	97.5	97.5	100.0	10,816	Nuclear Othr ->	6,582,768	1,000,000	6,582,768	1,805,600	0.2967
34													

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Aug-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
35	ST LUC 2	714	517,926	97.5	97.5	100.0	10,787	Nuclear Othr ->	5,587,028	1,000,000	5,587,028	1,525,600	0.2946
37	CAP CN 1	394	117,403	43.3	95.4	74.9	9,930	Heavy Oil BBLS ->	177,491	6,399,998	1,135,944	4,683,751	3.9895
38			9,559					Gas MCF ->	124,825	1,000,000	124,825	712,742	7.4565
40	CAP CN 2	394	125,354	46.2	95.2	76.6	9,835	Heavy Oil BBLS ->	187,921	6,400,000	1,202,697	4,958,982	3.9560
41			9,970					Gas MCF ->	128,152	1,000,000	128,152	728,896	7.3110
43	SANFRD 3	138	16,158	26.1	95.4	55.5	11,014	Heavy Oil BBLS ->	25,823	6,399,988	165,266	746,978	4.6231
44			10,664					Gas MCF ->	130,161	1,000,000	130,161	766,218	7.1850
46	PUTNAM 1	239	3,994	48.7	95.7	91.0	9,955	Light Oil BBLS ->	6,509	5,829,969	37,950	252,800	6.3293
47			82,635					Gas MCF ->	824,418	1,000,000	824,418	4,881,762	5.9076
49	PUTNAM 2	239	4,169	50.5	95.5	93.6	9,486	Light Oil BBLS ->	6,475	5,830,041	37,747	251,500	6.0331
50			85,616					Gas MCF ->	813,988	1,000,000	813,988	4,807,081	5.6147
52	MANATE 1	795	248,700	47.2	95.8	49.5	10,495	Heavy Oil BBLS ->	407,840	6,400,000	2,610,173	10,766,373	4.3291
53			30,593					Gas MCF ->	321,085	1,000,000	321,085	1,792,540	5.8593
55	MANATE 2	795	219,141	45.4	94.6	47.6	10,417	Heavy Oil BBLS ->	356,674	6,400,000	2,282,712	9,415,626	4.2966
56			49,475					Gas MCF ->	515,360	1,000,000	515,360	2,877,134	5.8154
58	CUTLER 5	68	13,714	27.1	97.8	61.7	13,410	Gas MCF ->	183,906	1,000,000	183,906	1,036,455	7.5577
60	CUTLER 6	138	22,174	21.6	97.1	48.4	12,532	Gas MCF ->	277,894	1,000,000	277,894	1,566,073	7.0626
62	MARTIN 1	807	223,496	58.4	96.2	61.0	10,231	Heavy Oil BBLS ->	350,931	6,400,001	2,245,961	9,326,921	4.1732
63			126,917					Gas MCF ->	1,339,186	1,000,000	1,339,186	7,607,277	5.9939
65	MARTIN 2	792	180,950	50.0	96.3	52.3	10,256	Heavy Oil BBLS ->	284,482	6,400,000	1,820,685	7,560,883	4.1784
66			113,845					Gas MCF ->	1,202,759	1,000,000	1,202,759	6,831,124	6.0004
68	MARTIN 3	443	280,281	85.0	94.7	93.7	7,198	Gas MCF ->	2,017,397	1,000,000	2,017,397	11,369,365	4.0564

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Aug-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
69													
70	MARTIN 4	443	278,019	84.4	94.5	94.5	7,160	Gas MCF ->	1,990,622	1,000,000	1,990,622	11,218,516	4.0352
71													
72	FM GT	552	45,285	11.0	98.4	65.4	15,169	Light Oil BBLS ->	117,829	5,829,998	686,945	4,303,700	9.5037
73													
74	FL GT	684	312	12.6	91.8	70.6	17,460	Light Oil BBLS ->	891	5,829,871	5,192	35,400	11.3425
75			63,609					Gas MCF ->	1,110,879	1,000,000	1,110,879	6,260,598	9.8423
76													
77	PE GT	348	377	14.5	88.4	62.5	18,946	Light Oil BBLS ->	1,166	5,829,889	6,799	43,600	11.5773
78			36,545					Gas MCF ->	692,706	1,000,000	692,706	3,903,846	10.6824
79													
80	SJRPP 1O	127	82,896	87.7	93.7	97.4	9,456	Coal TONS ->	32,086	24,429,977	783,853	1,221,900	1.4740
81													
82	SJRPP 2O	127	83,213	88.1	93.9	97.6	9,317	Coal TONS ->	31,736	24,429,987	775,300	1,208,600	1.4524
83													
84	SCHER #4	643	371,902	77.8	93.5	86.5	9,989	Coal TONS ->	212,283	17,500,003	3,714,944	5,851,300	1.5733
85													
86	FMREP 1	1,423	925,145	87.4	94.7	96.5	7,100	Gas MCF ->	6,568,577	1,000,000	6,568,577	37,018,455	4.0014
87													
88	SNREP4	888	582,419	88.2	94.7	98.0	6,869	Gas MCF ->	4,000,798	1,000,000	4,000,798	22,547,270	3.8713
89													
90	SNREP5	888	558,315	84.5	95.2	95.6	6,931	Gas MCF ->	3,869,848	1,000,000	3,869,848	22,058,793	3.9510
91													
92	FM SC	298	282	30.8	97.2	81.1	10,543	Light Oil BBLS ->	486	5,830,387	2,836	17,800	6.3031
93			68,009					Gas MCF ->	717,143	1,000,000	717,143	4,041,641	5.9428
94													
95	MR SC	298	17	36.7	96.6	81.1	10,526	Light Oil BBLS ->	28	5,823,944	165	1,300	7.8788
96			81,277					Gas MCF ->	855,526	1,000,000	855,526	4,821,478	5.9321
97													
98	TOTAL	18,306	8,896,772				9,411				83,724,631	296,401,890	3.3316

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Sep-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	93,253	41.3	95.2	63.8	10,212	Heavy Oil BBLS ->	143,763	6,400,000	920,085	3,966,354	4.2533
2			23,983					Gas MCF ->	277,167	1,000,000	277,167	1,550,023	6.4631
4	TRKY O 2	394	115,870	51.6	95.0	70.3	10,044	Heavy Oil BBLS ->	176,782	6,400,001	1,131,404	4,877,314	4.2093
5			30,471					Gas MCF ->	338,409	1,000,000	338,409	1,890,061	6.2028
7	TRKY N 3	693	389,192	78.0	78.0	100.0	11,233	Nuclear Othr ->	4,371,626	1,000,000	4,371,626	1,143,100	0.2937
9	TRKY N 4	693	486,491	97.5	97.5	100.0	11,244	Nuclear Othr ->	5,470,288	1,000,000	5,470,288	1,469,600	0.3021
11	FT LAUD4	422	277,504	91.3	94.3	96.7	7,896	Gas MCF ->	2,191,086	1,000,000	2,191,086	12,236,047	4.4093
13	FT LAUD5	424	275,103	90.1	94.9	95.4	7,742	Gas MCF ->	2,129,973	1,000,000	2,129,973	11,894,703	4.3237
15	PT EVER1	211	32,544	28.1	96.0	54.7	11,259	Heavy Oil BBLS ->	53,247	6,399,994	340,781	1,443,567	4.4357
16			10,100					Gas MCF ->	139,336	1,000,000	139,336	803,760	7.9582
18	PT EVER2	211	54,959	39.7	95.8	74.9	10,291	Heavy Oil BBLS ->	83,973	6,400,003	537,427	2,276,513	4.1422
19			5,289					Gas MCF ->	82,591	1,000,000	82,591	465,199	8.7963
21	PT EVER3	390	175,926	70.7	95.4	74.1	9,955	Heavy Oil BBLS ->	272,110	6,399,999	1,741,504	7,376,872	4.1932
22			22,560					Gas MCF ->	234,485	1,000,000	234,485	1,331,212	5.9009
24	PT EVER4	394	157,515	61.0	95.3	73.2	10,195	Heavy Oil BBLS ->	247,192	6,400,001	1,582,027	6,701,408	4.2545
25			15,637					Gas MCF ->	183,227	1,000,000	183,227	1,043,451	6.6729
27	RIV 3	282	71,758	38.9	93.7	68.7	10,440	Heavy Oil BBLS ->	111,013	6,400,001	710,481	3,012,109	4.1976
28			7,177					Gas MCF ->	113,580	1,000,000	113,580	639,486	8.9106
30	RIV 4	284	98,647	73.3	93.1	81.0	10,247	Heavy Oil BBLS ->	154,895	6,400,001	991,325	4,202,654	4.2603
31			51,286					Gas MCF ->	545,021	1,000,000	545,021	3,093,857	6.0325
33	ST LUC 1	839	588,980	97.5	97.5	100.0	10,816	Nuclear Othr ->	6,370,424	1,000,000	6,370,424	1,741,800	0.2957

Date: 9/2/2003
Company: *Florida Power & Light*

Schedule E4

Estimated For The Period of : Sep-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
35	ST LUC 2	714	501,219	97.5	97.5	100.0	10,787	Nuclear Othr ->	5,406,805	1,000,000	5,406,805	1,471,600	0.2936
36													
37	CAP CN 1	394	103,664	40.2	95.4	69.8	9,998	Heavy Oil BBLS ->	157,420	6,400,000	1,007,489	4,203,607	4.0550
38			10,511					Gas MCF ->	134,083	1,000,000	134,083	761,831	7.2479
39													
40	CAP CN 2	394	115,551	44.0	95.2	72.3	9,870	Heavy Oil BBLS ->	173,683	6,399,999	1,111,570	4,637,857	4.0137
41			9,279					Gas MCF ->	120,543	1,000,000	120,543	678,262	7.3098
42													
43	SANFRD 3	138	10,729	24.9	95.4	53.6	11,178	Heavy Oil BBLS ->	17,226	6,400,008	110,249	495,084	4.6144
44			13,976					Gas MCF ->	165,905	1,000,000	165,905	969,825	6.9392
45													
46	PUTNAM 1	239	3,624	44.9	95.7	89.9	9,986	Light Oil BBLS ->	5,925	5,829,952	34,545	227,500	6.2774
47			73,703					Gas MCF ->	737,653	1,000,000	737,653	4,331,163	5.8765
48													
49	PUTNAM 2	239	4,002	49.0	95.5	93.4	9,489	Light Oil BBLS ->	6,217	5,829,966	36,245	238,700	5.9653
50			80,274					Gas MCF ->	763,471	1,000,000	763,471	4,468,981	5.5672
51													
52	MANATE 1	795	234,509	46.5	95.8	48.7	10,528	Heavy Oil BBLS ->	385,764	6,400,001	2,468,887	10,270,353	4.3795
53			31,613					Gas MCF ->	332,813	1,000,000	332,813	1,841,282	5.8245
54													
55	MANATE 2	795	167,607	38.2	94.6	46.2	10,462	Heavy Oil BBLS ->	273,990	6,400,001	1,753,539	7,294,571	4.3522
56			51,051					Gas MCF ->	534,103	1,000,000	534,103	2,954,899	5.7882
57													
58	CUTLER 5	68	12,871	26.3	97.8	61.6	13,574	Gas MCF ->	174,709	1,000,000	174,709	975,642	7.5801
59													
60	CUTLER 6	138	21,748	21.9	97.0	48.2	12,544	Gas MCF ->	272,806	1,000,000	272,806	1,523,444	7.0051
61													
62	MARTIN 1	807	169,586	46.4	96.2	58.9	10,267	Heavy Oil BBLS ->	266,972	6,399,999	1,708,620	7,107,526	4.1911
63			99,734					Gas MCF ->	1,056,527	1,000,000	1,056,527	5,951,785	5.9676
64													
65	MARTIN 2	792	137,220	40.1	96.3	51.2	10,292	Heavy Oil BBLS ->	216,222	6,400,000	1,383,819	5,756,332	4.1950
66			91,594					Gas MCF ->	971,215	1,000,000	971,215	5,461,203	5.9624
67													
68	MARTIN 3	443	266,163	83.4	94.7	93.3	7,203	Gas MCF ->	1,917,210	1,000,000	1,917,210	10,706,623	4.0226

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Sep-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
69													
70	MARTIN 4	443	269,393	84.5	94.5	93.7	7,170	Gas MCF ->	1,931,599	1,000,000	1,931,599	10,786,911	4.0042
71													
72	FM GT	552	44,508	11.2	98.4	65.3	15,175	Light Oil BBLS ->	115,853	5,829,999	675,421	4,325,200	9.7177
73													
74	FL GT	684	141	13.2	91.8	70.5	17,468	Light Oil BBLS ->	401	5,829,220	2,338	16,000	11.3879
75			64,752					Gas MCF ->	1,131,200	1,000,000	1,131,200	6,317,113	9.7559
76													
77	PE GT	348	188	15.4	88.4	62.3	18,977	Light Oil BBLS ->	582	5,830,040	3,393	21,700	11.5610
78			37,646					Gas MCF ->	714,597	1,000,000	714,597	3,990,658	10.6005
79													
80	SJRPP 1O	127	81,027	88.6	93.7	97.6	9,455	Coal TONS ->	31,360	24,429,988	766,129	1,199,800	1.4807
81													
82	SJRPP 2O	127	81,431	89.1	93.9	97.7	9,317	Coal TONS ->	31,054	24,430,003	758,659	1,188,100	1.4590
83													
84	SCHER #4	643	362,149	78.2	93.5	86.4	9,989	Coal TONS ->	206,718	17,500,000	3,617,568	5,694,800	1.5725
85													
86	FMREP 1	1,423	874,250	85.3	94.6	95.6	7,108	Gas MCF ->	6,214,257	1,000,000	6,214,257	34,703,271	3.9695
87													
88	SNREP4	888	561,127	87.8	94.7	97.3	6,874	Gas MCF ->	3,857,033	1,000,000	3,857,033	21,553,028	3.8410
89													
90	SNREP5	888	535,817	83.8	95.2	94.5	6,946	Gas MCF ->	3,721,638	1,000,000	3,721,638	21,071,942	3.9327
91													
92	FM SC	298	395	28.6	97.2	81.0	10,542	Light Oil BBLS ->	680	5,829,928	3,966	25,400	6.4320
93			61,055					Gas MCF ->	643,805	1,000,000	643,805	3,595,259	5.8886
94													
95	MR SC	298	45	35.1	96.6	81.1	10,526	Light Oil BBLS ->	78	5,827,145	455	3,500	7.7093
96			75,307					Gas MCF ->	792,671	1,000,000	792,671	4,426,665	5.8782
97													
98	TOTAL	18,306	8,243,698				9,394				77,439,775	274,406,504	3.3287

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	394	110,079	50.9	95.2	63.8	10,165	Heavy Oil BBLS ->	170,089	6,400,001	1,088,571	4,805,037	4.3651
2			39,239					Gas MCF ->	429,220	1,000,000	429,220	2,430,597	6.1943
3													
4	TRKY O 2	394	130,401	58.6	95.0	67.5	10,014	Heavy Oil BBLS ->	199,927	6,400,001	1,279,530	5,647,929	4.3312
5			41,319					Gas MCF ->	440,154	1,000,000	440,154	2,491,233	6.0292
6													
7	TRKY N 3	693		0.0	0.0		0						
8													
9	TRKY N 4	693	502,707	97.5	97.5	100.0	11,244	Nuclear Othr ->	5,652,632	1,000,000	5,652,632	1,513,700	0.3011
10													
11	FT LAUD4	422	282,016	89.8	94.3	95.1	7,927	Gas MCF ->	2,235,417	1,000,000	2,235,417	12,649,531	4.4854
12													
13	FT LAUD5	424	136,420	43.2	59.9	94.6	7,754	Gas MCF ->	1,057,811	1,000,000	1,057,811	5,985,858	4.3878
14													
15	PT EVER1	211	33,863	27.3	96.0	60.0	11,101	Heavy Oil BBLS ->	55,015	6,400,006	352,096	1,527,062	4.5096
16			9,054					Gas MCF ->	124,314	1,000,000	124,314	721,083	7.9640
17													
18	PT EVER2	211	65,649	46.3	95.8	74.0	10,249	Heavy Oil BBLS ->	100,384	6,400,002	642,457	2,786,427	4.2445
19			7,017					Gas MCF ->	102,284	1,000,000	102,284	587,984	8.3789
20													
21	PT EVER3	390	146,815	57.2	95.4	72.3	9,980	Heavy Oil BBLS ->	227,504	6,399,999	1,456,026	6,314,929	4.3013
22			19,121					Gas MCF ->	200,019	1,000,000	200,019	1,145,975	5.9932
23													
24	PT EVER4	394	169,868	65.5	95.3	68.6	10,166	Heavy Oil BBLS ->	268,285	6,400,001	1,717,027	7,446,940	4.3840
25			22,126					Gas MCF ->	234,837	1,000,000	234,837	1,349,774	6.1003
26													
27	RIV 3	282	83,353	72.9	93.7	79.2	10,482	Heavy Oil BBLS ->	133,157	6,399,999	852,205	3,686,510	4.4228
28			69,663					Gas MCF ->	751,745	1,000,000	751,745	4,327,527	6.2121
29													
30	RIV 4	284	81,246	43.4	93.1	65.7	10,409	Heavy Oil BBLS ->	125,890	6,399,999	805,694	3,485,351	4.2899
31			10,504					Gas MCF ->	149,305	1,000,000	149,305	848,921	8.0817
32													
33	ST LUC 1	839	608,613	97.5	97.5	100.0	10,816	Nuclear Othr ->	6,582,768	1,000,000	6,582,768	1,794,700	0.2949
34													

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
35	ST LUC 2	714	517,926	97.5	97.5	100.0	10,787	Nuclear Othr ->	5,587,028	1,000,000	5,587,028	1,515,600	0.2926
36													
37	CAP CN 1	394	67,674	28.2	95.4	68.3	10,188	Heavy Oil BBLS ->	103,136	6,400,002	660,071	2,814,000	4.1582
38			15,010					Gas MCF ->	182,335	1,000,000	182,335	1,052,008	7.0086
39													
40	CAP CN 2	394	88,764	34.6	95.2	73.9	9,956	Heavy Oil BBLS ->	133,454	6,400,002	854,105	3,641,177	4.1021
41			12,789					Gas MCF ->	156,924	1,000,000	156,924	900,438	7.0408
42													
43	SANFRD 3	138	3,417	12.8	95.4	52.1	11,578	Heavy Oil BBLS ->	5,511	6,400,015	35,272	159,742	4.6745
44			9,691					Gas MCF ->	116,488	1,000,000	116,488	680,402	7.0211
45													
46	PUTNAM 1	239	1,013	26.0	95.7	87.6	10,059	Light Oil BBLS ->	1,666	5,830,173	9,715	63,800	6.2975
47			45,246					Gas MCF ->	455,592	1,000,000	455,592	2,671,626	5.9046
48													
49	PUTNAM 2	239	1,339	25.7	95.5	91.9	9,528	Light Oil BBLS ->	2,087	5,829,995	12,167	79,900	5.9676
50			44,304					Gas MCF ->	422,730	1,000,000	422,730	2,474,372	5.5849
51													
52	MANATE 1	795	184,322	35.1	95.8	49.8	10,528	Heavy Oil BBLS ->	303,254	6,400,001	1,940,825	8,226,244	4.4630
53			23,192					Gas MCF ->	243,791	1,000,000	243,791	1,367,446	5.8963
54													
55	MANATE 2	795	189,394	42.3	94.6	46.5	10,465	Heavy Oil BBLS ->	309,756	6,400,000	1,982,436	8,402,644	4.4366
56			60,980					Gas MCF ->	637,768	1,000,000	637,768	3,577,308	5.8664
57													
58	CUTLER 5	68	13,411	26.5	97.8	61.8	13,117	Gas MCF ->	175,910	1,000,000	175,910	995,434	7.4226
59													
60	CUTLER 6	138	23,936	23.3	97.1	48.6	12,454	Gas MCF ->	298,094	1,000,000	298,094	1,686,835	7.0473
61													
62	MARTIN 1	807	207,191	55.4	96.2	57.9	10,302	Heavy Oil BBLS ->	327,327	6,400,000	2,094,890	8,956,307	4.3227
63			125,453					Gas MCF ->	1,331,867	1,000,000	1,331,867	7,559,907	6.0261
64													
65	MARTIN 2	792	168,827	48.1	96.3	50.3	10,309	Heavy Oil BBLS ->	266,543	6,400,001	1,705,873	7,293,117	4.3199
66			114,838					Gas MCF ->	1,218,378	1,000,000	1,218,378	6,928,274	6.0331
67													
68	MARTIN 3	443	228,361	69.3	80.9	79.9	7,321	Gas MCF ->	1,671,770	1,000,000	1,671,770	9,460,062	4.1426

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Oct-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
69													
70	MARTIN 4	443	269,102	81.6	94.5	92.6	7,186	Gas MCF ->	1,933,757	1,000,000	1,933,757	10,942,580	4.0663
71													
72	FM GT	552	38,955	9.5	98.4	65.2	15,183	Light Oil BBLS ->	101,447	5,829,999	591,434	3,789,300	9.7275
73													
74	FL GT	684	22	14.0	91.8	70.5	17,475	Light Oil BBLS ->	64	5,833,856	372	2,500	11.1607
75			71,252					Gas MCF ->	1,245,140	1,000,000	1,245,140	7,045,810	9.8886
76													
77	PE GT	348	2	21.6	88.4	62.5	18,978	Light Oil BBLS ->	7	5,800,000	38	200	9.5238
78			55,035					Gas MCF ->	1,044,463	1,000,000	1,044,463	5,910,316	10.7392
79													
80	SJRPP 1O	127	83,666	88.5	93.7	98.4	9,456	Coal TONS ->	32,383	24,429,996	791,107	1,202,700	1.4375
81													
82	SJRPP 2O	127	83,989	88.9	93.9	98.5	9,317	Coal TONS ->	32,031	24,429,979	782,507	1,189,600	1.4164
83													
84	SCHER #4	643	371,424	77.7	93.5	86.7	9,988	Coal TONS ->	211,988	17,500,001	3,709,781	5,838,400	1.5719
85													
86	FMREP 1	1,423	868,930	82.1	94.7	93.8	7,128	Gas MCF ->	6,194,113	1,000,000	6,194,113	35,050,605	4.0338
87													
88	SNREP4	888	554,188	83.9	94.7	95.6	6,905	Gas MCF ->	3,826,491	1,000,000	3,826,491	21,712,559	3.9179
89													
90	SNREP5	888	521,491	78.9	95.2	93.3	6,970	Gas MCF ->	3,634,962	1,000,000	3,634,962	20,936,290	4.0147
91													
92	FM SC	298	813	24.5	97.2	80.8	10,533	Light Oil BBLS ->	1,400	5,829,859	8,160	53,200	6.4327
93			51,690					Gas MCF ->	544,670	1,000,000	544,670	3,082,080	5.9668
94													
95	MR SC	298	77	9.7	43.6	80.9	10,524	Light Oil BBLS ->	133	5,830,515	776	5,900	7.6227
96			20,681					Gas MCF ->	217,691	1,000,000	217,691	1,231,832	5.9563
97													
98	TOTAL	18,306	7,707,468				9,403				72,473,597	270,047,585	3.5037

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Nov-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	398	82,751	32.2	95.2	80.1	9,768	Heavy Oil BBLS ->	120,677	6,400,002	772,332	3,411,605	4.1228
2			9,644					Gas MCF ->	130,147	1,000,000	130,147	766,662	7.9499
3													
4	TRKY O 2	398	56,300	24.6	95.0	74.1	10,059	Heavy Oil BBLS ->	82,491	6,400,001	527,944	2,332,064	4.1422
5			14,325					Gas MCF ->	182,459	1,000,000	182,459	1,076,346	7.5136
6													
7	TRKY N 3	717	33,556	6.5	6.5	100.0	11,180	Nuclear Othr ->	375,165	1,000,000	375,165	110,400	0.3290
8													
9	TRKY N 4	717	503,332	97.5	97.5	100.0	10,897	Nuclear Othr ->	5,484,602	1,000,000	5,484,602	1,464,000	0.2909
10													
11	FT LAUD4	440	286,326	90.4	94.3	95.7	7,956	Gas MCF ->	2,278,112	1,000,000	2,278,112	13,391,508	4.6770
12													
13	FT LAUD5	442	187,565	58.9	76.8	93.6	7,923	Gas MCF ->	1,486,031	1,000,000	1,486,031	8,735,420	4.6573
14													
15	PT EVER1	212	5,899	7.7	96.0	56.6	12,605	Heavy Oil BBLS ->	8,815	6,399,971	56,418	244,285	4.1411
16			5,878					Gas MCF ->	92,031	1,000,000	92,031	542,354	9.2273
17													
18	PT EVER2	212	13,691	15.1	95.8	67.2	9,642	Heavy Oil BBLS ->	16,172	6,399,986	103,499	448,118	3.2732
19			9,287					Gas MCF ->	118,039	1,000,000	118,039	694,930	7.4829
20													
21	PT EVER3	392	120,165	47.1	95.4	86.9	10,206	Heavy Oil BBLS ->	186,907	6,399,999	1,196,205	5,179,490	4.3103
22			12,736					Gas MCF ->	160,187	1,000,000	160,187	952,012	7.4747
23													
24	PT EVER4	398	95,083	37.2	95.3	79.4	10,742	Heavy Oil BBLS ->	154,542	6,399,998	989,071	4,282,564	4.5040
25			11,617					Gas MCF ->	157,108	1,000,000	157,108	944,087	8.1271
26													
27	RIV 3	284	14,184	11.5	93.7	60.4	11,430	Heavy Oil BBLS ->	19,678	6,400,015	125,936	545,961	3.8491
28			9,330					Gas MCF ->	142,838	1,000,000	142,838	841,853	9.0230
29													
30	RIV 4	286	80,514	47.8	58.9	85.4	10,289	Heavy Oil BBLS ->	127,780	6,399,998	817,791	3,545,450	4.4035
31			17,969					Gas MCF ->	195,506	1,000,000	195,506	1,149,718	6.3982
32													
33	ST LUC 1	853	598,803	97.5	97.5	100.0	10,718	Nuclear Othr ->	6,417,858	1,000,000	6,417,858	1,744,300	0.2913
34													

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Nov-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
35	ST LUC 2	726	356,709	68.3	68.3	100.0	10,746	Nuclear Othr ->	3,833,125	1,000,000	3,833,125	1,036,500	0.2906
37	CAP CN 1	398	109,794	42.5	95.4	84.5	9,943	Heavy Oil BBLS ->	165,855	6,400,001	1,061,472	4,548,440	4.1427
38			11,869					Gas MCF ->	148,195	1,000,000	148,195	874,771	7.3705
40	CAP CN 2	398	131,148	51.0	95.2	89.4	9,743	Heavy Oil BBLS ->	194,892	6,400,002	1,247,308	5,344,744	4.0754
41			14,992					Gas MCF ->	176,528	1,000,000	176,528	1,040,177	6.9384
43	SANFRD 3	142	4,373	11.0	95.4	67.0	11,123	Heavy Oil BBLS ->	6,027	6,399,957	38,575	174,723	3.9952
44			6,909					Gas MCF ->	86,914	1,000,000	86,914	519,825	7.5238
46	PUTNAM 1	250	44,454	24.7	95.7	76.6	9,104	Gas MCF ->	404,732	1,000,000	404,732	2,430,537	5.4675
48	PUTNAM 2	250	26,665	14.8	95.5	74.2	9,174	Gas MCF ->	244,636	1,000,000	244,636	1,470,496	5.5147
50	MANATE 1	802	147,514	28.9	95.8	64.6	10,649	Heavy Oil BBLS ->	245,624	6,400,000	1,571,994	6,679,713	4.5282
51			19,214					Gas MCF ->	203,487	1,000,000	203,487	1,185,501	6.1701
53	MANATE 2	802	221,815	42.5	94.6	71.0	10,338	Heavy Oil BBLS ->	358,387	6,400,000	2,293,677	9,746,332	4.3939
54			23,524					Gas MCF ->	242,565	1,000,000	242,565	1,413,166	6.0073
56	CUTLER 5	70	2,980	5.9	97.8	63.9	13,766	Gas MCF ->	41,023	1,000,000	41,023	241,397	8.1003
58	CUTLER 6	142	5,626	5.5	97.0	52.0	12,107	Gas MCF ->	68,107	1,000,000	68,107	400,619	7.1212
60	MARTIN 1	813	137,104	38.2	96.2	66.7	10,942	Heavy Oil BBLS ->	229,433	6,400,001	1,468,374	6,313,903	4.6052
61			86,228					Gas MCF ->	975,433	1,000,000	975,433	5,895,437	6.8370
63	MARTIN 2	795	182,600	52.1	96.3	71.7	10,668	Heavy Oil BBLS ->	298,209	6,400,000	1,908,540	8,206,559	4.4943
64			115,865					Gas MCF ->	1,275,577	1,000,000	1,275,577	7,559,334	6.5243
66	MARTIN 3	465	285,181	85.2	93.1	93.8	7,127	Gas MCF ->	2,032,534	1,000,000	2,032,534	11,947,970	4.1896
68	MARTIN 4	466	281,791	84.0	94.5	93.7	7,041	Gas MCF ->	1,984,137	1,000,000	1,984,137	11,663,468	4.1390

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Nov-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
69													
70	FM GT	624	272	0.1	90.8	57.5	16,668	Light Oil BBLS ->	777	5,830,072	4,529	29,000	10.6735
71													
72	FL GT	768	21	0.4	91.8	63.5	16,348	Light Oil BBLS ->	55	5,827,273	321	2,200	10.6796
73			2,119					Gas MCF ->	34,655	1,000,000	34,655	205,183	9.6835
74													
75	PE GT	384	90	0.6	88.4	57.2	17,500	Light Oil BBLS ->	259	5,830,247	1,511	9,700	10.7301
76			1,582					Gas MCF ->	27,761	1,000,000	27,761	163,856	10.3556
77													
78	SJRPP 1O	130	84,034	89.8	93.7	99.5	9,634	Coal TONS ->	33,139	24,430,016	809,591	1,237,700	1.4728
79													
80	SJRPP 2O	130	84,383	90.2	93.9	99.6	9,495	Coal TONS ->	32,795	24,430,035	801,178	1,224,900	1.4516
81													
82	SCHER #4	648	371,902	79.7	93.5	88.5	9,823	Coal TONS ->	208,762	17,500,005	3,653,341	5,748,800	1.5458
83													
84	FMREP 1	1,467	802,984	76.0	83.0	84.4	7,070	Gas MCF ->	5,677,211	1,000,000	5,677,211	33,372,645	4.1561
85													
86	SNREP4	950	545,593	79.8	88.4	90.1	6,862	Gas MCF ->	3,744,094	1,000,000	3,744,094	22,009,044	4.0340
87													
88	SNREP5	950	555,296	81.2	95.2	92.9	7,055	Gas MCF ->	3,917,775	1,000,000	3,917,775	23,232,679	4.1838
89													
90	FM SC	326	4,687	19.0	97.2	82.2	10,463	Light Oil BBLS ->	8,191	5,829,949	47,753	321,900	6.4733
91			39,822					Gas MCF ->	432,828	1,000,000	432,828	2,549,356	6.2590
92													
93	MR SC	326	0	0.0	0.0	0.0	0	Light Oil BBLS ->	0	0	0	0	0.0000
94			0					Gas MCF ->	0	0	0	0	0.0000
95													
96	TOTAL	18,971	6,878,093				9,053				62,268,761	231,203,701	3.3615

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Dec-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
1	TRKY O 1	398	39,443	17.7	95.2	58.0	10,509	Heavy Oil BBLS ->	58,456	6,399,999	374,118	1,633,940	4.1426
2			12,936					Gas MCF ->	176,351	1,000,000	176,351	1,080,785	8.3551
3													
4	TRKY O 2	398	30,776	15.6	95.0	57.3	10,730	Heavy Oil BBLS ->	45,911	6,400,001	293,828	1,283,306	4.1699
5			15,316					Gas MCF ->	200,730	1,000,000	200,730	1,231,676	8.0416
6													
7	TRKY N 3	717	520,110	97.5	97.5	100.0	11,180	Nuclear Othr ->	5,815,045	1,000,000	5,815,045	1,705,300	0.3279
8													
9	TRKY N 4	717	520,110	97.5	97.5	100.0	10,897	Nuclear Othr ->	5,667,426	1,000,000	5,667,426	1,507,900	0.2899
10													
11	FT LAUD4	440	287,924	88.0	94.3	93.1	7,997	Gas MCF ->	2,302,636	1,000,000	2,302,636	14,099,643	4.8970
12													
13	FT LAUD5	442	279,217	84.9	94.9	89.9	7,987	Gas MCF ->	2,230,185	1,000,000	2,230,185	13,655,854	4.8908
14													
15	PT EVER1	212	3,021	5.4	96.0	45.1	14,154	Heavy Oil BBLS ->	4,615	6,399,961	29,534	125,977	4.1700
16			5,571					Gas MCF ->	92,078	1,000,000	92,078	565,710	10.1544
17													
18	PT EVER2	212	5,980	8.5	95.8	53.5	11,072	Heavy Oil BBLS ->	7,193	6,399,969	46,037	196,373	3.2838
19			7,449					Gas MCF ->	102,645	1,000,000	102,645	629,005	8.4445
20													
21	PT EVER3	392	79,326	33.2	95.4	69.7	10,530	Heavy Oil BBLS ->	124,994	6,400,002	799,964	3,413,113	4.3026
22			17,534					Gas MCF ->	219,934	1,000,000	219,934	1,356,998	7.7394
23													
24	PT EVER4	398	13,029	8.1	52.2	47.7	12,047	Heavy Oil BBLS ->	22,235	6,400,012	142,302	607,116	4.6598
25			11,078					Gas MCF ->	148,112	1,000,000	148,112	930,554	8.4000
26													
27	RIV 3	284	86,176	66.9	93.7	74.7	10,389	Heavy Oil BBLS ->	136,729	6,400,001	875,064	3,737,975	4.3376
28			55,086					Gas MCF ->	592,527	1,000,000	592,527	3,642,875	6.6131
29													
30	RIV 4	286	5,882	4.8	66.1	48.7	10,912	Heavy Oil BBLS ->	6,781	6,400,018	43,400	185,437	3.1525
31			4,420					Gas MCF ->	69,019	1,000,000	69,019	423,054	9.5709
32													
33	ST LUC 1	853	618,763	97.5	97.5	100.0	10,718	Nuclear Othr ->	6,631,784	1,000,000	6,631,784	1,796,600	0.2904
34													

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Dec-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned *Fuel Cost* ($)	(M) Fuel Cost *per KWH* (C/KWH)
35	ST LUC 2	726	169,861	31.5	31.5	100.0	10,746	Nuclear Othr ->	1,825,285	1,000,000	1,825,285	577,200	0.3398
36													
37	CAP CN 1	398	55,452	25.4	95.4	61.5	10,521	Heavy Oil BBLS ->	85,506	6,400,003	547,237	2,314,801	4.1745
38			19,769					Gas MCF ->	244,188	1,000,000	244,188	1,501,700	7.5962
39													
40	CAP CN 2	398	99,464	39.3	95.2	74.3	9,937	Heavy Oil BBLS ->	149,289	6,400,000	955,450	4,041,406	4.0632
41			16,899					Gas MCF ->	200,842	1,000,000	200,842	1,233,256	7.2979
42													
43	SANFRD 3	142	2,858	8.1	95.4	58.4	11,600	Heavy Oil BBLS ->	3,965	6,400,076	25,373	116,079	4.0620
44			5,735					Gas MCF ->	74,305	1,000,000	74,305	462,804	8.0698
45													
46	PUTNAM 1	250	958	13.7	95.7	74.3	9,296	Light Oil BBLS ->	1,457	5,829,868	8,495	55,500	5.7951
47			24,456					Gas MCF ->	227,761	1,000,000	227,761	1,426,849	5.8344
48													
49	PUTNAM 2	250	694	11.2	95.5	63.8	9,650	Light Oil BBLS ->	1,096	5,830,170	6,389	41,800	6.0231
50			20,073					Gas MCF ->	194,016	1,000,000	194,016	1,215,814	6.0569
51													
52	MANATE 1	802	108,691	21.7	95.8	55.1	10,784	Heavy Oil BBLS ->	183,423	6,399,999	1,173,908	4,929,658	4.5355
53			20,841					Gas MCF ->	222,917	1,000,000	222,917	1,352,313	6.4889
54													
55	MANATE 2	802	148,980	28.8	94.6	62.8	10,409	Heavy Oil BBLS ->	242,470	6,399,999	1,551,807	6,516,505	4.3741
56			22,844					Gas MCF ->	236,704	1,000,000	236,704	1,435,992	6.2862
57													
58	CUTLER 5	70	3,460	6.6	97.8	60.0	13,797	Gas MCF ->	47,741	1,000,000	47,741	292,362	8.4490
59													
60	CUTLER 6	142	5,665	5.4	97.1	47.1	12,271	Gas MCF ->	69,521	1,000,000	69,521	425,911	7.5178
61													
62	MARTIN 1	813	69,448	19.9	96.2	55.4	11,156	Heavy Oil BBLS ->	117,656	6,399,998	753,000	3,214,563	4.6287
63			50,969					Gas MCF ->	590,342	1,000,000	590,342	3,707,725	7.2745
64													
65	MARTIN 2	795	135,377	40.9	96.3	58.9	10,791	Heavy Oil BBLS ->	223,001	6,400,000	1,427,207	6,092,756	4.5006
66			106,655					Gas MCF ->	1,184,635	1,000,000	1,184,635	7,370,653	6.9107
67													
68	MARTIN 3	465	278,103	80.4	94.7	90.4	7,166	Gas MCF ->	1,992,923	1,000,000	1,992,923	12,203,066	4.3880

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Dec-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
69													
70	MARTIN 4	466	281,232	81.1	94.5	91.0	7,075	Gas MCF ->	1,989,649	1,000,000	1,989,649	12,183,043	4.3320
71													
72	FM GT	624	4,985	1.1	98.4	57.5	16,681	Light Oil BBLS ->	14,263	5,830,009	83,154	529,100	10.6143
73													
74	FL GT	768	7	2.2	91.8	62.9	16,378	Light Oil BBLS ->	18	5,819,209	103	700	10.6061
75			12,484					Gas MCF ->	204,466	1,000,000	204,466	1,253,426	10.0403
76													
77	PE GT	384	28	2.5	88.4	55.3	17,797	Light Oil BBLS ->	81	5,831,073	473	3,000	10.7527
78			7,212					Gas MCF ->	128,377	1,000,000	128,377	786,757	10.9091
79													
80	SJRPP 1O	130	86,081	89.0	93.7	98.8	9,634	Coal TONS ->	33,917	24,450,037	829,282	1,291,000	1.4998
81													
82	SJRPP 2O	130	86,422	89.4	93.9	98.9	9,494	Coal TONS ->	33,559	24,450,006	820,515	1,277,300	1.4780
83													
84	SCHER #4	648	379,246	78.7	93.5	87.8	9,824	Coal TONS ->	212,906	17,500,001	3,725,862	5,862,600	1.5459
85													
86	FMREP 1	1,467	845,823	77.5	89.0	87.6	7,053	Gas MCF ->	5,965,933	1,000,000	5,965,933	36,530,593	4.3189
87													
88	SNREP4	950	530,153	75.0	82.5	84.8	6,934	Gas MCF ->	3,675,908	1,000,000	3,675,908	22,542,495	4.2521
89													
90	SNREP5	950	559,436	79.2	95.2	88.6	7,127	Gas MCF ->	3,987,108	1,000,000	3,987,108	24,697,027	4.4146
91													
92	FM SC	326	3,117	29.3	97.2	76.8	10,560	Light Oil BBLS ->	5,429	5,830,068	31,651	207,900	6.4205
93			67,997					Gas MCF ->	733,652	1,000,000	733,652	4,496,674	6.4960
94													
95	MR SC	326	0	0.0	0.0	0.0	0	Light Oil BBLS ->	0	0	0	0	0.0000
96			0					Gas MCF ->	0	0	0	0	0.0000
97													
98	TOTAL	18,971	6,850,619				9,136				62,588,891	225,999,521	3.2990

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-04 Thru Dec-04

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)
	Plant Unit	Net Capb (MW)	Net Gen (MWH)	Capac FAC (%)	Equiv Avail FAC (%)	Net Out FAC (%)	Avg Net Heat Rate (BTU/KWH)	Fuel Type	Fuel Burned (Units)	Fuel Heat Value (BTU/Unit)	Fuel Burned (MMBTU)	As Burned Fuel Cost ($)	Fuel Cost per KWH (C/KWH)
1	TRKY O 1	396	927,641	32.4	95.2	63.6	10,208	Heavy Oil BBLS ->	1,413,228	6,400,000	9,044,658	38,939,497	4.1977
2			198,411					Gas MCF ->	2,449,855	1,000,000	2,449,855	14,318,369	7.2165
3													
4	TRKY O 2	396	950,654	33.8	89.6	68.5	10,131	Heavy Oil BBLS ->	1,442,012	6,400,000	9,228,875	39,630,673	4.1688
5			223,503					Gas MCF ->	2,666,951	1,000,000	2,666,951	15,576,252	6.9691
6													
7	TRKY N 3	703	4,950,735	80.2	80.2	100.0	11,211	Nuclear Othr ->	55,501,093	1,000,000	55,501,093	14,882,900	0.3006
8													
9													
10	TRKY N 4	703	6,020,518	97.5	97.5	100.0	11,097	Nuclear Othr ->	66,810,046	1,000,000	66,810,046	18,092,200	0.3005
11													
12	FT LAUD4	430	2,797,514	74.2	79.8	93.3	7,966	Gas MCF ->	22,285,895	1,000,000	22,285,895	130,571,941	4.6674
13													
14													
15	FT LAUD5	432	3,010,072	79.4	90.5	90.5	7,888	Gas MCF ->	23,742,755	1,000,000	23,742,755	140,647,220	4.6726
16													
17	PT EVER1	211	226,079	17.2	96.0	55.4	11,472	Heavy Oil BBLS ->	361,353	6,399,998	2,312,659	9,624,885	4.2573
18			92,749					Gas MCF ->	1,345,060	1,000,000	1,345,060	8,041,647	8.6704
19													
20	PT EVER2	211	337,572	21.9	82.7	69.7	10,437	Heavy Oil BBLS ->	507,670	6,400,001	3,249,089	13,586,791	4.0249
21			68,944					Gas MCF ->	993,824	1,000,000	993,824	5,894,522	8.5498
22													
23													
24	PT EVER3	391	1,514,859	50.6	95.4	72.2	10,143	Heavy Oil BBLS ->	2,353,952	6,400,000	15,065,293	62,757,216	4.1428
25			221,988					Gas MCF ->	2,552,260	1,000,000	2,552,260	15,214,785	6.8539
26													
27	PT EVER4	396	1,469,236	47.6	91.6	72.3	10,260	Heavy Oil BBLS ->	2,301,062	6,400,000	14,726,796	61,498,655	4.1858
28			185,207					Gas MCF ->	2,247,790	1,000,000	2,247,790	13,474,421	7.2753
29													
30	RIV 3	283	682,505	43.9	93.7	70.5	10,587	Heavy Oil BBLS ->	1,075,311	6,400,001	6,881,988	28,988,396	4.2474
31			408,436					Gas MCF ->	4,668,221	1,000,000	4,668,221	27,946,404	6.8423
32													
33	RIV 4	285	794,170	45.1	88.0	72.8	10,365	Heavy Oil BBLS ->	1,232,245	6,400,000	7,886,366	33,191,858	4.1794
34			334,850					Gas MCF ->	3,815,721	1,000,000	3,815,721	22,995,792	6.8675

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-04 Thru Dec-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
35													
36	ST LUC 1	845	6,741,235	90.8	90.8	100.0	10,775	Nuclear Othr ->	72,635,044	1,000,000	72,635,044	19,268,400	0.2858
37													
38	ST LUC 2	719	5,647,674	89.4	89.5	99.9	10,772	Nuclear Othr ->	60,837,184	1,000,000	60,837,184	16,802,700	0.2975
39													
40	CAP CN 1	396	951,010	32.1	95.4	66.4	10,183	Heavy Oil BBLS ->	1,451,179	6,400,000	9,287,548	38,510,755	4.0495
41			165,793					Gas MCF ->	2,084,674	1,000,000	2,084,674	12,549,792	7.5696
42													
43	CAP CN 2	396	1,227,955	39.3	95.2	71.5	9,927	Heavy Oil BBLS ->	1,846,049	6,400,001	11,814,717	49,196,148	4.0063
44			138,152					Gas MCF ->	1,746,269	1,000,000	1,746,269	10,415,954	7.5395
45													
46	SANFRD 3	140	67,536	12.2	75.9	54.8	11,296	Heavy Oil BBLS ->	105,550	6,399,995	675,520	3,066,890	4.5411
47			82,012					Gas MCF ->	1,013,772	1,000,000	1,013,772	6,081,577	7.4155
48			0						0		0	0	0.0000
49													
50	PUTNAM 1	244	18,831	28.0	94.4	80.3	9,990	Light Oil BBLS ->	30,783	5,829,984	179,464	1,217,800	6.4671
51			580,846					Gas MCF ->	5,811,557	1,000,000	5,811,557	34,738,544	5.9807
52													
53	PUTNAM 2	244	18,302	26.5	94.2	80.4	9,697	Light Oil BBLS ->	28,804	5,829,985	167,927	1,133,500	6.1932
54			548,049					Gas MCF ->	5,324,122	1,000,000	5,324,122	31,608,847	5.7675
55													
56	MANATE 1	798	1,904,451	31.3	95.8	49.7	10,600	Heavy Oil BBLS ->	3,154,905	6,400,000	20,191,395	85,205,773	4.4740
57			289,194					Gas MCF ->	3,061,042	1,000,000	3,061,042	17,593,364	6.0836
58													
59	MANATE 2	798	1,626,386	29.3	75.2	49.2	10,453	Heavy Oil BBLS ->	2,655,519	6,400,000	16,995,321	71,439,640	4.3925
60			428,208					Gas MCF ->	4,480,343	1,000,000	4,480,343	25,479,641	5.9503
61			0						0		0	0	0.0000
62													
63	CUTLER 5	69	95,336	15.8	97.8	61.0	13,559	Gas MCF ->	1,292,652	1,000,000	1,292,652	7,445,732	7.8100
64													
65	CUTLER 6	140	162,539	13.2	97.0	47.9	12,526	Gas MCF ->	2,035,981	1,000,000	2,035,981	11,723,562	7.2128
66													
67	MARTIN 1	810	1,816,573	41.2	96.2	57.9	10,437	Heavy Oil BBLS ->	2,902,058	6,400,000	18,573,169	77,824,402	4.2841
68			1,113,757					Gas MCF ->	12,011,821	1,000,000	12,011,821	70,490,197	6.3290

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-04 Thru Dec-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
69													
70	MARTIN 2	793	1,729,764	42.0	96.3	53.1	10,416	Heavy Oil BBLS ->	2,755,289	6,400,000	17,633,848	74,280,182	4.2942
71			1,199,162					Gas MCF ->	12,873,277	1,000,000	12,873,277	76,198,816	6.3543
72													
73	MARTIN 3	452	3,078,008	77.5	93.4	88.2	7,233	Gas MCF ->	22,261,950	1,000,000	22,261,950	131,402,397	4.2691
74													
75	MARTIN 4	453	3,089,719	77.7	90.7	87.3	7,184	Gas MCF ->	22,198,065	1,000,000	22,198,065	130,738,615	4.2314
76													
77	FM GT	582	310,581	6.1	96.5	62.0	15,242	Light Oil BBLS ->	811,960	5,829,999	4,733,727	29,694,200	9.5609
78													
79	FL GT	719	1,070	7.7	91.8	67.0	17,374	Light Oil BBLS ->	3,040	5,829,906	17,720	120,900	11.3043
80			485,621					Gas MCF ->	8,438,252	1,000,000	8,438,252	48,345,072	9.9553
81													
82	PE GT	363	2,007	8.9	88.4	58.6	18,854	Light Oil BBLS ->	6,112	5,830,028	35,631	229,700	11.4438
83			281,151					Gas MCF ->	5,303,064	1,000,000	5,303,064	30,396,107	10.8113
84													
85	SJRPP 1O	128	996,424	88.4	93.7	98.1	9,531	Coal TONS ->	388,479	24,446,762	9,497,063	14,697,600	1.4750
86													
87	SJRPP 2O	128	840,327	74.6	79.0	98.2	9,387	Coal TONS ->	322,655	24,448,864	7,888,543	12,185,700	1.4501
88													
89													
90	SCHER #4	645	3,886,182	68.6	82.3	86.8	9,927	Coal TONS ->	2,204,548	17,500,001	38,579,584	61,716,400	1.5881
91													
92													
93	FMREP 1	1,441	10,258,396	81.0	92.0	90.6	7,104	Gas MCF ->	72,870,821	1,000,000	72,870,821	430,264,485	4.1943
94													
95	SNREP4	914	6,577,093	81.9	93.1	92.5	6,905	Gas MCF ->	45,412,003	1,000,000	45,412,003	268,634,319	4.0844
96													
97	SNREP5	914	6,218,314	77.5	94.5	88.6	7,024	Gas MCF ->	43,680,108	1,000,000	43,680,108	260,324,439	4.1864
98													
99	FM SC	310	11,119	21.6	97.2	78.8	10,550	Light Oil BBLS ->	19,334	5,830,030	112,718	740,800	6.4091
100			575,423					Gas MCF ->	6,101,744	1,000,000	6,101,744	35,730,509	6.1673
101													
102	MR SC	310	737	20.7	76.0	78.2	10,651	Light Oil BBLS ->	1,298	5,829,868	7,566	57,600	7.8312

Date: 9/2/2003
Company: Florida Power & Light

Schedule E4

Estimated For The Period of : Jan-04 Thru Dec-04

	(A) Plant Unit	(B) Net Capb (MW)	(C) Net Gen (MWH)	(D) Capac FAC (%)	(E) Equiv Avail FAC (%)	(F) Net Out FAC (%)	(G) Avg Net Heat Rate (BTU/KWH)	(H) Fuel Type	(I) Fuel Burned (Units)	(J) Fuel Heat Value (BTU/Unit)	(K) Fuel Burned (MMBTU)	(L) As Burned Fuel Cost ($)	(M) Fuel Cost per KWH (C/KWH)
103			560,582					Gas MCF ->	5,954,123	1,000,000	5,954,123	34,787,705	6.2378
104													
105	TOTAL	18,583	89,141,159				9,326				831,294,522	2,948,213,187	3.3074

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : January 2004 thru December 2004

			January 2004	February 2004	March 2004	April 2004	May 2004	June 2004
	Heavy Oil							
1	Purchases:							
2	Units	(BBLS)	999,777	451,164	1,416,595	1,993,038	2,772,333	3,017,564
3	Unit Cost	($/BBLS)	24.6475	23.5347	24.3309	25.2991	26.1552	26.4389
4	Amount	($)	24,642,000	10,618,000	34,467,000	50,422,000	72,511,000	79,781,000
5								
6	Burned:							
7	Units	(BBLS)	942,595	926,932	1,744,878	1,694,355	2,066,963	2,717,564
8	Unit Cost	($/BBLS)	28.9083	28.7472	26.8975	26.3269	26.1361	26.2064
9	Amount	($)	27,248,782	26,646,686	46,932,866	44,607,040	54,022,406	71,217,656
10								
11	Ending Inventory:							
12	Units	(BBLS)	4,000,000	3,524,232	3,195,947	3,494,630	4,200,001	4,500,000
13	Unit Cost	($/BBLS)	28.3789	27.9640	27.1768	26.6034	26.4672	26.5026
14	Amount	($)	113,515,468	98,551,714	86,855,628	92,969,036	111,162,295	119,261,566
15								
16	Light Oil							
17								
18								
19	Purchases:							
20	Units	(BBLS)	16,118	5,982	5,564	161,163	106,205	118,986
21	Unit Cost	($/BBLS)	34.4961	33.7680	31.9914	34.6295	35.0831	35.2310
22	Amount	($)	625,000	202,000	178,000	5,581,000	3,726,000	4,192,000
23								
24	Burned:							
25	Units	(BBLS)	16,362	5,982	10,784	104,737	106,217	119,083
26	Unit Cost	($/BBLS)	38.9436	38.7329	39.8503	36.7964	36.0771	36.0088
27	Amount	($)	637,210	231,700	429,750	3,853,940	3,832,000	4,288,040
28								
29	Ending Inventory:							
30	Units	(BBLS)	534,794	534,794	528,039	584,464	584,452	584,336
31	Unit Cost	($/BBLS)	40.1403	40.0863	40.0252	39.1155	38.9356	38.7775
32	Amount	($)	21,466,767	21,437,689	21,134,889	22,861,602	22,756,013	22,659,065
33								
34	Coal - SJRPP							
35								
36								
37	Purchases:							
38	Units	(Tons)	67,559	59,798	33,936	35,787	63,505	66,544
39	Unit Cost	($/Tons)	38.5685	39.0481	39.0146	35.9069	36.5798	38.3806
40	Amount	($)	2,607,000	2,335,000	1,324,000	1,285,000	2,323,000	2,554,000
41								
42	Burned:							
43	Units	(Tons)	67,559	59,798	33,936	35,787	63,505	62,022
44	Unit Cost	($/Tons)	37.8982	38.5288	38.7218	37.4686	36.9678	37.8144
45	Amount	($)	2,560,367	2,303,944	1,314,062	1,340,869	2,347,637	2,345,326
46								
47	Ending Inventory:							
48	Units	(Tons)	45,217	45,217	45,217	45,217	45,217	49,739
49	Unit Cost	($/Tons)	38.2228	38.9148	39.1390	37.9022	37.3554	38.1530
50	Amount	($)	1,728,321	1,759,610	1,769,746	1,713,825	1,689,099	1,897,691
51								
52	Coal - SCHERER							
53								
54								
55	Purchases:							
56	Units	(MBTU)	3,754,748	3,189,883	0	2,165,765	3,687,915	3,901,048
57	Unit Cost	($/MBTU)	1.5735	1.5734		1.5736	1.5735	1.5734
58	Amount	($)	5,908,000	5,019,000	0	3,408,000	5,803,000	6,138,000
59								
60	Burned:							
61	Units	(MBTU)	3,754,748	3,189,883	0	2,165,765	3,687,915	3,610,495
62	Unit Cost	($/MBTU)	1.7258	1.6461		1.6150	1.5918	1.5812
63	Amount	($)	6,480,004	5,250,739	0	3,497,807	5,870,264	5,709,090
64								
65	Ending Inventory:							
66	Units	(MBTU)	2,905,543	2,905,543	2,905,543	2,905,543	2,905,525	3,196,078
67	Unit Cost	($/MBTU)	1.7258	1.6461	1.6461	1.6150	1.5918	1.5813
68	Amount	($)	5,014,427	4,782,706	4,782,706	4,692,567	4,624,929	5,053,823
69								
70	Gas							
71								
72								
73	Burned:							
74	Units	(MCF)	24,459,787	22,514,019	25,658,624	28,394,690	30,978,378	31,647,021
75	Unit Cost	($/MCF)	6.5250	6.4811	6.2900	5.9409	5.7180	5.7198
76	Amount	($)	159,600,680	145,915,370	161,393,840	168,690,230	177,134,700	181,015,020
77								
78	Nuclear							
79								
80								
81	Burned:							
82	Units	(MBTU)	23,772,693	22,238,966	21,633,435	19,526,900	23,469,148	22,712,081
83	Unit Cost	($/MBTU)	0.2647	0.2638	0.2654	0.2714	0.2724	0.2715
84	Amount	($)	6,292,258	5,867,240	5,741,960	5,300,562	6,392,483	6,166,949

System Generated Fuel Cost
Inventory Analysis
Estimated For the Period of : January 2004 thru December 2004

		July 2004	August 2004	September 2004	October 2004	November 2004	December 2004	Total
Heavy Oil								
1 Purchases:								
2 Units	(BBLS)	3,242,225	3,130,668	2,434,251	2,123,719	1,809,463	1,908,259	25,299,056
3 Unit Cost	($/BBLS)	26.8396	27.6280	28.6043	28.7077	28.1332	26.4456	26.7964
4 Amount	($)	87,020,000	86,494,000	69,630,000	60,967,000	50,906,000	50,465,000	677,923,000
5								
6 Burned:								
7 Units	(BBLS)	3,242,225	3,130,668	2,734,252	2,729,230	2,215,490	1,412,224	25,557,376
8 Unit Cost	($/BBLS)	26.3571	26.6340	26.9259	27.5511	27.5352	27.1976	26.9097
9 Amount	($)	85,455,658	83,382,297	73,622,129	75,193,416	61,003,941	38,409,085	687,741,961
10								
11 Ending Inventory:								
12 Units	(BBLS)	4,500,001	4,499,999	4,200,000	3,594,488	3,188,461	3,684,497	3,684,497
13 Unit Cost	($/BBLS)	26.6856	27.0992	27.6339	27.9925	28.0812	27.5129	27.5129
14 Amount	($)	120,085,387	121,946,339	116,062,434	100,618,748	89,535,683	101,371,068	101,371,068
15								
16 Light Oil								
17								
18								
19 Purchases:								
20 Units	(BBLS)	135,484	132,512	129,366	6,749	9,227	73,444	902,800
21 Unit Cost	($/BBLS)	35.6943	37.2721	38.4181	36.8944	37.7154	36.5449	36.0323
22 Amount	($)	4,836,000	4,939,000	4,970,000	249,000	348,000	2,684,000	32,530,000
23								
24 Burned:								
25 Units	(BBLS)	136,614	133,385	129,736	106,803	9,282	22,344	901,329
26 Unit Cost	($/BBLS)	36.3234	36.7806	37.4452	37.4042	39.0875	37.5121	36.8286
27 Amount	($)	4,962,290	4,905,970	4,857,980	3,994,880	362,810	838,170	33,194,740
28								
29 Ending Inventory:								
30 Units	(BBLS)	583,190	582,300	581,899	481,835	481,780	531,762	531,762
31 Unit Cost	($/BBLS)	38.6346	38.7492	38.9674	39.2873	39.2601	38.9638	38.9638
32 Amount	($)	22,531,296	22,563,654	22,675,062	18,930,016	18,914,742	20,719,478	20,719,478
33								
34 Coal - SJRPP								
35								
36								
37 Purchases:								
38 Units	(Tons)	64,467	63,821	62,414	59,891	65,934	67,476	711,132
39 Unit Cost	($/Tons)	37.6161	38.4043	38.4048	36.2158	37.4920	38.5174	37.8847
40 Amount	($)	2,425,000	2,451,000	2,397,000	2,169,000	2,472,000	2,599,000	26,941,000
41								
42 Burned:								
43 Units	(Tons)	64,467	63,821	62,414	64,413	65,934	67,476	711,132
44 Unit Cost	($/Tons)	37.6790	38.0833	38.2589	37.1384	37.3484	38.0617	37.8026
45 Amount	($)	2,429,053	2,430,515	2,387,888	2,392,196	2,462,532	2,568,253	26,882,662
46								
47 Ending Inventory:								
48 Units	(Tons)	49,739	49,739	49,739	45,217	45,217	45,217	45,217
49 Unit Cost	($/Tons)	38.0795	38.4837	38.6590	37.5769	37.7889	38.4714	38.4714
50 Amount	($)	1,894,036	1,914,141	1,922,860	1,699,204	1,708,699	1,739,562	1,739,562
51								
52 Coal - SCHERER								
53								
54								
55 Purchases:								
56 Units	(MBTU)	3,749,270	3,714,953	3,617,565	3,419,238	3,653,335	3,725,855	38,579,573
57 Unit Cost	($/MBTU)	1.5734	1.5734	1.5734	1.5735	1.5734	1.5733	1.5734
58 Amount	($)	5,899,000	5,845,000	5,692,000	5,380,000	5,748,000	5,862,000	60,702,000
59								
60 Burned:								
61 Units	(MBTU)	3,749,270	3,714,953	3,617,565	3,709,790	3,653,335	3,725,855	38,579,573
62 Unit Cost	($/MBTU)	1.5770	1.5751	1.5742	1.5738	1.5736	1.5735	1.5997
63 Amount	($)	5,912,689	5,851,354	5,694,778	5,836,441	5,748,847	5,862,615	61,716,628
64								
65 Ending Inventory:								
66 Units	(MBTU)	3,196,078	3,196,078	3,196,078	2,905,525	2,905,525	2,905,543	2,905,543
67 Unit Cost	($/MBTU)	1.5770	1.5751	1.5742	1.5738	1.5736	1.5735	1.5735
68 Amount	($)	5,040,316	5,034,126	5,031,299	4,572,737	4,572,126	4,571,853	4,571,853
69								
70 Gas								
71								
72								
73 Burned:								
74 Units	(MCF)	34,437,365	34,167,473	32,422,697	31,278,038	26,660,646	28,105,203	350,723,939
75 Unit Cost	($/MCF)	5.5916	5.6631	5.6139	5.6846	5.8990	6.1460	5.9010
76 Amount	($)	192,558,560	193,494,760	182,017,640	177,804,620	157,270,190	172,734,370	2,069,629,980
77								
78 Nuclear								
79								
80								
81 Burned:								
82 Units	(MBTU)	23,469,148	23,469,148	21,619,143	17,822,428	16,110,750	19,939,540	255,783,380
83 Unit Cost	($/MBTU)	0.2708	0.2700	0.2695	0.2707	0.2703	0.2802	0.2699
84 Amount	($)	6,356,262	6,336,279	5,826,111	4,823,903	4,355,119	5,586,899	69,046,025

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POWER SOLD

Estimated For the Period of : January 2004 Thru December 2004

(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWH Sold	(5) MWH Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWH)	(7B) Total Cost Cents / KWH	(8) Total $ For Fuel Adjustment (6) * (7A)	(9) Total Cost $ (6)*(7B)	(10) $ Gain From Off System Sales
January		OS	185,000		185,000	3.769	4.539	6,973,200	8,397,500	810,110
2004	St.Lucie Rel.		46,083		46,083	0.257	0.257	118,423	118,423	0
Total			231,083	0	231,083	3.069	3.685	7,091,623	8,515,923	810,110
February		OS	165,000		165,000	3.626	4.468	5,983,200	7,372,500	848,796
2004	St.Lucie Rel.		43,110		43,110	0.256	0.256	110,417	110,417	0
Total			208,110	0	208,110	2.928	3.596	6,093,617	7,482,917	848,796
March		OS	85,000		85,000	3.964	4.751	3,369,650	4,038,750	393,382
2004	St.Lucie Rel.		31,218		31,218	0.255	0.255	79,693	79,693	0
Total			116,218	0	116,218	2.968	3.544	3,449,343	4,118,443	393,382
April		OS	74,000		74,000	3.899	4.849	2,885,420	3,588,500	470,140
2004	St.Lucie Rel.		21,933		21,933	0.292	0.292	64,001	64,001	0
Total			95,933	0	95,933	3.074	3.807	2,949,421	3,652,501	470,140
May		OS	85,000		85,000	3.876	4.968	3,294,550	4,222,500	642,100
2004	St.Lucie Rel.		45,328		45,328	0.299	0.299	135,409	135,409	0
Total			130,328	0	130,328	2.632	3.344	3,429,959	4,357,909	642,100
June		OS	95,000		95,000	4.046	5.037	3,844,100	4,785,000	620,450
2004	St.Lucie Rel.		43,866		43,866	0.298	0.298	130,641	130,641	0
Total			138,866	0	138,866	2.862	3.540	3,974,741	4,915,641	620,450

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Company: Florida Power & Light

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POWER SOLD

Estimated For the Period of : January 2004 Thru December 2004

(1) Month	(2) Sold To	(3) Type & Schedule	(4) Total MWH Sold	(5) MWH Wheeled From Other Systems	(6) MWH From Own Generation	(7A) Fuel Cost (Cents / KWH)	(7B) Total Cost Cents / KWH	(8) Total $ For Fuel Adjustment (6) * (7A)	(9) Total Cost $ (6)*(7B)	(10) $ Gain From Off System Sales
July		OS	105,000		105,000	4.212	5.386	4,422,550	5,655,000	877,400
2004	St.Lucie Rel.		45,328		45,328	0.298	0.298	134,895	134,895	0
Total			150,328	0	150,328	3.032	3.852	4,557,445	5,789,895	877,400
August		OS	105,000		105,000	4.281	5.388	4,495,150	5,657,500	807,300
2004	St.Lucie Rel.		45,328		45,328	0.297	0.297	134,480	134,480	0
Total			150,328	0	150,328	3.080	3.853	4,629,630	5,791,980	807,300
September		OS	85,000		85,000	4.327	5.226	3,678,150	4,442,500	478,500
2004	St.Lucie Rel.		43,866		43,866	0.296	0.296	129,727	129,727	0
Total			128,866	0	128,866	2.955	3.548	3,807,877	4,572,227	478,500
October		OS	77,000		77,000	4.303	4.995	3,313,030	3,846,500	278,600
2004	St.Lucie Rel.		45,328		45,328	0.295	0.295	133,662	133,662	0
Total			122,328	0	122,328	2.818	3.254	3,446,692	3,980,162	278,600
November		OS	90,000		90,000	4.482	5.078	4,033,400	4,570,000	241,700
2004	St.Lucie Rel.		44,597		44,597	0.291	0.291	129,910	129,910	0
Total			134,597	0	134,597	3.093	3.492	4,163,310	4,699,910	241,700
December		OS	150,000		150,000	4.140	4.858	6,210,500	7,287,500	580,146
2004	St.Lucie Rel.		46,083		46,083	0.290	0.290	133,808	133,808	0
Total			196,083	0	196,083	3.236	3.785	6,344,308	7,421,308	580,146
Period		OS	1,301,000		1,301,000	4.036	4.909	52,502,900	63,863,750	7,048,624
	St.Lucie Rel.		502,068		502,068	0.286	0.286	1,435,065	1,435,065	0
Total			1,803,068	0	1,803,068	2.991	3.622	53,937,965	65,298,815	7,048,624

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Company: Florida Power & Light

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Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2004 thru December 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2004 January	Sou. Co. (UPS + R)		645,480			645,480	1.876		12,110,000
	St. Lucie Rel.		46,084			46,084	0.300		138,083
	SJRPP		265,976			265,976	1.506		4,006,000
	PPAs		97,253			97,253	7.286		7,086,244
	FPC		37,200			37,200	1.985		738,550
Total			1,091,993			1,091,993	2.205		24,078,877
2004 February	Sou. Co. (UPS + R)		538,120			538,120	1.876		10,095,000
	St. Lucie Rel.		43,110			43,110	0.299		128,758
	SJRPP		234,687			234,687	1.527		3,584,000
	PPAs		96,462			96,462	7.210		6,954,653
	FPC		34,750			34,750	1.996		693,752
Total			947,129			947,129	2.265		21,456,163
2004 March	Sou. Co. (UPS + R)		611,047			611,047	1.876		11,463,000
	St. Lucie Rel.		46,084			46,084	0.298		137,191
	SJRPP		130,786			130,786	1.538		2,011,000
	PPAs		97,861			97,861	6.738		6,593,835
	FPC		37,200			37,200	1.985		738,550
Total			922,978			922,978	2.269		20,943,576
2004 April	Sou. Co. (UPS + R)		621,876			621,876	1.876		11,666,000
	St. Lucie Rel.		43,867			43,867	0.299		131,102
	SJRPP		140,658			140,658	1.387		1,951,000
	PPAs		156,576			156,576	6.144		9,620,594
	FPC		36,000			36,000	1.991		716,650
Total			998,977			998,977	2.411		24,085,346
2004 May	Sou. Co. (UPS + R)		648,444			648,444	1.876		12,165,000
	St. Lucie Rel.		45,329			45,329	0.298		135,030
	SJRPP		252,201			252,201	1.404		3,540,000
	PPAs		93,622			93,622	6.186		5,791,334
	FPC		37,200			37,200	1.985		738,550
Total			1,076,796			1,076,796	2.077		22,369,914
2004 June	Sou. Co. (UPS + R)		668,159			668,159	1.876		12,535,000
	St. Lucie Rel.		43,867			43,867	0.297		130,261
	SJRPP		247,740			247,740	1.472		3,646,000
	PPAs		126,793			126,793	6.132		7,775,022
	FPC		36,000			36,000	1.991		716,650
Total			1,122,559			1,122,559	2.209		24,802,933
Period Total	Sou. Co. (UPS + R)		3,733,126			3,733,126	1.876		70,034,000
	St. Lucie Rel.		268,341			268,341	0.298		800,425
	SJRPP		1,272,048			1,272,048	1.473		18,738,000
	PPAs		668,567			668,567	6.555		43,821,682
	FPC		218,350			218,350	1.989		4,342,702
Total			6,160,432			6,160,432	2.236		137,736,809

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Purchased Power

(Exclusive of Economy Energy Purchases)

Estimated for the Period of : January 2004 thru December 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2004 July	Sou. Co. (UPS + R)		682,250			682,250	1.876		12,799,000
	St. Lucie Rel.		45,329			45,329	0.296		134,161
	SJRPP		256,946			256,946	1.445		3,713,000
	PPAs		231,478			231,478	5.918		13,699,194
	FPC		37,200			37,200	1.985		738,550
Total			1,253,203			1,253,203	2.480		31,083,905
2004 August	Sou. Co. (UPS + R)		682,250			682,250	1.876		12,799,000
	St. Lucie Rel.		45,329			45,329	0.295		133,734
	SJRPP		254,251			254,251	1.475		3,750,000
	PPAs		194,974			194,974	6.020		11,737,345
	FPC		37,200			37,200	1.985		738,550
Total			1,214,004			1,214,004	2.402		29,158,629
2004 September	Sou. Co. (UPS + R)		668,159			668,159	1.876		12,535,000
	St. Lucie Rel.		43,867			43,867	0.294		128,992
	SJRPP		247,000			247,000	1.475		3,643,000
	PPAs		173,723			173,723	5.946		10,329,304
	FPC		36,000			36,000	1.991		716,650
Total			1,168,749			1,168,749	2.340		27,352,946
2004 October	Sou. Co. (UPS • R)		676,474			676,474	1.876		12,691,000
	St. Lucie Rel.		45,329			45,329	0.293		132,850
	SJRPP		254,880			254,880	1.391		3,545,000
	PPAs		95,311			95,311	5.964		5,684,797
	FPC		37,200			37,200	1.985		738,550
Total			1,109,194			1,109,194	2.055		22,792,197
2004 November	Sou. Co. (UPS + R)		562,561			562,561	1.876		10,554,000
	St. Lucie Rel.		31,218			31,218	0.290		90,568
	SJRPP		254,146			254,146	1.467		3,729,000
	PPAs		38,015			38,015	6.384		2,426,846
	FPC		36,000			36,000	1.991		716,650
Total			921,940			921,940	1.900		17,517,064
2004 December	Sou. Co. (UPS + R)		636,447			636,447	1.876		11,940,000
	St. Lucie Rel.		14,866			14,866	0.339		50,433
	SJRPP		261,184			261,184	1.507		3,935,000
	PPAs		95,186			95,186	6.809		6,481,225
	FPC		37,200			37,200	1.985		738,550
Total			1,044,883			1,044,883	2.215		23,145,208
Period Total	Sou. Co. (UPS + R)		7,641,267			7,641,267	1.876		143,352,000
	St. Lucie Rel.		494,279			494,279	0.298		1,471,163
	SJRPP		2,800,455			2,800,455	1.466		41,053,000
	PPAs		1,497,254			1,497,254	6.290		94,180,393
	FPC		439,150			439,150	1.988		8,730,202
Total			12,872,405			12,872,405	2.243		288,786,758

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Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2004 thru December 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2004 January	Qual. Facilities		615,849			615,849	2.056	2.056	12,664,908
Total			615,849			615,849	2.056	2.056	12,664,908
2004 February	Qual. Facilities		584,380			584,380	2.052	2.052	11,992,554
Total			584,380			584,380	2.052	2.052	11,992,554
2004 March	Qual. Facilities		618,128			618,128	2.055	2.055	12,704,006
Total			618,128			618,128	2.055	2.055	12,704,006
2004 April	Qual. Facilities		517,627			517,627	2.156	2.156	11,158,287
Total			517,627			517,627	2.156	2.156	11,158,287
2004 May	Qual. Facilities		616,400			616,400	2.060	2.060	12,697,137
Total			616,400			616,400	2.060	2.060	12,697,137
2004 June	Qual. Facilities		604,894			604,894	2.071	2.071	12,526,632
Total			604,894			604,894	2.071	2.071	12,526,632
Period Total	Qual. Facilities		3,557,278			3,557,278	2.073	2.073	73,743,524
Total			3,557,278			3,557,278	2.073	2.073	73,743,524

Date: 8/11/2003
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Energy Payment to Qualifying Facilities

Estimated for the Period of : January 2004 thru December 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8A)	(8B)	(9)
Month	Purchase From	Type & Schedule	Total Mwh Purchased	Mwh For Other Utilities	Mwh For Interruptible	Mwh For Firm	Fuel Cost (Cents/Kwh)	Total Cost (Cents/Kwh)	Total $ For Fuel Adj (7) x (8A)
2004 July	Qual. Facilities		618,369			618,369	2.089	2.089	12,916,234
Total			618,369			618,369	2.089	2.089	12,916,234
2004 August	Qual. Facilities		618,309			618,309	2.094	2.094	12,947,931
Total			618,309			618,309	2.094	2.094	12,947,931
2004 September	Qual. Facilities		605,433			605,433	2.095	2.095	12,682,715
Total			605,433			605,433	2.095	2.095	12,682,715
2004 October	Qual. Facilities		617,250			617,250	2.083	2.083	12,855,682
Total			617,250			617,250	2.083	2.083	12,855,682
2004 November	Qual. Facilities		481,305			481,305	2.163	2.163	10,412,845
Total			481,305			481,305	2.163	2.163	10,412,845
2004 December	Qual. Facilities		617,721			617,721	2.057	2.057	12,707,717
Total			617,721			617,721	2.057	2.057	12,707,717
Period Total	Qual. Facilities		7,115,665			7,115,665	2.084	2.084	148,266,648
Total			7,115,665			7,115,665	2.084	2.084	148,266,648

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Company: Florida Power & Light

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Economy Energy Purchases

Estimated For the Period of : January 2004 Thru December 2004

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
January 2004	Florida	C	98,750	2.944	2,907,294	3.797	3,750,000	842,706
	Non-Florida	C	72,292	3.651	2,639,225	3.852	2,784,554	145,329
Total			171,042	3.243	5,546,519	3.820	6,534,554	988,035
February 2004	Florida	C	90,800	2.935	2,665,167	3.658	3,321,096	655,929
	Non-Florida	C	67,628	3.556	2,404,607	3.733	2,524,569	119,962
Total			158,428	3.200	5,069,774	3.690	5,845,665	775,891
March 2004	Florida	C	93,750	2.900	2,718,342	3.980	3,730,888	1,012,546
	Non-Florida	C	80,960	3.569	2,889,130	4.002	3,240,286	351,156
Total			174,710	3.210	5,607,472	3.990	6,971,174	1,363,702
April 2004	Florida	C	18,000	3.456	622,000	3.762	677,140	55,140
	Non-Florida	C	78,348	3.590	2,812,738	3.946	3,091,513	278,775
Total			96,348	3.565	3,434,738	3.912	3,768,653	333,915
May 2004	Florida	C	23,000	3.487	802,000	3.704	851,850	49,850
	Non-Florida	C	74,785	3.625	2,710,922	3.845	2,875,397	164,475
Total			97,785	3.592	3,512,922	3.812	3,727,247	214,325
June 2004	Florida	C	25,000	3.610	902,500	3.871	967,750	65,250
	Non-Florida	C	72,372	3.744	2,709,279	4.017	2,907,170	197,891
Total			97,372	3.709	3,611,779	3.980	3,874,920	263,141
Period Total	Florida	C	349,300	3.040	10,617,303	3.807	13,298,724	2,681,421
	Non-Florida	C	446,385	3.622	16,165,901	3.903	17,423,489	1,257,588
Total			795,685	3.366	26,783,204	3.861	30,722,213	3,939,009

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Economy Energy Purchases

Estimated For the Period of : January 2004 Thru December 2004

(1) Month	(2) Purchase From	(3) Type & Schedule	(4) Total MWH Purchased	(5) Transaction Cost (Cents/KWH)	(6) Total $ For Fuel ADJ (4) * (5)	(7A) Cost If Generated (Cents / KWH)	(7B) Cost If Generated ($)	(8) Fuel Savings (7B) - (6)
July	Florida	C	22,000	3.645	802,000	4.015	883,300	81,300
2004	Non-Florida	C	74,785	3.836	2,868,788	4.181	3,126,992	258,204
Total			96,785	3.793	3,670,788	4.144	4,010,292	339,504
August	Florida	C	22,000	3.700	814,000	4.094	900,660	86,660
2004	Non-Florida	C	74,785	3.836	2,868,788	4.252	3,179,837	311,049
Total			96,785	3.805	3,682,788	4.216	4,080,497	397,709
September	Florida	C	22,000	3.727	820,000	4.087	899,060	79,060
2004	Non-Florida	C	78,348	3.655	2,863,954	4.301	3,369,513	505,559
Total			100,348	3.671	3,683,954	4.254	4,268,573	584,619
October	Florida	C	38,000	3.947	1,500,000	4.214	1,601,320	101,320
2004	Non-Florida	C	103,280	3.562	3,678,910	4.310	4,451,863	772,953
Total			141,280	3.666	5,178,910	4.285	6,053,183	874,273
November	Florida	C	52,000	4.050	2,106,000	4.540	2,360,820	254,820
2004	Non-Florida	C	69,960	3.600	2,518,425	4.536	3,173,722	655,297
Total			121,960	3.792	4,624,425	4.538	5,534,542	910,117
December	Florida	C	52,000	3.858	2,006,000	4.214	2,191,240	185,240
2004	Non-Florida	C	72,292	3.746	2,708,417	4.211	3,044,495	336,078
Total			124,292	3.793	4,714,417	4.212	5,235,735	521,318
Period	Florida	C	557,300	3.349	18,665,303	3.972	22,135,124	3,469,821
Total	Non-Florida	C	919,835	3.661	33,673,183	4.106	37,769,911	4,096,728
Total			1,477,135	3.543	52,338,486	4.055	59,905,035	7,566,549

SCHEDULE E10

COMPANY: FLORIDA POWER & LIGHT COMPANY

	AUG 03 - DEC 03	PROPOSED JAN 04 - DEC 04	DIFFERENCE FROM CURRENT $	DIFFERENCE FROM CURRENT %
BASE	$40.22	$40.22	$0.00	0.00%
FUEL	$37.11	$37.50	$0.39	1.05%
CONSERVATION *	$1.80	-	-	-
CAPACITY PAYMENT	$6.53	$6.25	($0.28)	-4.29%
ENVIRONMENTAL	$0.19	$0.13	($0.06)	-31.58%
SUBTOTAL	$85.85	-	-	-
GROSS RECEIPTS TAX	$0.88	-	-	-
TOTAL	**$86.73**	-	-	-

* The Conservation Cost Recovery Clause Factor will be filed on September 26, 2003

Company: Florida Power & Light Company

Schedule H1

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

		PERIOD				DIFFERENCE (%) FROM PRIOR PERIOD		
		ACTUAL	ACTUAL	ESTIMATED/ACTUAL	PROJECTED			
		JAN - DEC	JAN - DEC	JAN - DEC	JAN - DEC	(COLUMN 2)	(COLUMN 3)	(COLUMN 4)
		2001 - 2001	2002 - 2002	2003 - 2003	2004 - 2004	---	---	---
		(COLUMN 2)	(COLUMN 3)	(COLUMN 4)	(COLUMN 4)	(COLUMN 1)	(COLUMN 2)	(COLUMN 3)
	FUEL COST OF SYSTEM NET GENERATION ($)							
1	HEAVY OIL	993,639,285	669,789,553	875,109,252	687,741,961	(32.6)	30.7	(21.4)
2	LIGHT OIL	14,088,154	17,235,168	27,189,268	33,194,740	22.3	57.8	22.1
3	COAL	104,731,935	101,539,862	110,851,772	88,599,340	(3.1)	9.0	(19.9)
4	GAS	1,018,816,753	1,205,960,702	2,019,267,504	2,069,629,980	18.4	67.4	2.5
5	NUCLEAR	69,855,439	70,877,908	66,127,950	69,046,020	1.5	(6.7)	4.4
6	OTHER	0	0	0	0	0.0	0.0	0.0
7	TOTAL ($)	2,201,131,566	2,065,402,993	3,098,365,746	2,948,212,041	(6.2)	50.0	(4.9)
	SYSTEM NET GENERATION							
8	HEAVY OIL	25,802,011	18,708,283	19,584,987	16,226,393	(27.5)	4.7	(17.2)
9	LIGHT OIL	161,593	188,173	287,460	362,646	16.5	52.8	26.2
10	COAL	6,266,830	5,977,062	6,425,315	5,722,932	(4.6)	7.5	(10.9)
11	GAS	24,497,016	34,545,924	38,957,049	43,469,023	41.0	12.8	11.6
12	NUCLEAR	24,069,938	25,295,157	23,580,883	23,360,161	5.1	(6.8)	(0.9)
13	OTHER	0	0	0	0	0.0	0.0	0.0
14	TOTAL (MWH)	80,797,388	84,714,599	88,835,694	89,141,155	4.9	4.9	0.3
	UNITS OF FUEL BURNED							
15	HEAVY OIL (Bbl)	40,994,892	29,790,686	30,957,699	25,557,382	(27.3)	3.9	(17.4)
16	LIGHT OIL (Bbl)	381,359	472,694	666,028	901,329	24.0	40.9	35.3
17	COAL (TON)	772,666	760,021	733,243	2,915,681	(1.6)	(3.5)	297.6
18	GAS (MCF)	212,955,990	286,112,118	303,243,643	350,723,939	34.4	6.0	15.7
19	NUCLEAR (MMBTU)	262,850,564	276,217,616	254,230,352	255,783,364	5.1	(8.0)	0.6
20	OTHER (TONS)	0	0	0	0	0.0	0.0	0.0
	BTU'S BURNED (MMBTU)							
21	HEAVY OIL	260,956,241	190,168,594	197,907,042	163,567,248	(27.1)	4.1	(17.4)
22	LIGHT OIL	2,195,828	2,704,322	3,852,492	5,254,748	23.2	42.5	36.4
23	COAL	61,112,685	59,238,746	61,797,748	55,965,192	(3.1)	4.3	(9.4)
24	GAS	222,327,090	296,722,566	309,813,050	350,723,939	33.5	4.4	13.2
25	NUCLEAR	262,850,563	276,217,616	254,230,353	255,783,364	5.1	(8.0)	0.6
26	OTHER	0	0	0	0	0.0	0.0	0.0
27	TOTAL (MMBTU)	809,444,407	825,051,844	827,600,685	831,294,491	1.9	0.3	0.5
	GENERATION MIX (%MWH)							
28	HEAVY OIL	31.93	22.08	22.05	18.20	-	-	-
29	LIGHT OIL	0.20	0.22	0.32	0.41	-	-	-
30	COAL	7.76	7.06	7.23	6.42			
31	GAS	30.32	40.76	43.85	48.76	-	-	-
32	NUCLEAR	29.79	29.86	26.54	26.21	-	-	-
33	OTHER	0.00	0.00	0.00	0.00	-	-	-
34	TOTAL (%)	100.00	100.00	100.00	100.00	-	-	-
	FUEL COST PER UNIT							
35	HEAVY OIL ($/Bbl)	24.2381	22.4832	28.2679	26.9097	(7.2)	25.7	(4.8)
36	LIGHT OIL ($/Bbl)	36.9419	36.4615	40.8230	36.8286	(1.3)	12.0	(9.8)
37	COAL ($/TON)	34.7820	34.5097	34.8564	-1.1150	(0.8)	1.0	(103.2)
38	GAS ($/MCF)	4.7842	4.2150	6.6590	5.9010	(11.9)	58.0	(11.4)
39	NUCLEAR ($/MMBTU)	0.2658	0.2566	0.2601	0.2699	(3.5)	1.4	3.8
40	OTHER ($/TON)	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
	FUEL COST PER MMBTU ($/MMBTU)							
41	HEAVY OIL	3.8077	3.5221	4.4218	4.2046	(7.5)	25.5	(4.9)
42	LIGHT OIL	6.4159	6.3732	7.0576	6.3171	(0.7)	10.7	(10.5)
43	COAL	1.7138	1.7141	1.7905	1.5831	0.0	4.5	(11.6)
44	GAS	4.5825	4.0643	6.5178	5.9010	(11.3)	60.4	(9.5)
45	NUCLEAR	0.2658	0.2566	0.2601	0.2699	(3.5)	1.4	3.8
46	OTHER	0.0000	0.0000	0.0000	0.0000	0.0	0.0	0.0
47	TOTAL ($/MMBTU)	2.7193	2.5034	3.7438	3.5465	(7.9)	49.6	(5.3)
	BTU BURNED PER KWH (BTU/KWH)							
48	HEAVY OIL	10,114	10,165	10,105	10,080	0.5	(0.6)	(0.3)
49	LIGHT OIL	13,589	14,371	13,402	14,490	5.8	(6.7)	8.1
50	COAL	9,752	9,911	9,618	9,779	1.6	(3.0)	1.7
51	GAS	9,076	8,589	7,953	8,068	(5.4)	(7.4)	1.5
52	NUCLEAR	10,920	10,920	10,781	10,950	0.0	(1.3)	1.6
53	OTHER	0	0	0	0	0.0	0.0	0.0
54	TOTAL (BTU/KWH)	10,018	9,739	9,316	9,326	(2.8)	(4.3)	0.1
	GENERATED FUEL COST PER KWH (c/KWH)							
55	HEAVY OIL	3.8510	3.5802	4.4683	4.2384	(7.0)	24.8	(5.1)
56	LIGHT OIL	8.7183	9.1592	9.4585	9.1535	5.1	3.3	(3.2)
57	COAL	1.6712	1.6988	1.7221	1.5481	1.7	1.4	(10.1)
58	GAS	4.1589	3.4909	5.1834	4.7612	(16.1)	48.5	(8.1)
59	NUCLEAR	0.2902	0.2802	0.2804	0.3208	(3.5)	0.1	14.4
60	OTHER	0.0000	0.0000	0.0000	0.2956	0.0	0.0	0.0
61	TOTAL (c/KWH)	2.7243	2.4381	3.4877	3.3074	(10.5)	43.1	(5.2)

Note: Scherer coal is reported in MMBTU's only. Scherer coal is not included in TONS.

(Continued from Sheet No. 10.100)

ESTIMATED AS-AVAILABLE AVOIDED ENERGY COST

For informational purposes only, the estimated incremental As-Available Energy costs for the next five periods are as follows. In addition, As-Available Energy cost payments will include .0001¢/kWh for variable operation and maintenance expenses.

Applicable Period	On-Peak ¢/KWH	Off-Peak ¢/KWH	Average ¢/KWH
October 1, 2003 – March 31, 2004	4.06	3.69	3.80
April 1, 2004 – September 30, 2004	4.12	3.88	3.95
October 1, 2004 – March 31, 2005	4.07	3.69	3.80
April 1, 2005 – September 30, 2005	4.14	3.54	3.71
October 1, 2005 – March 31, 2006	3.78	3.41	3.52

A MW block size ranging from 36 MW to 40 MW has been used to calculate the estimated As-Available Energy cost.

DELIVERY VOLTAGE ADJUSTMENT

The Company's actual hourly As-Available Energy costs shall be adjusted according to the delivery voltage by the following multipliers:

Delivery Voltage	Adjustment Factor
Transmission Voltage Delivery	1.0000
Primary Voltage Delivery	1.0226
Secondary Voltage Delivery	1.0495

For informational purposes the Company's projected annual generation mix and fuel prices are as follows:

PROJECTED ANNUAL GENERATION MIX AND FUEL PRICES

	Generation by Fuel Type (%)					Price by Fuel Type ($/MMBTU)			
Year	Nuclear	Oil	Gas	Coal	Purchased Power	Nuclear	Oil	Gas	Coal
2004	23	16	43	6	12	.31	4.27	5.90	1.58
2005	22	15	43	7	13	.33	3.87	5.66	1.59
2006	21	13	48	6	12	.33	3.78	5.60	1.62
2007	21	11	50	6	12	.42	3.79	5.62	1.65
2008	21	8	54	6	12	.43	3.90	5.64	1.68
2009	20	6	58	6	11	.44	4.01	5.78	1.70
2010	19	4	61	6	10	.44	4.13	5.92	1.73
2011	19	4	61	6	10	.45	4.26	6.07	1.76
2012	19	3	63	5	10	.46	4.40	6.23	1.79

NOTE: The Company's forecasts are for illustrative purposes, and are subject to frequent revision. Amounts may not add to 100% due to rounding.

(Continued on Sheet No. 10.102)

(Continued from Sheet No. 10.102)

Customer Rate Schedule	Charge($)	Customer Rate Schedule	Charge($)
GS-1	8.37	CST-1	102.27
GST-1	11.44	GSLD-2	158.05
GSD-1	32.54	GSLDT-2	158.05
GSDT-1	38.58	CS-2	158.05
RS-1	5.25	CST-2	158.05
RST-1	8.32	GSLD-3	371.88
GSLD-1	38.12	CS-3	371.88
GSLDT-1	38.12	CST-3	371.88
CS-1	102.27	GSLDT-3	371.88

B. **Interconnection Charge for Non-Variable Utility Expenses:**

The Qualifying Facility shall bear the cost required for interconnection, including the metering. The Qualifying Facility shall have the option of (i) payment in full for the interconnection costs upon completion of the interconnection facilities (including the time value of money during the construction) and providing a surety bond, letter of credit or comparable assurance of payment acceptable to the Company adequate to cover the interconnection costs, (ii) payment of monthly invoices from the Company for actual costs progressively incurred by the Company in installing the interconnection facilities, or (iii) upon a showing of credit worthiness, making equal monthly installment payments over a period no longer than thirty-six (36) months toward the full cost of interconnection. In the latter case, the Company shall assess interest at the rate then prevailing for the thirty (30) days highest grade commercial paper rate, such rate to be specified by the Company thirty (30) days prior to the date of each installment payment by the Qualifying Facility.

C. **Interconnection Charge for Variable Utility Expenses:**

The Qualifying Facility shall be billed monthly for the cost of variable utility expenses associated with the operation and maintenance of the interconnection facilities. These include (a) the Company's inspections of the interconnection facilities and (b) maintenance of any equipment beyond that which would be required to provide normal electric service to the Qualifying Facility if no sales to the Company were involved.

In lieu of payments for actual charges, the Qualifying Facility may pay a monthly charge equal to a percentage of the installed cost of the interconnection facilities necessary for the sale of energy to the Company. The applicable percentages are as follows:

Equipment Type	Charge
Metering Equipment	0.154%
Distribution Equipment	0.270%
Transmission Equipment	0.117%

D. **Taxes and Assessments**

The Qualifying Facility shall be billed monthly an amount equal to any taxes, assessments or other impositions, for which the Company is liable as a result of its purchases of As-Available Energy produced by the Qualifying Facility. In the event the Company receives a tax benefit as a result of its purchases of As-Available Energy produced by the Qualifying Facility, the Qualifying Facility shall be entitled to a refund in an amount equal to such benefit.

TERMS OF SERVICE

(1) It shall be the Qualifying Facility's responsibility to inform the Company of any change in the Qualifying Facility's electric generation capability.

(Continue on Sheet No. 10.104)

APPENDIX III

CAPACITY COST RECOVERY

KMD-6
DOCKET NO. 030001-EI
FPL WITNESS: K. M. DUBIN
EXHIBIT _____
PAGES 1-5
SEPTEMBER 12, 2003

APPENDIX III
CAPACITY COST RECOVERY

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PAGE(S)	DESCRIPTION	SPONSOR
3	Projected Capacity Payments	K. M. Dubin
4	Calculation of Energy & Demand Allocation % By Rate Class	K. M. Dubin
5	Calculation of Capacity Recovery Factor	K. M. Dubin

FLORIDA POWER & LIGHT COMPANY
PROJECTED CAPACITY PAYMENTS
JANUARY 2004 THROUGH DECEMBER 2004

		PROJECTED												
		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL
1	CAPACITY PAYMENTS TO NON-COGENERATORS	$14,769,044	$14,769,044	$14,769,044	$14,769,044	$14,769,044	$14,769,044	$14,769,044	$14,769,044	$14,769,044	$14,769,044	$14,769,044	$14,769,044	$177,228,528
2	SHORT TERM CAPACITY PAYMENTS	$6,180,400	$6,180,400	$3,886,960	$2,847,390	$6,066,800	$13,666,640	$13,666,640	$13,666,640	$7,412,100	$2,609,640	$2,953,140	$5,262,060	$84,454,210
3	CAPACITY PAYMENTS TO COGENERATORS	$29,190,707	$29,190,707	$29,190,707	$29,190,707	$29,190,707	$29,190,707	$29,190,707	$29,190,707	$29,190,707	$29,190,707	$29,190,707	$29,190,707	$350,288,484
4a	SJRPP SUSPENSION ACCRUAL	$422,797	$422,797	$422,797	$422,797	$422,797	$422,797	$422,797	$422,797	$422,797	$422,797	$422,797	$422,797	$5,073,564
4b	RETURN REQUIREMENTS ON SJRPP SUSPENSION PAYMENTS	($298,153)	($302,316)	($306,478)	($310,640)	($314,803)	($318,965)	($323,128)	($327,290)	($331,452)	($335,615)	($339,777)	($343,940)	($3,852,557)
5b	OKEELANTA SETTLEMENT	$3,028,467	$3,026,015	$3,023,574	$3,021,133	$3,018,691	$3,016,250	$3,013,809	$3,011,368	$3,008,926	$3,006,485	$3,004,044	$3,001,602	$36,180,354
6	INCREMENTAL PLANT SECURITY COSTS	$1,139,468	$1,139,468	$1,139,468	$1,139,468	$1,139,468	$1,139,468	$1,139,468	$1,139,468	$1,139,468	$1,139,468	$1,139,468	$1,139,468	$13,673,611
7	TRANSMISSION OF ELECTRICITY BY OTHERS	$602,197	$564,887	$515,285	$485,010	$541,247	$490,429	$412,670	$440,383	$444,182	$529,144	$627,612	$606,340	$6,259,386
8	TRANSMISSION REVENUES FROM CAPACITY SALES	($582,350)	($521,400)	($268,350)	($232,840)	($265,850)	($320,450)	($355,050)	($366,050)	($285,850)	($254,870)	($294,900)	($477,750)	($4,235,810)
9	SYSTEM TOTAL	$54,452,566	$54,489,602	$52,370,607	$51,311,968	$54,647,901	$62,074,920	$61,955,956	$61,977,066	$55,769,922	$51,076,799	$51,472,134	$53,670,328	$665,069,770
10	JURISDICTIONAL %*													98 84301%
11	JURISDICTIONALIZED CAPACITY PAYMENTS													$657,374,979
12	SJRPP CAPACITY PAYMENTS INCLUDED IN THE 1988 TAX SAVINGS REFUND DOCKET													($56,945,592)
13	FINAL TRUE-UP -- overrecovery/(underrecovery) JANUARY 2002 - DECEMBER 2002 $12,676,723			EST \ ACT TRUE-UP -- overrecovery/(underrecovery) JANUARY 2003 - DECEMBER 2003 $16,048,425										$28,725,148
14	TOTAL (Lines 10+11+12)													$571,704,239
15	REVENUE TAX MULTIPLIER													1 01597
16	TOTAL RECOVERABLE CAPACITY PAYMENTS													$580,834,356

'CALCULATION OF JURISDICTIONAL %

	AVG 12 CP AT GEN (MW)	%
FPSC	17,353	98 84301%
FERC	203	1 15699%
TOTAL	17,556	100 00000%

* BASED ON 2002 ACTUAL DATA

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2004 THROUGH DECEMBER 2004

Rate Class	(1) AVG 12CP Load Factor at Meter (%)	(2) Projected Sales at Meter (kwh)	(3) Projected AVG 12 CP at Meter (kW)	(4) Demand Loss Expansion Factor	(5) Energy Loss Expansion Factor	(6) Projected Sales at Generation (kwh)	(7) Projected AVG 12 CP at Generation (kW)	(8) Percentage of Sales at Generation (%)	(9) Percentage of Demand at Generation (%)
RS1	62.965%	53,694,499,279	9,734,788	1.09449148	1.07375594	57,654,787,546	10,654,643	53.28639%	58.10925%
GS1	64.280%	6,085,869,172	1,080,793	1.09449148	1.07375594	6,534,738,174	1,182,919	6.03961%	6.45151%
GSD1	74.244%	22,784,873,809	3,503,331	1.09438581	1.07367680	24,463,590,399	3,833,996	22.61003%	20.91019%
OS2	63.104%	22,034,093	3,986	1.05884095	1.04655264	23,059,838	4,221	0.02131%	0.02302%
GSLD1/CS1	79.544%	10,444,350,417	1,498,890	1.09287381	1.07253706	11,201,952,890	1,638,098	10.35320%	8.93401%
GSLD2/CS2	83.996%	1,721,709,924	233,990	1.08506569	1.06615414	1,835,608,163	253,895	1.69653%	1.38472%
GSLD3/CS3	84.848%	180,075,156	24,227	1.02896017	1.02363751	184,331,684	24,929	0.17037%	0.13596%
ISST1D	77.366%	0	0	1.09482749	1.05371640	0	0	0.00000%	0.00000%
SST1T	107.912%	146,444,940	15,492	1.02896017	1.02363751	149,906,534	15,941	0.13855%	0.08694%
SST1D	77.366%	58,882,752	8,688	1.06491778	1.05342951	62,028,828	9,252	0.05733%	0.05046%
CILC D/CILC G	90.386%	3,462,136,755	437,259	1.08267759	1.06493286	3,686,943,196	473,411	3.40759%	2.58193%
CILC T	96.508%	1,591,014,236	188,194	1.02896017	1.02363751	1,628,621,851	193,644	1.50522%	1.05611%
MET	65.506%	93,722,226	16,333	1.05884095	1.04655264	98,085,243	17,294	0.09065%	0.09432%
OL1/SL1/PL1	290.896%	551,019,353	21,623	1.09449148	1.07375594	591,660,303	23,666	0.54683%	0.12907%
SL2	99.875%	76,974,890	8,798	1.09449148	1.07375594	82,652,246	9,629	0.07639%	0.05252%
TOTAL		100,913,607,000	16,776,392			108,197,966,895	18,335,538	100.00%	100.00%

(1) AVG 12 CP load factor based on actual calendar data.
(2) Projected kwh sales for the period January 2004 through December 2004
(3) Calculated: Col(2)/(8760 hours * Col(1))
(4) Based on 2002 demand losses.
(5) Based on 2002 energy losses.
(6) Col(2) * Col(5).
(7) Col(3) * Col(4).
(8) Col(6) / total for Col(6)
(9) Col(7) / total for Col(7)

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
JANUARY 2004 THROUGH DECEMBER 2004

Rate Class	(1) Percentage of Sales at Generation (%)	(2) Percentage of Demand at Generation (%)	(3) Energy Related Cost ($)	(4) Demand Related Cost ($)	(5) Total Capacity Costs ($)	(6) Projected Sales at Meter (kwh)	(7) Billing KW Load Factor (%)	(8) Projected Billed KW at Meter (kw)	(9) Capacity Recovery Factor ($/kw)	(10) Capacity Recovery Factor ($/kwh)
RS1	53.28639%	58.10925%	$23,808,126	$311,555,509	$335,363,635	53,694,499,279	-	-	-	0.00625
GS1	6.03961%	6.45151%	$2,698,473	$34,590,078	$37,288,551	6,085,869,172	-	-	-	0.00613
GSD1	22.61003%	20.91019%	$10,102,062	$112,110,990	$122,213,052	22,784,873,609	50.00702%	51,970,307	2.35	-
OS2	0.02131%	0.02302%	$9,522	$123,427	$132,949	22,034,093	-	-	-	0.00603
GSLD1/CS1	10.35320%	8.93401%	$4,625,765	$47,900,099	$52,525,864	10,444,350,417	65.06632%	21,988,841	2.39	-
GSLD2/CS2	1.69653%	1.38472%	$758,001	$7,424,217	$8,182,218	1,721,709,924	66.42656%	3,550,548	2.30	-
GSLD3/CS3	0.17037%	0.13596%	$76,118	$728,956	$805,074	180,075,156	69.07629%	357,110	2.25	-
ISST1D	0.00000%	0.00000%	$0	$0	$0	0	61.46847%	0	**	-
SST1T	0.13855%	0.08694%	$61,903	$466,135	$528,038	146,444,940	16.91303%	1,166,124	**	-
SST1D	0.05733%	0.05046%	$25,614	$270,540	$296,154	58,882,752	61.46847%	131,224	**	-
CILC D/CILC G	3.40759%	2.58193%	$1,522,496	$13,843,149	$15,365,645	3,462,136,755	73.29325%	6,470,791	2.37	-
CILC T	1.50522%	1.05611%	$672,528	$5,662,400	$6,334,928	1,591,014,236	80.20421%	2,717,403	2.33	-
MET	0.09065%	0.09432%	$40,504	$505,699	$546,203	93,722,226	56.00086%	229,258	2.38	-
OL1/SL1/PL1	0.54683%	0.12907%	$244,322	$692,024	$936,346	551,019,353	-	-	-	0.00170
SL2	0.07639%	0.05252%	$34,131	$281,564	$315,695	76,974,890	-	-	-	0.00410
TOTAL			$44,679,565	$536,154,791	$580,834,356	100,913,607,000		88,601,606		

Note:There are currently no customers taking service on Schedule ISST1(T). Should any customer be taking service on this schedule during the period, they will be billed using the ISST(D) Factor.

(1) Obtained from Page 2, Col(8)
(2) Obtained from Page 2, Col(9)
(3) (Total Capacity Costs/13) * Col (1)
(4) (Total Capacity Costs/13 * 12) * Col (2)
(5) Col (3) + Col (4)
(6) Projected kwh sales for the period January 2004 through December 2004
(7) (kWh sales / 8760 hours)/((avg customer NCP)(8760 hours))
(8) Col (6) / ((7) *730) For GSD-1, only 83.265% of KW are billed due to 10 KW exemption
(9) Col (5) / (8)
(10) Col (5) / (6)

Totals may not add due to rounding

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

Reservation Demand Charge (RDC) = (Total col 5)/(Doc 2, Total col 7)(.10) (Doc 2, col 4) / 12 months

Sum of Daily Demand Charge (SDD) = (Total col 5)/(Doc 2, Total col 7)/(21 onpeak days) (Doc 2, col 4) / 12 months

CAPACITY RECOVERY FACTOR

	RDC ** ($/kw)	SDD ** ($/kw)
ISST1 (D)	$0.29	$0.14
SST1 (T)	$0.27	$0.13
SST1 (D)	$0.28	$0.13

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
FILED: 9/12/03

EXHIBITS TO THE TESTIMONY OF

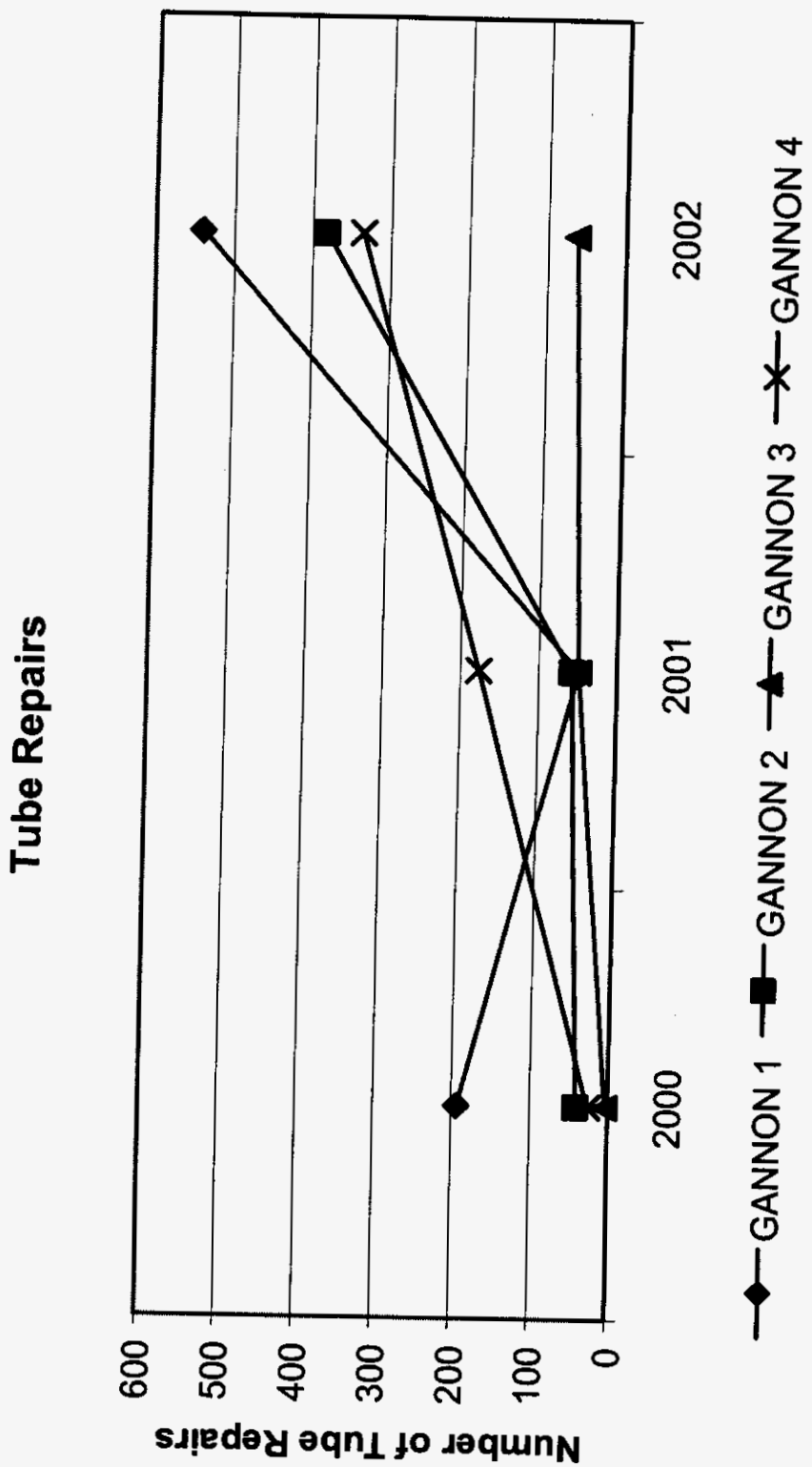
WILLIAM T. WHALE

DOCUMENT NO. 1

GANNON STATION PERFRMANCE AND REALIABILITY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET 030001-EI
NO. _____ EXHIBIT NO. 14
COMPANY/ TECO
WITNESS: WTW-1
DATE: 11/12-15/03

EXHIBIT NO. 14
TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
(WTW-1)
DOCUMENT NO. 1
PAGE 1 OF 3
FILED: 9/12/03



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 14
COMPANY/ TECO
WITNESS: WTW-1
DATE: 11/12-15/03

EXHIBIT NO. ____
TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
(WTW-1)
DOCUMENT NO. 1
PAGE 2 OF 3
FILED: 9/12/03

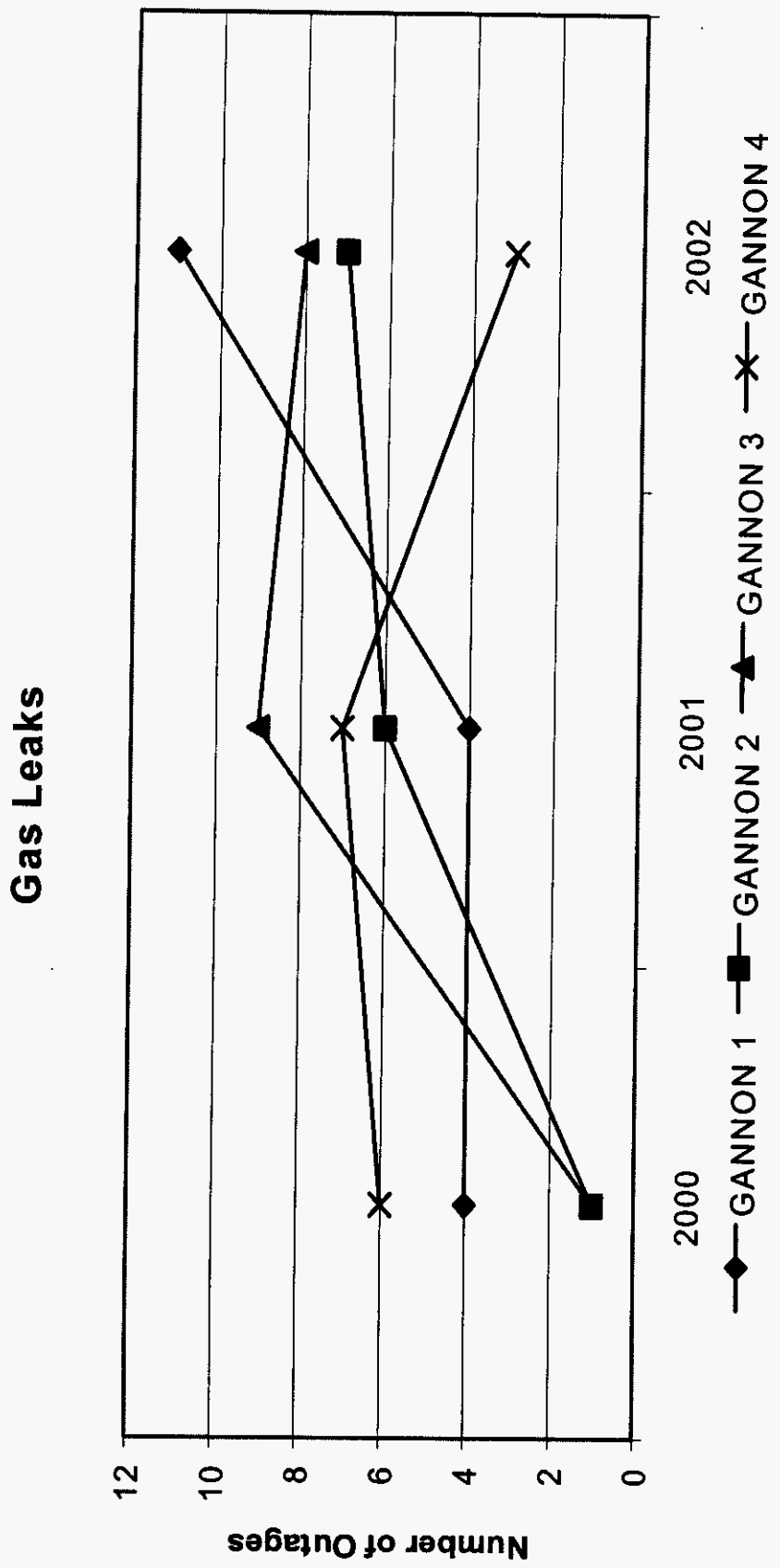
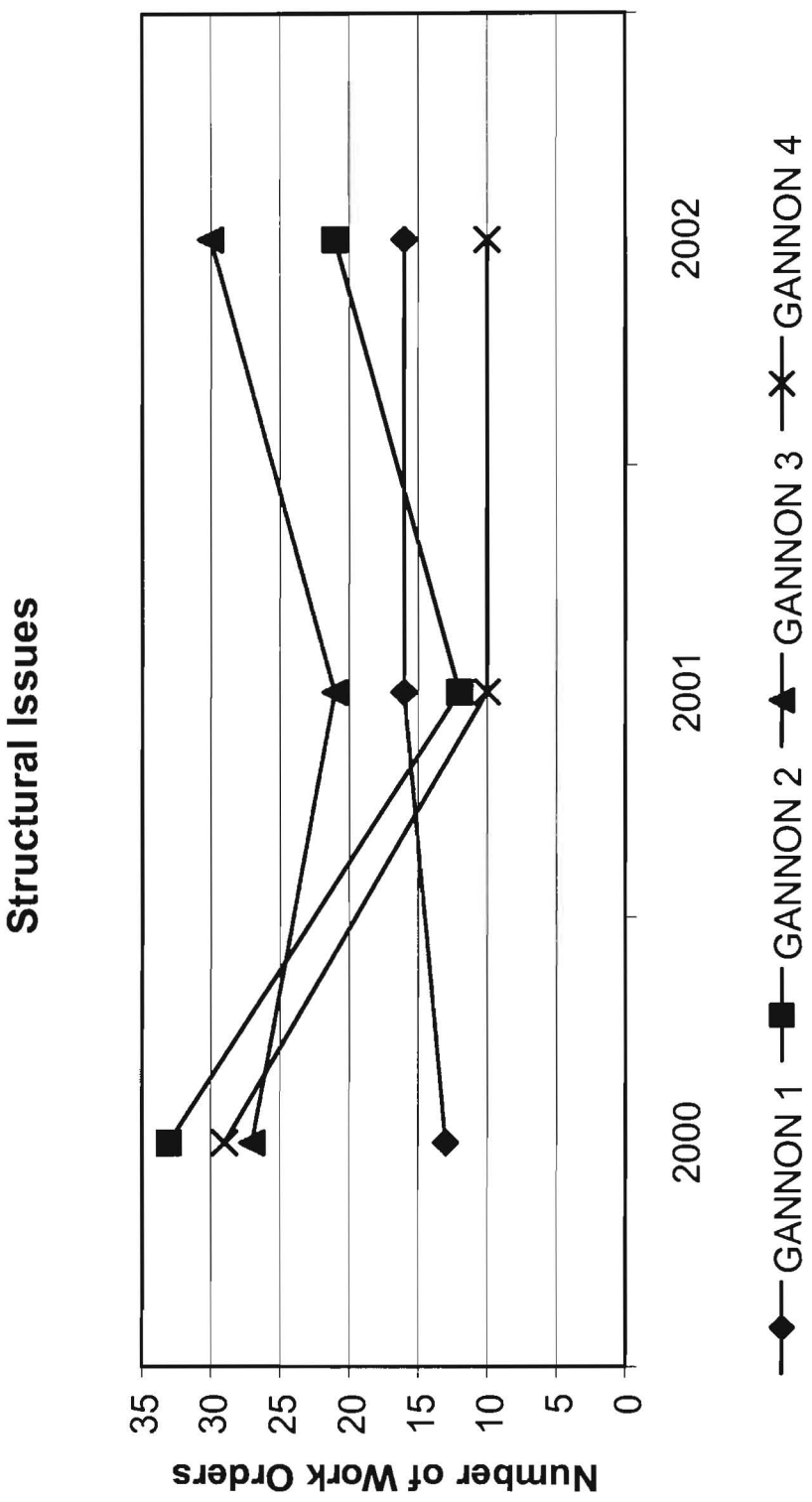


EXHIBIT NO. _____
TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
(WTW-1)
DOCUMENT NO. 1
PAGE 3 OF 3
FILED: 9/12/03



From: Chuck Hemrich
To: Bill Whale
Date: 8/7/02 2:46PM
Subject: Gannon 2003 and 2004 budgets

Bill,

Here is our reevaluation of our budget needs and consequences of cost reductions. Let us know what else you may need.

Karen, John and Chuck

CC: Chuck Hemrich; John Knight; Karen Sheffield; Roger Campeau

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO 15
COMPANY/ DPC
WITNESS: 8-7-02 - Hemrich Memo
DATE: 11-12-03

2003

28-day outages on units 1 thru 4 are planned in order to get these units ready for 18-month runs with only minimal cost cleanup outages in 2004 on each unit. The cost of these 2003 outages is $4M. The primary outage work needed for these units is repair of cyclones, ductwork, screenwell equipment, furnace tubes, precipitator and boiler refractory. If Gannon is required to reduce our 2003 budget by $1.3 in order to meet the TEFIS assumption, the reduction would have to come from these units. It is estimated that this amount of reduction will result in a 20% increase in our forced outage rate for these units starting in the summer of 2003 and continuing until they are shut down in 2004. This assumes that dollars are removed from all four of these outages which is preferred over picking two units to eliminate their outages completely as this would affect environmental and safety related work. The effect of this outage strategy is that the forced outage rates on each of the 1 through 4 units will increase by 20% in 2003 and 2004. The FOR's will change as shown below.

Gannon Station 2003 GFI Budget Inputs				
	FOR		FOR increase by 20%	
Unit	2003	2004	2003	2004
Gannon 1	15.93	18.05	19.12	21.66
Gannon 2	26.94	27.94	32.33	33.53
Gannon 3	16.33	17.07	19.60	20.48
Gannon 4	24.49	25.61	29.39	30.73
Gannon 1-4	20.75	21.95	24.90	26.34

The Bayside tie-in outages for units 5 and 6 are needed to make the conversion to Bayside. These outages are 30 days for construction and up to several weeks for additional startup testing. There is also some O&M work needed such as screenwell repairs, tunnel cleaning, cooling tower repairs, turbine work and condenser maintenance. $200k is needed to make outage repairs to repowered equipment on units 5. $300k is needed for unit 6. It is not recommended that this amount be reduced since it will affect the reliability of the new Bayside units and too much load will be at risk.

The reasons we are off by $1.3M from the August, 2001 TEFIS assumption are the following:

Our budget and outage schedule supports running units 1 and 2 until 9/04, not 10/03 as assumed in the August, 2001 TEFIS.

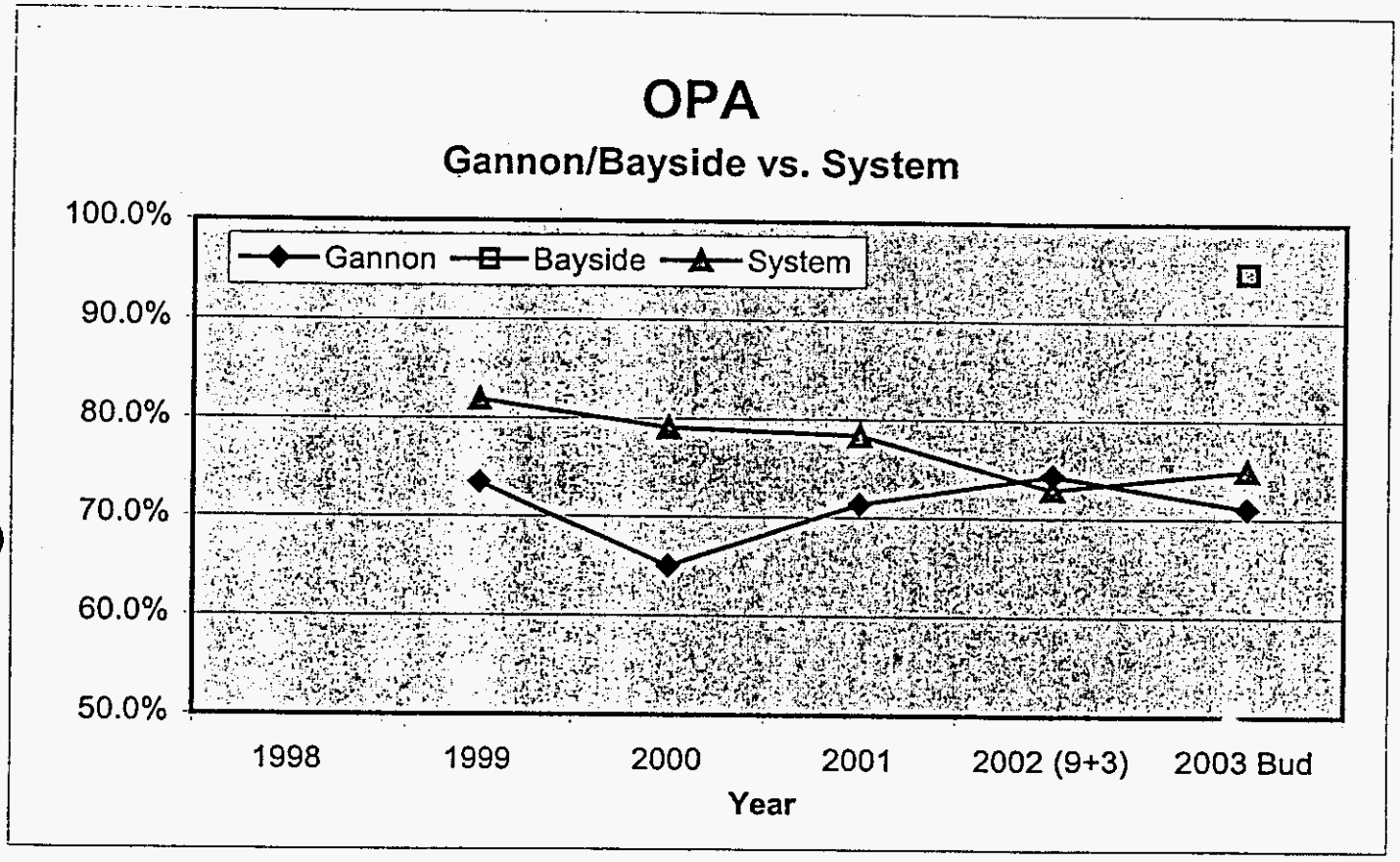
The 2003 outage costs on units 5 and 6 will be covered by Gannon's O&M. Bayside will only cover the capital portion of the outage work.

2004

We have reevaluated our O&M need for 2004 and agree with the TEFIS projection of $22.092M which includes $2.5M for parts write-off.

On-Peak Availability

The on-peak availability factor is based on peak hours instead of period hours. Peak hours occur when native load is greater than 2900 MW.



	1998	1999	2000	2001	2002 (9+3)	2003 Bud
Gannon	No data	73.5%	65.0%	71.4%	74.4%	71.1%
Bayside	No data					95.0%
System	No data	81.9%	79.1%	78.4%	73.0%	75.0%

Analysis:

OPA is projected to be 5 percentage points worse than last year but only 0.1 percentage points worse than the 4-year average. This projected drop in OPA is due to decreasing O&M and capital budgets on our coal units.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 16
COMPANY/ OPC
WITNESS: 3/12/03 OPA Document
DATE: 11-12-13

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power costs recovery clause with generating performance incentive factor.
Docket No. 030001EI
Filed: April 29, 2003
----------/

DEPOSITION OF: **BUDDY MAYE**

TAKEN AT: TECO Plaza
702 North Franklin Street
Tampa, Florida

DATE & TIME: May 13, 2003
10:48 a.m.

REPORTED BY: Mary Elizabeth Blazer, RPR
Notary Public
(813) 229-8225
(813) 229-7223

ASCII ENCLOSED

STENOGRAPHICALLY RECORDED
COMPUTER-AIDED TRANSCRIPTION
BY ECLIPSE

ORIGINAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 17
COMPANY/ OPC - 5/13/03
WITNESS: Buddy Maye depo Transcript
DATE: 11-12-03

Berryhill & Associates, Inc.
501 East Kennedy Boulevard, Suite 1225
Tampa, Florida 33602

(10:48 a.m.) P R O C E E D I N G S

Thereupon,

BUDDY MAYE,

was called as a witness and, after having been first duly sworn/affirmed to testify the truth, was examined and testified as follows:

THE WITNESS: I do.

DIRECT EXAMINATION

BY MR. VANDIVER:

Q Good morning.

A. Good morning.

Q. Could you state your name for the record, please?

A. Buddy Maye, M-A-Y-E.

Q. What's your educational background, Mr. Maye?

A. High school.

Q. And what was your job history prior to joining Tampa Electric Company?

A. I joined Tampa Electric in 1970 after separating from the U.S. Army.

Q. And can you describe your job history within Tampa Electric Company?

A. I started as a craft employee with Tampa Electric in November of 1970; worked several craft

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WILLIAM COCHRAN KEATING, IV, ESQUIRE
Public Service Commission
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Tallahassee, Florida 32399-7019
(850)413-6193
(Appearing by telephone)

Also Present:

Todd Bohrmann (Appearing by telephone)
Michael Haff (Appearing by telephone)
Earl Poucher
Denise Jordan
Penelope Rusk

positions through maintenance and operations; made superintendent of operations in 1984. As a superintendent of operations, followed several major projects with Tampa Electric, including the startup and staffing of several facilities, starting up and shutting down in such places as Hooker's Point and restaffing and rehiring of Hooker's Point. Approximately four to five years ago, I was appointed operations manager at the Gannon Station facility. This last November, I was appointed general manager of Gannon Bayside.

Q. All right, sir.

Who is your supervisor?

A. Bill Whale, vice president of Energy Supply.

Q. Who does he reports to?

A. John Ramil, president of Tampa Electric.

Q. Who reports directly to you?

A. I have a basic management staff of Tim Panoff, operations engineer; Gene Edwards, maintenance -- excuse me, operations manager; Gene Edwards, maintenance manager; John Knight, financial manager; Ben Willoughby, safety coordinator, are my direct reports.

Q. And do you have a secretary?

A. No, sir, we have a shared administrative

specialist, Randy Sumner.

Q. And who are your peers at Tampa Electric?

A. Karen Sheffield, general manager of Big Bend Station; Darryl Scott, general manager of operations, production Energy Supply staff; Mark Hornick, general manager, Polk Power Station, directly under Energy Supply operations.

Q. And is that the entire fleet of the Tampa Electric generating?

A. That is -- yes, sir.

Q. Okay. And what are your responsibilities at Gannon Station, Gannon Bayside?

A. I am responsible -- responsible for overall O & M, operation and maintenance needs of Gannon Bayside.

Q. How often is your performance evaluated?

A. At a minimum, annually.

Q. Okay. And what's the basis of that evaluation?

A. We use a developing employee performance, which is basically a matrix of goal initiatives set forth by myself and my staff, along with my department, supporting company goals, and then a major emphasis on dimensions and personal growth, my own personal development.

Q. Is meeting or exceeding budget expectations a significant part of that evaluation?

A. That's one of my goals.

Q. All right, sir.

I would like to go into the Bates stamped pages at this point now and go to Bates stamp page 405.

Q Now originally, I believe, there's been -- Gannon 1 and 2 were shut -- the shutdown for units 1 and 2 was March 15; is that correct?

A. That was the plan.

Q. And this memo changes that; is that correct?

A. Yes, sir.

Q. Okay. What is the distinction between decommissioning and shutdown?

A. I'm looking for the word "decommission" as referenced in the document. Is it --

Q. It's not.

A. Okay, excuse me.

Q. I'm trying to get a sense of what -- of the terminology here for -- so I can refer to it properly in discussing it with you.

A. Decommissioning to me is a term that's used in the power industry where you're basically shutting the unit down for the last time with no

anticipation of ever bringing the unit back on.

Q. Okay.

A. Shutdown is basically a term where depending on what the plan is, how you safely shut the unit down and what status you leave the unit in.

Q. And that was my next question: Is there a difference between long-term and short-term shut down?

A. Yes, sir, there is a difference. And there's as many variations --

Q. Okay.

A. -- as there is ways.

Q. And is there a difference, is there -- do we need to bring the term "dismantlement" in here? Is that a term of art?

A. Yes, that's another term.

Q. Very well.

A. And then you will bring the term "lay up."

Q. Okay. Okay. Now, which of these terms applies to each of our Gannon units?

A. I'd say the scenario that we're in right now is Gannon 1 and 2 were placed in long-term reserve shutdown.

Q. 1 and 2 are long-term reserve shutdown?

A. Yes.

Q. Okay. Long-term reserve shut down.

Okay, very well.

Now, for these individuals here, I think you've discussed your relationship with Mr. Scott. He was a peer. And Mr. Whale is your superior. Who's Tom Barry?

A. Tom Barry is the -- a manager that's under Darryl Scott, whose daily responsibility is the daily coordination of generation and maintenance interfaces with our system dispatchers. He also was responsible for annual maintenance outage planning.

Q. Okay. Now, who actually made this decision -- who makes this decision on extending the life here of Gannon 1 and 2?

A. Extending the life?

Q. Well, it says --

A. Could I speak to the document?

Q. Yes, sir, please?

A. This document was actually produced when on March 12th we realized that Bayside 1 was not up and stable.

Q. Okay.

A. We had run into some start up glitches and this was the first variation to the March 15th date.

Q. Okay.

A. The original plan basically said that

there would be some stable megawatts being produced from Bayside 1.

Q. Okay. And it wasn't ready to go, and so you were going to run Gannon 1 a little longer?

A. Gannon 1 and 2.

Q. 1 and 2, a little longer. Okay.

So, can you define -- so, are the dynamic uncertainties of the generation and fuel marketplaces, some of that's referring to things within Tampa Electric Company?

A. Yes.

Q. Okay. And so -- all right, very well, sir.

Can we flash -- flash cut to 1240? And can you describe this document to me, please, sir?

A. This document was a document that was sent by Tom Barry to some of the major players in the day-to-day generating responsibilities. And it is a request that includes moving Gannon 1 and 2 to 4/18, it includes Gannon 3 outage beginning -- it delayed the beginning of Gannon 3 outage.

In other words, this was -- this was a draft request to look at an extension of running 1 and 2 till April the 18th and moving the start date of the Gannon 3 outage back. And I don't remember the exact

start date of that outage, but move it back.

Q. Okay. Now, who's the asset management -- or asset management request? Is that a specific --

A. Asset management is a group that basically deals on a day-to-day basis, which is one of their responsibilities, of purchase power requirements, fuel requirements, fuel purchases, gas nominations, et cetera.

Q. Who's their leader?

A. John Currier.

Q. John Currier?

A. And when I say leader, he is my peer or my level leader.

Q Okay.

A He is the director.

Q. And Ms. Young and Mr. Hubona are within that group?

A. Beth Young is the manager of systems operations who handles the dispatch of the power, and Ken Hubona is a report of John Currier.

MR. VANDIVER: Fair enough.

Okay. We'll go ahead and pause. We'll just take a short break while we do this.

(Whereupon, an off-the-record discussion was held.)

BY MR. VANDIVER:

Q. Go back on the record.

On Bates stamp 1240, sir, what are the references to the DG, DCB, OKE megawatt purchases?

A. Recognizing the acronyms, the first one is Dinner Lake. DCB, I don't know the details, but it is a power purchase agreement; and OKE is Okeelanta, which is our -- some power purchase agreements that they have in place.

Q. And the T?

A. Don't know.

Q. Don't know. Okay.

Were the Gannon units kept open to sell more power?

A. No, sir.

Q. Okay. Were there any extraordinary maintenance necessary to continue operations from March 15th to 4/18?

A. There was, and I do not have the details. Some forced outages during that period, a minimum of one, okay.

Q. Do you recall which unit it was?

A. No. No.

Q. Okay. And do you recall how long it was?

A. It was basically two to three days forced

outage, boiler tube failure type scenario.

Q. And Bayside 1 opened on April 24th; is that correct?

A. The first megawatts produced?

Q. When were the first megawatts produced?

A. I think it was April 24th.

Q. Okay. I have a Tampa Tribune article here in which you're quoted. I'll show that to you. And that says that -- I believe you're quoted as saying "Gannon 1 and 2 have not run since" --

A. April -- this is media. 1 and 2 were shutdown April 7th and April 8th.

Q. And is that the correct shutdown date for 1 and 2 or -- what is the shutdown date for 1 and 2? What's the status? Can you help me with this conundrum?

A. Yes.

Q. Okay.

A. Gannon -- and I know this. Gannon 1 and 2 were shutdown on April 7th and April 8th or the generator breaker was opened.

Q. Okay.

A. When we talked long-term reserve shutdown, we did go through a process where we fired all the igniters and dried the boilers out.

Q. Yes, sir.

A. But the last megawatts produced were on April 7th for Gannon 1, April 8th for Gannon 2.

Q. Okay.

A. At that point in time, they were both secured, the boilers were dried out, the -- all fuel was removed, all coal fuel was removed from any coal feed equipment in the plant and basically left in a somewhat safe state.

Q. Okay.

A Okay?

Q All right.

Now, we took a tour of Gannon yesterday?

A. Yes, sir.

Q. Okay. And at that time, it was my understanding that Gannon 2 was operational?

A. Yes, sir.

Q. Okay. And that was because of extraordinary weather conditions or what -- what happened to fire Gannon 2 back up? And I guess I'll preface my question with between April the 8th and yesterday, had it been in operation between then and yesterday?

A. No, sir.

Q. Okay.

A. There had not been any operation.

Q. Very well.

A. As of late Friday afternoon, I think there was some major transmission constraints within the state, the system was tight. People who know our businesses is the whole state is in the tail end of their outage season.

Q. Yes, sir.

A. We had some extremely hot weather for the state of Florida and generation was tight. As of about 4:00, 4:30 last week, Seminole lost a large unit in Palatka. We have a contract agreement with the TPS Hardee Station, which Seminole basically, with a loss of unit, has first call on the Hardee Power Station. They made that call.

As an attempt to meet our needs of our customers and do the right things, the decision was made -- I think I received a call about 4:30 or 5:00 on Friday afternoon, what would it take to bring Gannon 1 and 2 on?

And we -- we made an attempt, we were successful. Gannon 2 ran through yesterday. Gannon 1 made it through Saturday afternoon or Saturday noon. Lost it with two failures.

We had several units within our own system. Don't remember the exact details of it, but I

think it was Big Bend 1 and Big Bend 3 played into the scenario. The Bayside 1 BCT was down due to an equipment failure, a warranty GE, warranty issue, and the decision was made to bring them up and run them through a minimum of Sunday evening.

Q. Okay.

A. When we became more stable with our own generation picture.

Q. Okay. Now, is Gannon 2 running today?

A. No, it's not.

Q. Okay.

A. Gannon 2 was -- went back through the process of basically it run yesterday to vacate the bumpers of the fuel that was put in there to meet the weekend run and it was shut off last night.

Gannon 1, the two repairs are being made. That boiler will be fired and the coal will be run out of bumpers this week to put it back on long-term reserve standby status.

Q. Okay. And so as we speak right now, they're both returning to that long-term reserve shutdown?

A. (Nods head.)

Q. Okay. And how long does it take to fire up those boilers? I believe you said it was 14 hours?

A. Basically, we were able to produce power within 14 hours. To caveat that, we put them in a long-term reserve shutdown with a 10-day notice. We did not take the 10-day notice, we did not take the outages on those units to continue this mode of operation.

Q. Okay. Just for my information, my ignorance, who is the 10-day notice given to? DEP?

A. To me.

Q. Okay. All right, sir.

Can you go, please, sir, to Bates stamp page 436?

This is from Mr. Whale's officer's presentation of 8/26/02.

Can you explain what "patch and go" means as an operating strategy?

A. Patch and go is basically a mode where you do things to get you to a next major maintenance event; i.e., a long duration planned outage.

Q. Okay. How about "run to failure"?

A. Run to failure is a term that's been used that when you get to that point, there's major decisions that have to be made.

Q. All right, sir.

A. An example would be if Gannon 4 generator failed today.

Q. And that plan is scheduled to go down September 30 -- September 1st, I believe?

A. Yes.

Q. Okay.

A. It brings you to a major decision for it.

Q. All right. Okay.

Can we go to 454, please?

Oh, before we go there, could you go to 437? What's the "demonstrate gasifier" reference mean there? Do you know?

A. I have no idea.

Q. Okay. Fair enough.

And does this labor strategy go with what you've just discussed on patch and go?

A. Which labor strategy?

Q. The one on 454? If you'll go to 454, please?

And, again, this is holding the workforce to a minimal level and using -- keeping a preventive maintenance workforce. Does that go with the patch and go kind of --

A. Not necessarily. It's not the -- the intent was not to support the patch and go. The intent was to support the long-term transition needs as you moved to Bayside.

Q. Okay.

A. In other words, it's not the time to hire a whole lot of new employees knowing their job could be at risk in the next year.

Q. Okay. Let's go to 512 now, please, sir.

This is the EPA, DEP letter. And this states that "For environmental purpose -- for environment purposes, the effective date of Bayside 1 is March 6, 2003"; is that correct?

A. On or about.

Repeat the question, make sure I understand.

Q. It states: "For environmental purposes, the effective date of Bayside 1 is March 6, 2003."

A. Yes. This -- this letter is part of a permitting requirement where you have to give notification to the agencies what your intent of when you're shoring up, and I think it opens a window.

Q. Yes, sir.

A. And that window was open at that time.

Q. All important here is, is there a difference between environmental and commercial operations?

A. Yes.

Q. What is that difference?

A. I am not the guru to speak to this.
Q. Okay. This letter seemed to make a distinction and I just wanted to know what it was.
A. Yeah. This is the environmental notification point.
Q. Okay.
A. Okay? That you have certain testing that has to be performed and you have to meet certain emission standards.
Q. Right.
A. Okay? So from an environmental point, there is a commissioning commercial date.
Q. Right.
A. From the business drives and from your shops and others, there is another definition --
Q. Yes, sir.
A. -- for commercial operations.
Q. And you-all have been selling power out of Bayside prior to this date for testing purposes, right?
A. We have been producing power from Bayside for testing purposes? Yes.
Q. Okay. And some power has been sold into the grid, right? Or no?
A. I do not know.
Q. Okay. Who would know? Do you know?

A. I think of the deposees, probably someone like Bill Smotherman could speak to this.

Q. Okay. Okay. I'll ask Mr. Smotherman.

A. Yeah.

Q. I'm just trying to get a handle on it. I'm just trying to understand how those dates interplay and what the situation is because I was curious about it from this letter.

Now, there are 369 megawatt turbines; is that correct?

A. Nominal, yes.

Q. Okay. And that's dependent on temperature as you explained yesterday?

A. Yes.

Q. Okay. And can you briefly explain how they're configured?

A. Bayside --

Q. Yes, sir.

A. -- 1?

Bayside 1 is a combination of three GE frame 7 combustion turbines and Alstrom heat recovery steam generators that each -- the configuration of Bayside 1 makes up four generating points. Each of the three CT's independent generators and the combination and merging of steam from those three HRSGs supply the

old Gannon 5, which is now referred to as Bayside 1 steam turbine and the steam turbine load associated from that generator.

Q. All right, sir.

Now, if I wanted to find out how much power Bayside had generated into the grid, I should ask Mr. -- prior to this official opening, I should talk to Mr. Smotherman?

A. Yes.

Q. Okay. Could you go to 606, please, sir?

And we had talked some with Mr. Knight about this. We see that their outage costs here are $4 million for the various 1 through 4 units.

A. I haven't seen this document before, it will take me a minute.

Q. I'll give you a minute.

A. Okay.

Q. I'll give you a minute. I apologize.

(Pause.)

Let me know when you're ready?

A. I'm ready.

Q. All right, sir.

Are the outage costs spread equally over the four Gannon units there? I see the planned outage costs are $4 million. For the planned outage cost of

these 2003 outages for $4 million? Are they equally over the four Gannon units?

A. I don't know the details --

Q. Okay.

A. -- of this costs.

Q. Okay. And you see there that the -- since Gannon was required to reduce budget by 1.3 million, it has increased the forced outage rate. Has that generally been your experience?

A. Anytime you quit doing planned outages, your forced outage rate will increase.

Q. All right, sir. And that's the inevitable consequence of reducing planned maintenance?

A. Yes.

Q. Okay. And the numbers really speak for themselves in terms of the forced outage rate going out.

All right, sir.

A. In one respect, Ron, it does. In another respect, it also reflects the age of the units.

Q Okay.

A But you do hit the point of diminished returns.

Q. Okay. And this -- and -- there's not a date on here, but this also -- this also reflects that there's a -- continuing through 2004, so this is the old

plan, isn't it?

A. (Nods head.)

Q. Yes.

A. This is --

Q. All right. Let's go to 611, please, sir. Are you familiar with this document?

A. Not really.

Q. Okay. I'll give you a chance to look at it.

This is basically another proposal for -- the first paragraph basically speaks to another proposal for cutting maintenance in Gannon 1 through 4, does it not?

A. It -- it references cutting planned outages and increasing a forced outage pot of money.

Q. Yeah. And this has been done, again, in the past, has it not?

A. What?

Q. Reducing planned outages?

A. The scenarios we've already looked at, outage schedules were condensed to impact for numerous reasons and I think what this documents -- the first paragraph is trying to imply if you give up in one, you pay in another.

Q. Okay. Okay. And then -- in the second

paragraph is -- is the proposal that was ultimately adapted by the company, and that is to shutdown Gannon early, isn't it?

A. It is someone's anticipation of another way to handle it.

Q. Okay. Fair enough.

Would you agree that Tampa Electric ultimately combined paragraphs 1 and 2 to arrive at a final strategy?

A. No, not necessarily. I think that -- as we -- we know that -- that a lot of options were looked at at developing a transition is that got it Gannon to Bayside.

Q. Well, if we can go to 1411, please.

A. That's the other stack.

Q. Yeah. Making progress. We'll probably go back, Mr. Maye, there's no -- there ain't no free lunch here.

What does this chart tell us about the Gannon units?

A. It references Gannon's history since 1997 on what we refer to as on-peak availability.

Q. Would you call this a reliability index?

A. No. Reliability to me is typically measured through such things as EAF.

Q. Okay.

A. On-peak availability is you might sacrifice some reliability long-term, but you're there when the system really needs you.

Q. Okay. And it says that the Gannon units were -- had a bad year in 2000 but are coming up in on-peak availability; is that correct?

A. That graph is a little deceiving.

Q. Okay.

A. Because this does tie back to reliability. What you'd have to look at is what the expected generations outs of each unit were year in and year out. I know in -- in the early 2000s we derated some units like a Gannon 2 --

Q. Uh-huh (indicating affirmatively).

A. -- by reducing the header, which raised its overall reliability, but decreased its net generation.

Q. So, we can't look at this one in isolation and go "ah"?

A. Not without knowing the score card.

Q. Fair enough.

And I might have already asked this, but is this for the Gannon units collectively?

A. Yes.

Q. So this is for all six?
A. Gannon 1 through 6.
Q. All right, sir.
Can we go to 1425? What's non-outage maintenance?
A. Non-outage maintenance would be PMs that don't require equipments to be removed from service or it's not generating related maintenance, general plant maintenance.
Q. I don't want to put words in your mouth is it like every day kind of get to stuff? You don't have to take the plant down for?
A. PM and predictive-type maintenance.
Q. All right, sir.
Can we go to 1429?
I'm going to go through what makes up non-recoverable fuel and what's make up other expense. And if you're not the proper witness to answer this, I can pose this to another witness.
A. I don't know what the definition of "other expense."
Q. Okay.
A. All I can do is assume it was associated with the fuel expense.
Q. All right, sir. Can we go to 1433,

please, sir?

And the first sentence there under "plant operations." Could you read that first sentence into the record, please?

A. (By stipulation between counsel, stricken from record.)

Q. Does that violate OSHA safety or union guidelines?

A. No, sir, not in the least, if you understand the sentence.

Q. Okay. Explain it to me.

A. That's kind of what the paragraph goes on to explain.

Q. Okay.

A. Is this is the period that we started identifying other resources.

Q. All right.

A. It references classifications like production --

MR. BEASLEY: Can -- as we get into these confidential pages, could we --

MR. VANDIVER: Yes, sir.

MR. BEASLEY: -- ask that -- that the portions of it not be read into the record?

MR. VANDIVER: I apologize.

MR. BEASLEY: If you could just refer to it.

MR. VANDIVER: Okay. We'll do it.

MR. BEASLEY: You stipulate to have it stricken from the record, the portion that he's read?

MR. VANDIVER: Yes. Just strike what was read into the record.

BY MR. VANDIVER:

Q. So, go ahead and explain.

A. When we say we're below the minimum number required to run the plant, the people were not actually working in the actual classification they were hired into. We started taking a lot of other maintenance entry-level classes, like production apprentices, production workers who we at this time, with Bayside being under construction, knew that their future and proceeding in their current ranks, and we did some career adjustments.

We actually put them through the auxillary operator training courses, et cetera, and started working them out of their classification and into plant operations, and that's how we made up the minimum required number.

Q. Okay.

A. We never worked in operations short-staffed.

Q. Okay.

A. Okay. It was just a strategy to get to the end.

Q. Okay. Can you briefly walk me through some of these abbreviations here?

A. Sure. The one PW --

Q. Yeah.

A. -- is a production worker working as an AO. Well, he's -- STD is short-term disability, which means he is -- is out on either a job or non-job related incident. WE is watch engineer. That is one of your senior operating crews.

Q. Okay.

A. HEAC is hazardous energy control which is just our -- our variation of lockout, tag out. He was assigned on a special assignment.

PA is production apprentice. AO is auxillary operator. BTO was a boiler turbine operator.

Q. All right, sir. Thank you.

Let's see. 1435. Let's see. There the heading "capital." You see -- you see a -- capital spending was reduced by half in 1997; is that correct?

A. Well, since 1997.

Q. Right. What was the reason for the 50 percent reduction?

A. I have no idea.

Q. Okay. What does "PRB" stand for?

A. Powder River Basin.

Q. Okay. You're talking down there about the coal and other off spec fuels?

A. Yes.

Q. Is that raised end cost?

A. Yes.

Q. What were the other problems that it's caused for the -- that they discuss there?

A The Powder River Basin, which is a lower BTU, midwestern fuel, which is part of -- been part of the industry's overall knock strategy is a highly erosive fuel. So it -- it wears and tears on refractory tubes, okay.

Q. Okay.

A. Its ash is also highly combustible at times and has to be dealt with in a more precarious manner.

Q. If we can go to 1437. Let's see. And let's see. The -- we see that there were certain outages in 2001. There were units 3 and 4, four-week outages were canceled due to cost control; is that

correct? That's about the -- I'm looking under outage schedule?

A. Yes.

Q. Okay. What does that do to a plant's future reliability?

A. It will raise O & M cost and hurt reliability, but what I need to understand, and I don't have those details where they canceled or shifted, because quite often, we'll move an outage from the fall to the spring.

Q. Okay. Well, looking a little bit further down the page, the -- we see revised -- original 2002 outage plan. Do you see where you have 2001, you see the outages, four-week units 3 and 4 outage canceled. And then we have a 2002 outage, and then you see its canceled. Do you see the --

A. Yes.

Q. Okay. And so, I'm back to my question, is it -- and I guess I've got two questions: Does future O & M go up and is it a pay me now or pay me later deal? Because it looks like you canceled the outage two years in a row.

A. What I would like to speak to --

Q. Sure.

A. -- and without having all the outage

schedules and the revisions, it's like the unit 3 outage that was canceled in 2003.

Q Yes, sir.

A It was actually moved to this spring. So, that outage has occurred. That, we just come out of. That was the outage that was referenced in the Tom Barry outage that got even delayed two days, but that outage did happen. Okay.

Q. Okay.

A. And -- and Jim, I don't remember the actual publication date of this document, but --

Q. Okay. Well, I'll tell you what --

A. And I don't want to assume, but I think at one time there was an outage schedule that actually moved 1 and 2 to this spring.

Q. Is a four-week outage a major outage?

A. Yes.

Q. Okay. I would like for you to provide me with a late filed exhibit, if you could. And that would be total outage days canceled for the Gannon units due to cost control from 1998 to 2002, due to cost control, budget reasons. Can you provide that for me?

A. I don't know that I can provide it. I don't know if it's really cost control.

Q That assumes --

A. Assumes they were canceled for that reason.

MR. BEASLEY: There's a cause and effect relationship between some assumed cost control and cancellation of outages. And it might not be cancelled, it might be postponed, as Mr. Maye indicated, rescheduled.

MR. VANDIVER: Well, it's written here that, you know, the -- we've got -- this sentence that's written here says in 2001, units 3 and 4 four-week outages were canceled due to O & M cost control. And then we have revised 2002 outage plan, unit 1, outage canceled; unit 2, outage cancel; unit 3, outage canceled.

And Mr. Maye, I'll pose the question to you: What was the reason for those three outages in 2002? You're the plant manager at Gannon.

MR. BEASLEY: You mean outage cancellations or --

MR. VANDIVER: Yes, outage cancellations.

THE WITNESS: I don't know why those outages were actually canceled or if those outages were canceled or shift to the first quarter of 2003.

BY MR. VANDIVER:

Q. Okay.

A. That's what I'm not prepared to speak to. And I made reference to Gannon 3. That outage was not canceled, I know it was shifted.

Q. Okay.

How about an exhibit showing all outages canceled or shifted and where they were canceled or shifted to? Because we have at least one here that was canceled due to cost control, and I think we can find some other examples as we go through our references. Would that be fair?

MR. BEASLEY: Can you -- is that information available? Or --

THE WITNESS: The only place that I think you can do that and you would have to look at the revisions of all the outage schedules and how the outages were to be laid out.

MR. BEASLEY: Off the record?

MR. VANDIVER: Sure.

(Whereupon, an off-the-record discussion was held.)

MR. VANDIVER: In fact, that's what precipitated the request for the exhibit was that one sentence.

Okay. We'll go back on the record and

we'll -- I'll revise the request for the exhibit.

MR. BEASLEY: Okay.

BY MR. VANDIVER:

Q. Back on the record.

I would like an exhibit for the years 2000 to date for all outages that have been canceled due to cost control. And if they've been -- not been cancelled or if they've been deferred forward, you could -- you're certainly welcome to show that. And if they've been deferred out -- you would so note, Mr. Maye, and that would be reflected in the exhibit, if they have been deferred forward.

Okay. Let's see. When maintenance is deferred or outages are canceled, what does that do to plant's future reliability?

A. If they're deferred, I don't know there is any cause and effect. If they're canceled, it will affect the units reliability long-term.

Q. Okay. So, maintenance deferred, a plant might be able to keep on going for a longer period of time, kind of keep on going without that maintenance; is that what you're suggesting?

A. Could I relate it to something as simple as an oil change in your vehicle?

Q. Absolutely.

A. Okay. We should all change our oil at 3,000 miles.

Q. Yes, sir.

A. If it's not convenient, and you go to 4,000 miles --

Q. Right.

A. -- have you really hurt anything? Or you've just deferred that maintenance?

Q. Okay.

A. Okay. And with that simple example, you decide at some point never to change your oil, you're going to pay long-term.

Q. Okay. Fair enough.

And I guess those kind of decisions are accentuated as you get near the end of the life of a car or a plant, aren't they?

A. Correct.

Q. Let's see.

Now, these -- and this -- on 1437, as long as we're there, these units 1, 2, 3 outages, you don't know if they're due to cost control why they were canceled?

A. No.

Q. Okay.

1439. The title here is "Risk Associated

with Plan"; did you prepare this?

A. No, sir.

Q. Okay. Do you know who did?

A. Not -- no.

Q. Okay. This talks about the -- the deferral of the outages and talks about the -- what it's going to do to station performance; is that correct?

A. Yes.

Q. Okay. And -- let's see, can you walk me through these numbers? The EAF and -- as I recall, which one did you say was the most critical one for reliability? Or is it here?

A. To me, it's not here.

Q. Okay.

A. It's what we refer to as OPA, on-peak availability.

Q. Okay.

A Okay.

Q And it just isn't here?

A. It's not one of the standards.

Q. Fair enough.

Okay. But this makes some pretty dire warnings about deferring the maintenance, doesn't it?

A. Uh-huh (indicating affirmatively).

Q. And it -- it -- can you walk me through

these -- some of these numbers?

A. If you start on the left-hand column, we're looking at a column that's labeled "Original Outage Schedule of 7/10 of '01."

Q. Right.

A. Rev. 1.

Q Yeah.

A. New T & D outage Bayside.

The T & D outages make reference to some of the transmission issues and what we refer to as energy delivery side, the -- the wire side of the business that had to be done to support Bayside. And I think it's looking at when we take those outages.

Q. Uh-huh (indicating affirmatively).

A. Okay?

Some of the T & D outages were rather lengthy outages. And part of the goal here was not to take two outage windows in a fairly short period. That we didn't want to take a 10-day maintenance outage and then come back two months later and need a T & D wire outage, okay?

And from there, this gets a little muddy on me. I think it's someone's calculation if you shifted these outages, what effect it could have on EAF plant outage rates and forced outage rates.

Q. Okay. I just wanted to very briefly talk about the goals on 1443 and 1444, and take a look at some of these goals, and ask you how Gannon Station did, if you recall.

A Just a minute. Off the record?

(Whereupon, an off-the-record discussion was held.)

BY MR. VANDIVER:

Q. I don't want to go through this in any great detail.

A. Okay. A recap of 2002. As far as operational goals, I think Gannon met all -- met or exceeded all of its operational goals as stated in this document.

Q. All right.

A. I do not have the details.

Q. Okay.

Okay. That's -- I don't want -- I don't want to walk through these --

A. Yeah.

Q. -- in any great detail. I just want to --

A. But I do know we -- we exceeded or met these goals.

Q. Okay, sir. That's all I wanted to talk about today.

Let's see. Let's go to 1533.

A. Would you believe I don't have a 1533.

Q. You don't? Here you go, sir.

Do you know when these budget assumptions were adopted?

A. Not exactly. I do know these were the budget assumptions for the base case 9, which was the base case of the business plan for Gannon Station.

Q. Okay.

A. That I inherited as an unapproved budget at about November of last year.

Q. What's it take to change those assumptions?

A. What does it take?

Q. (Nods head.)

A. A change in business drivers and business needs.

Q. Did you have any reason to think they were tentative or temporary?

A. To think they were tentative or temporary? I never assumed these to be inflexible.

Q. Okay.

A. Okay.

Q. Fair enough.

Let's go to 1535, if we could, please,

sir. And here's the safety budget for Gannon. Is safety more of an issue in older plants than newer plants?

A. It shouldn't be.

Q. Does safety deteriorate at each specific plant at each year to some degree?

A. If you let it get complacent.

Q. I knew you were going to say that.

Let's go back to 1420.

And if I'm not mistaken, I believe this is the prior year safety budget. I think the one I showed you just a minute ago was the 2003 safety budget.

A. This is the 2002 and this is the 2003?

Q. Yes, sir.

A. Okay.

Q. And I think the --

MR. BEASLEY: Where does this indicate that it is? Are you accepting that it is?

THE WITNESS: I was taking his --

MR. VANDIVER: Well, I would like for him to do it subject to check, but we can certainly walk through it line-by-line and page-by-page. One is in the -- one Gannon operation report and we can go back to page 1 of each document, Jim, if you prefer.

MR. BEASLEY: Okay. I just want to verify that it is, in fact --

MR. VANDIVER: Certainly.

MR. BEASLEY: -- what it's represented --

BY MR. VANDIVER:

Q Let's go back then. The one document -- let's -- let's slowly go back.

1535. And if you'll just flip back several pages there, I think you'll find that -- that to be --

A. 21532?

Q. 1407 is the first page of that. Wait a minute, that's not right.

MR. BEASLEY: I thought 1521 was.

MR. VANDIVER: 1521 is the first page of that. Thank you, Jim.

BY MR. VANDIVER:

Q I think that is the 2003 budget; is that right? That's the 2003 Gannon report?

A. Business plan.

Q. Yes, business plan, thank you. 2003 Gannon business plan.

And then if you go back to 1420, I believe you will find -- Earl, can you help me out -- that if you go back to 1407, you'll find that the first page of

that is the identical document, Gannon business plan, again -- 1407, you'll see 2002 business plan. You'll see that there's -- they're virtually identical documents.

A Except for the date.

Q. Except for the date, yes.

A. This is a later rev. of the 2003 business plan.

Q. Right.

Yes, in other words -- is that correct? One is a 2002 document, one is a 2003 document; is that correct?

A. Right.

Q. Okay. Do we have our first pages? I apologize, I should have done that in advance, Mr. Beasley. And I apologize to you, Mr. Maye.

But one is a 2002 business plan and one is a 2003 business plan. Have we confirmed that? And it's the identical document in both cases? It's the same pages --

A. Identical format in two different years.

Q. Yes, sir.

A Okay.

Q Okay. Yeah. And is everybody with me?

MR. BEASLEY: (Nods head.)

BY MR. VANDIVER:

Q. Okay. Okay. And I'm getting to my question now. And I apologize for this confusion. It's my fault.

And my question is: Why is the safety budget lower in 2003 than it is in 2002?

A. As far as a safety budget and understanding the -- the integral details that go into this, they're relatively the same --

Q. Okay.

A. -- to me.

Probably two to three years ago, Tampa Electric Energy Supply brought on site Pacific Safety Coordinators. And I think we have seen some peaks in safety budgets, getting up-to-date programs, up-to-date equipment, little things, like it references confined space rescue equipment.

Q. Uh-huh (indicating affirmatively).

A. That's something new to the industry. And I think you will see deviations from year-to-year in what equipment the safety coordinator feels he needs, what programs he feels he needs, okay. But to me, it's -- this looks like an average quarter million dollars a year.

Q. Okay.

A. Okay.

Q. And that's Mr. Willoughby's shop?

A. Ben Willoughby.

Q. Okay. Can I go ahead and get an exhibit on that from '98 to 2003, that safety budget number? I would like to go ahead and highlight that number?

A. The only thing --

Q. Is there a caveat with it?

MR. BEASLEY: Hold on a second. Off the record.

MR. VANDIVER: Okay.

(Whereupon, an off-the-record discussion was held.)

MR. VANDIVER: Let's go back on the record.

Okay. We would revise that -- I think that would be late filed Exhibit 2.

MR. BEASLEY: 2 --

MS. JORDAN: 3.

MR. VANDIVER: 3? And that would be safety budget from the year 2000 forward. Again, the same format for the Gannon Station.

Thank you.

BY MR. VANDIVER:

Q. Okay. Moving along. 1538, talked a

little bit about this yesterday.

What are fly ash sales?

A. Fly ash sales are the sale of the top ash, the cement consistency ash that's produced or pulverized coal.

Q. Sold to cement companies?

A. It's sold to somebody.

Q. And slag sales?

A. Slag sales is bottom ash. It is the black stuff that you stepped in yesterday around the slag tanks. That's usually used in somebody's product as an aggregate, like an adder to asphalt or cement.

Q. And are those dollars run through the fuel cost or do you know?

A. I do not know.

Q. Okay, sir.

Let's see. Can we go to 1548, please, sir?

Base case 9 is the base case; did that ever change after October of 2002?

A. As far as the case, no.

Q. Okay. Do you know when scenario 9 became the base case?

A. No.

Q. Okay. We go to 2122.

Do you know what the 925 number means?

A. Let me get familiar with the document.

Q. Sure.

MR. BEASLEY: Have you seen this before?

THE WITNESS: I don't think I've seen this sheet before.

BY MR. VANDIVER:

Q. If you're not able to help, Mr. Maye, I understand, that's fine. Do you know what the 925 number represents --

A. No.

Q. -- under maintenance?

A. I do not know the details of the 925 number.

Q. Okay. Or the 700 number?

A. Or the 700 number.

Q. Okay, fair enough.

Let's go to 2286, if we could for a second. Tell you what, we're going to come back to this one, Mr. Maye. We'll go to some other sheets and come back to this one.

Can we go to 800 and 801?

MR. BEASLEY: Can I get a point of clarification?

MR. VANDIVER: Sure.

MR. BEASLEY: I just need to check on the number -- this is off the record.

(Whereupon, an off-the-record discussion was held.)

BY MR. VANDIVER:

Q. Okay. All right, sir. Have you ever seen this document before, Mr. Maye?

A. Yes, I've seen it.

Q. Okay. Does this page identify the O & M costs for Gannon, assuming the plant continues to operate 1 through 4 until September of 2004; is that correct?

A. I don't know -- I don't know the assumptions.

Q. Okay.

A. Or the -- the root case the assumption was built off of, but I have seen the document.

Q. Okay. Well, the assumptions are right there for the 2004 base case. Do you see them right there up at the top?

A. Let me restate that. I don't know the dates the assumptions were built around it, if it was September, December, et cetera.

Q. Okay.

These were the O & M costs that were used

to evaluate the various options. Do you know who produced this?

A. I believe it was produced by Karen Sheffield.

Q. Okay.

Let's try 4044 through 4049. Have you ever seen this before?

A. 4044?

Q. Yes, sir. 4,044. We've been skipping around some, so -- all right, sir. Can you describe this document and its purpose?

A. It is a revision of the key strategies -- and I just say revision because I don't know that this is the current revision that's in the business plan -- of the key strategies associated with the Gannon business plan for 2003.

Q. Okay. And you may not know the answer to this one, but the next version we have is dated October 16th. Do these two documents reflect the actual budget commitments for 2003?

A. No. Because both of those dates, this was still in the draft form, and it wasn't approved budget plan.

Q. Okay. When did it become the approved budget plan; do you recall?

A. Somewhere right around the first of the year.

Q. Okay. How do you go about this? Do you produce the budget and then the key strategy or vice versa?

A. This was produced by Karen Sheffield.

Q. Okay.

A. I think the scenarios in the cases that we discussed were run and then Karen was given direction to build her budget plan around case 9.

Q. Okay.

Do you know what the date that she got those instructions were?

A. Not exactly, no. It was late third quarter.

Q. Okay. Can we go to 1521 to 1547?

A. You-all got me straight over here? Okay.

Q. I think we've discussed this one before, too, sir?

A. Okay.

Q. This is the Gannon Station 2003 business plan; is that correct?

A. Okay. Recognize it as -- yes.

Q. Yes.

A. The revision of the Gannon --

Q. Yes, sir.

And does TECO prepare the same business -- a business plan for each of its generating stations?

A. Each generating facility is responsible for producing a business plan to be approved.

Q. Okay. And what's included in these business plans?

A. Basically your O & M requirements, your capital requirements, your staffing needs and associated dollars to fulfill your plan for the following year.

Q. And the intended audience, I believe you said, was the upper management, the officers of -- who is the intended audience?

A. All right. Let's -- I think -- I think the intended long-term audience is the officers of the company.

Q. Okay.

A. Basically, the way this process works is as a general manager, we present our business plans to the financial director and the vice president of Energy Supply.

Q. And you as the general manager or Karen Sheffield in this case produces that plan or your management team?

A. Because of the baton swapping during this

period, Karen started the plan, I was the one that presented the plan.

Q. Fair enough.

Okay. And it goes up in management, it doesn't go down?

A. From this point, yes.

Q. Okay. And whose approval was required to send it out? Yours?

A. To send this --

Q. (Indicating affirmatively).

A. -- to Bill Whale?

Q. Yes?

A. Yes.

Q. Okay, sir.

A. Or the general managers of each facility.

Q. And this plan is dated October 17th, 2002?

A. Yes.

Q. Okay. And when did Mr. Whale approve it? Do you recall?

A. Somewhere right around the first of the year.

Q. Okay. And I think we just discussed this, but walk me through how this relates to the budget.

A. This is your budget --

Q. Okay.

A. -- for the following year.

Q. Okay. Okay. Let's see.

Let's go to 1523. Can you explain what the EAF is and why is it important to TECO? Or is it?

A. It is very important to TECO.

Q. Okay.

A. It's very important to all of us. In other words, that is the anticipated performance equivalent availability factor that you're planning to see out of your units for the following year.

Q. Uh-huh (indicating affirmatively).

And in the past two years, it's been significantly higher than 2000; is that correct?

A. 2000, yes.

Q. Okay. And it looks like it may even be going up in 2003? It looks like Gannon is becoming more reliable?

A. That's -- know the score card.

Q. Okay.

A. What happened in 2000.

Q. What happened in 2000?

A. I would have to go back and do some research, but I believe that's probably the after effect of the Gannon 6 explosion, some major replacements on Gannon 5. In other words, that's actual year end EAF.

Q. Okay.

A. If you don't produce what you said you were going to produce, the line dips, okay?

2001, 2002, 9 plus 3 is where you were actually at. Remember that the load requirements at 2001, 2002, might have been lowered to make the unit more reliable. So, you're not necessarily comparing apples to apples there.

An example would be if Gannon 2 was at 115 in 2000 and it was 105 or 90 in 2001, its EAF would go up, but its total generation would go down. And the 2003 is a budget target, what you're building your budget to.

Q. All right, sir. Let's go to the next page and -- EUOF. Again, can you walk me -- tell me about this chart first?

A. This is a history of equivalent unplanned outage factor. It is the total outage picture; forced maintenance and plants durations.

Q. All right. And this is -- and this is the time that the plant's out of service, correct?

A. Or derated.

Q. Okay. What -- can you define "derated" for me?

A. I lose a boiler or feed pump, one that

takes full load. It takes two feed pumps to make full load operation, which is typically -- that's 40 to 60 percent derating. The unit is still on, but it's not meeting your predicted generation numbers, would be an example.

Q. Now, Gannon is the oldest thing in your fleet, right?

A. Oldest running thing in our fleet.

Q. Okay. It's only a few percentage points above the rest of your fleet, correct, in terms of EUOF, equivalent unplanned outage factor?

MR. BEASLEY: If I might inquire, where is the 2 percent you're referring to?

MR. VANDIVER: I said a few.

MR. BEASLEY: Oh, a few.

MR. VANDIVER: Yeah.

MR. BEASLEY: Oh.

MR. VANDIVER: Well, let me -- I'll tell you what --

THE WITNESS: Yeah, it's -- this chart shows that the system outage rate is running lower than the stations.

BY MR. VANDIVER:

Q. Okay. Is -- is the reason that Gannon is higher, is it because it's the oldest plant or is it

because you've been cutting back on maintenance?

A. No, it's because we've been doing the right things.

Q. Okay.

A. And that's a true picture. In other words, the only way Gannon can be higher than the system is we are meeting our expectations.

Q. Okay.

A. For the system to drop, somebody has had to miss their expectations.

Q. And that would be Big Bend and the rest of the fleet?

A. (Nods head.)

Q. Could we go to 1529 and talk about on-peak availability, please?

And the on-peak availability factor for TECO has dropped since '99; is that correct?

A. No.

Q. Okay.

A. On-peak availability is a measure that the department started using in '99. Okay?

Q. Okay.

A. And there again, there was a dip in 2000.

Q. Okay. What's happened to the Gannon availability factor between '99 and 2003?

A. The on-peak availability?

Q. Yeah.

A. It looks like it took a dip in 2000. And it's climbed in 2002, 72.4, and budgeted for 70.1 in 2003.

Q. Okay. Can we go to 1531, sir? What does this graph show us?

A. 1533?

Q. 31, sir.

Let's see, where am I here? Hold on.

Excluding the start up years and the current year when you were in shutdown mode, it appears that Gannon fluctuates around 5 million megawatt hours a year; is that right?

A. You straight-lined the graph?

Q. Sometimes more, sometimes less?

A. (Nods head.)

Q. Do you see any evidence of decline in this chart?

A. Just at the tail end, and I can't read the dates. And I'm assuming that's the phasing out of Gannon and the startup of Bayside.

Q. Do you know what the approximate fuel cost for KWH for Bayside is?

A. That's a tough question to answer. This

week it's -- gas is in the mid 5s.

Q. Uh-huh (indicating affirmatively).

What is it for Gannon?

MR. BEASLEY: When you say the mid 5s --

THE WITNESS: 550 to 575 for MMBTU.

MR. BEASLEY: $5.50?

THE WITNESS: Yes, for MMBTU. That's for Bayside. Wasn't that the question?

BY MR. VANDIVER:

Q. Yes, sir, it was.

A Okay.

Q And what would it be for Gannon?

A. I don't have those details. I'd say in the $2 per MMBTU range, low 2s.

Q. Okay.

A. Or around 2.

Q. Okay. And the increased cost to Bayside fuel would be picked up by the customers; would you agree with that?

A. Don't quite understand the question.

Q. I'll save that for the fuel panel.

A. Thank you.

Q. Okay. Bayside has lower O & M expenses than Gannon; is that correct?

A. Overall, yes.

A. Okay.

Q. All right, sir.

A. There is a payroll for both Bayside and Gannon.

MR. VANDIVER: Can we go off the record for just a second?

(Whereupon, an off-the-record discussion was held.)

BY MR. VANDIVER:

Q. We can go back on the record.

Mr. Maye, can we go to 1525, please, sir?

And earlier you and I discussed the planned outage factor?

A. Yes.

Q. And here we see it graphically represented, is that correct?

A. Correct.

Q. And we see that the Gannon numbers are in decline; is that correct?

A. In 2003?

Q. Yes, sir.

A. Yes.

Q. Okay. And I'm curious about that because we had just discussed making up some of those planned outages in 2003. Could you help me there?

A. The graph shows an interesting picture.
Q. Yeah, it really does.
A. Okay. And it kind of speaks to these deferred outages.
Q. Yeah, it does.
A. If you look at 2001 through 2002, there was actually an increase --
Q. How about that?
A. -- in planned outages. Okay? And that's where I was referencing that sometimes outages are deferred from one season to the next.
Q. Yes, sir.
A. Okay. As you move into 2003, and I think this chart really speaks to Gannon, not Gannon slash Bayside.
Q. Okay.
A. Okay?
Q All right.
A That with the early removal of service of Gannon 1 and 2, there isn't a planned outage.
Q. Okay.
A. The planned outage is for 3 and 4. So, your percent of planned outages will go down.
Q. Okay.
A. Okay. And, of course, it will be zero --

Q. Okay.

A. -- in 2004.

But this does reflect how outages get -- the question we had earlier.

Q. Kind of bumped forward?

A. Yeah.

Q. And so the same thing would be true of Tampa Electric Company generally of planned outages?

MR. BEASLEY: Same thing.

THE WITNESS: Same thing.

BY MR. VANDIVER:

Q. Same thing?

A. The system is in light of what Gannon reflects.

Q. Okay. And so that would be true of the entire fleet of Tampa Bay generation?

A. (Nods head.)

Q. Turning now to Bates stamp 1526. Net capacity. This is another important graph, is it not?

A. Yes.

Q. Okay. A flatter graph's never been seen; would you agree? Gannon is putting out flat numbers, is it not?

A. It's 1155 in '98 compared to 1120 at the tail end of 2002. That is a net change of minus 35.

Most of that 90 minus 35 is associated with Gannon 1 through 4, primarily Gannon 1 and 2, and the header pressure rating. So, it's -- in a 0 to 5,000 chart, it doesn't show, but there has been a net, okay.

Q. Okay.

A. I'll make reference to it, but a -- a net change of 10 megawatts on a Gannon 2 by dropping the header --

Q. Okay.

A. -- can raise your reliability as much as 5 to 10 points.

Q. Could you define "header" for me, sir?

A. "Header" is basically a term that's used for boiler operating pressure.

Q. Okay.

A. It's -- it's the amount of pressure that's on the internal of your pressure parts.

Q. All right, sir.

Okay. And lastly, we come to -- next we come to 1527, a net generation number. And I guess this is sort of the bottom line of how much power it puts out, isn't it?

A. Yes.

Q. And this shows -- well, I guess that decline at the end is due to our shutdowns, is it not?

A. Yes. And there again, this chart references Gannon, not Gannon/Bayside.

Q. Okay. And so the only decline we have for the Gannon units is due to the shutdown, correct?

A. Shutdown of 1, 2 and later -- later year shutdowns --

Q. Okay.

A. -- of 3, 4 and 6.

Q. And so for all of our deferred maintenance and everything, the Gannon units are trucking along pretty good, aren't they?

A. I --

Q. Would you agree with that?

A. Met expectations.

Q. Even exceeded; is that going too far for 50-year-old units?

A. Yes.

Q. Now, I would like to turn to --

MR. VANDIVER: Can we take just a two-minute break for a second?

THE WITNESS: Sure.

MR. VANDIVER: Why don't we just take lunch now? How about that?

MR. BEASLEY: Sure. Come back and finish up Mr. Maye after lunch. Take 45 minutes? Okay.

Come back at 1:15.

(Thereupon, a lunch recess was taken from 12:30 p.m. until 1:22 p.m.)

BY MR. VANDIVER:

Q. Okay. We're back on the record.

Mr. Maye, could I refer you to 3048 through 3052 of Bates stamp, please, sir?

A. 3048 to what now?

Q. This is -- if you can take a look at this, sir?

A. Excuse me, Rob, it was 3048 to?

Q. 3052.

A. Okay.

Q. I believe it's a presentation?

A. Yes, sir.

Q. All right, sir.

MR. VANDIVER: 3048, 3052. It's a series of overheads, Jim.

MR. BEASLEY: I've got them. This thing goes from 290 to 403.

MR. VANDIVER: I'll let counsel get there.

MR. BEASLEY: It ain't going to get there in this stack.

MR. POUCHER: Do you want me to find it for you?

MR. BEASLEY: Sure.

MR. VANDIVER: Pause for just a second while counsel locates the documents.

MR. BEASLEY: Oh, I've got it. Thank you.

MR. VANDIVER: Okay, sir.

MR. BEASLEY: I was a digit off, I apologize.

MR. VANDIVER: No problem.

BY MR. VANDIVER:

Q What's the date of this document and who originated it?

A. 3048 is an e-mail from Chuck Drake to Karen Sheffield and myself --

Q. Okay.

A. -- that I think referenced this attached presentation.

Q. And what's the purpose of this presentation, sir?

A. This presentation was the first step in discussing the transition plan as it would be presented to the employees. These overheads were the overheads that were used in that meeting with a group of personnel who were involved including energy delivery, labor relations, et cetera.

Q. Was this presentation given to the

Union --

A. No, sir.

Q. -- people?

A. No, sir.

Q. Okay.

A. This is not the Union presentation.

Q. Okay. Who was this presentation intended for?

A. It was intended for the general managers and directors who were responsible to put together the transition plan.

Q. Okay. And when was this presentation presented?

A. Around the time of this date. I would say first of November.

Q. Okay.

And the -- the dates here are -- the closure dates on overhead Number 4 are for March 15th, Gannon 1 and 2 closure and 3 and 4 Gannon -- Gannon 3 and 4 to be closed September 1st, 2003; is that correct?

A. Correct.

Q. Okay. And this is basically base case 9; is that correct?

A. I think there's references from base case 9 or the business plan. Remember, this document and

this presentation was made before we had the approved business plan --

Q. Right.

A. -- which it was built on, but the dates are very similar to the base case 9 or are the dates for the base case 9.

Q. All right, sir. What's overhead 2 mean?

A. That's basically that we have decided to implement base case 9.

Q. Okay.

Yeah, okay. Yeah, the -- the first overhead said, "It's been considerable time since we got together to discuss the Bayside transition plans." What -- can you enlighten me a little bit on that?

A. Yeah. In -- this was basically Karen Sheffield's first shot at getting overheads, what overheads should say.

When we first announced Bayside, we had a series of employee meetings that we sat down with all the Union crafts, management, supervisors, technical support, and basically said, "This is the direction we're going towards Bayside." This was the actual -- the first meetings with the announcement of the Bayside; explanations, consent decree, where we stood within that, and a plan on how we saw getting there, the number

of jobs and people that are going to be affected, encouraging the employees to don't miss any opportunities for careers elsewhere. So the -- probably 18 months plus lapse between we had gotten with the employees until we were going in the direction with base case 9.

Q. Was an adaptation of this eventually given to the Union people?

A. Yes.

Q. Okay. Can we turn now to 3,087 to 3,099, please, sir?

I'll give you a second to look at that. I know there's a number of sheets there.

When did you first present the shutdown to the Union leadership?

A. Late January, early February.

Q. Was this part of an employee presentation?

A. No, not really.

Q. Okay.

A. Page 1 is kind of a summary of the --

MR. POUCHER: Go ahead, I'm sorry.

BY MR. VANDIVER:

Q. Go ahead.

A. 3087 is kind of a summary of the employee presentation.

Q. Okay.

A. 3088 is a time line that deals with things that were presented in the presentation and how we saw the transition folding out; basically bids, moves, et cetera.

Q. Okay. Okay. And this adapted or a form of this earlier presentation was what was given to the employees or the Union leadership, this one we had previously discussed on 3048 to 52?

A. No, the first one we first discussed is when management sat down and started putting the presentation together.

Q. Okay.

A. The Union was given the finalized presentation.

Q. Okay.

A. Okay.

Q. Which was different from this one.

A. Which was different from that.

Q. Okay.

A. Which is in the record.

Q. All right, sir.

All right. If we can go to 8598 to 8600? And I notice that -- and I'll let you take a look at this.

What are red circles?

A. Red circle is a Union craft term that's used widely where you take a man whose current rate of pay is X and you move him to another job, but you've maintained his existing rate of pay.

An example, a certified -- or let's go in the operating ranks: A control center operator through the transition bump and roll ends up being an auxillary operator. The differential of pay is like $7 an hour. Red circle would mean you would hold him at his existing rate of pay to do a lesser paying job.

Q. All right. So he gets the same money.

And do you know what the reference is here to "Given our fixed budget dollars, it is preferred to use our dollars to preserve jobs for our employees"? What's meant by that statement?

A. As it's spelled out in the transition plan, we made some jobs or some landing zones for some employees, okay, to keep more people employed instead of just cutting the cord and say, "We're laying off X number of people to preserve the dollars."

Q. Okay.

A. I would like to also add to that that that's not an added expense. That basically this landing zone, parking lot, maintenance crew that's

spelled out in the transition plan displaces what would normally be contract maintenance.

Q. Okay.

A. So we would let the contractors go and keep the permanent employees.

Q. Okay. And in the third paragraph there, you made the -- you're making clear to the Gannon employees that this Gannon shutdown schedule is accelerated and you told them about it in January and you, in fact, did that; is that correct?

A. Yes.

Q. Okay. And what's the reference to market driven? Is that --

A. I think the reference here to market driven was there wasn't necessarily an identified market for the power from Gannon 1 and 2.

Q. Okay. All right, sir.

If I could direct your attention now, sir, to page 2820. I don't think I recognize any of these names. Can you help me out? Who is Dave Darden?

A. I have no idea.

Q. Do you know who Dave Dennison is?

A. I know the name.

Q. Do you know what group he works with?

A. I think they're all -- I think they're all

T & D associated or energy delivery -- wire side.

Q. Jack Stewart and Mark Milton?

A. Mark Milton, I know is.

Q. All right. Do you know anything about this Stealth project?

A. (Shakes head.) No.

Q. Okay. Thank you.

A. They must have kept it quiet.

Q. Must have been pretty quiet.

11,193 through 11,195, please, sir. 119 -- 11193 through 11195. And I think we'll start with these somewhat truncated graphs. One is anyway. What are tube repairs?

A. Tube repairs basically talk about internal water and steam or boiler steam and water tubes, which includes the whole boiler proper, steam side, water side, et cetera.

Q. Okay. And how do the Gannon -- how do the numbers for tube repairs for Gannon 1 through 4 compare to 5 and 6?

A. I haven't made the comparison.

Q. Okay, sir.

MR. VANDIVER: Do we need to pause? We'll go off the record for a second.

(Whereupon, an off-the-record discussion

was held.)

MR. VANDIVER: Okay. Okay, we're back on the record.

BY MR. VANDIVER:

Q. Did I ask you what tube repairs were, Mr. Maye?

A. I think John did.

Q. Okay.

A. But basically tube repairs are -- this is a history of -- documented through our workmen and work order system of the number of tubes that have been repaired in recent years on Gannon 1 through 4.

Q. Okay. And do these tube repairs -- are these done during planned outages?

A. All of the above. Typical scenario is a forced outage due to a tube rupture will take you off the line.

Q. Okay.

A. As they go in and do that and we go through the normal maintenance process of hydrostatic fills and static fills to identify leaks, this is inclusive. There's times that a single leak will take us off and before we come back and have a static test, we'll find 15 or 16 leaks.

Q. Okay.

A. Okay.

Q. How long -- is there a typical tube leak that -- that you could cite me to that would take -- and how long would that outage be if you could give me a for instance? Or is there a typical tube leak or tube outage? Do you understand my question?

A. A tube failure outage?

Q. Yeah.

A. There's two extremes.

Q. Okay.

A. Okay. Typically, is one that one causes you an operational problem that shuts you down, similar to what we had this weekend on Gannon 2.

Q. Yes, sir.

A. That we weren't able to maintain flame. We couldn't keep our slag taps open. We just couldn't maintain stable combustion.

Q. Okay.

A. Okay. Typically on a controlled shutdown of the unit where you can maintain water in the vessel and you can properly relieve and cool pressure, you can turn these -- in as little as two shifts, probably average is three to four shifts, to turn the unit back around and get it in service.

Q. Is that a 12-hour or an 8-hour shift?

A. 8-hour shifts.

Q Okay.

A We're talking maintenance. There's three shift dates.

Q. Okay.

A. So in -- typical breaker-to-breaker would run 24 to 48 hours on these types of repairs.

The other extreme is when you have a tube failure, something that you lose drum level, the unit trips. You're not able to maintain water and you have to go through an extended cool down period to get all your turbine and metal temperatures, et cetera, right so you can actually fill the vessel back up. Typically, those will take four to five days.

Q. So that's a lot bigger deal?

A. Yeah.

Q. How do these two repair numbers, how would they compare with Big Bend?

A. I don't know.

Q. Okay.

A. I actually had these graphs run just for myself to get a history on tube failures on Gannon 1 through 4.

Q. All right, sir. And -- and is there a normal course of business? Would you repair it or

replace it or would that depend on the situation during a forced outage?

A. During a forced outage?

Q. (Nods head.)

A. A forced outage is a classic patch and go.

Q Okay.

A. Okay? Where you will cut a window.

Q. Uh-huh (indicating affirmatively).

A. And -- or use what they call a dutchman, which is just a piece of the tube and seal weld it in place.

And one of the reasons you document this is to build a history of where your problem areas in the boilers are.

Q. Okay.

A. That are typically in planned outages, come back and addressed.

Q. Okay. And just eyeballing it, it looks like Gannon 1 took a heck of a jump in 2002, didn't it?

A. Kind of like a cancer.

Q. Yeah. Big time.

Same thing with 2.

Three is going along pretty good, isn't it?

A. Yes.

Q. Okay. All right, sir.

Referencing 1195, who is Jennifer Fisher?

A. She is an engineer who works in generation planning, who basic -- primary job responsibility is to track forced outage rate, EAF, the type of generating status reports that are put out monthly.

Q. Okay. And did you specifically request this from Ms. Fisher?

A. Yeah.

Q. Okay. And did you already know what this graph was going to show or did you telegraph to her in advance what you -- when you -- in other words, this -- this seems to foreshadow that you had already told her what you thought this was going to show. Can you talk to me a little bit about this?

A. And when I say I asked Jennifer Fisher for the graph, I asked her to run the numbers.

Q. Okay.

A. Okay. And really, that's why this shows it in two forms. And it's typical engineer; they'll give you the raw numbers and they'll give you the graph.

Q. Okay.

A. And --

Q. It says she -- I think it definitely paints a picture you needed?

A. Yeah.
Q. Okay.
A. That -- that the number is drastically increased.
Q. All right, sir. And that's the picture you needed?
A. (Nods head.)
Q. Okay. Okay. I would like to turn now to 2286 to 2290. I think we had some difficulty with those page numbers. Basically, this is that -- the documents that we discussed earlier in some length with Mr. Knight.
A. 2286?
Q. Yes, sir.
It may be better to talk about 2289 and 2290, because they're the same documents. It shows it's a -- how much money it's going to cost to get Gannon Station up to an 85 percent availability rate and 60 percent availability rate. I'll let you take a look at that for a second here.
A. I'm fine.
Q. Okay, sir. If we can look at 2289 first. Let me get squared away here with my pages because -- all right, do you know who requested these documents be provided, prepared?

A. Yes. Yes. Bill Whale requested of me what the effect if we ran Gannon 1 through 4 for an extended period of time, and I'll just say reference base case 9, lower than base case 9. What will be the significant requirements to accomplish that.

Q. Okay. So now, you've been at Gannon 20 years?

A. Off and on; probably 20 plus.

Q. Okay, sir. Have any of the Gannon units ever run at 85 percent capacity?

A. Yes.

Q. Which ones?

A. The latest recollection I've got is Gannon 2.

Q. When was that?

A. Probably the year 1999 or 2000.

Q. Okay.

A. And I would like to caveat that by saying that's the first unit I lowered the header on because of the rear wall failures and the unit achieved 92 percent EAF failure.

Q. Okay. How realistic is it for the Gannon units to run at 85 percent capacity today?

A. It is not very realistic. And really that's what this document represents, is it comes at a

significant price.

Q. Right. And do you believe it to be, in your expert opinion, to be cost effective to run Gannon units at 85 percent availability?

A. At this point in time, only being permitted in any shape or form not to run past December 31st of 2004, it's not a wise investment.

Q. It wouldn't be cost effective and you wouldn't recommend it to anybody to run them at 85 percent capacity and to spend this money?

A. No.

Q. Great.

Now we'll go to 2290. This might be a more realistic scenario.

A. Correct.

Q. In your opinion?

A. Correct.

Q. Okay. And this is a 60 percent availability?

A. (Nods head.)

Q. And is this a more typical availability for the Gannon 1 through 4 units for the past five years?

A. It is -- it reflects a depreciating availability over the next couple of years.

Q. Okay. And might in the last days of a plant, would it might be cost effective to run a unit at even a slightly lesser availability rate than this? Where is that trade off?

A. It's -- we're sitting here with a prime example today. And we'll talk about Gannon 2.

Q. Okay.

A. Okay, where we roll the dice.

Q. Sure

A. Okay? To make an attempt to roll that unit one day is probably going to end up costing my O & M budget a quarter of a million dollars.

Q. That's what you did yesterday?

A. Yes. And that's what the need dictated. The expectations were that if you don't spend the money, you're not even going to come close to 60 percent.

Q. All right.

A. So, I don't think that without spending significant O & M dollars on these units, they -- they're at their useful life.

Q. Let me ask you a "what if" question: What if dollars had been expended on planned outages back in 1999, 2000, 2001? Could these units have gone a little bit longer? Another six months? Another year?

A. That is truly a "what if" question. And I

think we talked about a document that showed the planned outage factors. And I don't think you see a decrease in planned outages up until this year on Gannon 1 through 4. In fact, if anything, there was a slight increase in 2001, 2002 in planned outages.

I think what we're strongly feeling now is the effect of it's at its useful life. It's past just the option of planned outages. You're entering the realm, and that's kind of what the 80 and 85 percent availability factors show of major, major outages to extend the lives of these units.

Q. Now --

A. And really, that's what got us to the consent decree.

Q. And can we subdivide the units? Are the four units individualized?

A. They're -- they're individualized in a sense -- and I think the business plan really reflects that, is they're twins. And when you understand and look at the whole picture, even to the vintage of 1 and 2, the man power and staffing required for 1 and 2 and then you segregate 3 and 4, the vintage, and 5 and 6 in the vintage, I've always referred to them as kind of being twins or sisters.

Q. Okay.

A And --

Q. And I guess I'm harkening you back to that boiler tube number where 3 was so low and it kind of stood out --

A. It's still running.

Q. -- yeah, from its sisters?

A. Yeah.

Q. Maybe 3 can go longer than 4.

Which of the -- of Gannon 1, 2, 3 and 4, which operation is the best -- is the soundest unit?

A. Traditionally, it's been Gannon 3.

Q. And which of the four is the worst?

A. I'd say Gannon 2.

Q. Okay. We had considerable talk about -- this morning about whether this number in the center of the page should have been 2003 or 2004. Can you clarify that for me? We had some talk as to whether that was correct or not. And I think you might be -- I know you're not an accountant, sir, but you may be the better judge of --

A. Knowing the intent of the number --

Q. Yes, sir?

A. -- I think the number is correct.

Q. Okay.

A. Okay.

Q. I will take that to the bank.

And just for my clarification here, on this -- I'm back on 2290 here. 2003, 28-day outage, when would that outage occur?

A. I don't understand the question.

Q. Okay. It says 2003. Do you see there where it says "28-day outage"?

A. Yes, but it shows 28-day outages for Gannon 1, 2, 3 and 4.

Q. Okay.

A. The 28-day outage for Gannon 3 and 4 did occur.

Q. So that's done?

A. Okay.

Q. And it's in the can?

A. It's there.

Q. Okay.

A. Gannon 3 come out of its 28-day outage last week.

Q. It was the normal spring outage?

A. Yes.

Q. Okay. And it's happened, okay.

And 1 and 2, that didn't occur --

A. Did not occur.

Q. -- because they were retired --

A. April 7.

Q. -- April 7th.

Okay, sir.

A. And this paper reflects that if you were going to continue running Gannon 1 and 2, this is the outage requirements, and this is the financial impact and these are the days required.

Q. Okay. So, if -- if, for example, the -- the cost -- if you elected to run 3 and 4 slightly longer, but not 1 and 2, we would subtract out the cost for 1 and 2 and just have the cost for 3 and 4 then? We would take out the 1 and 2 cost?

A. Correct.

Q. Okay, sir.

All right. Back to deferred questions, let's see. Okay.

Go to 1548 to 1561, please, sir.

All right, sir. This is October 16, 2002, Gannon strategies.

Go to 1552, please.

Mr. Maye, have we discussed the outage strategy that's discussed on this page yet?

A. I think it's pretty much what we've been discussing.

Q. Let's see. Hold on a minute, sir.

Let's go to 1560, sir. This talks about the risk associated with this plan. And I believe this is base case 9. And I direct your attention there to the third bullet point and ask if you agree with that risk, risk factor?

A. Yes.

Q. Okay.

A. That's -- and these are budget risk.

Q. Right.

A. Okay, and that was basically things that would have been classified as capital in years past, would be a direct hit to your O & M in your final year.

Q. All right.

And the same way with the fourth bullet point, that's the kind of things we've been talking about as well?

A. (Nods head.) Yes.

Q. Okay. The reference to the Gannon 6 explosion insurance defraud is not in the plan; do you know what that has reference to, sir?

A. I know what it makes reference to, I don't know the details.

Q. What does it make reference to?

A. It makes reference to an insurance settlement.

Q. Okay.

A. But it's not settled, that could come out of someone's budget.

Q. Hold it right there.

Let's see. Okay.

While we're on the risk thing, can we go back to 765, 767?

Again, we're at the risk. And this was referred to you by Mr. Knight. This deals with the risk associated with base case 9.

A. Could you direct me where you're at in the document?

Q. Yes, sir. It's the first bullet point right up there at the top. It says "risk" at the top of the page and the first bullet point says "base case 9."

A. Okay.

Q. Okay. Is this part of the Gannon business plan?

A. Yes, it is.

Q. Do you know who prepared these risks?

A. Karen Sheffield.

Q. Was this information shared with the officers before they made the decision to shutdown the units early?

A. I don't know that.

Q. Okay. Could you talk about the fourth bullet from the bottom that starts with "present funding levels."

A. Oh, fourth from the bottom.

Q. Yes, sir, "present funding levels."

A. I really can't.

Q. Okay. Fair enough.

How about on 766, the next page up. Let's try the third bullet from the bottom.

MR. VANDIVER: Let's go off the record.

(Whereupon, an off-the-record discussion was held.)

BY MR. VANDIVER:

Q. We're back on the record.

It's my understanding that this business plan relates to Big Bend; is that correct?

A. That's correct.

Q. This risk assessment?

Is it true that some of your coal field equipment may be transferred to Bayside at some time -- or to Big Bend at some time?

A. Yes.

Q. Okay.

A. Big Bend will basically be able to replace or use any of our equipment that helps them upgrade

their -- their coal equipment fleet.

Q. Okay, sir. Thank you.

Can we go to page 711, please, sir? And this is a memo from Bill Whale to Karen Sheffield dated 5/20/2002; is that correct?

A. Correct.

Q. Okay. And does this establish the base case for planning purposes on the schedule conversion from Gannon to Bayside at that time?

A. Repeat that.

Q Does this establish the base case for planning purposes at that time from Bayside to Gannon?

A. I really can't speak to that.

Q. Okay.

A. In May of last year.

Q. Do you know if this would have been part of the 2002 budget process in May of 2002?

A. It should have been not part of the 2002 budget plan. It should have been long over by then.

Q. Okay.

A. We were well into year 2002 budget in May.

Q. All right, sir.

MR. VANDIVER: Mr. Maye, I would like to thank you very much for your cooperation. That concludes all my questions.

THE WITNESS: Thank you.

MR. VANDIVER: Thank you, sir.

CROSS-EXAMINATION

BY MR. McWHIRTER:

Q. Mr. Maye, look at pages 1548 and 1552.

A. Yes, sir.

Q. 1548 is base case number 9. And it appears to be in the same memorandum as the -- page 1552, which is a 2003 outage plan. I perceive that the outage plan on 1552 was the old plan and the one on 1548 is the new plan?

A. No, sir. The outage schedule that's on 1552 --

Q. Uh-huh (indicating affirmatively).

A. -- is reflective of the base case 9. There's -- I'll assume you're referencing no outages on unit 1 and 2?

Q. Right.

A. And that was based on the fact they were being shutdown on March 15th in the plan.

Q. What you're saying is there were going to be no forced outages until the shutdown time?

A. No, there was no planned outage.

Q. No planned outages, okay. I'm with you. So, the outage plan has to do with maintenance and the

base case number 9 is the plan?

A. Yes.

Q. And when was that plan initiated?

A. It was approved right around the first of the year.

Q. First of?

A. This year, 2003.

Q. All right. Thank you that's all the questions I have.

CROSS-EXAMINATION

BY MR. BEASLEY:

Q. I have a few.

Would you look at page 611? You were asked some questions about that page.

Mr. Maye, did you prepare that document?

A. No, sir.

Q. Do you know if it provides all of the information that was being looked at and evaluated by whomever did prepare it?

A. I couldn't make any assumption because I don't have enough details to know what this story was built around.

Q. Okay.

A. And what the question -- or the -- what directed this.

Q. Okay. This talks about retiring units 1 through 4 early. Do you know what that reference to early is in comparison to? Early vis-a-vis something else, presumably later?

A. The only factual and -- I was involved in some of the scenarios as far as manpower input. But we permitted to run until December 31, 2004, and then we're no longer permitted to burn coal at Gannon Station.

Q Uh-huh.

A. And I guess these assumptions were looking at when was the right time to park the Gannon units.

Q. Okay. Could you look at page 1439 about which you were asked some questions?

A. Yes, sir.

Q. It was suggested to you in a question about that document that it suggests some dire warnings about the revised outage schedule shown there. Do you recall that reference?

A. Yes, sir.

Q. Do you see anything on that page that would suggest to you that dire warnings are evidenced by this document?

A. Not -- not really. If I was to trend this, I mean, it basically shows that we've been hoovering around a station EAF of the low 60s and

it's -- no, it doesn't indicate that way.

Q. Could you look at page 1443, about which you were asked some questions?

Do you know, Mr. Maye, if these goals have been modified to reflect any operational changes?

A. Repeat that, Jim.

Q. Do you know if these goals have been modified to reflect any operational changes that you -- that you-all have experienced?

A. I think these goals reflect some of the deratings, the header restrictions that we've put into play at Gannon over the last couple of years to -- to meet these goals.

Q. Okay. I don't know that you need to refer to the page, but look at page 1531. That's the context in which this next question was asked of you.

A. That the page?

Q. Right.

You were asked some questions regarding the difference in the cost per KWH -- excuse me, per MMBTU for coal fire generation versus gas fire generation from Bayside; do you recall those questions?

A. Yes, sir.

Q. And gas fire generation, at least currently, is higher than the coal fire generation on an

MMBTU basis; was that your response?

A. Correct.

Q. Why wouldn't you just continue to run the coal fired Gannon stations right on up to the end of 2004 if that is the case now and if that were to remain the case between now and 2004 -- the end of 2004?

A. That's a -- that's a tough multi-part question. One, we have to transition. We're under the consent decree. We had the requirement of having 200 megawatts of generation on this May that was within the new regulations. We also have to land Gannon Station. And -- I mean --

Q. When you say "land it," what do you mean?

A. Park it in a safe, sensible manner. In other words, I can't run to the end and park this thing with a coal field full of coal, with a plant full of people. It's just not feasible to -- to make the transition in that move. It's not, you know, turn the switch on, turn the switch off. I mean, I love coal power.

Q. Well, if it were feasible, then you would do that, wouldn't you?

A. Yeah. I mean, it's -- it's -- you know, it comes back to the cost of the fuel and -- $2 to $22.

Q. Yeah. Well, what other factors other than

fuel cost play into the decision of how and when to park the units?

A. As a personal note, I don't want another catastrophic failure at Gannon Station in the interim. And you know, it's -- and I'm sure people saw signs of it yesterday. It's beyond the point of just major, major renovations and upgrades to think that you're going to see stations like Gannon 1 through 4 continue to run without major changes. And I hope that answered you.

Q. All right. It did.

Page 1527 had to do with -- well, let me go back to that for a second.

Can you just describe for us with respect to Gannon units 1 through 4, what physical condition they're in that you're dealing with at the present time?

A. You're dealing with 50-plus-year-old equipment that structurally -- and I'm not a structure engineer, but it's obvious that it's losing its tinsel strength, it's losing its original capability. I'd reference to something that we just did repair on this Gannon 3 outage where the stack was actually starting to crinkle and collapse.

We've had numerous supports over the last two or three years tear loose. We've had external tube

leaks, and when I reference an external tube leak, I'm talking a tube leak that ruptures outside of the box and it's not contained. It's on the operating floor where our people are at.

The gas leaks are -- kind of use the term because I kind of feel that way sometimes, it's like a cancer. The damage is done. It's spreading and you're chasing skin cracks, you're replacing lagging. Even on Gannon 5 and 6, we put up extensive lagging and rework after the explosion, which was really unrelated to the explosion, but needed to be done. And even after two years, this stuff was continuing to deteriorate. I think we're in a mode now. It's not completed.

Q. If you look at page 1527?

And you were asked some questions about the -- the Gannon units. Could you tell me what the capacity rating is on Gannon units 1 through 4?

A. Currently today, 1 and 2 are shutdown. Gannon 3 is at 160 megawatts, Gannon 4 is at 170, Gannon 6 is at 365.

Q. Okay. Page 11193, if you could turn to that, please?

I'm sorry, 11193. I'll show you this one.

A. Here you go.

Q. Okay. This is the page that you had been

asked about regarding tube repairs. And I think you've indicated that those numbers in that little matrix there show the tube failures --

A. Uh-huh (indicating affirmatively).

Q. -- that you've experienced at Gannon 1 through 4.

You were asked about 1, 2, and 3, but with respect to Gannon unit 4, what has been the trend with respect to tube failures since 1999?

A. If you take the raw data, there was 54 in '99. In the year 2000, it dropped to -- to 26.

Q. Uh-huh (indicating affirmatively).

A. I think if I went back and did the research, I would probably find out there was some major outage work done and some tube replacements or section replacements.

In fact, I do remember now in Gannon 4 there was pretty extensive rear wall work done. That was actually caused by hydrogen and brittlement condenser-related problems. I think we turned the corner in 2000 and in 2001 and 2002 that you basically started escalating.

Q. Uh-huh (indicating affirmatively).

A. On Gannon 4, it is what is known as hydrogen brittlement, which is basically attack on the

metal that's associated with chlorides.

Q. Uh-huh (indicating affirmatively).

And on Gannon unit 3, what has been the experience with that unit on tube failures?

A. It's more -- it's more flat line. You can see, and I think I stated earlier, that it's probably been the most reliable of the four units.

Q. Uh-huh (indicating affirmatively).

A. I think in -- and I don't remember the year, Jim, but I think it was the last unit that went through the total cyclone replacements.

Q. Uh-huh (indicating affirmatively).

MR. BEASLEY: All right, that's all we have.

MR. KEATING: Jim, this is Cochran.

MR. BEASLEY: Hey, Cock.

MR. KEATING: If there's no objection, I did have a few questions and I think being on the phone, I missed my cue when John McWhirter finished up his.

MR. BEASLEY: Go ahead.

CROSS-EXAMINATION

BY MR. KEATING:

Q. Okay. Mr. Maye, my name's Cochran Keating, I'm an attorney for the Public Service

Commission.

A. Yes, sir.

Q. And I just have a few questions that follow-up on some discussion about the status of the units at Gannon. You discussed it with Mr. Vandiver early on in the deposition.

Really what I want to get is just a basic understanding of the difference between some of the different status classifications. You talked about long-term reserve shutdown. Is that -- is that basically the same as long-term reserve standby?

A. Yes.

Q. Okay. I just -- I heard both terms and wanted to make sure I got the record straight.

A. I speak not knowing that there's any difference in the definition in one or the other.

Q. Okay. And how does long-term reserve standby differ from retirement, if at all?

A. In long-term reserve shutdown or standby, I think you're still basically permitted to bring the unit back into service. And you haven't committed that it is not your intention -- you haven't moved into a dismantlement stage.

Q. When you say "permitted," is that in terms of environmental permits or -- or is that in reference

to some other --

A. Both operating and environmental permits are still active.

Q. Okay.

A. And -- and I think the key to it is you don't do anything that dismantles the unit like sell the generator so it couldn't run.

Q. And what is the distinction between long-term reserve shutdown and short-term reserve shutdown?

A. Long term reserve shutdown is typically associated with -- there's constraints that says you're not there at the beck and call if someone picks up the phone and tells you to run. Examples of some plants that have been in long-term -- there's actually been plants in long-term reserve shutdown who basically, totally destaff. There's no one there but a fire watch. So, to start the plant up, you'd have to -- I've actually experienced cases where I've had to bring people, train people and teach them how to run the plant.

Q. Okay. And just to be clear, and I know you-all discussed this earlier, Gannon units 1 and 2, those were placed in -- was it long-term reserve shutdown on April 7th and 8th, respectively?

A. Yes.

Q. Okay. But they were brought back up again for a few days just this past weekend?

A. Yes.

Q. And the purpose of that was to meet load requirements?

A. Yes.

Q. And what is the status of both of those two units now?

A. Gannon 1 didn't make it past Saturday at noon before we had a tube rupture. That tube rupture is being repaired just so it can be brought back up long enough to strip the coal feed equipment of combustibles and fuel.

Gannon 2 has been run out of coal and shutdown as of early this morning. And it is back in a reserve shutdown mode.

Q. Are both of those -- considered now a Gannon long-term reserve shutdown?

A. Yes. The way we have been advertising it is we have a long-term reserve shutdown with supposedly a 10-day notice if someone is expecting to bring these units up and run them for any extended period of time.

Q. Would these -- is there a -- a set retirement date for Gannon 1 and 2?

A. I -- I can't say that I know a -- a set retirement date, other than the permits expire -- we are no longer permitted to run them on coal past December 31st, 2004.

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

THE WITNESS: Thank you.

MR. BEASLEY: Thanks.

Okay. Let's see what we've got exhibit wise. Exhibit 1 was total outage days canceled or shifted for cost control.

MR. VANDIVER: Right.

MR. BEASLEY: Gannon units 2000 to date.

MR. VANDIVER: Yeah.

MR. BEASLEY: And Exhibit 2 is the safety budget 2000 forward.

MR. VANDIVER: Yes.

MR. BEASLEY: In the same format as pages 1420 and 1535.

MR. VANDIVER: Yes, sir.

MR. BEASLEY: Okay. We'll do that.

THE WITNESS: Thank you.

MR. VANDIVER: Thank you, sir.

(Whereupon, the deposition was concluded at 2:35 p.m.)

CERTIFICATE OF OATH

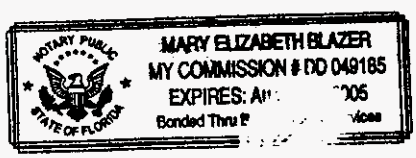
STATE OF FLORIDA

COUNTY OF HILLSBOROUGH

I, the undersigned authority, certify that BUDDY MAYE personally appeared before me and was sworn.

Witness my hand and official seal this 25th day of May, 2003.

MARY ELIZABETH BLAZER, RPR
Notary Public - State of Florida
My Commission No. DD049185
Expires: August 19, 2005



STATE OF FLORIDA

COUNTY OF HILLSBOROUGH

I, MARY ELIZABETH BLAZER, Registered Professional Reporter, certify that I was authorized to and did stenographically report the foregoing deposition; and that the transcript is a true record of the testimony given by the witness.

I further certify that I am not a relative, employee, or 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 25th day of May, 2003.



MARY ELIZABETH BLAZER, RPR

ERRATA SHEET

Instructions: Please read the original transcript of your deposition, and make note of any errors in transcription on this page. DO NOT mark on the original transcript itself. Please sign and date this sheet.

Reporter: Mary Elizabeth Blazer

In re: Fuel and purchased power costs recovery clause 5/13/03

Page	Line	Error or Amendment

I have read the original transcript and, except for any corrections and/or amendments noted above, I hereby subscribe to the transcript as an accurate record of the Statements made by me.

Signature of Deponent: _____

BUDDY MAYE

Date: _____

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and purchased power recovery clause with generating performance incentive factor.
_____/

Docket No. 03001EI
Filed: October 28, 2003

TELEPHONIC DEPOSITION OF WILLIAM T. WHALE

Taken in the above-styled cause, pursuant to notice, at the Office of Public Counsel, 111 West Madison Street, Room 812, Tallahassee, Florida, on November 4, 2003, commencing at 9:05 a.m.

COPY

Reported by:

MARLO D. FARNSWORTH

CERTIFIED SHORTHAND REPORTI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 12
COMPANY/ OPC 10-28-03
WITNESS. William Whale D
DATE: 11-12-03

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D E P O S I T I O N

MR. VANDIVER: Good morning, Mr. Whale.

MR. WHALE: Good morning.

MR. VANDIVER: Do you have a notary there, Mr. Beasley?

MR. BEASLEY: Yes. This is Jim Beasley, and I would like to introduce Angie Llewellyn, one of our capable folks here who is a notary and will swear the witness in.

Whereupon,

WILLIAM T. WHALE

was called as a witness, having been first duly sworn to speak the truth, the whole truth, and nothing but the truth by Notary Public Angie Llewellyn, was examined and testified as follows:

MR. VANDIVER: Does the court reporter need anything else in terms of the Notary certification?

(Discussion off the record.)

EXAMINATION

BY MR. VANDIVER:

Q Mr. Whale, you were deposed on May 13, 2003, is that correct?

A Yes, that's correct.

Q At that time, were you an officer of Tampa Electric Company?

A Yes.

Q And are you currently an officer of Tampa Electric Company?

A Yes.

Q In that time I believe your job title has changed, is that correct?

A My title is still the same. We're working through -- my title is still vice-president of Energy Supply.

Q Have your responsibilities changed in that time?

A Slightly, yes.

Q Can you explain the shuffle in responsibilities, please, sir?

A I have assumed the warehouse function, which was under a different individual, and I've also assumed the responsibilities of the Asset Management Group that was under a different individual.

Q Is the Asset Management Group, would that be the hedging?

A No.

Q What does the Asset Management Group do?

A The Asset Management Group was -- reported to John Currier and at that time was responsible for dispatching our -- having our system utilized in the most efficient manner as possible. Now that they're in my group, there are

some things as far as code of conduct that they've -- some responsibilities they've relinquished and some responsibilities they've picked up, so there's been a change in that group also, and we'll probably change the name of that group.

Q All right. I'm unclear as to what code of conduct is, sir. Can you expand on that just a tad?

A The code of conduct as far as the -- what can be done between the regulated and unregulated businesses, what information can be shared, what information can't be shared.

Q All right, sir.

MR. VANDIVER: Who just joined us on the line, please?

MS. RODIN: This is Jennifer Rodin with the Public Service Commission.

MR. VANDIVER: All right. Welcome, Jennifer.

BY MR. VANDIVER:

Q If we could turn to your rebuttal testimony, please, Mr. Whale?

MR. BEASLEY: While we're doing that, Rob, this is Jim, and I'll just give you the notary's name and commission number.

MR. VANDIVER: Okay.

MR. BEASLEY: It's Angela, A-n-g-e-l-a, Lynn, L-y-n-n, Llewellyn, L-l-e-w-e-l-l-y-n, and her

commission number is D as in David, D as in David, 101584, commission expires March 24, 2006.

MR. VANDIVER: Okay. Thank you for that.

BY MR. VANDIVER:

Q Mr. Whale, at page 2, line 18, you reference the term *certified safety professional*?

A That's correct.

Q What does that term mean, sir?

A These are individuals that have completed a series of qualifications and exams to obtain a certification. It's very similar process that like the certified professional engineer, and there's requirements and exams that these folks must complete to obtain a certification, and then there's requirements for continual education that they have to meet to keep that certification current.

Q Are you a certified safety professional?

A No, I'm not.

Q How many such safety -- certified safety professionals are employed by Tampa Electric Company?

A I do not know as far as within Tampa Electric. Within Energy Supply, my particular department, I had one on staff that reported directly to me, I had one at Polk Power Station, one at Big Bend Station and one at Gannon Bayside Station.

Q Who are those individuals?

A Nancy Hitchins was the manager that reported to me that was on my staff. Now, she has -- she has shifted to Greg Nelson and presently reports to Greg Nelson, this environmental safety and health and the new organization, but during this time period, she reported to me.

At Gannon Bayside, we have Ben Willoughby. At Big Bend, you have John Lewis. At Polk, we have Bonnie Lazeer.

Q So basically you have one at each plant, is that --

A That's correct.

Q Okay. Do you have any industry recognized safety credentials?

A No, I do not.

Q Okay. Does Big Bend's coal generation plant have boiler leaks?

A Yes, they do.

Q How many boiler leaks have they experienced during the past 12 months?

A I don't have that figure off the top of my head.

Q Okay. How do you measure the carbon monoxide in the air at Big Bend?

A Carbon monoxide is measured by a testing device that the safety professionals have. I guess what I'm struggling with is carbon monoxide inside a plant, then there's carbon monoxide within the boilers that is produced

and going out the stack, and that is measured through CEMs.

Q And is there some residual in the areas that the employees are in outside -- in the work areas that the employees are in?

A I don't know exactly what that measure is. When there is a question of the carbon monoxide in a particular area, the safety professionals go out and test it.

Q Okay. Well, there on page 3 of your testimony, at lines 10 through 12 -- I'll give you a second to get there.

A Uh-huh.

Q You say, "Therefore, any leaks in the boiler walls create a safety concern because they allow the gases to escape." I was assuming that referenced carbon monoxide. Am I correct in my assumption?

A Boiler gas is a combination of gases that are byproducts to the combustion products. The cyclone-fired units have a construction that does not have the tubes welded together, and when they have a leak, they pull those tubes together, it creates a crack where the gases from the inside of the boiler can escape into the work areas.

The boilers at Big Bend are welded membrane boilers, the tube is welded, and that basically creates a steel structure there, so as far as within the boilers, gases creating those flow out of that boiler and then through the ductwork.

Q Okay, so it's a combination of gases, it's not just carbon monoxide, then, that's escaping?

A Right.

Q Okay. Could you -- is there a breakdown of those gases *per se* and is it the same at Gannon as at Big Bend? Or were you referring to Gannon then?

A In my rebuttal testimony I was referring to Gannon because that's what was in question.

Q Okay. How many boiler leaks have you experienced at Gannon over the past year?

A Tube leaks?

Q Yes, sir, or boiler leaks.

A Well, a boiler leak -- you have to clarify. A boiler leak is a tube leak, or is there --

Q Well, again, I'm at that same place in your testimony on page 3, "any leaks in the boiler walls and ductwork." I guess we can go ahead and distinguish here.

A Okay. In that particular document, what I was talking about there was gas leaks.

Q Okay. And tube leaks are something different? That's --

A Yes, that's correct.

Q Okay. What comes out of the tube leaks? Is that water, is that gas?

A When you have a boiler tube leak, as far as people

in the industry, when you have a tube leak, that is the water which turns into steam exiting from the inside of the tube. Normally you want it -- it goes inside the firebox of the unit. Our concern again, and again on some of those things, is they were going external, which meant into the work spaces.

Q Okay.

A On these particular units, because of their construction, that at times caused the tube to pull apart, which now broke the seal of the firebox, and so any leaks in the boiler walls, those walls, the way they're constructed, would allow gas leaks through it as, i.e., the ductwork would do the same thing.

Q Okay. Now, how many -- are these leaks here boiler leaks *per se?* And I want to be careful in our terminology as we walk through this. How many boiler leaks have you experienced at Gannon over the past year? Can you refer me to a chart or anything? I know you have referenced a number of charts in your testimony, and that might be a good place to start, or do you have that figure on --

A I think we provided it in one of the interrogatories. Give me a chance, a minute here.

Q I've got the interrogatories with me here, too, and if you can reference me to that, that would be great.

A Because I think that was a question of tube leaks.

Q Well, I'm referring to boiler leaks here. And are the boiler leaks gas leaks?

A In this particular paragraph what I was talking about, when I said *leaks* I was referring to gas leaks.

Q Okay. And if you could find that interrogatory, that would be great.

A Okay. Well, the interrogatory I was thinking of was talking about boiler tube leaks. I do think that we provided something, a graph on gas -- yes, Interrogatory No. 32, page 2 of 2.

Q 32, 2 of 2?

A Yes. Interrogatory 32, page 2 of 2, gives the number of tube leaks through time between Gannon and Big Bend.

Q Okay, and is that -- and are tube leaks synonymous with boiler leaks?

A When I hear *boiler leak*, I think of a tube leak.

Q Okay.

A When we talk about gas leaks, we don't call them boiler leaks.

Q Okay, and the -- and these leaks in the boiler walls, are those the ones that are in Interrogatory 32?

A Some of them, and then -- I mean, those are just encompassing of all particular areas of the boiler. We don't quantify in there where the particular boiler tube

leak occurred, whether it was a floor tube or a super heater, those type of things. That's just the number of tubes on that graph.

Q Okay, so is there a chart or anywhere that I could find the ones that are referenced on lines 10 through 12? Because there's so many graphs, you know, in the wealth of documents you all have, I'm just trying to --

A On page -- interrogatory 9, page 3 of 3.

Q All right. Okay, 9, 3 of 3, I'm getting there, hold on one second. 9, 3 of 3. 9, 3 of 3, it just takes me a second to get there because I have to fight Mr. Poucher for every page. Here we go, tube repairs. I'm there.

Is that the gas leaks or the structural issues?

A Gas leaks.

Q Okay.

A Now, the thing on this graph, though, it's not showing the number, it's showing the outages that we had due to gas leaks.

Q Okay, so we kind of back into it, then?

A Well, that graph is showing the times we took the unit down specifically because of the gas leak.

Q Okay.

A Other times we come down for something else. Like a tube failure, we'll go and repair the gas leaks. This graph is showing the number of times that it actually forced

the unit off because of a gas leak.

Q I see. Okay, sir. Now, did you measure the carbon monoxide in the air again over the past year? And again, I'm back to the work station here for the employees.

A I don't know how many times that was measured.

Q Okay. And do you know how the carbon monoxide in the air at Gannon compared to the carbon monoxide in the air at Big Bend over the past twelve months?

A No, I don't know that.

Q Okay. And do you have gas monitors at Gannon and Big Bend to check for that?

A Yes, we have. The safety professionals have the testing equipment to test for this.

Q Okay, and are those fixed monitors that check for carbon monoxide? Is there an alarm that goes off or something when there's a certain amount of carbon monoxide in the air?

A These are portable.

Q Okay. Because carbon monoxide is odorless, colorless, et cetera, isn't it?

A I'm not sure on that.

Q All right, sir. You stated at page 3 and 4 of your rebuttal that by late 2003 it became apparent you had to close down Gannon in 2003 because of the potential for safety accidents, among other things?

A Right.

Q What potential for safety accidents are you referring to in this part of your testimony?

A The concern we had with one, the units experienced external tube leaks. An external tube leak is something that causes greater concern because of the fact that the leak will now be releasing high pressure steam or water that will turn into steam into the work area where people will be. Internal, which is the bulk of your tube leaks, that leak stays with them in the firebox and individuals are not susceptible to being injured from that. Gas leaks were getting very bad, so much so at times that we had to monitor what was going on in the control rooms to make sure that the gas in the control rooms was not getting where they would have to shut down.

Structural steel is another area that is a concern because of the fact that -- what it was supporting and the fact of somebody possibly walking on a grating that would give way, and these things were of concern to us.

Q In your opinion, was Gannon unsafe to operate?

A We tried to do things to make it safe. As far as the internal pressures, we reduced the header pressures to provide more margin of safety. The structural steel, we started blocking areas off that people would not go in. As far as the gases, we were taking samples, we gave them

instructions that if levels reached a certain layer, to shut down and go away. So as we address potential risk, we try to adjust our operations to make it safe, as safe as possible.

Q Okay. So the plant was not dangerous for your employees to work in, then?

A No, it wasn't dangerous to work in because we were doing things to try to address the concerns that we had, but safety is kind of one of those things that -- you know, I guess I use the analogy of a crossing, you know, a dangerous crossing. You know, today we put the stoplight in it when there are seven deaths. I guess who decided seven deaths was acceptable before we did something versus saying let's not have any deaths, let's recognize what is the risk and take steps to reduce those risks to make sure nobody gets hurt, but that's a constant process of addressing that risk and then making changes to it until such time as you say, look, we've got to do something here, we don't want to wait until we have a death to do something.

Q Well, according to your testimony, that decision wasn't made until February, to shut down Gannon, was made in February when your Board approved it, is that correct?

A The Board never -- the Board doesn't approve things such as that. We made a decision in February to shut it down, but again, that decision, safety was one of several

parts to the decision of the shutdown. It's just one aspect of it.

Q Okay. Was the Gannon Station safety record unsatisfactory in 2001?

A Gannon was improving. I'd say unsatisfactory is even one reportable. We like to have a goal of zero.

Q Well, was it unsatisfactory in 2002?

A It was improving.

Q Okay.

A It was improving.

Q And how about 2003?

A From 2001 to 2000 -- from 2000 to 2001, it was improving.

Q Okay. And as I recall Mr. Maye's performance evaluation, he always met those safety criteria, did he not?

A I don't remember on that. He was -- Karen Sheffield was there, and he had just taken over.

Q Okay. But -- and I'm just recalling from those performance criteria, safety was one of his job criteria, and as I recall he always got a satisfactory in that, and the OSHA reports reflect no accidents?

A Safety at Tampa Electric on the whole has improved, I mean, all across the state, and that was a departmental-wide initiative to improve the safety across the departments. So Big Bend, Polk, Gannon, all the

stations have improved, and that was primarily addressed through educating our employees both on their knowledge as to potential risks so they could learn how to mitigate their risk, and also changing some of the procedures of how we did things.

Q But I asked a yes or no question as to whether or not you believe the safety record was satisfactory or not during that period.

A It was improving. Zero is what I want.

Q Right. But as manager, you're responsible for results. Was it satisfactory or was it not?

A The fact that it was improving was satisfactory.

Q Thank you.

Do you have any analysis that suggested an increase in the accident rate at Gannon since 2001?

A I'm sorry, repeat that question.

Q Do you have any analysis that suggested an increase in the accident rate at Gannon since 2001?

A The accident rate was declining at Gannon.

Q Okay, sir. When was the last time there was a lost-time accident at the plant?

A I don't have that on the top of my head.

Q Can you remember one?

A Yes, there were several there before. In the history of it, there are several. The generator is one that

sticks in my mind. I don't remember what the last lost-time was as far as '01.

Q Okay. Can you -- how many lost-time accidents did Gannon experience in 2003 to date?

A I don't have that figure on the top of my head.

Q Can you remember any in 2003 today?

A I'd have to look at the record. I don't have that committed to memory.

Q Okay, and so do you recall if any of the ones in 2003 to date were due to faulty equipment?

A I would have to look at each one. I don't remember. I don't know.

Q All right, sir. On page 5 of your testimony, you talk about the increases in the company's safety program. What's the relationship between the 1999 explosion and the increased expenditures for safety in 2001 and 2002?

A Ask that question again.

Q Yes, sir. On page 5 of your testimony, you talk about the increases in the company's safety program.

A Right.

Q What's the relationship between the 1999 explosion and the increased expenditures for safety in 2001 and 2002?

A I don't know if there's any correlation at all. I wasn't in the job in 1999. When I came into the job, safety was important to me and improving our record was important

to me, putting in safety professionals was important to me, so -- the explosion wasn't on my watch. The safety initiative was an initiative that I thought personally was an important thing to do.

Q All right, sir. On page 6 of your testimony, and I'm at lines 18 and 19, you state that Tampa Electric was faced with a question of how to allocate maintenance funds prudently.

A Correct.

Q When was this decision crossroads made? Was this after the consent decree was entered, and when did you start cutting back on maintenance and when -- I just would like for you to discuss this decision tree here.

A Every year -- and maybe I'm struggling with the question. Every year the plant manager has to decide where to put funds. That decision tree is a constant process that goes on looking at funds, what the maintenance requirements are, and making sure that the dollars are allocated to the highest priority issue, and so it's a continual process, and it's a continual process that happens throughout the year. The allocation of maintenance fund is a, just a daily triaging that occurs on a day-by-day basis in running a fire station.

Q Okay. Can you explain what you're talking about in your -- in this paragraph? I guess what I'm trying to

get at is when did the decision to patch and go -- when did the decision to change to patch and go for the Gannon units, when did you change to that philosophy for these units?

A When the consent decree was signed, that assigned an end date for those stations, for those units, and so they're going to have to stop, cease doing coal. And at that point, we looked at, you know, how are we going to run the units? And as those units started experiencing failures, we started looking to say, okay, how best do you keep the unit as reliable as you can, as safe as you can, but at the same time bring this thing in a wide slope where the consent decree is a final date. And that was a continual process that occurred once a consent decree was signed because there was a final end date for those particular units, and that really changed, you know, how to address those. The patch and go really started developing as to how best to repair that unit and keep it as available as much as possible.

Q And so that patch and go philosophy developed after the consent decree, the consent decree was signed in -- help me out. Was it -- I believe it's somewhere in your testimony. Was it 1999, December 6th?

A Yes. There was two, there was consent final judgment and consent decree.

Q Right.

A And they've got different dates, both of them. It's around the '99-2000 time period.

Q Right. And so sometime after that, the philosophy changed because the retirement date for the Gannon units changed, is that correct?

A Again, I took over when the consent decree was signed, and when I had the consent decree started establishing strategies to fit that.

Q Sure, and that's in early 2000, correct?

A Right.

Q So in early 2000, the life of the Gannon units was suddenly shortened?

A Very much so. The consent final judgment was signed on December 6, 1999. The consent decree was signed February 29, 2000.

Q So all of a sudden, the Gannon unit life is December 31, 2004, it turns into a pumpkin, is that correct, or that's the end of the life for the Gannon units?

A The consent decree said we had to cease operations there and also said that we had to have 200 megawatts --

Q Of gas?

A -- powered by May 1st.

Q Yes, sir. Okay. And so patch and go was adopted sometime after that. Can you tell me when, about, patch and go became the guiding maintenance philosophy for the Gannon

units?

A I can't remember the date on that.

Q Okay.

A That's something that we evolved to. As the units were experiencing age, that was something we evolved to because of, you know, how the units were performing and how best to get them to run.

Q All right, sir. Did your decision to close down the Gannon units early include consideration of the total impact on the company and its customers?

MR. BEASLEY: I'd like to, Rob, just caution you that the use of the term *early* is a relative term, and if you could refer to it as your decision to shut down the units in 2003 or on the schedule that the company is on, but not necessarily early. That connotes that there was a definite plan to shut them down later.

MR. VANDIVER: Well -- and again, we can fuss about that forever, but I'll just -- I'll refer to it as the decision to shut it down in 2003. But Tampa Electric documents referred to it as accelerated shutdown, early shutdown and the like. I don't want to quibble about it, but the decision to shut the units down in 2003.

BY MR. VANDIVER:

Q Did that decision include consideration of the

total impact on the company and its customers?

A There were several runs that were made on the shutdown, different evaluations that were run on that, and my primary focus was from the plant side of the business about running the plant, how to get, you know, the people issues, the construction issues, those issues, that was my primary focus.

Q What discussions did you have with top management regarding the increased fuel costs the customers would have to pay?

A I didn't have any discussion with top management on that.

Q Well, Mr. Whale, in your deposition on May 13, 2003, you'll recall that we discussed a PowerPoint presentation you gave?

A Right.

Q And in that PowerPoint presentation, if you'll look at the testimony of Mr. Majoros, MJM-3, I believe, if you'll take a look at that, please, sir? Do you have your deposition from May 13, 2003?

A I sure do.

Q Okay. Take a look at page 31 of that deposition, please, sir.

A You're jumping ahead on me here.

Q Okay. I'll give you a second to get there.

A Okay.

Q Are you with me?

A Which page on Majoros?

Q Take a look at MJM-3, and I'll give you a minute, because I know that's kind of a lengthy deal.

A Okay. Is that page 21 or 34? Because my copy has the M-J cut off.

Q What it is, if you look down at the bottom, it's Bates stamp 535 to Bates stamp 567.

A Okay. I've got 535.

Q To 5 -- wait a minute. Bates stamp 535 to Bates stamp 568.

A Okay, got that.

Q Okay. Now, what I want to confirm is that this -- and I don't want to rush you here, sir, and I don't want to --

A I got it. I got it.

Q Okay. That this is basically a PowerPoint presentation that you presented to the officers of Tampa Electric Company, and it's on August 26, 2002, and that it's in fact this same document that I'm referencing here on page 31 of your deposition, because I believe it to be those same documents that you and I talked about on -- there's so many documents moving around -- on May 13, 2003, in your deposition?

A Okay. I've got the page 31 and I've got the presentation.

Q Okay, sir. And that that in fact was a discussion with the officers of Tampa Electric Company, and if you'll go to page 5 -- Bates stamp -- Bates stamp 555, and we can go through and there where -- in fact, the -- one of the slides there in fact talks about the higher purchased power cost?

A Right, and maybe I misunderstood the word *discussion*.

Q Okay.

A A discussion as having a sit-down talk about it. This presentation was a presentation that I gave the officers, and I --

Q Okay. Well, good. That's -- then this was the only time that you discussed as a group with the officers of Tampa Electric Company the higher purchased power cost to consumers?

A I just listed it as an item there.

Q Okay. Did you have any individual discussions with Mr. Ramil or Mr. Barringer or any of the other officers of Tampa Electric Company about the higher purchased power cost with consumers?

A No.

Q Okay. Did you have any discussions about the

higher cost of gas or the higher costs that would be passed on to consumers as a result of the -- and again, I don't want -- the 2003 shutdown or -- of Gannon units?

A No.

Q Okay. And did, at any other time subsequent to this meeting did the officers of Tampa Electric get together and talk about this issue? And by that I mean this closure of the Gannon plants, be it characterized as the early closure of Gannon, the closure in 2003, I think you know what issue I'm talking about.

A No. Can you clarify the question?

Q Yes, sure. The Gannon plants were closed prior to the 12/31/04 date, they were closed in I believe April and September or October, early shutdown, 2003 shutdown. Did you discuss that as a group, did the officers of Tampa Electric discuss that as a group at any other time other than this meeting, they discussed it on September 9th, I believe, and we discussed that in your last deposition?

A There was discussions about what, you know, could I have the availability up to try to make sales on the units because of the fact that there -- you know, we had additional power --

Q Yes.

A -- you know, could I do that, and at the time, I said, you know, that the cost to get to a reliability that

you could do a sale was going to be enormous.

Q Sure.

A And, you know, the confidence factor of going and trying to sell this stuff and the question of me, could I provide that confidence factor, and I couldn't.

Q Okay.

A I felt it was going to be we were going to go do a sale and then the units would be unreliable and then we would have to buy power to make a sale.

Q Okay. So -- okay. I'd like to turn now, sir, to kind of a discussion generally of gas versus coal, and in general terms, is it correct that gas generation runs about $30 more per megawatt hour and fuel costs than coal?

A You're out of my realm.

Q Okay. Who's the proper person at Tampa Electric to talk to about that?

A About gas prices and coal prices?

Q Yes.

A The Fuels Department.

Q Okay. And who would that be? Would it be Mr. Smith, Ms. Wheeley, who would I -- would it be Mr. Smith?

A No, he is no longer with the company.

Q Benjamin Smith is no longer with the company?

A Oh, Benjamin Smith is with the company. I thought you were talking about Hugh Smith.

Q No. I'm trying to get the proper witness to have that kind of general discussion as to $30 -- the proper general discussion as to gas versus coal, you know, that high level, $20 versus $50, you know, that -- kind of 30,000 feet?

A Yes, that would be Joanne Wheeley out of our Fuels Department is who I would --

Q Okay. So that's who I would inquire about that and kind of have that -- and I don't want to get down to the real nitty-gritty, I just want to do gas versus coal and that kind of general discussion as to what that different price is. And you're not prepared to discuss that in the very high level --

A No, no.

Q -- discussion?

A No, fuel pricing is not my particular realm of responsibility.

Q All right, sir. We can go to page 10, please, sir. You talk there -- you talk, I believe it's line 12, about the unplanned outage factors. Isn't the amount of unplanned outages directly related to the planned outages?

A Unplanned outage factor is directly related to planned outage factors?

Q Yes.

A No, there's a lot of factors that go into

unplanned outage factor that I wouldn't make the connection there.

Q Okay. If you schedule more planned outages, is it not correct that you would have fewer unplanned outages?

A If you schedule more planned outages, you should have less unplanned outage?

Q Yes, sir.

A Generally, yes.

Q Okay. And the reverse is true, is it not? If you scheduled fewer planned outages you would have more unplanned outages?

A I guess what I'm wrestling with is it depends on how the equipment is performing and the technology that it's having and the difficulties.

Q But as a general rule, isn't that kind of self-evident?

A As a general rule, if -- general rule, I would say yes.

Q Okay. On page 10 of your testimony, starting at line 10, could you explain what you're trying to tell us here?

A Say it again.

Q Page 10, line 10, could you just explain what you're trying to tell us here?

A Okay. The actual 2001 saying that the unplanned

outage factor for the units is going up. I mean, 2002 was what I considered an anomaly in the fact that that was a major component that went out that caused a -- something unusual when you look at the trend, but that the unplanned outage factor is going up.

Q So it's your testimony that the unplanned outage data shows that Gannon was unreliable and that's why you had to execute the early shutdown?

A The outage -- the units were becoming unpredictable as far as when they would come off and when they would stay on.

Q Okay. And on page 11, you take exception to the testimony of Mr. Zaetz starting on page 11. Could you please explain what you're trying to tell us in this paragraph of your testimony?

A This graph shows the maximum capacity of the machines, that is, a rating of what you can do on an instantaneous time period for a short period of time, kind of like you're peaking type thing, if you have a car that can go a hundred miles an hour, if you can go to a hundred miles an hour.

What was happening, though, with the machines is that we were reducing the header pressures on them, which was reducing the capacity on what the machines were operating on a daily basis, and we were doing that, again,

to reduce the internal pressures on the machines to get some more reliability out of them.

So this graph was showing kind of instantaneously what they can do, but it was different then as far as what they were kind of operating out on a daily basis. If it comes in, it's a real great peak and we make a decision, okay, do we go ahead and run them up, realizing that we're going to risk a two fader on it to make this particular peak, or do we keep it down and reduce header. And we only reserve that as a -- you know, if it's an emergency situation in the state.

Q Is the OPA measurement something you look at frequently?

A OPA is a new measurement that we put in, and again, that's something that we measure just seeing how we respond when our native load goes over 2,900.

Q Is it an important measure of reliability for the company?

A It's more of a measure of -- you can have an unreliable machine and have a good OPA, and the reason why is that's available during the peak time.

Q Okay. But you build for the peak, right?

A Try to build for the peak. I don't know about building for the peak. When you say *building*, you're talking about lay a new generation?

Q Yes.

A Well, no, a new generation is really meeting what your loads come in for peak. Sometimes there are strategies to buy for the peak because that's a better thing to do than to build.

Q Okay. Well, in your opinion, during 2002 as opposed to 2001, was Gannon more available to respond to peak loads or was it less available to respond to peak loads?

A In 2002, it was doing a better job of being there for the peak, and again, that was primarily with the reduced header operations that allowed the machine to be there.

Q Okay. And was it more reliable for the peak demand in 2002 than in '99, 2000 and 2001?

A It was more reliable for the peak in -- yes, 2002, a nine plus three. Now, the thing is, a three is just a projection.

Q Okay.

A 2001, 2002 and '99 are actual data. The 2002 is nine actual plus three projected.

Q Okay.

A So I don't know what the actual ended up being.

Q Okay. On page 12, the first paragraph, could you please explain what you're stating here? Do you disagree with Mr. Zaetz on the subject of net generation?

A Okay. The top of the page, which sentence are you talking about?

Q I'm talking about those two sentences there. Do you disagree?

MR. BEASLEY: Which line?

MR. VANDIVER: Lines 1 through 6. I'm just unclear as to what he's stating there, I'm just --

MR. BEASLEY: What's the question?

BY MR. VANDIVER:

Q Do you disagree with Mr. Zaetz on the subject of net generation?

MR. BEASLEY: This is Jim Beasley. Rob, it might be helpful to refer to Mr. Zaetz where he's used that term so we know specifically what you're asking the question.

BY MR. VANDIVER:

Q The previous page, Mr. Zaetz also cites net generation values shown on page 7 of the exhibit to support his argument, and then he goes on to make some statements, and I want to know if he disagrees with Mr. Zaetz. It's kind of a Ken Hart question.

A He had a statement -- I was trying to look at the net generation is buried into the net capacity concession, so that's why I needed to find it, so that's where my difficulty was with the statement there.

He listed the net generation, he lists the actual numbers of the net generation for the station, and states that, you know, the performance of the station, you know, that based on that and the net generation, the ability of Gannon to generate is driven a lot because of the patch and go and the reduced header operations allowed the units to be more available to generate. Again, that was a short-term type of strategy to get to there's an end date, and that particular strategy was utilized to get the station there. Net generation 2002 was less than 2001, less than '98. Again, that was a nine plus three --

Q Okay, so if you're attempting to evaluate the reliability of the plant, would you first look at peak demand reliability and would you also look at the net generation?

A No, I wouldn't look at net generation. Net generation is -- has so much involved in it on how the units are dispatched, what's required, control, those type of things that come into play, net generation is not a -- there's so many other factors that impact that particular goal, it's something that's nice to know about and to look at, but you can have a station that has an availability of 99 percent, may have a very small net generation because of other factors that come into play.

EAF is what is tracked from our viewpoint as far

as availability. Trying to understand EAF, you look at your E-4 and your planned outage factor, and then OPA is a new one that we've been working with.

Q Okay. And so --

A In fact, some of the Gannon units had to run because it couldn't be on control, and --

Q Couldn't be -- excuse me, sir, I didn't hear that last term. Couldn't be uncontrolled?

A Could not be controlled by our AGC. And they had to base-load them because they couldn't control them as far as -- the way the system works is that they figure out the load, and then the dispatch center sends out control to the different units to make sure we're optimizing our system to the best that we can, and those units were -- had gotten to a state where they couldn't ramp them up or ramp them down and had to base them, which caused other units, the Big Bend units, to have to be backed down, which were the more efficient units.

Q Okay. So could you sum up and tell me what the most important reliability factors are, just in a nutshell, in one place?

A EAF is the one that we really look at the most.

Q Okay. All right, sir. If we could go to page 13, line 4, and if you could explain what you're saying there on line 4, starting there in that paragraph, and --

A Mr. Zaetz I guess was implying that because the station was meeting its goal, its performance was not a reason for shutting the units down. We adjusted the goals for what we thought the units could do, for the folks to shoot for. Normally the goals are set in the way people strive to perform. That doesn't -- you know, the goals were adjusted to what we thought where the units would be.

Q Okay. What declining reliabilities are you talking about on lines 10 and 11?

A -- more accurately reflect our age conditions and declining reliabilities, that would be looking at the EAF of the units.

Q Did the patch and go strategy save money?

A It avoided big, planned outages, but patch and go costs money. I don't -- I mean, it's a strategy to get you there, you know, save money from what I guess is probably the question.

Q Well, you forego the big planned outages, and the 28-day outages are, what, a half a million dollars?

A Sir?

Q How much is -- how much is a 28-day planned outage?

A Different outages cost different amounts. There's never --

Q How much is a 28-day planned outage at a Gannon

unit?

A I don't know.

Q Okay. Do you believe the patch and go strategy improved reliability?

A I think it definitely helped it, yes.

Q Okay. Do you believe the patch and go strategy saved capital expenditures?

A Patch and go strategy definitely avoided having a large capital major outage.

Q All right, sir. I'd like to go now to your direct testimony, please, Mr. Whale, and that would be at page 16. And let me get situated here for that. I have to move some papers around to get there.

A I've got it.

Q Thank you, Mr. Whale. I'm still getting situated, but I'm close.

Okay. There you state it would cost $57 million to keep Units 1 through 4 operating somewhat reliably. By the way, Mr. Whale, are you fine, do you need a break or anything?

A No, I'm fine.

Q Okay, good deal.

MR. VANDIVER: Does anybody else need a break?

(No response.)

MR. VANDIVER: Okay.

BY MR. VANDIVER:

Q You state there that it would cost $57 million to keep Units 1 through 4 operating somewhat reliably, is that correct?

A Correct.

Q Can you define *somewhat reliable*?

A Looking for a reliability that the units will be predictable and that, you know, that we can count on them in our plans versus having all these spot purchases and the failures coming off, the units are reaching a point to where the repairs were repairs that we could not be continually redoing, we were going to have to go in and do major component replacements to get the units to stay on. And it's kind of like falling off a cliff, you can work to a point and then repair cannot be made anymore and you have to do a major component changeout.

Q Okay. Now, what I want to do is I want to go to Mr. Majoros' testimony -- well, wait a minute. Yes, let's go ahead and go to Mr. Majoros' testimony at -- let me get the proper exhibit number. I think that would be -- I want to put WTW-2 next to MJM something as soon as I can find that proper number. But basically that's the earlier estimates that your -- that TECO had prepared on March 3rd. And I'll find that number in just a second.

I've got that now, sir.

A Okay.

Q That's MJM-5. And what I want to try to do is I want to tie this 57 million to a number. I want to tie somewhat reliably --

MR. BEASLEY: Hold on one second. He's locating the documents.

MR. VANDIVER: Oh, I'm sorry, Jim.

THE WITNESS: I guess you're talking about WW-2.

BY MR. VANDIVER:

Q Okay. What I want to do, sir --

MR. BEASLEY: Just one moment.

MR. VANDIVER: Okay, fair enough.

MR. BEASLEY: Are you sure you want MJM-5 or is it MJM-6?

MR. VANDIVER: Let's see. Oh, you're right, you're right. It's not 5, it is MJM-6. Thank you, Mr. Beasley.

BY MR. VANDIVER:

Q Mr. Whale?

A Yes.

Q I'm trying to tie your 57 million -- first off, do you recognize MJM-6?

A Let's make sure we're talking about the same thing. This is from John Knight?

Q Yes, sir.

A Okay.
Q Do you recognize MJM-6?
A Yes.
Q What is MJM-6?
A MJM-6 is an estimate to get the operations to 80 to 85 percent.
Q Okay. And do you know why MJM was prepared, or who prepared it and why it was prepared?
MR. BEASLEY: As an exhibit to Mr. Majoros' testimony, why Majoros prepared it, or --
MR. VANDIVER: I'm asking Mr. Whale if he recognizes it and when it was prepared and who prepared it and why it was prepared.
THE WITNESS: It looks like it was prepared on March the 3rd, 2003, and it was prepared on -- I'm trying to look at what it was going to cost to get certain availabilities on the machine.
BY MR. VANDIVER:
Q Okay. And you don't recognize it at all?
A No, I recognize it.
Q Okay. What is it?
A I'm sorry, what is it?
Q Yes.
A It's dollars to achieve a variability of 80 to 85 percent.

Q Why was it prepared? We can short-circuit this. Do you have the deposition of Buddy Maye?

A Yes.

Q Let's go to page 80 of that.

A Okay.

Q Okay. And, in fact, you requested that this document be prepared, didn't you, Mr. Whale?

A Which document are you referring to now?

Q Page 79, bottom of the page: "Do you know who requested these documents be provided, prepared?" Top of the page, "Yes, yes, Bill Whale requested of me what the effect if we ran Gannon 1 through 4 for an extended period of time." Are you with me, Mr. Whale?

A Yes, I see that. I asked for a lot of documents to be prepared.

Q Yes, sir. I'm just trying to refresh your recollection and get you out of here at a reasonable time.

A But I'll also say -- I'll just say reference Bates case 9, lower case 9, will be the significant parts to accomplish that. We ran several scenarios for looking at different stuff, and I don't know whether in Buddy's deposition he's referencing this document or referencing a different document.

Q Yes, sir. I'll give you a second to look at this. I'm not trying to trick you or anything.

MR. BEASLEY: Rob, this is Jim Beasley. All we want to do is to make sure that we have a question that we can understand --

MR. VANDIVER: Yes, sir.

MR. BEASLEY: -- and try to answer it.

MR. VANDIVER: Yes, sir, and I'm just trying to expedite the process.

BY MR. VANDIVER:

Q Mr. Whale, did you ask that this document -- these two documents be prepared?

A Which two documents, now? We need to be specific.

Q 2289 and 2290.

A I may have. I was looking for, again, trying to respond to people asking me what it was going to take to get these units reliable to do some sales, and I was asking the station what is it going to take to get these units up where we can have a confidence factor potentially that people would be looking at sales, and what was the cost going to be associated with that.

So I think these documents may have been prepared in looking at some of that information, but that's an assumption on my part. I was asking those questions as to what does it take to get to reliability where we have a confidence factor.

Q All right, sir, okay, and what I'm trying to get

at is I want to try to understand the difference between the document in WJM-6 that was prepared -- when was WJM-6 prepared -- MJM-6 prepared?

A According to the cover on this, March 3rd.

Q Right. And when was WTW-2 prepared? That's attached to your testimony.

A Yes. I don't know the date on that.

Q I think there's a date indicated there at the top of the page on that. It was filed September 9th --

A Oh, September 9, 2003, okay. All right. I see that, okay.

Q Okay, Mr. Whale, I'm sorry.

A Okay.

Q What I'm trying to discern is what happened between the two documents -- you understand what I'm trying to do?

A You're trying to understand the difference between the 57 and the 53 nine zero?

Q Exactly.

A Okay. All right.

Q Okay, that's all I'm trying to do. Okay. I'm trying to figure out what happened in those.

A Okay. Out of the units that run, we have learned more and more, and we can walk down. The cycloned work has stayed the same.

Q Sure.

A Okay. The rear wall, quite frankly, has -- the pricing has dropped on the rear wall. We can do the rear wall replacement.

Expansion joints, we've got -- well, I can't tie these numbers.

Q I know you can't, but here's my main question, Mr. Whale.

A Okay.

Q Okay. The 57 million and the *somewhat reliably*, is that at the 85 percent?

A Yes.

Q Okay.

A 80, 85 percent.

Q Okay. So *somewhat reliably* in your direct testimony means 85 percent, it's the same 85 percent that's in MJM-6 --

A Yes.

Q -- on 2289? There we go. Okay. Now I've got -- now we can go ahead and go on, because I have a number of questions about the specifics of the numbers and some other questions, okay, because now we're all on the same page and we can go ahead and go forward and we can get this thing over with. I just wanted to tie these two together and see what the difference was between the six months and the two

numbers. The numbers are very similar and there are a lot of commonalities between the two, but there are some differences.

A Okay.

Q Okay, sir. Thank you. Okay. Now, is the peak availability -- is the on-peak availability factor or the equivalent availability factor what you're using here for the 60 and the 85 percent?

A This would be the equivalent availability factor.

Q Okay, sir. All right. Is -- all right. Now, is Big Bend somewhat reliable? Is Big Bend -- are Big Bend -- how does Big Bend compare to these numbers?

A Which number?

Q The 85 percent.

A Big Bend is running in the 70s, 60s, 70s, right now.

Q Okay. Do you consider Big Bend somewhat reliable?

A Well, reliability is a -- there's not a defined, you know, 70 percent is reliable. And again, we're talking about Big Bend Station, or --

Q Yes.

A -- Big Bend compared -- the whole station compared to Gannon or --

Q Just Big Bend generally.

A Big Bend in general?

Q Yes, sir.

MR. BEASLEY: Does that mean the whole station or individual units?

MR. VANDIVER: The whole station.

MR. BEASLEY: The whole station.

THE WITNESS: Reliability is not -- there's not a defined standard out there that says 70 percent is the reliable for the unit. Each year has ups and downs because of the fact that you might have planned outages, you might have forced outages, and you're trying to look at what the age of the unit is, where it is in its life cycle, what the, you know, needs are and trying to find it there. You want to get to a point where you can predict what's going on with it, but I don't think there's an absolute number to say yes, that is or it isn't.

BY MR. VANDIVER:

Q Okay. My confusion arose from the term *somewhat reliably* in your direct testimony, and you've clarified it by referencing that it means 85 percent, so that clears it up.

Referring to the Gannon business plan, what was the actual -- I'm on page 3 of 45 now of Mr. Zaetz's testimony.

A The exhibit?

Q Yes, sir, and I believe this is -- can we get that out? I believe this has been requested to be -- the exhibit itself has been requested to be confidential.

MR. VANDIVER: I'm not sure that the individual chart is, Mr. Beasley, and you may need to help me on this. I think the exhibit has been, but I'm not sure that this individual chart is.

MR. BEASLEY: It's marked confidential.

THE WITNESS: Yes.

MR. VANDIVER: Yes, it has been?

MR. BEASLEY: Yes.

MR. VANDIVER: We had this same chart in our white pages, but I'm not going to dispute.

MS. RODIN: Rob, this is Jennifer Rodin. What page are you referring to?

MR. VANDIVER: Three of 45. I may not need -- I may better not ask this question, then.

BY MR. VANDIVER:

Q Are the numbers -- are the actual performance numbers for Gannon correct in that chart? There's one for 2001 and 2002, there's one of -- it's got a common number there for 2001 at the end. And are you with me, Mr. Whale?

A I see a 2001 -- I mean, the numbers from 2001 back, I mean, I'm assuming they're correct because they're in this document.

Q Okay.

A I didn't prepare this document, so I would assume that the station management got the correct numbers.

Q Is that reasonably reliable?

A 67.7?

Q Yes, sir. I was trying to avoid articulating that number, but is that reasonably reliable, and the following number, which is slightly below that number, is that reasonably reliable? Just yes or no.

A Reasonably, yes --

MR. BEASLEY: What do you mean?

THE WITNESS: -- yes.

BY MR. VANDIVER:

Q Is it somewhat reliable?

A Reliable, yes. Reliability, again, is not a defined number, it's the -- what the expectations are --

MR. BEASLEY: Let me jump in for a second. Are you talking about is that number reliable meaning is it reasonably accurate?

MR. VANDIVER: No, is the plant reliable.

MR. BEASLEY: Okay.

MR. VANDIVER: Okay. No, I didn't mean is the number accurate, I mean is the plant reliable.

MR. BEASLEY: The plant --it would have to be considered in the witness's mind reliable, is that what

you're saying?

MR. VANDIVER: Yes, sir. And thank you for clearing that up, Mr. Beasley.

THE WITNESS: Yes, sir. It was not reliable enough for people to build plans on that in the planning process, and what -- and what they were looking at was a better reliability. So, you know, in some cases it is reliable enough, in other cases it's not reliable enough. There's not an absolute number in the industry that says that that's reliable.

BY MR. VANDIVER:

Q Okay. During the last five years of operations, has Gannon Station ever come close to 85 percent EAF?

A In the last five years?

Q Yes.

A I don't know. In the history of it, yes, it did.

Q But in the last five years?

A In the last -- I don't have '97, '96 data.

Q How about back to '98?

A In '98, it did not. It had 74.6 in '98.

Q So it was -- it never -- it never came close to the somewhat reliable figure of the -- of your direct testimony, did it?

A Since '98, it has not been at 80 percent, yes.

MR. VANDIVER: Okay. All right. Can we take a

break?

MR. BEASLEY: Sure.

THE WITNESS: Sure.

MR. VANDIVER: Okay. Can we take about 10 minutes? Thank you.

MR. BEASLEY: Sounds good, Rob.

MR. VANDIVER: Okay. Thank you very much.

(Brief recess.)

BY MR. VANDIVER:

Q Mr. Whale, we're back on, sir.

A Okay.

Q All right. I want to take you now to if you could have the -- we just discussed that the Gannon units had never operated at the 85 percent level, and I'd like to go to your WTW No. 2.

A Okay.

MR. BEASLEY: Again, to clarify, I think the witness indicated it had not for the years shown on that document that you're referring to, but doesn't say hasn't ever.

MR. VANDIVER: Yes, sir, I apologize. I'm just referring to the years shown here.

BY MR. VANDIVER:

Q And in your WTW-2, I believe you state that, "The total estimated maintenance cost" -- I'm halfway down --

"expected" --

MR. BEASLEY: What page?

MR. VANDIVER: First page.

"The total estimated maintenance cost to keep Gannon 1 through 4 in operation until December 2004" --

MR. BEASLEY: Wait a minute. The first page of --

MR. VANDIVER: WTW-2.

MR. BEASLEY: Okay, fine. Okay.

BY MR. VANDIVER:

Q " -- near historical levels is approximately 57.4 million." Are you with me?

A Correct.

Q Okay. And we established earlier this references the 85 percent levels, correct?

A Correct.

MR. BEASLEY: I think it was 80 to 85.

THE WITNESS: Yes, 80 to 85.

BY MR. VANDIVER:

Q Right. And earlier we established that from '99 to 2000 it hadn't operated at that level, correct?

A Correct.

Q Okay. So can you explain what you mean here?

A In previous years, Gannon had run at that level.

Q Prior to 1999?

A Prior to 1998.

Q Prior to 1998. So when you reference historical levels, you're talking before 1998?

A Right.

Q EAF. Are those the historical levels you mean?

A Yes.

Q Okay. So it's not recent history?

A Well, that depends on what your -- it depends on what you define as recent.

Q I'm just trying to understand what *historical levels* means.

Okay, now, on page 2 and 3 of that same exhibit, WTW-2 --

A Correct.

Q -- is this O&M or capital or both?

A Because the units have got to cease operation, you know, by the consent decree, there was a final date, you really can't capitalize, so it all has to go to O&M.

Q All right, sir. Okay. Now, again, just to clarify, I know we just talked about it, but originally in all of your plans you said you had never planned to run Units 1 through 4 through 12/31?

A Correct.

Q But these estimates are geared through 12/31/04, is that correct?

A Correct.

Q Okay. And that includes the -- only the cost of keeping only Gannon 1 running beyond their original shutdown of last spring?

A You know, the question said -- described keeping Units 1 through 4 in operation until December of 2004. So it was kind of responding to that question. So this is keeping the Gannon Units 1 through 4 operate through December 31, 2004.

Q Okay. But it includes the -- only the cost of keeping Gannon 1 and 2 running beyond their original shutdown date of last spring?

A 1, 2, 3 and 4.

Q Okay. Spring for 1 and 2, and autumn for 3 and 4?

MR. BEASLEY: The question speaks for itself, Rob.

BY MR. VANDIVER:

Q Are those only the costs of keeping Gannon 1 and 2 running beyond their original shutdown date of last spring?

A I think I overheard --

Q Yes, Mr. Poucher is coaching me. He wants this question --

A The cost -- the first block of the costs include, you know, what needed to be done to get the units, you know, the major areas that are causing problems of reliability in the units. Then you have a 2003 cost is the seven million

that's incrementally over 2003 dollars to run the units to the present schedule they have, or I'd say what was stated there because we did run them longer. Then the 2004 was the cost -- was a total cost to keep the units operating in '04, so it's not an incremental cost, and that's, again, O&M. It says maintenance, but it's really O&M. It's paying for the staff, paying for the water, paying for those type of aspects.

Q Okay.

A Is that --

Q I think that's what -- I think we got what we wanted. Okay. And that number only includes the additional cost required to run Gannon 3 -- 3 and 4 from November until next December?

A These include costs for 1 and 2 and 3 and 4.

Q Right. Okay. And just to walk through it, it would be about 20 months for Gannon 1 and 2, and 13 to 14 months for 3 and 4?

A Well --

Q Approximately?

A The '03 cost is including Gannon 1 and 2 and 3 and 4 in '03.

Q Right, that would be --

A The '04 cost is including 1, 2, 3 and 4.

Q Yes, sir. Yes, pick up about eight months of --

MR. BEASLEY: Rob, that's not totally fair because it depends on which scenario you're looking at. You all can do the math, I don't know -- you haven't laid a predicate for that eight months reference.

MR. VANDIVER: Okay. The eight months reference would be the April 7th closure for 1 and 2, and that would be from April forward in '03, and so you get eight months in '03, would that be correct?

MR. BEASLEY: What are you comparing it to, the planned shutdown dates?

MR. VANDIVER: We're just trying to -- I think we're trying to establish the actual shutdown dates and get the months correct, and these numbers.

MR. BEASLEY: That doesn't compute. Rob, can we go off the record a minute and get this straightened out?

MR. VANDIVER: Sure, sure.

(Discussion off the record.)

BY MR. VANDIVER:

Q What were the --

MR. BEASLEY: Have you got what you need?

MR. VANDIVER: I'll just go ahead and ask the question.

BY MR. VANDIVER:

Q What were the shutdown dates for Units 1 and 2 and

3 and 4, Mr. Whale?

A Are you still there?

Q I'm sorry, I muted when I should have unmuted.

What were the shutdown dates for Units 1 and 2, Mr. Whale?

A You're talking about the shutdown dates assumed in this document?

Q Yes.

A That was March 15th. And what else -- we ran until April, but April 7th and 8th was 1 and 2, because we planned for the 15th, we ran them to April 7th and 8th. Then for 3 and 4, it was -- 6 was the first of October 1, and 3 and 4 was October the 15th.

Q And that's what those O&M costs are calculated on on WTW-2?

A Right.

Q Okay.

MR. BEASLEY: Just for clarification, are we back on the record?

MR. VANDIVER: Yes.

MR. BEASLEY: Okay.

THE WITNESS: Yes, we ran them until the first of April.

BY MR. VANDIVER:

Q All right, sir.

A That was longer.

Q All right, sir. Looking at page 2, the first item is cyclone replacements. Could you explain why this is necessary?

A Cyclones, we have gone in and tried to patch those cyclones, and that by patching we're talking about pad welding on the tubes, putting small Dutchmen in those tubes. The Dutchman is very, very difficult because of the fact that these tubes are curved, and in that issue you can only do that so long because the pad will start creating a problem in themselves, and that repair keeps it where you can do it for a while, but then you get to a point where you cannot continue doing that because the repair itself doesn't work, the Dutchman doesn't work, and you end up having to do a complete replacement.

Q When was the last time you replaced the cyclones at Gannon?

A I don't remember the exact dates on the replacement on those, when we replaced those, I don't remember the exact dates on that.

Q When in the life cycle of a plan are cyclones typically replaced?

A Normally in a boiler, components last 15 to 20 years. These particular cyclones, though, have -- these boilers went through several modifications as far as going

from coal to oil and back to coal. I don't know how that's impacted the life of these particular cyclones.

Q Okay. Did these -- did the existing cyclones cause the plants to shut down early?

A Cyclones were a big factor on impact and the reliability of the units.

Q When were these cyclones installed?

A I don't know that.

Q Do you know what the specific reliability problem was with these cyclones? Is that the curved tube problem you referred to?

A The particular tubes are having thinning of them, they're having some pluggage issues that's causing some plugging internally, and they just -- the pad wells are -- there are just too many pad wells on them right now.

Q So this is not a place where you could do patch and go, is that correct?

A We have exhausted the patch and go technique in this particular area.

Q Okay. And did these cyclones cause forced outages?

A Yes.

Q Okay. When?

A I don't have exactly when. The record -- I'd have to look at the records on that.

Q Okay. And you don't know how many, either?
A How many of the tubes are cyclone tube failures?
Q No, how many forced outages were caused.
A No, I do not.
Q Okay. But the 57 million figure includes the 21 million for the cyclone replacement, is that correct?
A That's correct.
Q And that's basically the difference between the 60 and the 85 percent replacement figure in the Majoros number? I'm sorry to keep switching back and forth, but if we could go to Mr. Majoros's number -- back to Mr. Majoros, I think it's MJM-6 --
A Right.
Q -- is that cyclone number the difference between the 60 and the 85 percent?
A Yes, that is. I mean, it appears to be the bulk of it is the --
Q Just eyeballing it to me, it looks like that's the --
A Right.
Q -- gist of it. Would that be a fair assumption?
A Yes, it looks -- it appears to be the bulk of it.
Q All right, sir. I'd like to go now, sir, to -- but that would leave about 36 million in other costs, is that correct?

A Correct.

Q And that includes all of the O&M expenses, is that correct?

A Correct.

Q And you're familiar with the O&M budget for Gannon for 2002, are you not?

A Somewhat familiar with it.

Q You are familiar with it?

A Somewhat. I don't have specific details on it. I'm familiar with it.

Q Okay. Could we go to page 19 of Mr. Zaetz's exhibit again? That's that 45-page exhibit, WMZ-1. That's page 19 of 45. This is a confidential exhibit. I don't really think this page, again, is confidential, but again, this whole document has been ruled, I think it's been ruled confidential, so let's not verbalize. I want to reference you to the 2002 graph there.

A Uh-huh.

Q Okay. And the number you see there for Gannon, that's the O&M budget and the business plan for Gannon, and that's the budget for the -- O&M budget for Gannon, is that correct?

A Correct.

Q And that would include the O&M expense, correct?

A Correct.

Q And that would be the planned and forced outage expense?

A Yes.

Q And the non-outage maintenance, correct?

A Yes.

Q And -- okay. These would be the normal yearly O&M expenses for Gannon 1 through 6, correct?

A 2002 would be Gannon 1 through 6.

Q Right, and so 1 through 4 would be something less?

A Yes.

Q So that's an even number there and I could divide that by six and come up with a unit figure, couldn't I?

A No.

Q No? Why not?

A Because the unit -- different units require different amount of O&M.

Q Okay. So it's not quite that simple?

A No, it's not.

Q Okay. All right.

Excluding the cyclone replacements, do you consider the 36 million that you say you would need to spend to be exceptional or excessive based on the normal O&M cost to run Gannon?

A Ask that question again.

Q Excluding the cyclone replacements, do you

consider the 36 million to be exceptional or excessive based on normal O&M cost to run Gannon?

A 36?

Q That's from the 57, recall that we subtracted the 21 to get to the 36.

A 36,940?

Q Right, yes, sir. I apologize for the imprecision.

A That's what the station felt, you know, was needed to run the station.

Q But is that excessive or out of the pale, beyond the pale?

A I don't know, I haven't compared it to -- ran an analysis of how that compares.

Q Okay, one final thing on the WTW-2. On the -- let's see, about halfway down there, in the coal field equipment --

MR. BEASLEY: You know, just to clarify, because I got confused here --

MR. VANDIVER: Sure.

MR. BEASLEY: -- this 36 million is not -- it's the incremental number plus, you know, for the two-year run. This has got 2003 and 2004, this is not an annual number here. It's a 2003 incremental plus the 2004 total run.

MR. VANDIVER: Can we go off the record for a

second?

MR. BEASLEY: Sure.

(Discussion off the record.)

BY MR. VANDIVER:

Q Okay. Mr. Whale, it's my understanding that your 2003 budget is in addition to what was already budgeted for 2003, is that correct?

A 2003, what -- ask that question again.

Q The $57 million, the 2003 -- the 57 million is incremental to what was budgeted for 2003, is that correct?

A The 57 million includes a portion which is incremental to my 2003 budget and the total cost for 2004.

Q All right. That's all the questions I have -- wait.

A And, you know, in an exhibit, again, I'm not sure that in the Exhibit 5 the 2003 number in that exhibit is what the Gannon budget ended up being. I don't have the official budget number on me and I can't add those. I just see that block, I can't add the numbers.

MR. BEASLEY: You're referring to Bates stamp exhibit 18 -- or Bates stamp page number 1833?

THE WITNESS: Right.

MR. VANDIVER: Okay.

BY MR. VANDIVER:

Q All right. How long -- what's the status of

Gannon 1 and 2 as of today?

A They're in long-term reserve standby.

Q And 3 and 4?

A 3 and 4 is in the same mode.

Q And how long would it take to start them up?

A Gannon 1 and 2 is 90 days, Gannon 3 and 4 I think is in a, to the best of my knowledge, is in a 15-day -- that's to the best of my knowledge right now. Gannon 4, you know, is having its transmission (TELEPHONE CUTS OUT), so exactly how long that requirement is to get that back, I don't have that exactly.

Q All right, sir. That's all the questions I have. As always, Mr. Whale, thank you.

MS. KAUFMAN: I've got some questions, if that's okay, Jim.

MR. BEASLEY: Go ahead.

EXAMINATION

BY MS. KAUFMAN:

Q Mr. Whale, I'm Vicki Kaufman, and I'm here on behalf of the Florida Industrial Power Users Group, and I've got just a few questions for you.

The first one, I'm going to be looking at your direct testimony, and you go over your qualifications and you tell us that you have a Bachelor of Science degree. Can you tell me what that degree is in?

A Marine engineering.

Q Marine engineering?

A Marine engineering.

Q Okay. I just -- and I just I want to clarify for myself, if you don't mind, the shutdown dates that you talked with Mr. Vandiver. As I understand it, and you correct me if I'm wrong, 1 and 2 were supposed to have been shut down March 15, '03, but they were actually shut down April 7th and 8th, is that right?

A That's correct.

Q And 3 and 4 were supposed to have been shut down October 15th. Is that when they actually came down?

A No, that's not.

Q When were they shut down?

A Gannon 3 shut down the 24th, and Gannon 4 the 12th of October.

Q Okay. Gannon 3 October 24th and Gannon 4 October 12th?

A Correct.

Q Okay. If you would look at your direct testimony, sir --

A Uh-huh.

Q -- page 8, line 10, and you say there due to necessary modifications to the company's outage schedule and unforeseen system and statewide operational issues, you

continued operating 1 and 2 beyond the mid-March shutdown dates, correct?

A Correct.

Q Okay. What are these necessary modifications that you refer to on line 10?

A At the particular time, Bayside was not producing reliable electricity -- did I say Bayside 2 or Bayside 1? Bayside 1 was not producing reliable electricity coming out of the machine, and there were some other outage issues that were associated with the Big Bend units, and concerns as far as some of the flows within the transmission grid that required us to keep the units on.

Q So you had expected more production from Bayside and you had not expected some outages at Big Bend that occurred and therefore you kept Gannon unit on longer?

A Well, we were always -- test power at our new machine is hard to predict, and that was something that we -- a dynamic that until we felt confident in the -- that power coming out of there, we would assess that. Again, it was a continual process looking at the system, Bayside, the state, and making that decision. So it was a combination of events there.

Q All I'm trying to get at is the reason you kept 1 and 2 operating beyond the mid-March shutdown date was because, for whatever reason, the Bayside 1 unit wasn't

where you wanted to be and there were some outages at Big Bend, is that what you're saying?

A Yes, and there was some transmission issues that were of concern to folks also.

Q Okay. On the very next line, on line 11 -- maybe this is what you were referring to, I don't know -- you talk about unforeseen system and statewide operational issues. What are these unforeseen system issues you're referring to?

A The transmission issues are things that, you know, kind of take them on a day-by-day basis as to how the flows are going, and the -- it's something that I think the state is kind of wrestling with as to how these different flows are and learning more and more about them, you know, and it changes depending on how a unit in another utility happens, what happens there when they take a transmission line out because of forced outage type issues, and so it's kind of unforeseen on those things.

Q Is there something -- are you referring to something particular when you talk about an unforeseen system issue on line 11, and if so, what is it?

A I think there was a combination of events going on at that time. I don't think there was one specific. There were a combination of events going on at that time.

Q And can you articulate exactly what those events were?

A I don't remember right now.

Q Okay. And then on line 12, you talk about statewide operational issues. What issues are those that you're referring to?

A I don't remember the exact issues that were going on at that time, but again, generally when we're talking about statewide issues, we're worried about transmission flows, worried about, you know, whether this is coming in, is there enough power to buy in certain areas, and that's something that everybody kind of works with each other as to addressing issues that are facing the state. I can't remember exactly what the weather issues were at that time.

Q Okay, so there were some statewide operational issues, but as we sit here today you don't -- you can't recall what they were?

A No.

Q Then on line -- actually, the sentence begins on line 14. You say once the Bayside Unit 1 produced energy reliably, generating units returned from outages and system conditions warranted, Tampa Electric finalized the dates to shut down 1 and 2. What kind of system conditions are you talking about there on line 16?

A Yes, I don't remember them right now. I know there's some things that had to get stabilized; I don't remember exactly what they were.

Q When Tampa Electric was in the decision-making mode of determining when the Gannon Units 1 through 4 would be shut down, who was it, if there was a single person, that had ultimate responsibility for that decision?

A There was a lot of different people looking at a lot of different scenarios. I don't --

Q Was there one person who, after the team, if you will, did their analysis, did someone have to sign off on that decision?

A No. I mean, there was no signoff, you know. We set some plans, and, like I said, as we got close to what those were, we shifted them around as, i.e., 3 and 4, and this year we keep looking at them on a daily basis and make changes as appropriate.

Q Well, we talked about the shutdown date. Let's just take, I guess, Gannon Unit 1. It shut down on April 7th. There was no one person who said, "Okay, the time is right, shut the unit down"?

A We communicated with the, you know, the system operations folks and, you know, the -- those folks looking at our system, looking at how the units are doing in reliability and we want to shut down this date, and then if there's things that they view it's not in the best of our system, then they ask us to keep on and to hold on until such time that we shut down, and that's a dynamic process

that happens every day, you know, when outages are scheduled, when a unit is scheduled to shut down, when it starts back up and those type of things.

Q I understand the dynamics, Mr. Whale, but we're talking about a decision to permanently shut the units down, right?

A Right.

Q Okay. And I'm just trying to find out, you know, is there a particular person that had the ultimate responsibility for making or approving that decision, or a team of people?

A A lot of different folks looked at the particular unit, you know, what we're going to do, but ultimately it says that, you know, we're going to it shut down on this date, I'm the one saying we're going to shut it down on the 15th.

Q You, Mr. Whale? You're the one with the ultimate decision in that regard?

A Well, a lot of folks look at the decision throughout the company as to what we're doing as outage plans, a lot of people look at it and ultimately says we're going to, you know, let's go ahead and shut it down this date. That's -- that's -- that comes from my office.

Q Okay. Is that your call, then, to give the final approval, say, for the April 7th shutdown date?

A I guess I don't make that call in a vacuum.

Q I understand that. I'm just trying to get to the ultimate decision-maker here, and I just want to know if that's you, and if it's not, who is it?

A There's a lot of parties involved in it. There's not, you know, one person says we're going to do this and everybody has to do it. There are a lot of parties that put input into the decision as to doing the shutdown. I'm primarily providing that basis as far as operationally what we can do, the people side, those type of things, saying, you know, this is when we need to look at shutting it down.

Q Okay, I'll just try one more time. I understand you've gotten input, you've gotten input from your plant people, your human resources people, everybody that you needed to consult with. Are you the one with the ultimate responsibility to make the decision, and if you are not, who is?

A I guess, you know, I make a recommendation what we need to do, and in that recommendation, because of the impact, it impacts a lot of different folks, and that recommendation is really a collective decision as to yes, we need to go forward with it, a collective decision of several of the divisions within Tampa Electric. You know, I make a recommendation, we agree, yes, let's go ahead and do that, and that agreement is a lot of different folks. Then it's

turned back to me to work out the exact date of when that shutdown will occur.

Q To whom do you make your recommendation?

A The Tampa Electric Officer Group.

Q Is anybody at TECO Energy involved in the decision-making process?

A No, not to my knowledge.

Q If you'll take a look at your -- this is still your direct testimony, page 9.

A Page 9?

Q Yes, sir. Starting at line 18, I'll just paraphrase, you say that Tampa Electric made a determination to try to keep the units running as long as reliably possible without incurring significant expenditure. Do you see that? That's about line 18 to 21.

A Yes. Yes, uh-huh, I've got that. Okay.

Q What would you categorize as a significant expenditure in dollars?

A To me, when you're -- these major capital component changeouts that you're going to invest in something that it's like you're not going to be able to utilize the full life of that component, that, to me, is -- comes into play on this expenditure. And, you know, when you are making those decisions about how long this is, you can say, well, that expenditure versus the life, it's not

going to get there.

Q When you wrote this testimony that we just looked at on page 9 and you used the term *significant expenditure*, what dollar amount do you have in mind there?

A I was thinking of the -- you know, when you've got a half a million and above, that's a lot of money.

Q Half a million or above?

A Yes. That's per activity.

Q So, for example, your WTW-2 that you looked at with Mr. Vandiver, when you say per activity, sort of each line item, anything that's above a half a million you would consider a significant expenditure?

A That's a large expenditure.

Q I want to go back for a minute to the shutdown dates, and putting aside for a moment the consent decree and the final judgment that you entered into with the environmental agencies, putting that aside, when were the Gannon units scheduled to go out of service?

A I think we've, in interrogatories, provided that information of what was in the site plan.

Q Well --

A That's what I would have to reference is the document or plan.

Q Okay. Well, do you know or can you give me the reference?

A Let me -- I'm trying to refresh my -- I thought I saw it. I'm flipping pages here.

Q That's okay. I know there's a lot of paper in this case.

A Well, and that was prior to my, you know, when I took over the consent decree had been -- was in the process of being signed.

Q Okay. Mr. Vandiver has helpfully referred me to Interrogatory No. 6.

A Right, page 1 of 1.

Q Right. Okay. So Unit 1 was supposed to go out 2007. Is that at year-end? Is that at --

A I think it just lists the dates -- I mean, it just lists the year, I don't know when they --

Q So you don't know if it's January 1, '07, or December 31, '07?

A I don't know. It just lists the year.

Q And then Gannon 2 was supposed to go out '08 and 3 in 2010 and 4 in 2013, correct?

A Correct.

Q So if you had not entered into the consent decree and the final judgment, you would have continued to operate those plants up through those dates, correct?

A Repeat the question again.

Q I said putting aside the consent decree and the

final judgment, the environmental settlements, you would have continued to operate the Gannon units up through those dates?

A I don't know, you know, because we take each -- you know, each year we continually look at the units and try to decide what -- you know, where we want to go with that particular unit. As units get older and they have a major event, that unit is re-evaluated and said, okay, is this unit, do we continue running it for this time period or do we shut it down at that particular time as they get near. I don't know what the profile will be in the future.

Q Well, when you responded to this interrogatory on April 1, 2003, that was -- that would have been your current plan at that point in time anyway, right, putting aside the environmental settlements?

A I'm trying to read this question again. This is the scheduled retirement dates prior to the consent decree, yes, and that's establishing the depreciation schedules. Again, those dates change.

Q Right, I understand. Again, I guess I'm like Mr. Vandiver, it's not a trick question, just, at the time you answered this interrogatory on April 1, that was your best estimate of what would have occurred if you had not entered into the consent decree?

A Well, again, this -- I'm responding to the

question based on information that we had produced prior to the consent decree, and I wasn't involved in that, those discussions, so this is what we had published.

Q Do you have some plan you're aware of that differs from what you published?

A As far as the retirement dates of these?

Q Right, yes, sir.

A No, I don't, because I -- all of my activity has been after the consent decree, and so that's what I've been -- you know, plans that I've worked on is based with the consent decree and the retirement of them being December -- or the end date of the things being in December.

Q Right, I understand. All I'm trying to find out is you don't have any information that would suggest that in the absence of the consent decree, that this Interrogatory 6 is incorrect?

A Run that question by me again.

Q As we sit here today, you don't have any information that you're aware of that would suggest that this Interrogatory No. 6 is in error?

A No. The depreciation schedule and retirement dates is, to my knowledge, what we published and what our plan was.

Q Okay. And again, I'm going to try to paraphrase your testimony, and you're going to correct me if I misstate

anything.

Basically, though, since you had entered into the consent decree and you knew you were going to have to shut down the units no later than December 31, 2004, basically it didn't make a lot of sense to expend a lot of funds to keep them operating, is that a fair statement?

MR. BEASLEY: Just operating?

BY MS. KAUFMAN:

Q To operate and maintain them.

A Yes. We were trying -- again, we were utilizing our funds to operate as best as possible, realizing that there was an end date of December 31st that they could not operate, also realizing other factors were involved with it, being the construction schedule requirements that we had there, the safety issues that came into play, so it became -- a lot of factors started interplaying in it versus just one thing, saying we're going to run it to here and not, you know, and we have no construction activities, those type of activities, going on.

Q Would it be fair to say that since you knew that the shutdown date was coming that you began to defer capital expenditures that you might otherwise have made?

A We did not do major component changeouts. We went to patching those, again trying to get it to, you know, an end date. We didn't want to change out.

Let me use an example. A super heater that's got a 15-year life and several million dollars to install, we were going to have to take that long planned outage during this time period where the unit could be available, replace that component, bring the machine back up, and then all you're going to run it is a year of useful life out of that particular thing when it has 15 years of life.

Q Right. So essentially you were deferring some of these big capital expenditures in recognition of the fact that, in your example, the plant wasn't going to operate for 15 more years, right?

A Right, but we were also avoiding taking a lot of planned outage time during that year.

Q When, timewise, did Tampa Electric begin deferring these capital expenditures in anticipation of the shutdown?

A When the consent decree was signed, that really forced us to start relooking at, you know, the components and the failure rates on them and, you know, whether you could go to a repair strategy versus a component replacement strategy.

Q So end of 1999, beginning of 2000, was when you started that review and deferral of these major expenditures, is that right?

A I think sometime around 2000, because, again, '99 --

Q Was the very end?

A Yes, it was the very end, we were trying to figure out what this consent decree is, and really it's more in the year 2000.

Q Take a look with me at, Mr. Whale, at your Exhibit WTW-2. Let me know when you get there.

A WTW-2?

Q Right. It's the three-page exhibit you discussed some with Mr. Vandiver. This is to your rebuttal.

A Okay.

Q Are you there, sir?

A Yes. It's which document?

Q It's document number 2.

A Document number 2, okay.

Q Okay. It's got the first page, a little paragraph, and then a two-page chart, call it.

A Okay.

Q Okay. I just want to be sure that I understand what you're saying here, and my interpretation, subject to your correction, is that basically it would have cost Tampa Electric $57.4 million -- and that number appears on page 3 of 3?

A Right.

Q -- to maintain and repair Gannon Units 1 through 4 and keep them going through up to December 31, 2004. Is

that a correct interpretation of this exhibit?

A Right.

Q Okay. And on the second page of the exhibit, you've got a number on the very last line, total major activities costs of $28.4 million, right?

A Correct.

Q Am I right that these are maintenance costs that we generally would capitalize, but I think you discussed with Mr. Vandiver, since the end was in sight, they were expensed, right?

A The bulk of these 28.4 would have been capitalized. Some of the insulation may not have been, but the bulk of them would have been capital. The pond dredge would have been O&M.

Q And then on the next page, you show total 2003 maintenance cost of seven million, correct?

A Correct.

Q And total 2004 maintenance cost of 22 million, right?

A Correct.

Q And that's how you get to the 57.4 million?

A Correct.

Q Okay.

A Again, the 7,000 was incremental.

Q Right. I think we're clear on that now.

Did you prepare an estimate of what it would cost to operate the units in 2003 and 2004?

A We had an estimate of the -- built in the budget for '03. For '04, I think there was a rough -- you know, rough ballpark number.

Q Well, let's go a year at a time so we can be clear.

What was your estimate to operate the Units 1 through 4 in '03?

A I don't have that number with me. I don't -- that would be the Gannon '03 budget.

Q Okay. Is that the document that you were looking at with Mr. Vandiver that's attached to Mr. Zaetz's testimony?

A That was the business plan. I don't know if that was the final number.

Q I'm just looking at the document for a second, Mr. Whale. It's the one you looked at before, Bates-stamped 1833 --

A Correct.

Q -- to Mr. Zaetz's testimony.

A Right.

Q So for 2003, the number is in the ballpark of what's shown on this exhibit for operating a plant?

A I can't read the numbers on this.

Q That's a good point.
A I mean, it's -- and I just --
Q (Question redacted per counsel's instructions.)
A This is confidential.
Q I'm so sorry. Don't type that. It doesn't say confidential.
A Well, I guess the yellow pages.
Q Okay. I'm sorry. The one I'm looking at, that was not clear to me.
Okay. Well, looking at the 2003 number that's all the way to the right on this -- my face is red and that's why everybody is laughing -- that's the budgeted amount to operate Units 1 through 4 in 2003, correct?
A That's in the business plan, yes.
Q Okay. And you said that you had a number for '04?
A That's correct.
Q Okay. And can you tell me what that number is?
A Well, looking at the sheet that, you know, is there is, it looks like 22.
Q Are you looking at Bates stamp 1833?
A Well, 1833 doesn't have an --
Q Oh, okay. You're right, it doesn't.
A The -- you know, the document 2 has got, you know, the 22 for '04 costs.
Q All right. Let me get back to that one.

A And again, this is O&M.

Q Okay. That's kind of where I'm going. You're anticipating me. It says "maintenance," right, it says, "total 2004 maintenance," but you're telling me that it includes operating costs as well, right?

A Yes, that -- and I apologize, that says maintenance costs, it's really maintenance and operations. It says maintenance costs, but that's maintenance and operations.

Q Okay. Tell me, looking at your exhibit, which of those costs are operating expenses that would be booked, for example, to Account 500, 502, some of those?

A If it's hard to subdivide it in because the, you know, the staffing has got both maintenance and operations but, you know, you've got staffing, stevedoring, the water chemicals, equipment repairs and those type of things. The planned outages is maintenance.

Q Okay. You're going to have to help me a little bit.

A I'm sorry.

Q What your testimony is now, as I understand it, that even though these pages are all labeled *maintenance*, they actually include some operating costs in them?

A Yes, I'm sorry about that.

Q That's okay. What I want to understand from you

is what costs on here are operating costs that would be booked, for example, like I said, to Account 500 or 502. Can you identify those costs specifically for me?

A No, I can't get down to that level of detail. I just know from a general -- you know, from a general viewpoint, the planned outages maintenance, the 28-day planned outages maintenance, that and benefits is, you know, an O&M operations and maintenance components in there.

Q Okay, so let's just take that one for a second.

Looking at 2003, on page 3 of 3, you've got additional staff and benefit costs and you show $3.2 million, right?

A Okay, I lost you.

Q Page 3 of 3, document number 2.

A Okay.

Q Under *2003 Maintenance Costs*, you have -- the third line down says, "Additional staff and benefit costs," right?

A Okay. Correct.

Q And now, I thought I heard you say that some of that would be, in your view, operating expense?

A Yes.

Q Okay. How much?

A I don't know that.

Q And I think you made the same comment about the

stevedoring costs on the next line?

A Yes.

Q How much of that's operating?

A I don't know that, either.

Q So we can -- let's just cut to the chase. You can't tell me as we sit here out of these numbers what would be apportioned to operating costs?

A No, no, I can't. And again, you know, looking at O&M, that's kind of like the Bates stamp 1823, they're looked at together, you know, generally you have them as -- and that's why I call it O&M and -- you know, we said maintenance cost in here and I should probably say O&M.

Q They're not looked at together for accounting purposes, are they?

A When you get down to the -- there is, you know, some of the accounts that charge out, but I don't get too far down in there. As a maintenance guy, I may go over and perform some operations for some time period, and we had a lot of that where maintenance people went over and performed in operations, and, you know, if you get that far down in the weeds, you can see how time is being accounted, but as far as budgeting-wise, that person's time is normally budgeted as just maintenance.

Q Mr. Whale, are you involved in the Tampa Electric budget process?

A Yes.

Q And do you provide that portion of the budget that relates to the operation and maintenance of the plants, the generating units?

A Yes.

Q Okay. When does that budget process start, what time of the year?

A It's different every year.

Q Okay.

A Every year it's different.

Q When did it start in 2003, for example?

A I don't remember the exact date on that.

Q Do you remember what quarter?

A No, I don't even remember the quarter.

Q I'm assuming, and again you'll correct me if I'm wrong, that you prepare a budget for your area of responsibility and that it's submitted and made part of a larger budget for the company, is that correct?

A That's correct.

Q Okay. When you are involved in that activity, are you given a budget target?

A We're -- there's targets established, yes.

Q Okay. Now, for your area of responsibility, is it a total generation target or is it by unit?

A It's a total departmental.

Q Okay. So --
A My whole area target.
Q So you are not given a target unit by unit or station by station?
A No.
Q You looked with Mr. Vandiver at -- this is an exhibit to Mr. Majoros's testimony. I'm going to have to -- oh, I've got the wrong one. Let me get you to the right page. It's MJM-3, and I have -- it's going to take me a minute because I have those little slide versions.
A M-J --
Q M-3. I'll give you the page in one second.
A PowerPoint slide.
Q Right. Okay. It's page 16 of 34, and it's Bates-stamped 550 at the bottom.
A Okay.
Q Well, just to back up for a moment, this list identifies this was a PowerPoint presentation that you made to the Tampa Electric officers, is that correct, on August -- at the end of August, '02?
A Yes, correct.
Q Okay. Did you prepare these slides or did someone prepare them at your direction?
A I think Craig Cameron prepared them for me.
Q Okay. But I'm correct, am I not, that you are the

one that, I guess, spoke from these slides and used them in the presentation?

A Correct.

Q And can I assume that you reviewed them and approved them before the presentation was made?

A Yes.

Q Okay. Taking a look at page 550 -- are you there?

A Yes, I am.

Q Okay. That references Gannon accelerated shutdown, correct?

A Correct.

Q Okay. And above that, it says, "Reductions to achieve 2003-2004 plug." Do you see that?

A Correct.

Q What does that mean?

A That was part of a presentation that I was giving to the officers to educate them as to how we spend money within the department. It was primarily focused on the financial and understanding how our business works, and one of the plugs was a target and I highlighted what was occurring basically that was addressing that plug. I didn't highlight everything, I just highlighted, you know, that the Gannon shutdown basically was part of that plan.

Q Okay. This was a presentation you were making to the officers regarding the generating stations and their

reliability and their profitability, et cetera, correct?

A Again, it was trying to educate the officers as to how money is spent within energy supply, where money is allocated within the supply, and that's why there's so much up-front talking about the, you know, where the different stations the money is going to and where the different groups it's spent to, and also looking at different things that we do within our business that drives some of our costs.

Q When you use the phrase, "reductions to achieve 2003 and 2004 plug," what are you referring to? What -- when I think of a plug, it's like a hole that you're trying to fill. What is it that you meant when you used that phrase in your presentation to the Tampa Electric officers?

A It was referring to the difference between what our total budget request, and again, racking all the stations up to the particular needs that they were looking at, that number was different than the particular target number, and there was a delta between that.

Q So you were trying to achieve -- well, that's your words here. You were trying to fill this difference, if you will, correct?

A It was offsetting those differences as far as here we were allocating monies, those monies of our budget, we wanted to allocate the bulk of them to Big Bend Station for

the particular machine. There again, I'm looking at the total budget, trying to allocate where the best place to allocate those monies, and using our budget, the bulk of the monies we want to allocate to the Big Bend Station, and that there were a lot of other factors to shut down Gannon and this was one of them.

Q And one of the factors that led to the decision to shut down Gannon was to plug this revenue hole, right?

A Not plugging a revenue hole. It's -- again, we work on a cost budget. I don't have a revenue hole.

Q What were you plugging there on page 550, sir?

A What we're trying to accomplish there was that the stations request initial rack-up of the budget, never does get where we're trying to be because it's -- everybody loads in all the niceties that they would like to have, and that number is always much higher than what your -- you've got in your mind as far as historical trends and those type of things. So there was a delta there, and that delta is what we were trying to address there.

Q Right, and if I'm understanding this slide, which is related specifically to the Gannon shutdown, one way to do that was to accelerate the shutdown, correct?

A Again, we were looking at, you know, there were several things that was of -- advantageous in shutting the station down, and one of them is that that would -- that

definitely allows funds to go to Big Bend Station.

Q I'm just flipping back. Give me a second.

A You know, you get what you're going to get, and then we're trying to direct the dollars and the best place that provides the most benefit, the most bang for the buck.

Q Well, let's talk about the most bang for the buck while I try to stumble through these pages. Was there an analysis done by Tampa Electric of the impact of the early shutdown on the fuel cost recovery?

A There was multiple scenarios, multiple runs, done on the shutdown.

Q Did Tampa Electric do an analysis of the impact to ratepayers through increased fuel prices as a result of the Gannon accelerated shutdown?

A In looking at documentation, yes, there was one done.

Q Are you looking at something in particular?

A No, I just looked through all the documentation. I know one was done.

Q And what did that show, sir?

A I don't know. I don't remember.

Q Can you take a look, we're still on Mr. Majoros's MJM-3, Bates stamp 555 --

A That's page 21 of 34?

Q Yes, sir.

A Correct.

Q And this slide, which again is one from your presentation, is titled *Changes and Consequences*?

A Correct.

Q "Gannon accelerated shutdown," paren, "(consequences)," correct?

A Correct.

Q And isn't one of the consequences you list higher purchased power costs?

A Yes.

Q And another one you list is that TECO Transport coal movements will be reduced, correct?

A Yes.

Q Still flipping here. Bear with me.

A Those were things that I was highlighting to people as possible impacts. I didn't have analysis of that when I was putting this presentation together.

Q So are you saying that, looking at 555, that you didn't know whether or not there would be higher purchased power costs, you just included that in the slide?

A Yes, I just -- I just assumed that as a possible impact of this. I didn't know for sure. This was part of the slide what I was highlighting that that's potentially an impact, but I did not do any analysis to confirm all that. That was other folks' responsibilities, and I was just

highlighting it.

Q Is TECO Transport an affiliate company of Tampa Electric --

A Yes.

Q -- or of TECO Energy, I guess?

Of what significance would it be to this analysis that TECO Transport coal movements would be reduced?

A It was just a fact, that it's, you know, potentially could impact the coal movement to that company. Again, I was highlighting to folks that that could be an impact. I didn't have any analysis or anything, it was just something that we were going to reduce -- possibly reduce coal.

Q Why would that be something that would be of interest to the Tampa Electric officers?

A At times you get into dead freight issues and those type of issues that incur penalties, and again, I don't know all the, you know, the intricacies there, I just know it's -- you know, there is certain movements that -- certain volumes that you get into dead freight issues.

Q So, I don't want to put words in your mouth, are you saying you don't know why that would be of interest to the officers?

MR. BEASLEY: He just responded.

/ / / / /

BY MS. KAUFMAN:

Q I'm sorry, if you did, I didn't understand, so let me just ask it again so we're clear. Do you need to me to repeat it?

A Yes.

Q What I want to know is under these consequences on page 555, what import would it be to the Tampa Electric officers to understand that their sister company's coal movements might be reduced?

A What I was trying to accomplish here, because I don't know the specifics in everybody's particular area, and so I was kind of thinking through to highlight with them what things they might want to be thinking about from potential consequences of this, and on the TECO coal movement, I know there's dead freight issues that come into play, and it wasn't in my area, but I was highlighting it to make sure that the Fuels Group would, because they understand the contract is with us and, you know, it's -- it can't -- they didn't highlight it.

Q Were there questions and answers during this presentation?

A More questions than answers on the specifics of what -- where we spend money, you know, as I have such a big labor budget and, you know, were we being as efficient as we can with our people, and that's -- labor is the, you know,

that's the bulk of our budget, and a lot of question comes in is are we being as efficient with our labor as possible and, you know, how we're doing that, how we're doing our plans and multi-skilling, how we're moving people back and forth and those type of issues.

Materials, people understand you consume materials when you use your machine, and it's like gas and oil for your car. Labor, you get lots of questions, are we being as effective with them and moving around, moving them between stations and those type of things. So it's kind of, you know, understanding that and understanding, you know, how we plan the planned outages because of the fact that you cannot do a planned outage on every machine every year because the system cannot absorb that, and you've got to pick and choose which machines to shut down for how long, and how do we plan that and work that into the schedule.

Q So there were questions and answers during this presentation?

A Yes, but --

Q Okay.

A It was a long presentation.

Q I understand. It sounds like it was.

Take a look at page 551, please, of Mr. Majoros's MJM-3.

A Okay.

Q And this is still in the section of your presentation talking about the Gannon accelerated shutdown, correct?

A Correct.

Q Okay. And you show on that presentation savings in 2003 of 11.2 million and in '04 of 16 million, correct?

A Correct.

Q And *savings* I'm interpreting to mean money that Tampa Electric will not need to spend to keep the units running. Is that how you meant *savings*?

A This was really -- it was part of what was money that was going to be -- I've got my delta between what all the stations asked for and what the target number was at, again, how much money we were allocating over to Big Bend, so it was kind of the money that would be shifted over to Big Bend and also get down to reaching the target number.

Q Right, but just to be clear, this is money that, if the accelerated shutdown plan was implemented, would not be spent at Gannon, correct?

A Correct.

Q Do you -- was there a base O&M number against which these two numbers on page 551 were calculated?

A There's a -- there's a plan number that's plugged into a five-year plan that are long-range estimates that I think these numbers were talking off of.

Q Does that five-year plan, does that contemplate what we might call normal O&M as opposed to what you show in WTW-2 that we just looked at?

A No. The, as I said, the flaw in the plan is that it kind of takes a past year number and kind of rolls up a standard three percent increase through time, and that's kind of a starting discussion, because there's years that we swing above it and years below it because of planned outages and those things, so it's kind of a starting point to work off of --

Q So --

A -- until you do the total rack-up. When you do the total rack-up you kind of move off that.

Q So the two savings numbers on 551 are, would it be fair to say, not as accurate as what you've given us in WTW-2?

A Those numbers were -- yes, I guess they're estimates.

Q The numbers on 551 are estimates?

A Those are estimates.

Q So if we wanted to get a good handle on the -- what it would have cost to keep Gannon 1 through 4 going, we're best to look at your most current WTW, correct, WTW-2?

A Yes. Yes, document number 2.

Q Okay.

A Those savings -- I mean, that's saying that you have money to spend and you were going to spend it, but it's -- the reality is that we never end up with the estimate that, the budget that everybody asks for.

Q Do you know, Mr. Whale, since January 1 of 2002 how many employees in the production portion of Tampa Electric have been -- I don't mean this in a bad way, I was going to say have been eliminated -- are no longer employed there, for whatever reason?

A I don't have the exact number because of the fact that folks -- we try to work a transition plan that -- you know, we used a heavy amount of contractors at Big Bend and Gannon, so there are folks that have moved to Gannon, there are folks that have moved into Energy Delivery because the needs of Energy Delivery have gone to different jobs, and there are a large number of folks, and then we have some folks who have early-retired.

Q Right, and I'm just trying to get a ballpark of how many employees in production are no longer there since, say, the beginning of 2002.

A At Tampa Electric or in -- just in Energy Supply?

Q Is that what your area is called, Energy Supply?

A Right. Right.

Q In Energy Supply.

A I don't have that number off the top of my head.

Q Do you have an estimate?

A Well, I don't want to give you an estimate because I don't know how many of that estimate went to Energy Delivery.

MR. BEASLEY: Don't guess if you don't know.

THE WITNESS: Yes, I'd rather not guess on that one.

BY MS. KAUFMAN:

Q So you don't know if it's one or 500?

A It's not 500; it's not one.

Q So somewhere between one and 500 would be fair.

Is that information -- you seem very familiar with the documents. Is that information in any of the discovery that you've responded to in this case?

A All I'm looking at is the -- I know we provided a -- in the discovery our presentation to the union.

Q Right.

A And there's numbers in there of what we estimated. Now, how the actual numbers came into the estimate, I'm -- that's -- I'm unsure of that. The reason I know it's in discovery, people got several revisions of it which they talked about.

Q Mr. Whale, do these people in Energy Supply, they work under your direction and supervision, is that right?

A The bulk of the people in Energy Supply work under

my direction. There was a group that worked under Chuck Black's direction, but they were primarily professional people.

Q And how long have you been in this position?

A Since early, I think sometime in '99.

Q Okay, and -- but you don't know approximately how many folks no longer work for you now that worked for you in 2002?

A I'd have to look at the graphs, look at the numbers.

Q Okay. If you would give me a second?

A Yes.

(Brief pause.)

MS. KAUFMAN: I think we're done, Mr. Whale. Thank you.

THE WITNESS: Okay. Thank you.

MS. KAUFMAN: I don't know if the staff has anything.

MS. RODIN: I don't have any questions.

MR. VANDIVER: Bill, thank you very much for your time.

MR. BEASLEY: We have some redirect.

MS. KAUFMAN: We forgot you, Jim. Sorry.

MR. BEASLEY: It's all right.

/ / / / /

EXAMINATION

BY MR. BEASLEY:

Q Mr. Whale, the $57 million amount that we were talking about, that being the amount that your company calculated you would have to spend to achieve, I believe, the 80 to 85 percent availability of Gannon Units 1 through 4 if you ran them through the end of 2004, was that an amount that was ever budgeted by Tampa Electric for that purpose?

A No.

Q The budgeted amount, were there any savings resulting by the fact that you did not run the unit into 2004, but instead shut it down under the schedule that you used for shutdown purposes?

A No, because it was never budgeted.

Q When the decision was being made about when to shut down Gannon Units 1 through 4, what were the conditions of the boiler tubes in those units?

A The boiler tubes in those units are -- were very aged, they've got a lot of life, service life, on them. The cyclone tubes have got problems, the furnace wall tubes have got problems, the screen tubes have got problems, so it's -- there are several areas of the boiler that the tubes are experiencing problems and different types of problems. They've got a lot of life on them.

Q Life on them, or --

A Well, they don't -- they don't have a lot of life left.

Q Okay. Would that have made the Gannon units less safe than if those conditions did not exist?

A If those conditions didn't exist, the units would be safer.

Q What was the state of the structural steel in the units at the time that the decision of when to shut them down was being made?

A The structural steel was in rough condition also. The steel has lost a lot of its strength. The time outside, the weather, the aging of it has occurred and the -- it's not as sound as it was when it was brand new.

Q Well, what impact would that have on the safety of the Gannon units vis-à-vis a scenario where those conditions didn't exist?

A If those conditions didn't exist, the station would be much safer.

Q With respect to outages, is it possible to postpone a planned outage to meet system requirements without affecting your unplanned outage frequency?

A Yes, it is. You know, we look at these outages on a 12-month basis, but the reality is if you push an outage from October into January, it's not having a big impact on

the unit, even though if you look at that particular year, it got moved out, basically it just got delayed, and that happens a lot to handle different things that happen in the system that we will push it out and address it at that time and combine it with another one at that time.

Q Is it possible to use a forced outage to accomplish what you might have later done at a planned outage?

A Most definitely. You do that a lot. You have a forced -- you know, especially if it's a forced outage of -- a lot of time we will try to accomplish planned maintenance work at that time during that forced outage.

Q Are there any hard and fast rules on the relationship between planned and forced outages?

A No, there's not any hard and fast rules. You can have a unit that has got a planned outage and then have a major forced outage occur because of the particular equipment involved.

Q I think you said earlier that you avoided some planned outage time by not performing major component changeouts on the Gannon units. What effect, if anything, did the avoidance of the planned outages have on your company and the customers that you serve?

A By not doing the planned outages, it made the unit more available that particular year, and again, we're trying

to look at an end date, it made the unit more available for those two years. If there was no defined end date, then you would pay for that going down, but if you've got a defined end date, it really makes the unit more available that particular year.

Q Okay. Back on the safety issue, my notes indicate that you were asked whether the Gannon units have been safe as you've operated them. Were they safe and can there be relative degrees of safety?

A You can -- I guess -- and maybe using a -- let me use a car analogy. Everybody's got cars. You've got tires on your car, let's do that.

If you have your car and you have new tires on that car, that car and those tires are very -- it's a very safe deal. You hit a water patch or those things, those tires have got lots of tread and you're going to get through that fine.

Now, through time, that tire is going to wear as you drive it, you know, it's going to wear as normal usage, and as that tread wears, you know, you're going to start looking at it, saying, "I need to get -- I need to replace those tires." So you're going to start looking around, seeing what you can do to buy. Now, when you look at that tread and you see it's going to wear, you say, "I've got to be a little more careful here." You're going to see this

thing is wearing and I need to do a change how I'm operating this thing. I may go a little slower, maybe be a little more careful if I see that water coming up because I don't have all that tread there. I can still be safe, but I've got to adjust how I'm functioning with these tires.

You keep running and running until it's a point where you say, "Hey, I'm not going to wait until a blowout, I'm going to change these tires," and change them out.

And I guess that's comparing Gannon to an -- to automotive, maybe that's the easiest way to address that. So even though your tire's wearing, it can be safe; you've just got to just how you're driving.

Q Do you know -- was it your job to determine the big picture time and date for the shutdown in Gannon Units 1 through 4, in other words, the year and month?

A No. My challenge was to, you know, look at the units, make sure that we're -- you know, we're running them as, you know, optimum as we can, keep it safe, you know, and as reliable as you can with the age and the components of what we had. And so the units were this age, we need to make sure we operate them to the best of our abilities, both safety and with best reliability that we can get within the time frames we had, realizing it's going to shut down, realizing you've got Bayside construction going on and realizing we've got these other dynamics to deal with.

Q Okay, and one other question. Concerning the reference on Bates stamp page 555 on Mr. Majoros's exhibit, Ms. Kaufman asked you about the reference there to TECO Transport coal movements reduced.

A Right.

Q Did I hear you correctly that your company has a contract with TECO Transport?

A Yes, it does.

Q So why would you have raised that issue in considering the timing of the shutdown of the Gannon units?

A Because we have a contract with them, you know. And again, as I said before, I know we have a contract with them and I'm not responsible for managing that contract, but I know that we're shutting the units down, that we're not moving as much coal, and now we have gone to Big Bend, I don't know that, I was just highlighting it, it is going to impact, you know, this coal movement and for those that have that contract, it's going to get into dead freight issues and those things that they need to be aware of, you know.

These things were just part of the presentation as things that I thought needed to be highlighted, so I highlighted them. I didn't have specifics on those.

Q If you were asked to evaluate potential for an action that the company was considering taking, and it would impact your company's obligations under a contract with some

non-affiliate, would you feel obligated to raise that for your management?

A Sure. I need to let my peers know what I think is going to hit.

One thing, I came in March of 2000. I said '99, March of 2000 is when I came over to Tampa Electric.

MR. BEASLEY: I think that's all we have.

We would like to read and sign the deposition.

(Whereupon, the witness did not waive reading and signing of the deposition, and the deposition was concluded at 12:20 p.m.)

C E R T I F I C A T E

STATE OF FLORIDA)

COUNTY OF LEON)

I, MARLO D. FARNSWORTH, Certified Shorthand Reporter and Notary Public at Tallahassee, Florida, hereby certify that the witness in the foregoing transcript was first duly sworn, having identified himself to me;

That the foregoing transcript was taken down as stated in the caption, and the questions and answers thereto were reduced to typewriting under my direction;

That the foregoing pages 4 through 108 represent a true, correct, and complete transcript of the evidence given upon said hearing;

And I further certify that I am not of kin or counsel to the parties in the case; am not in the regular employ of counsel for any of said parties; nor am I in anywise interested in the result of said case.

Dated this 10th day of November, 2003.

_____

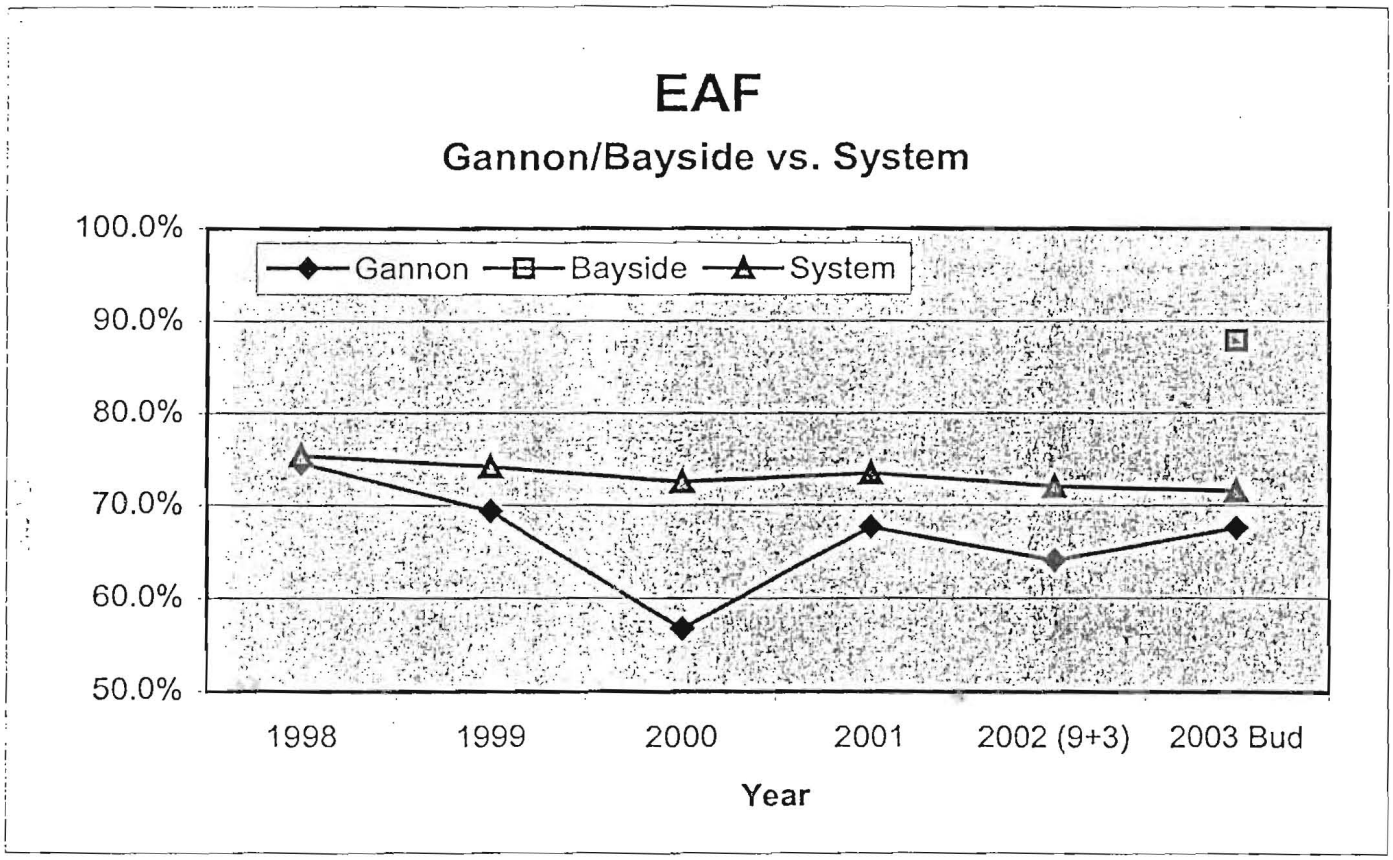
MARLO D. FARNSWORTH
Court Reporter and Notary Public
State of Florida at Large

EXH. 19

03/12/2003

Equivalent Availability Factor

The equivalent availability factor is based on period hours. Period hours are all of the hours in the year.



	1998	1999	2000	2001	2002 (9+3)	2003 Bud
Gannon	74.6%	69.4%	56.8%	67.7%	64.1%	67.6%
Bayside						87.9%
System	75.4%	74.2%	72.6%	73.5%	72.1%	71.6%

Analysis:

EAF is projected to be 3.5 percentage points better than last year and it is 1.1 percentage points better than the 5-year average. The EAF projection is increasing in 2003 due to the reduction/elimination in planned outages.

2473

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 19
COMPANY/ OPC
WITNESS: EAF Document dated 3/12/03
DATE: 11-12-03

From: Gene Edwards
To: Buddy Maye; Gene Edwards; John Knight; Tim Panoff
Date: 3/3/03 1:52PM
Subject: Gannon Units 1 thru 4 Cyclone replacements

The estimates we have been able to put together for the replacement of the Gannon unit cyclones is as follows:

Unit 1 has 3 cyclones
Unit 2 has 3 cyclones
Unit 3 has 4 cyclones
Unit 4 has 4 cyclones

* $1.5 mil per cyclone (not unit) for materials and labor to replace same

* 20 to 24 weeks delivery for the cyclone assemblies from the manufacturer

* 7 to 8 week outage time to replace the cyclones per unit

* You would need time for folks to put the scope of work together to be able to order the cyclone assemblies

I understand that these costs can be obtained in the Tampa Electric 20 year capital plan and that the last cyclones were replaced in 1993/94 time frame.

THANKS GENE EDWARDS 35303 abree

CC: Bill Whale

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO 20
COMPANY/ OPC
WITNESS: 3-3-03 Email Edwards-Maye
DATE 11-12-03

X-3

From: Charles Shelnut
To: Scott, Darryl; Sheffield, Karen
Date: 9/27/02 12:16PM
Subject: ES Personnel Numbers - 9/03

After Darryl had reviewed the personnel numbers from our meeting Wednesday with his managers he had some slight adjustments in some classifications. He gave me those personnel numbers for 9/03 this morning and they are shown on the attached sheet.
This is within one of the 286 number we were using for BB on Wednesday. So our projected TEC layoff number still is about 41 and TSSI remaining about 25.
As I understand it the 41 comes from an adjustment in the BB business plan of about 30 people and the inclusion of supervisory people in the layoff number.
If anyone has any questions please call, thanks, Charles.

CC: Black, Charles R.; Cameron, Craig; Whale, Bill

407

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO 21
COMPANY/ FIPUG
WITNESS. 9-27-02 E-mail-Shelnut-Sco
DATE: 11-12-03

ES Personnel Numbers

9/27/2002

Classifications	Big Bend			Gannon			Bayside			Totals		
	9/02(1)	9/03(2)	9/04(3)	9/02(1)	9/03(2)	9/04(3)	9/02(1)	9/03(2)	9/04(3)	9/02(1)	9/03(2)	9/04(3)
Watch Engineer	16	9		10						26	9	
Control Center Operator	5	14		12						17	14	
Boiler Turbine Operator	33	35		18	5					51	40	
Auxiliary Operator	9	22		6						15	22	
Combined Cycle Spec.							23	35	35	23	35	35
Fuel Equip Oper	19	19		11						30	19	
Fuel Handler	4	9		5						9	9	
W&F Analyst	11	12		5						16	12	
Control Analyst	16	18		12	1					28	19	
Electrician	11	18		11	2					22	20	
MCW	28	28		17	4					45	32	
Maint Mech	53	53		37	3					90	56	
PA	6			7						13		
PW	9			5						14		
SUW		14		1						1	14	
Machinist/M Blader	6	6		4						10	6	
SPO/Supt Prod	5	5		4						9	5	
Supt Maint	1	1								1	1	
Supvr Prod/ES	28	22		11	1		6	7	7	45	30	7
TOTAL	260	285	0	176	16	0	29	42	42	465	343	42

NOTES: 408

1) Numbers from plant reports.
2) Numbers from Case Nine.
30 Future Requirements if different from 03.

From: Charles Shelnut
To: Scott, Darryl; Sheffield, Karen
Date: 9/26/02 4:24PM
Subject: ES Craft Personnel

Attached is a summary of the personnel numbers that I gathered from our meeting yesterday. These are the numbers from the 9/02 station reports, and the numbers from the 9/03 case #9. They are by station and by classification. Would you please check the numbers for 9/03 and see if they are correct.

Also, Darryl would you please let me know if you expect any changes in any of the classifications in the future. If we need to get together just pick a time and let me know. Thanks, Charles.

CC: Black, Charles R.; Cameron, Craig; Whale, Bill

ES Personnel Numbers

9/12/2002

Classifications	Big Bend			Gannon			Bayside			Totals		
	9/02(1)	9/03(2)	9/04(3)	9/02(1)	9/03(2)	9/04(3)	9/02(1)	9/03(2)	9/04(3)	9/02(1)	9/03(2)	9/04(3)
atch Engineer	16	10		10						26	10	
ontrol Center Operator	5	14		12						17	14	
oiler Turbine Operator	33	34		18	5					51	39	
uxiliary Operator	9	22		6						15	22	
ombined Cycle Spec.							23	35	35	23	35	35
uel Equip Oper	19	20		11						30	20	
uel Handler	4	7		5						9	7	
&F Analyst	11	12		5						16	12	
ontrol Analyst	16	21		12	1					28	22	
ectrician	11	20		11	2					22	22	
CW	28	28		17	4					45	32	
aint Mech	53	53		37	3					90	56	
A	6			7						13		
W	9			5						14		
UW		14		1						1	14	
achinist/M Blader	6	6		4						10	6	
P.O/Supt Prod	5	5		4						9	5	
uptMaint	1	1								1	1	
upvr Prod ES	28	21		11	1		6	7	7	45	29	7
TOTAL	**260**	**288**	**0**	**176**	**16**	**0**	**29**	**42**	**42**	**465**	**346**	**42**

OTES:

410

Numbers from plant reports.
Numbers from Case Nine.
) Future Requirements if different from 03.

TAMPA ELECTRIC COMPANY
TOTAL ENERGY SUPPLY O&M EXPENSE
(Budgeted and Actual)
(000)

	2000	2001	2002	2003	2004
O&M					
BUDGET	104,000	107,784	117,450	102,429	96,000
ACTUAL	112,385	109,996	124,962	110,274*	-
VARIANCE	8,385	2,212	7,512	7,845*	-

*2003 based on 9 months actual/3 months estimated.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 22
COMPANY/ TECO
WITNESS: Total Energy Supply O&M Exp.
DATE: 11-12-03

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

Final True-Up Amount
January through December 2002

VARIANCE ANALYSIS (JP-1)

DOCUMENT NUMBER-DATE
03039 APR-1 8
FPSC-COMMISSION CLERK

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 23
COMPANY/ Progress Energy FL, Inc.
WITNESS: Javier Portuondo
DATE: 11-12-03 JP1-JP4
Schedules A1-A9(JP-4)

Progress Energy Florida, Inc.
Docket No. 030001-EI
Witness: Portuondo
Exhibit No. (JP-1)
Sheet 1 of 3

PROGRESS ENERGY FLORIDA, INC.
Fuel Adjustment Clause
Summary of Final True-Up Amount
January through December 2002

Line No.	Description	Contribution to Over/(Under) Recovery Period to Date
1	**KWH Sales:**	
2	Jurisdictional KWH Sales	(283,990,747)
3	Non-Jurisdictional KWH Sales	(121,320,533)
4	Total System KWH Sales Decreased	
5	Schedule A2, pg 2 of 4, Line C3	(405,311,280)
6		
7	**System:**	
8	Fuel and Net Purchased Power Costs - Difference	
9	Schedule A2, page 3 of 4, Line D4	$ (2,857,514)
10		
11	**Jurisdictional:**	
12	Fuel Revenues - Difference	
13	Schedule A2, page 3 of 4, Line D3	$ (34,463,854)
14		
15	True Up Provision for the Period Over/(Under)	
16	Collection - Estimated	
17	Schedule A2, page 3 of 4, Line D7	(950)
18		
19	Net Fuel Revenues	(34,464,804)
20		
21		
22	Fuel and Net Purchased Power Costs - Difference	
23	Schedule A2, page 3 of 4, Line D6	(2,635,786)
24		
25	True Up Amount for the Period	(31,829,018)
26		
27	True Up for the Prior Period - Actual	
28	Schedule A2, page 3 of 4, Line D9+D10	-
29		
30	Interest Provision - Actual	
31	Schedule A2, page 3 of 4, Line D8	143,306
32		
33	Actual True Up ending balance for the period	
34	January 2002 through December 2002	(31,685,712)
35		
36	Estimated True Up ending balance for the period included in	
37	filing of Levelized Fuel Cost Factors January through December 2003,	
38	Docket No. 020001-EI.	34,585,760
39		
40	Final True Up for the period January 2002 through	
41	December 2002 (Line 34 - Line 38)	$ (66,271,472)

Progress Energy Florida, Inc.
Docket No. 030001-EI
Witness: Portuondo
Exhibit No. ____ (JP-1)
Sheet 2 of 3

FUEL AND NET POWER VARIANCE ANALYSIS
FOR THE PERIOD OF: JANUARY - DECEMBER 2002

	(A) ENERGY SOURCE	(B) MWH VARIANCES	(C) HEAT RATE VARIANCES	(D) PRICE VARIANCES	(E) TOTAL
1	Heavy Oil	($2,976,579)	$2,657,623	$10,862,747	$10,543,791
2	Light Oil	1,074,147	(4,165,563)	(516,023)	(3,607,439)
3	Coal	(15,023,017)	2,463,793	(25,569,766)	(38,128,990)
4	Gas	50,704,689	(16,859,766)	(36,229,998)	(2,385,075)
5	Nuclear	367,448	(183,520)	(416,911)	(232,983)
6	Other Fuel	0	0	0	0
7	Total Generation	34,146,688	(16,087,433)	(51,869,951)	(33,810,696)
8	Firm Purchases	(2,090,062)	0	557,712	(1,532,350)
9	Economy Purchases	2,862,553	0	17,225,659	20,088,212
10	Schedule E Purchases	0	0	0	0
11	Qualifying Facilities	(829,545)	0	1,559,877	730,332
12	Total Purchases	(57,054)	0	19,343,248	19,286,194
13	Economy Sales	0	0	(165,155)	(165,155)
14	Other Power Sales	1,435,134	0	6,289,061	7,724,195
15	Supplemental Sales	(18,851,434)	0	21,716,894	2,865,460
16	Total Sales	(17,416,300)	0	27,840,800	10,424,500
17	Nuclear Fuel Disposal Cost	0	0	178,593	178,593
18	Nuclear Decom & Decon	0	0	46,044	46,044
19	Other Jurisdictional Adjustments Sch A2 Page 1 of 4 Line 6b	0	0	1,017,851	1,017,851
20	Total Fuel and Net Power	$16,673,334	($16,087,433)	($3,443,415)	($2,857,514)

Progress Energy Florida, Inc.
Docket No. 030001-E1
Witness: Portuondo
Exhibit No. (JP-1)
Sheet 3 of 3

GAS CONVERSION PROJECTS
SCHEDULE OF SYSTEM DEPRECIATION AND RETURN
FOR THE PERIOD JANUARY THROUGH DECEMBER 2002

		INTERCESSION CITY 7 & 9	INTERCESSION CITY 8 & 10	DEBARY 8	DEBARY 7 & 9	BARTOW 2 & 4	SUWANNEE 1 & 3	TOTAL
	PLANT INVESTMENT							
1	BEGINNING BALANCE	$ 108,755	$ 160,583	$ 1,062,537	$ 3,352,257	$ 2,444,925	$ 3,460,560	$ 10,589,617
2	PRIOR PERIOD ADJUSTMENT	-	-	168,408	-	-	-	168,408
3	ADD INVESTMENT	-	-	-	-	-	-	-
4	LESS RETIREMENTS	108,755	160,583	-	3,352,257	2,444,925	1,654,263	7,720,783
5	ENDING BALANCE	-	-	1,230,945	-	-	1,806,297	3,037,242
6								
7	ACCUMULATED DEPRECIATION							
8	BEG. BALANCE ACCUM. DEPRECIATION	107,872	153,382	348,695	2,973,408	2,176,509	2,707,802	8,467,668
9	PRIOR PERIOD ADJUSTMENT	-	-	239,987	-	-	-	239,987
10	DEPRECIATION EXPENSE	883	7,201	246,192	378,849	268,416	570,206	1,471,747
11	LESS RETIREMENTS	108,755	160,583	-	3,352,257	2,444,925	1,654,263	7,720,783
12	END. BALANCE ACCUM. DEPRECIATION	-	-	834,874	-	-	1,623,745	2,458,619
13								
14								
15	ENDING NET INVESTMENT (LINE 4-10)	$ -	$ -	$ 396,071	$ -	$ -	$ 182,552	$ 578,623
16								
17	TOTAL RETURN REQUIREMENTS	4	127	60,147	12,748	8,594	50,034	$ 131,654
18								
19	TOTAL ACCUMULATED DEPRECIATION							
20	AND RETURN (LINE 8+ 15)	$ 887	$ 7,328	$ 306,339	$ 391,597	$ 277,010	$ 620,240	$ 1,603,401
21								
22								
23	ESTIMATED FUEL SAVINGS	37,778	1,037,147	2,693,833	4,545,114	1,816,087	1,607,223	11,737,182
24								
25	TOTAL DEPRECIATION & RETURN (1)	887	7,328	306,339	391,597	277,010	620,240	1,603,401
26								
27	NET BENEFIT (COST) TO RATEPAYER	$ 36,891	$ 1,029,819	$ 2,387,494	$ 4,153,517	$ 1,539,077	$ 986,983	$ 10,133,781
28								
29								
30								

31 **DEPRECIATION EXPENSE IS CALCULATED BASED UPON A FIVE YEAR PERIOD.**
32 **RETURN ON AVERAGE INVESTMENT IS CALCULATED USING AN ANNUAL RATE OF 8.37% (EQUITY 5.12%, DEBT 3.25%).**
33 **THIS IS THE MIDPOINT AUTHORIZED BY THE FPSC IN DOCKET NO. 91-0890-EI.**
33 **RETURN REQUIREMENT IS CALCULATED BASED UPON A COMBINED STATUTORY INCOME TAX RATE OF 38.575%**
34 **(1) TOTAL AMOUNT DIFFERS FROM SCHEDULE A-2, PAGE 1 OF 4, LINE 6b BECAUSE A-2 EXCLUDES COST ASSIGNED TO SUPPLEMENTAL KWH SALES.**

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

Final True-Up Amount
January through December 2002

CAPACITY COST RECOVERY (JP-2)

Progress Energy Florida, Inc.
Docket No. 030001-EI
Witness: Portuondo
Exhibit No. (JP-2)
Sheet 1 of 3

PROGRESS ENERGY FLORIDA, INC.
Capacity Cost Recovery Clause
Summary of Actual True-Up Amount
January through December 2002

Line No.	Description	Actual	Original Estimate	Variance
1				
2	**Jurisdictional:**			
3	Capacity Cost Recovery Revenues			
4	Sheet 2 of 3, Line 42	330,158,586	339,056,499	(8,897,913)
5				
6	Capacity cost Recovery Expenses			
7	Sheet 2 of 3, Line 38	334,370,551	339,056,499	(4,685,948)
8				
9	Plus/(Minus) Interest Provision			
10	Sheet 2 of 3, Line 44	(196,173)	(263,527)	67,354
11				
12	Sub Total Current Period Over/(Under) Recovery	(4,408,138)	(263,527)	(4,144,611)
13				
14	Prior Period True-up - January through			
15	December 2001 - Over/(Under) Recovery			
16	Sheet 2 of 3, Line 46	(11,499,656)	(3,712,132)	(7,787,524)
17				
18	Prior Period True-up - January through			
19	December 2001 - (Refunded)/Collected			
20	Sheet 2 of 3, Line 47	11,499,656	3,712,132	7,787,524
21				
22				
23				
24				
25				
26	Actual True-up ending balance Over/(Under) recovery			
27	for the period January through December 2002			
28	Sheet 2 of 3, Column G, Line 49	(4,408,138)	(263,527)	(4,144,611)
29				
30	Estimated True-up ending balance for the			
31	period included in the filing of Levelized			
32	Fuel Cost Factors January through December 2003			
33	Docket No. 020001 - E1.	(8,906,021)		
34				
35				
36	Final Over/(Under) Recovery for the period January			
37	through December 2002 (Line 28 - Line 33)	4,497,883		

PROGRESS ENERGY FLORIDA, INC.
CAPACITY COST RECOVERY CLAUSE
TRUE-UP CALCULATION
FOR THE PERIOD JANUARY THROUGH

	DESCRIPTION	2002 JANUARY	2002 FEBRUARY	2002 MARCH	2002 APRIL	2002 MAY	2002 JUNE	2002 JULY	2002 AUGUST	2002 SEPTEMBER	2002 OCTOBER	2002 NOVEMBER	2002 DECEMBER	12 Months Cumulative
	Base Production Level Capacity Charges:													
1	Auburndale Power Partners, L.P. (AUBRDLFC)	$394,230	$419,050	$419,050	$419,050	$419,050	$419,050	$419,050	$419,050	$419,050	$419,050	$419,050	$419,050	$5,003,780
2	Auburndale Power Partners, L.P. (AUBSET)	1,987,798	2,089,680	2,089,680	2,089,680	2,089,680	2,089,680	2,089,680	2,089,680	2,089,680	2,089,680	2,089,680	2,089,680	24,974,275
3	Bay County (BAYCOUNT)	194,700	206,910	206,910	206,910	206,910	206,910	206,910	206,910	206,910	206,910	206,910	206,910	2,470,710
4	Cargill Fertilizer, Inc. (CARGILLF)	412,050	432,750	432,750	432,750	432,750	432,750	432,750	432,750	432,750	432,750	432,750	432,750	5,172,300
5	Central Power & Lime (FLACRUSH)	18,000	18,000	18,740	18,000	15,480	0	0	0	0	0	0	0	86,220
6	Jefferson Power L.C. (JEFFPOWER)	0	0	0	0	0	0	0	136,000	65,349	55,836	58,878	58,878	374,941
7	Lake County (LAKCOUNT)	369,623	392,955	392,955	392,955	392,955	392,955	392,955	392,955	392,955	392,955	392,955	392,955	4,692,128
8	Lake Cogen Limited (LAKECOGL)	2,099,277	2,311,590	2,205,434	2,205,434	2,203,237	2,206,532	2,092,070	2,125,407	2,152,556	2,098,067	2,167,376	2,164,224	26,031,204
9	Metro-Dade County (METRDADE)	757,267	811,410	795,837	757,588	835,122	765,648	758,363	744,179	740,381	753,340	742,240	778,817	9,240,192
10	Orange Cogen (ORANGECO)	1,785,040	1,873,899	1,873,899	1,873,899	1,873,899	1,873,899	1,873,899	1,873,899	1,873,899	1,873,899	1,873,899	1,873,899	22,397,933
11	Orlando Cogen Limited (ORLACOGL)	1,584,957	1,666,192	1,666,192	1,666,192	1,666,192	1,666,192	1,666,192	1,666,192	1,666,192	1,666,192	1,639,381	1,666,192	19,866,257
12	Pasco Cogen Limited (PASCOGL)	2,779,800	2,907,448	2,907,448	2,907,448	2,907,448	2,907,448	2,907,448	2,907,448	2,907,448	2,907,448	2,907,448	2,907,448	34,761,727
13	Pasco County Resource Recovery (PASCOUNT)	666,540	708,860	708,860	708,860	708,860	708,860	708,860	708,860	708,860	708,860	708,860	708,860	8,464,000
14	Pinellas County Resource Recovery (PINCOUNT)	1,586,655	1,687,395	1,687,395	1,687,395	1,687,395	1,687,395	1,687,395	1,687,395	1,687,395	1,687,395	1,687,395	1,687,395	20,148,000
15	Polk Power Partners, L. P. (MULBERY)	2,236,020	2,329,911	2,329,911	2,329,911	2,329,911	2,202,441	1,922,398	1,913,589	1,901,540	1,894,402	1,879,793	1,878,506	25,150,337
16	Polk Power Partners, L. P. (ROYSTER)	824,504	866,637	866,637	866,637	866,637	866,637	779,243	775,675	770,794	767,903	761,985	761,465	9,774,753
17	Tiger Bay Limited Partnnership (ECOPEAT)	1,160,133	1,160,133	1,160,133	1,160,133	1,160,133	1,160,133	1,160,133	1,160,133	1,160,133	1,160,133	1,160,133	1,160,133	13,921,596
18	Tiger Bay Limited Partnnership (GENPEAT)	4,229,940	4,229,940	4,229,940	4,229,940	4,229,940	4,229,940	4,229,940	4,229,940	4,229,940	4,229,940	4,229,940	4,229,940	50,759,280
19	Tiger Bay Limited Partnnership (TIMBER2)	147,900	147,900	147,900	147,900	147,900	147,900	147,900	147,900	147,900	147,900	147,900	147,900	1,774,800
20	Timber Energy Resources, Inc. (TIMBER)	380,780	380,780	380,780	380,780	0	0	137,500	137,500	137,500	137,500	137,500	136,568	2,347,188
21	U.S. Agri-Chemicals (AGRICHEM)	39,268	40,960	41,626	41,626	41,626	41,626	41,626	41,626	41,626	41,626	41,626	41,626	496,490
22	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	784,290	769,012	763,963	757,870	749,282	733,503	727,298	744,715	750,298	743,042	704,123	747,882	8,975,079
23	Tiger Bay (EcoPeat lease credit)	(66,667)	(66,667)	(66,667)	(416,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(66,667)	(1,150,004)
24	UPS Purchase (409 total mw)	2,009,338	3,805,481	3,737,087	3,839,883	3,548,022	3,785,324	3,639,764	4,034,604	3,711,595	3,803,443	3,826,366	3,927,657	43,668,544
25	Incremental Security Costs (5060001 & 5240001)	0	0	0	0	0	0	0	0	0	0	0	4,831,124	4,831,124
26	Subtotal - Base Level Capacity Charges	26,383,443	29,190,227	28,994,441	28,703,974	28,445,763	28,458,156	27,954,707	28,509,740	28,128,084	28,151,503	28,149,522	33,163,195	344,252,855
27	Base Production Jurisdictional Responsibility	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	
28	Base Level Jurisdictional Capacity Charges	25,316,761	28,010,066	27,822,195	27,543,473	27,295,700	27,307,593	26,824,498	27,357,091	26,990,865	27,013,434	27,011,437	31,841,598	330,334,712
	Intermediate Production Level Capacity Charges:													
29	TECO Power Purchase (50 mw)	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	565,567	6,786,804
30	Schedule H Capacity Sales	(3,508)	(6,677)	(3,508)	(3,395)	(3,593)	(3,477)	(3,593)	(3,593)	(3,477)	(3,593)	(3,477)	(3,593)	(45,484)
31	Subtotal - Intermediate Level Capacity Charges	562,059	558,890	562,059	562,172	561,974	562,090	561,974	561,974	562,090	561,974	562,090	561,974	6,741,320
32	Intermediate Production Jurisdict. Responsibility	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	
33	Intermediate Level Jurisdict. Capacity Charges	486,597	483,853	486,597	486,695	486,523	486,624	486,523	486,523	486,624	486,523	486,624	486,523	5,836,230
34	Peaking Production Level Capacity Charges	55,922	55,922	0	0	0	0	0	142,788	0	0	0	734,287	988,897
35	Sebring Base Rate Credits	(414,761)	(293,899)	(321,992)	(336,309)	0	0	0	0	0	0	0	0	(1,366,961)
36	Adjustments - 2001 FPSC AUDIT	0	0	0	(2,292)	0	0	0	0	0	0	0	0	(2,292)
37	Retail Wheeling	(155,543)	(43,253)	(146,242)	(98,253)	(35,881)	(15,079)	(14,385)	(8,982)	(124,915)	(41,839)	(377,702)	(357,962)	(1,420,035)
38	Jurisdictional Capacity Charges	25,288,975	28,212,689	27,840,556	27,593,313	27,746,343	27,779,138	27,296,637	27,977,400	27,352,574	27,458,119	27,120,358	32,704,447	334,370,551
39	Capacity Cost Recovery Revenues (net of tax)	27,852,583	22,760,326	23,440,863	24,054,018	30,742,150	29,019,255	32,054,161	32,267,337	33,381,531	30,823,903	29,000,310	26,261,805	341,658,242
40	Capacity Cost Revenues Adjustment (Net of Tax)	0	0	0	0	0	0	0	0	0	0	0	0	0
41	Prior Period True-Up Provision	(309,344)	(309,344)	(309,344)	(309,344)	(309,344)	(309,344)	(309,344)	(309,344)	(309,344)	(309,344)	(309,344)	(8,096,869)	(11,499,856)
42	Current Period Capacity Cost Recovery Revenues (net of tax) (sum of lines 39 through 41)	27,543,239	22,450,981	23,131,518	23,744,674	30,432,806	28,709,911	31,744,817	31,957,993	33,072,187	30,514,559	28,690,966	18,164,936	330,158,586
43	True-Up Provision - Over/(Under) Recovery (line 42 - line 38)	2,254,264	(5,761,708)	(4,709,039)	(3,848,639)	2,686,463	930,773	4,448,180	3,980,593	5,719,613	3,056,440	1,570,608	(14,539,511)	(4,211,965)
44	Interest Provision for the Month	(15,112)	(17,176)	(24,598)	(30,510)	(30,748)	(27,680)	(22,995)	(16,242)	(9,011)	(2,167)	1,346	(1,260)	(196,173)
45	Current Cycle Balance (line 43 + line 44) Cumulative	2,239,151	(3,539,733)	(8,273,371)	(12,152,520)	(9,496,805)	(8,593,712)	(4,168,527)	(204,176)	5,506,426	8,560,699	10,132,653	(4,408,138)	
46	True-Up & Interest Provision (beginning)	(11,499,656)	(11,499,656)	(11,499,656)	(11,499,656)	(11,499,656)	(11,499,656)	(11,499,656)	(11,499,656)	(11,499,656)	(11,499,656)	(11,499,656)	(11,499,656)	
47	Prior Period True-Up Collected/(Refunded) Cumulative	309,344	618,689	928,033	1,237,377	1,546,722	1,856,066	2,165,410	2,474,754	2,784,099	3,093,443	3,402,787	11,499,656	
48	Other:	0	0	0	0	0	0	0	0	0	0	0	0	
49	Net True-Up (lines 43 through 48) Over / (Under)	($8,951,161)	($14,420,701)	($18,844,994)	($22,414,799)	($19,449,740)	($18,237,302)	($13,502,773)	($9,229,078)	($3,209,132)	$154,486	$2,035,784	($4,408,138)	($4,408,138)

PROGRESS ENERGY FLORIDA, INC.
CAPACITY COST RECOVERY CLAUSE
TRUE-UP CALCULATION
FOR THE PERIOD JANUARY THROUGH DECEMBER 2002

	DESCRIPTION	2002 JANUARY	2002 FEBRUARY	2002 MARCH	2002 APRIL	2002 MAY	2002 JUNE	2002 JULY	2002 AUGUST	2002 SEPTEMBER	2002 OCTOBER	2002 NOVEMBER	2002 DECEMBER
	Interest Provision:												
1.	Beginning True-Up	($11,499,856)	($8,951,161)	($14,420,701)	($18,844,994)	($22,414,799)	($19,449,740)	($18,237,302)	($13,502,773)	($9,229,078)	($3,209,132)	$154,486	$2,035,784
2.	Ending True-Up	(8,936,049)	(14,417,512)	(18,820,396)	(22,384,289)	(19,418,992)	(18,209,623)	(13,479,778)	(9,212,836)	(3,200,121)	156,652	2,034,438	(4,406,858)
3.	Total True-Up (line 1 + line 2)	(20,435,705)	(23,368,674)	(33,241,097)	(41,229,284)	(41,833,790)	(37,659,362)	(31,717,080)	(22,715,609)	(12,429,199)	(3,052,480)	2,188,924	(2,371,074)
4.	Average True-Up (50% of line 3)	(10,217,853)	(11,684,337)	(16,620,548)	(20,614,642)	(20,916,895)	(18,829,681)	(15,858,540)	(11,357,805)	(6,214,599)	(1,526,240)	1,094,462	(1,185,537)
5.	Interest Rate - First Day of Reporting Month	1.780%	1.770%	1.750%	1.800%	1.750%	1.770%	1.750%	1.730%	1.710%	1.760%	1.650%	1.300%
6.	Interest Rate - First Day of Subsequent Month	1.770%	1.750%	1.800%	1.750%	1.770%	1.750%	1.730%	1.710%	1.760%	1.650%	1.300%	1.290%
7.	Total Interest (line 5 + line 6)	3.550%	3.520%	3.550%	3.550%	3.520%	3.520%	3.460%	3.440%	3.470%	3.410%	2.950%	2.590%
8.	Average Interest Rate (50% of line 7)	1.775%	1.760%	1.775%	1.775%	1.760%	1.760%	1.740%	1.720%	1.735%	1.705%	1.475%	1.295%
9.	Monthly Average Interest Rate (line 8 / 12)	0.1479%	0.147%	0.148%	0.148%	0.147%	0.147%	0.145%	0.143%	0.145%	0.142%	0.123%	0.108%
10.	Interest Provision (line 4 x line 9)	(15,112)	(17,176)	(24,598)	(30,510)	(30,748)	(27,680)	(22,995)	(16,242)	(9,011)	(2,167)	1,346	(1,280)
11.	Cumulative Interest for the Period Ending	($15,112)	($32,288)	($56,887)	($87,396)	($118,144)	($145,824)	($168,819)	($185,060)	($194,071)	($196,239)	($194,893)	($196,173)

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

Final True-Up Amount
January through December 2002

TIGER BAY REVENUES AND EXPENSES (JP-3)

Progress Energy Florida, Inc.
Docket No. 030001-EI
Witness: Portuondo
Exhibit No. (JP-3)
Sheet 1 of 1

TIGER BAY EXPENSE AND REVENUE TRACKING

		A	B	C	D	E	F	G	H	I	J	K	L
	Capacity Clause Revenues	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02
1	Retail Capacity Revenues	$ 5,250,101	$ 5,250,101	$ 5,250,101	$ 4,914,252	$ 5,250,101	$ 5,250,101	$ 5,250,101	$ 5,250,101	$ 5,250,101	$ 5,250,101	$ 5,250,101	$ 5,250,101
2													
3	Retail Related Interest on Reg. Asset	538,778	517,608	498,181	493,309	469,604	440,991	415,270	390,666	365,492	338,690	320,831	289,959
4													
5	Funds Available for Amortization	$ 4,711,323	$ 4,732,493	$ 4,751,920	$ 4,420,943	$ 4,780,497	$ 4,809,110	$ 4,834,831	$ 4,859,435	$ 4,884,609	$ 4,911,411	$ 4,929,270	$ 4,960,142
6													
7													
8	***Fuel Adjustment Clause Revenues***												
9													
10	Retail Energy Revenues	$ 2,834,218	$ 2,053,209	$ (138,676)	$ 2,975,768	$ 3,604,966	$ 2,950,026	$ 2,888,886	$ 2,849,238	$ 2,746,515	$ 1,673,119	$ 3,619,481	$ 2,796,077
11													
12	Retail Fuel Expenses	3,807,577	3,355,518	3,752,833	3,211,232	3,333,086	3,017,446	3,391,220	3,275,688	2,911,722	3,439,594	3,112,558	3,298,574
13													
14	Funds Available for Amortization	$ (973,359)	$ (1,302,309)	$ (3,891,509)	$ (235,464)	$ 271,880	$ (67,420)	$ (502,334)	$ (426,450)	$ (165,207)	$ (1,766,475)	$ 506,923	$ (502,497)
15													
16	Underrecovery	-	-	-	-	-	-	-	-	-	-	-	-
17													
18													
19													
20													
21	***Tiger Bay Regulatory Asset - R***												
22													
23	Beginning Balance	$ 95,132,965	$ 91,395,001	$ 87,964,817	$ 87,104,406	$ 82,918,927	$ 77,866,550	$ 73,124,860	$ 68,792,363	$ 64,359,378	$ 59,639,976	$ 56,495,040	$ 51,058,847
24													
25	Amortization (Line 5+ Line 14 + Line 16)	(3,737,964)	(3,430,184)	(860,411)	(4,185,479)	(5,052,377)	(4,741,690)	(4,332,497)	(4,432,985)	(4,719,402)	(3,144,936)	(5,436,193)	(4,457,645)
26													
27	Additional Amortization	-	-	-	-	-	-	-	-	-	-	-	-
28													
29	Ending Balance	$ 91,395,001	$ 87,964,817	$ 87,104,406	$ 82,918,927	$ 77,866,550	$ 73,124,860	$ 68,792,363	$ 64,359,378	$ 59,639,976	$ 56,495,040	$ 51,058,847	$ 46,601,202

EXHIBITS TO THE TESTIMONY OF JAVIER PORTUONDO

Final True-Up Amount
January through December 2002

SCHEDULES A1 through A9 (JP-4)
(Period-to-Date)

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
TWELVE MONTH PERIOD ENDING - DECEMBER, 2002

	$				MWH				CENTS/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1 FUEL COST OF SYSTEM NET GENERATION (SCH A3)	855,890,122	848,829,151	7,060,971	0.8	34,481,078	32,645,940	1,835,138	5.6	2.4822	2.6001	(0.1179)	(4.5)
2 SPENT NUCLEAR FUEL DISPOSAL COST	6,342,975	6,164,382	178,593	2.9	6,700,267	6,592,923	107,344	1.6	0.0947	0.0935	0.0012	1.3
3 COAL CAR INVESTMENT	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3b NUCLEAR DECOMMISSIONING AND DECONTAMINATION	1,729,044	0	1,729,044	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4 ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	(30,574,817)	10,962,000	(41,536,817)	(378.9)	(1,412,706)	0	(1,412,706)	0.0	2.1643	0.0000	2.1643	0.0
4a ADJUSTMENTS TO FUEL COST - DISPOSAL COST REFUND	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
5 TOTAL COST OF GENERATED POWER	833,387,324	865,955,533	(32,568,209)	(3.8)	33,068,372	32,645,940	422,432	1.3	2.5202	2.6526	(0.1324)	(5.0)
6 ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	57,767,866	59,300,216	(1,532,350)	(2.6)	3,202,373	3,319,365	(116,992)	(3.5)	1.8039	1.7865	0.0174	1.0
7 ENERGY COST OF SCH C,X ECONOMY PURCHASES - BROKER (SCH A9)	1,707,361	0	1,707,361	0.0	31,657	0	31,657	0.0	5.3933	0.0000	5.3933	0.0
8 ENERGY COST OF ECONOMY PURCHASES - NON-BROKER (SCH A9)	38,488,012	20,107,161	18,380,851	91.4	742,865	678,000	64,865	9.6	5.1810	2.9657	2.2153	74.7
9 ENERGY COST OF SCH E PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
10 CAPACITY COST OF ECONOMY PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
11 PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	159,374,840	158,644,508	730,332	0.5	6,476,107	6,510,148	(34,041)	(0.5)	2.4610	2.4369	0.0241	1.0
12 TOTAL COST OF PURCHASED POWER	257,338,079	238,051,885	19,286,194	8.1	10,453,002	10,507,513	(54,511)	(0.5)	2.4619	2.2655	0.1964	8.7
13 TOTAL AVAILABLE MWH					43,521,374	43,153,453	367,921	0.9				
14 FUEL COST OF ECONOMY SALES (BROKER) (SCH A6)	(165,155)	0	(165,155)	0.0	(9,798)	0	(9,798)	0.0	1.6856	0.0000	1.6856	0.0
14a GAIN ON ECONOMY SALES (BROKER) - 80% (SCH A6)	0	0	0	0.0	(9,798)	0	(9,798)	0.0	0.0000	0.0000	0.0000	0.0
15 FUEL COST OF OTHER POWER SALES (SCH A6)	(25,472,095)	(34,059,150)	8,587,055	(25.2)	(996,742)	(1,035,000)	38,258	(3.7)	2.5555	3.2907	(0.7352)	(22.3)
15a GAIN ON OTHER POWER SALES - 100% (SCH A6)	(5,628,586)	(4,765,728)	(862,858)	18.1	(996,742)	(1,035,000)	38,258	(3.7)	0.5647	0.4605	0.1042	22.6
16 FUEL COST OF SEMINOLE BACK-UP SALES (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
17 FUEL COST OF SUPPLEMENTAL SALES	(68,144,269)	(71,009,729)	2,865,460	(4.0)	(2,279,110)	(1,800,987)	(478,123)	26.6	2.9900	3.9428	(0.9528)	(24.2)
18 TOTAL FUEL COST AND GAINS ON POWER SALES	(99,410,105)	(109,834,607)	10,424,502	(9.5)	(3,285,650)	(2,835,987)	(449,663)	15.9	3.0256	3.8729	(0.8473)	(21.9)
19 NET INADVERTENT AND WHEELED INTERCHANGE					23,660	0	23,660					
20 TOTAL FUEL AND NET POWER TRANSACTIONS	991,315,297	994,172,811	(2,857,514)	(0.3)	40,259,384	40,317,466	(58,082)	(0.1)	2.4623	2.4659	(0.0036)	(0.2)
21 NET UNBILLED	114,497	(2,650,036)	2,764,533	(104.3)	(4,650)	140,165	(144,815)	(103.3)	0.0003	(0.0069)	0.0072	(104.4)
22 COMPANY USE	2,866,770	3,509,127	(642,357)	(18.3)	(116,427)	(144,000)	27,573	(19.2)	0.0076	0.0092	(0.0016)	(17.4)
23 T & D LOSSES	59,416,087	53,867,853	5,548,234	10.3	(2,413,032)	(2,183,046)	(229,986)	10.5	0.1575	0.1413	0.0162	11.5
24 ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 4)	991,315,297	994,172,811	(2,857,514)	(0.3)	37,725,275	38,130,585	(405,310)	(1.1)	2.6277	2.6073	0.0204	0.8
25 WHOLESALE KWH SALES (EXCLUDING SUPPLEMENTAL SALES)	(23,360,110)	(26,252,740)	2,892,630	(11.0)	(893,156)	(1,014,477)	121,321	(12.0)	2.6155	2.5878	0.0277	1.1
26 JURISDICTIONAL KWH SALES	967,955,187	967,920,071	35,116	0.0	36,832,119	37,116,108	(283,989)	(0.8)	2.6280	2.6078	0.0202	0.8
27 JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00235	970,220,678	972,856,464	(2,635,786)	(0.3)	36,832,119	37,116,108	(283,989)	(0.8)	2.6342	2.6211	0.0131	0.5
28 PRIOR PERIOD TRUE-UP	(1,500,794)	23,640,300	(25,141,094)	(106.4)	36,832,119	37,116,108	(283,989)	(0.8)	(0.0041)	0.0637	(0.0678)	(106.4)
28a MARKET PRICE TRUE-UP	0	0	0	0.0	36,832,119	37,116,108	(283,989)	(0.8)	0.0000	0.0000	0.0000	0.0
28b RECOVERY OF PRIOR PERIOD NUCLEAR REPLACEMENT COST	0	0	0	0.0	36,832,119	37,116,108	(283,989)	(0.8)	0.0000	0.0000	0.0000	0.0
29 TOTAL JURISDICTIONAL FUEL COST	968,719,884	996,496,764	(27,776,880)	(2.8)	36,832,119	37,116,108	(283,989)	(0.8)	2.6301	2.6848	(0.0547)	(2.0)
30 REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
31 FUEL COST ADJUSTED FOR TAXES									2.6320	2.6867	(0.0547)	(2.0)
32 GPIF	266,918	266,919			36,832,119	37,116,108			0.0007	0.0007	0.0000	100.0
33 TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									2.633	2.687	(0.055)	(2.0)

CALCULATION OF TRUE-UP AND INTEREST PROVISION

FLORIDA POWER CORPORATION

DECEMBER 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
A .	FUEL COSTS AND NET POWER TRANSACTIONS								
1 .	FUEL COST OF SYSTEM NET GENERATION	$65,046,291	$63,869,321	$1,176,970	1.8	$855,890,122	$848,829,151	$7,060,971	0.8
1a.	NUCLEAR FUEL DISPOSAL COST	$554,220	543,990	10,230	1.9	6,342,975	6,164,382	178,593	2.9
1b.	NUCLEAR DECOM & DECON	$4,192	0	4,192	100.0	1,729,044	0	1,729,044	100.0
2 .	FUEL COST OF POWER SOLD	($4,485,860)	(3,430,946)	(1,054,914)	30.8	(25,637,250)	(34,059,150)	8,421,900	(24.7)
2a.	GAIN ON POWER SALES	($1,718,194)	(234,681)	(1,483,513)	632.1	(5,628,586)	(4,765,728)	(862,858)	18.1
3 .	FUEL COST OF PURCHASED POWER	$4,526,524	5,117,369	(590,845)	(11.6)	57,767,866	59,300,216	(1,532,350)	(2.6)
3a.	ENERGY PAYMENTS TO QUALIFYING FAC.	$14,885,690	12,357,123	2,528,567	20.5	159,374,840	158,644,508	730,332	0.5
3b.	DEMAND & NON FUEL COST OF PURCH POWER	$0	0	0	0.0	0	0	0	0.0
4 .	ENERGY COST OF ECONOMY PURCHASES	$489,595	1,348,448	(858,853)	(63.7)	40,195,373	20,107,161	20,088,212	99.9
5 .	TOTAL FUEL & NET POWER TRANSACTIONS	79,302,458	79,570,624	(268,166)	(0.3)	1,090,034,384	1,054,220,540	35,813,843	3.4
6 .	ADJUSTMENTS TO FUEL COST:								
6a.	FUEL COST OF SUPPLEMENTAL SALES	($4,429,877)	(2,507,076)	(1,922,801)	76.7	(68,144,269)	(71,009,729)	2,865,460	(4.0)
6b.	OTHER- JURISDICTIONAL ADJUSTMENTS (see detail below)	($2,171,796)	734,000	(2,905,796)	(395.9)	(30,574,817)	10,962,000	(41,536,817)	(378.9)
6c.	OTHER - PRIOR PERIOD ADJUSTMENT	$0	0	0	0.0	0	0	0	0.0
7 .	ADJUSTED TOTAL FUEL & NET PWR TRNS	$72,700,785	$77,797,548	($5,096,763)	(6.6)	$991,315,297	$994,172,811	($2,857,514)	(0.3)
		$0							
	FOOTNOTE: DETAIL OF LINE 6B ABOVE								
	INSPECTION & FUEL ANALYSIS REPORTS (Wholesale Portion)	7,674	0	7,674		23,463	0	23,463	
	OTHER	0	0	0		0	0	0	
	UNIV.OF FL STEAM REVENUE ALLOCATION (Wholesale Portion)	1,930	0	1,930		28,290	0	28,290	
	ADD'L ADJUSTMENT FOR 516.13 CLEANUP	(4,192)	0	(4,192)		(50,055)	1,683,000	(1,733,055)	
	GAS CONVERSION PROJECTS. (DEPRECIATION & RETURN)	50,274	53,000	(2,726)		1,508,820	1,551,000	(42,180)	
	EMISSIONS	1,136,008	681,000	455,008		8,933,684	7,728,000	1,205,684	
	TANK BOTTOM ADJUSTMENT (Grossed up)	0	0	0		(30,055)	0	(30,055)	
	2001 FPSC FUEL AUDIT ADJ (GROSSED UP)	0	0	0		(117,296)	0	(117,296)	
	TIGER BAY NET GENERATION	(3,363,490)	0	(3,363,490)		(40,871,668)	0	(40,871,668)	
	SUBTOTAL LINE 6B SHOWN ABOVE	($2,171,796)	734,000	(2,905,796)		(30,574,817)	10,962,000	(41,536,817)	

CALCULATION OF TRUE-UP AND INTEREST PROVISION
FLORIDA POWER CORPORATION
DECEMBER 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
B .	SALES REVENUES (EXCLUDE REVENUE TAXES)								
1 .	JURISDICTIONAL SALES REVENUE								
1a.	BASE RATE INTERIM REFUND	(3,242,375)	$0	($3,242,375)	0.0	(35,000,000)	$0	($35,000,000)	0.0
1b.	FUEL RECOVERY REVENUE	70,100,480	76,448,251	(6,347,771)	(8.3)	937,157,784	996,762,732	(59,604,948)	(6.0)
1c.	JURISDICTIONAL FUEL REVENUE	70,100,480	76,448,251	(6,347,771)	(8.3)	937,157,784	996,762,732	(59,604,948)	(6.0)
1d.	NON FUEL REVENUE	133,133,521	145,519,935	(12,386,414)	(8.5)	1,786,437,004	1,905,476,735	(119,039,731)	(6.3)
1e.	TOTAL JURISDICTIONAL SALES REVENUE	199,991,626	221,968,186	(21,976,560)	(9.9)	2,688,594,788	2,902,239,467	(213,644,679)	(7.4)
2 .	NON JURISDICTIONAL SALES REVENUE	14,207,956	9,804,321	4,403,635	44.9	199,097,068	187,522,574	11,574,494	6.2
3 .	TOTAL SALES REVENUE	$214,199,582	$231,772,507	($17,572,925)	(7.6)	$2,887,691,856	$3,089,762,041	($202,070,185)	(6.5)
C .	KWH SALES								
1 .	JURISDICTIONAL SALES	2,829,794,564	2,846,677,000	(16,882,436)	(0.6)	36,832,117,253	37,116,108,000	(283,990,747)	(0.8)
2 .	NON JURISDICTIONAL (WHOLESALE) SALES	55,730,311	70,909,000	(15,178,689)	(21.4)	893,156,467	1,014,477,000	(121,320,533)	(12.0)
3 .	TOTAL SALES	2,885,524,875	2,917,586,000	(32,061,125)	(1.1)	37,725,273,720	38,130,585,000	(405,311,280)	(1.1)
4 .	JURISDICTIONAL SALES % OF TOTAL SALES	98.07	97.57	0.50	0.5	97.63	97.34	0.29	0.3

CALCULATION OF TRUE-UP AND INTEREST PROVISION
FLORIDA POWER CORPORATION
DECEMBER 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
D .	TRUE UP CALCULATION								
1 .	JURISDICTIONAL FUEL REVENUE (LINE B1c)	$70,100,479.98	$76,446,251	($6,347,771)	(8.3)	$937,157,783.56	$996,762,732	($59,604,948)	(6.0)
2 .	ADJUSTMENTS: PRIOR PERIOD ADJ	0.00	0	0	0.0	0.00	0	0	0.0
2a.	TRUE UP PROVISION	23,171,068.79	(1,970,025)	25,141,094	(1,276.2)	1,500,793.79	(23,640,300)	25,141,094	(106.4)
2b.	INCENTIVE PROVISION	(22,242.17)	(22,246)	4	(0.0)	(266,917.92)	(266,919)	1	0.0
2c.	OTHER: MARKET PRICE TRUE UP	0.00	0	0	0.0	0.00	0	0	0.0
3 .	TOTAL JURISDICTIONAL FUEL REVENUE	93,249,306.60	74,455,980	18,793,327	25.2	938,391,659.43	972,855,513	(34,463,854)	(3.5)
4 .	ADJ TOTAL FUEL & NET PWR TRNS (LINE A7)	72,700,785.14	77,797,548	(5,096,763)	(6.6)	991,315,297.44	994,172,811	(2,857,514)	(0.3)
5 .	JURISDICTIONAL SALES % OF TOT SALES (LINE C4)	96.07	97.57	0.50	0.5				
6 .	JURISDICTIONAL FUEL & NET POWER TRANSACTIONS (LINE D4 * LINE D5 * .235% "LINE LOSSES")	71,465,209.49	76,293,882	(4,828,673)	(6.3)	970,220,678.11	972,856,464	(2,635,786)	(0.3)
7 .	TRUE UP PROVISION FOR THE MONTH OVER/(UNDER) COLLECTION (LINE D3 - D6)	21,784,097.11	(1,837,902)	23,621,999	0.0	(31,829,018.68)	(951)	(31,828,068)	0.0
8 .	INTEREST PROVISION FOR THE MONTH (LINE E10)	(33,435.49)				143,306.29			
9 .	TRUE UP & INT PROVISION BEG OF MONTH/PERIOD	(30,265,305.18)				1,500,793.82			
10.	TRUE UP COLLECTED (REFUNDED)	(23,171,068.79)				(1,500,793.79)	23,640,300	(25,141,094)	0.0
11.	END OF PERIOD TOTAL NET TRUE UP (LINES D7 + D8 + D9 + D10)	(31,685,712.35)				(31,685,712.54)			
12.	OTHER:								
					0.19				
13.	END OF PERIOD TOTAL NET TRUE UP (LINES D11 + D12)	(31,685,712.35)				(31,685,712.54)			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
FLORIDA POWER CORPORATION
DECEMBER 2002

		CURRENT MONTH				PERIOD TO DATE		
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE
E .	INTEREST PROVISION							
1 .	BEGINNING TRUE UP (LINE D9)	($30,265,305)	N/A	--	--			
2 .	ENDING TRUE UP (LINES D7 + D9 + D10 +D12)	(31,652,277)	N/A	--	--		NOT	
3 .	TOTAL OF BEGINNING & ENDING TRUE UP	(61,917,582)	N/A	--	--			
4 .	AVERAGE TRUE UP (50% OF LINE E3)	(30,958,791)	N/A	--	--			
5 .	INTEREST RATE - FIRST DAY OF REPORTING MONTH	1.300	N/A	--	--			
6 .	INTEREST RATE - FIRST DAY OF SUBSEQUENT MONTH	1.290	N/A	--	--			
7 .	TOTAL (LINE E5 + LINE E6)	2.590	N/A	--	--		APPLICABLE	
8 .	AVERAGE INTEREST RATE (50% OF LINE E7)	1.295	N/A	--	--			
9 .	MONTHLY AVERAGE INTEREST RATE (LINE E8/12)	0.108	N/A	--	--			
10.	INTEREST PROVISION (LINE E4 * LINE E9)	($33,435)	N/A	--	--			

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA
Schedule A-3

FUEL COST OF SYSTEM		ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
NET GENERATION ($)					
1	HEAVY OIL	221,008,292	210,464,501	10,543,791	5.0%
2	LIGHT OIL	52,447,821	56,055,260	-3,607,439	-6.4%
3	COAL	322,518,187	360,647,177	-38,128,990	-10.6%
4	GAS	237,581,107	199,094,514	38,486,593	19.3%
5	NUCLEAR	22,334,715	22,567,698	-232,983	-1.0%
6					
7					
8	TOTAL ($)	855,890,122	848,829,150	7,060,972	0.8%
SYSTEM NET GENERATION (MWH)					
9	HEAVY OIL	6,261,481	6,351,294	-89,813	-1.4%
10	LIGHT OIL	683,473	670,623	12,850	1.9%
11	COAL	14,406,461	15,032,797	-626,336	-4.2%
12	GAS	6,429,397	3,998,303	2,431,094	60.8%
13	NUCLEAR	6,700,267	6,592,923	107,344	1.6%
14					
15					
16	TOTAL (MWH)	34,481,079	32,645,940	1,835,139	5.6%
UNITS OF FUEL BURNED					
17	HEAVY OIL (BBL)	9,850,631	9,994,584	-143,953	-1.4%
18	LIGHT OIL (BBL)	1,547,027	1,638,169	-91,142	-5.6%
19	COAL (TON)	5,564,857	5,703,539	-138,682	-2.4%
20	GAS (MCF)	56,163,957	40,339,721	15,824,236	39.2%
21	NUCLEAR (MMBTU)	68,947,790	68,386,964	560,826	0.8%
22					
23					

FLORIDA POWER CORPORATION
GENERATING SYSTEM COMPARATIVE DATA
Schedule A-3

	FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
	BTUS BURNED (MILLION BTU)				
24	HEAVY OIL	64,868,317	64,964,785	-96,468	-0.1%
25	LIGHT OIL	8,977,691	9,501,385	-523,694	-5.5%
26	COAL	138,370,054	143,370,145	-5,000,091	-3.5%
27	GAS	58,186,575	40,339,721	17,846,854	44.2%
28	NUCLEAR	68,947,790	68,386,964	560,826	0.8%
29					
30					
31	TOTAL (MILLION BTU)	339,350,427	326,563,000	12,787,427	3.9%
	GENERATION MIX (% MWH)				
32	HEAVY OIL	18.2	19.46	-1.3	-6.7%
33	LIGHT OIL	2.0	2.05	-0.1	-3.5%
34	COAL	41.8	46.05	-4.3	-9.3%
35	GAS	18.6	12.25	6.4	52.2%
36	NUCLEAR	19.4	20.20	-0.8	-3.8%
37					
38					
39	TOTAL (% MWH)	100.0	100.0	0.0	0.0%

FLORIDA POWER CORPORATION

GENERATING SYSTEM COMPARATIVE DATA

Schedule A-3

	FUEL COST OF SYSTEM	ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
	FUEL COST PER UNIT ($)				
40	HEAVY OIL ($/BBL)	22.44	21.06	1.38	6.5%
41	LIGHT OIL ($/BBL)	33.90	34.22	-0.32	-0.9%
42	COAL ($/TON)	57.96	63.23	-5.28	-8.3%
43	GAS ($/MCF)	4.23	4.94	-0.71	-14.3%
44	NUCLEAR ($/MBTU)	0.32	0.33	-0.01	-1.8%
45					
46					
	FUEL COST PER MILLION BTU ($/MILLION BTU)				
47	HEAVY OIL	3.41	3.24	0.17	5.2%
48	LIGHT OIL	5.84	5.90	-0.06	-1.0%
49	COAL	2.33	2.52	-0.18	-7.3%
50	GAS	4.08	4.94	-0.85	-17.3%
51	NUCLEAR	0.32	0.33	-0.01	-1.8%
52					
53					
54	SYSTEM ($/MBTU)	2.52	2.60	-0.08	-3.0%
	BTU BURNED PER KWH (BTU/KWH)				
55	HEAVY OIL	10,360	10,229	131	1.3%
56	LIGHT OIL	13,135	14,168	-1,033	-7.29%
57	COAL	9,605	9,537	68	0.7%
58	GAS	9,050	10,089	-1,039	-10.3%
59	NUCLEAR	10,290	10,373	-82	-0.8%
60					
61					
62	SYSTEM (BTU/KWH)	9,842	10,003	-162	-1.6%

FLORIDA POWER CORPORATION

GENERATING SYSTEM COMPARATIVE DATA

Schedule A-3

FUEL COST OF SYSTEM		ACTUAL	ESTIMATED	DIFFERENCE	DIFFERENCE (%)
GENERATED FUEL COST PER KWH (CENTS/KWH)					
63	HEAVY OIL	3.53	3.31	0.22	6.5%
64	LIGHT OIL	7.67	8.36	-0.68	-8.2%
65	COAL	2.24	2.40	-0.16	-6.7%
66	GAS	3.70	4.98	-1.28	-25.8%
67	NUCLEAR	0.33	0.34	-0.01	-2.6%
68					
69					
70	SYSTEM (CENTS/KWH)	2.48	2.60	-0.12	-4.5%

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FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
Schedule A-4

01-2002 Thru 12-2002
FINAL

(A) PLANT	(B) NET CAP (MW)	(C) NET GENERATION (MWH)	(D) CAP FAC (%)	(E) EQUIV AVAIL FAC (%)	(F) NET OUTPUT FAC (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURN (UNITS)	(J) FUEL HEAT VALUE (MMBTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH CENTS/KWH	(N) FUEL COST PER UNIT ($)
Steam													
Anclote													
UNIT 1	510	1,934,363.00	43			10,311				19,944,585	70,263,283	3.632	
		1,801,431.76					#6	2,818,487	6.590	18,573,974	64,583,421	3.585	22.914
		131,045.26					GS	1,305,708	1.035	1,351,165	5,346,812	4.080	4.095
		1,885.98					#2	3,359	5.789	19,446	333,050	17.659	99.152
UNIT 2	509	2,200,597.00	49			10,109				22,245,265	77,555,019	3.524	
		2,111,946.13					#6	3,237,361	6.595	21,349,116	73,459,690	3.478	22.691
		86,514.28					GS	844,689	1.035	874,550	3,727,515	4.309	4.413
		2,136.59					#2	3,732	5.787	21,598	367,814	17.215	98.557
Bartow													
UNIT 1	122	458,221.00	43			10,606				4,859,917	15,330,408	3.346	
		457,726.51					#6	739,597	6.564	4,854,672	15,302,443	3.343	20.690
		0.00					GS	0	0.000	0	-691	0.000	
		494.49					#2	901	5.821	5,245	28,656	5.795	31.805
UNIT 2	120	549,471.00	52			10,728				5,894,850	19,221,933	3.498	
		549,471.00					#6	897,317	6.569	5,894,850	19,221,933	3.498	21.422
UNIT 3	206	1,078,406.00	60			10,045				10,832,095	36,239,912	3.361	
		964,658.06					#6	1,474,317	6.572	9,689,549	31,437,443	3.259	21.323
		113,747.94					GS	1,105,237	1.034	1,142,546	4,802,469	4.222	4.345
Crystal River 1 & 2													
UNIT 1	381	2,579,432.00	77			9,800				25,277,727	54,028,830	2.095	
		6,242.52					#2	10,521	5.815	61,175	310,000	4.966	29.465
		2,573,189.48					CA	1,001,051	25.190	25,216,552	53,718,830	2.088	53.662
UNIT 2	477	3,004,112.00	72			9,813				29,480,514	62,975,708	2.096	
		5,611.50					#2	9,471	5.814	55,068	277,583	4.947	29.309
		2,998,500.50					CA	1,168,399	25.184	29,425,446	62,698,125	2.091	53.662

FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
Schedule A-4

(A) PLANT	(B) NET CAP (MW)	(C) NET GENERATION (MWH)	(D) CAP FAC (%)	(E) EQUIV AVAIL FAC (%)	(F) NET OUTPUT FAC (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURN (UNITS)	(J) FUEL HEAT VALUE (MMBTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH CENTS/KWH	(N) FUEL COST PER UNIT ($)
Crystal River 4 & 5													
UNIT 4	717	4,194,801.00	67			9,460				39,681,197	98,429,908	2.346	
		21,636.73					#2	35,234	5.809	204,675	1,194,035	5.519	33.889
		4,173,164.27					CA	1,598,018	24.703	39,476,522	97,235,873	2.330	60.848
UNIT 5	725	4,687,322.00	74			9,494				44,502,817	110,710,345	2.362	
		26,466.66					#2	43,251	5.810	251,282	1,844,986	6.971	42.658
		4,660,855.34					CA	1,792,389	24.689	44,251,534	108,865,359	2.336	60.738
Suwannee Plant													
UNIT 1	33	113,706.00	39			12,771				1,452,116	5,506,195	4.842	
		103,823.40					#6	201,206	6.590	1,325,907	4,985,307	4.802	24.777
		9,746.93					GS	121,098	1.028	124,476	509,879	5.231	4.210
		135.67					#2	336	5.157	1,733	11,008	8.114	32.762
UNIT 2	32	119,669.00	43			12,294				1,471,239	5,559,293	4.646	
		119,572.12					#6	222,951	6.594	1,470,048	5,552,636	4.644	24.905
		96.88					#2	204	5.839	1,191	6,657	6.871	32.632
UNIT 3	81	272,293.00	38			11,344				3,088,915	12,312,372	4.522	
		150,756.99					#6	259,395	6.593	1,710,200	6,465,419	4.289	24.925
		121,370.71					GS	1,339,818	1.028	1,376,840	5,836,390	4.809	4.356
		165.31					#2	321	5.842	1,875	10,562	6.389	32.903
TOTAL	3,913	21,192,393.00				9,849				208,731,236	568,133,204	2.681	
Nuclear													
Crystal River 3													
UNIT 3	782	6,700,267.00	98			10,291				68,949,397	22,343,550	0.333	
		0					NF	68,947,790	1.000	68,947,790	22,334,715	0.000	0.324
		0					#2	287	5.601	1,608	8,836	0.000	30.787
TOTAL	782	6,700,267.00				10,291				68,949,397	22,343,550	0.333	
Gas Turbine													
Avon Park Peaker	56	25,470.00	5			16,470				419,499	1,971,810	7.742	
		6,347.69					#2	17,993	5.811	104,548	622,518	9.807	34.598
		19,122.31					GS	304,036	1.036	314,950	1,349,292	7.056	4.438
Bartow Peaker	205	97,937.00	5			16,575				1,623,301	7,901,573	8.068	

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FLORIDA POWER CORPORATION
SYSTEM NET GENERATION AND FUEL COST
Schedule A-4

01-2002 Thru 12-2002
FINAL

(A) PLANT	(B) NET CAP (MW)	(C) NET GENERATION (MWH)	(D) CAP FAC (%)	(E) EQUIV AVAIL FAC (%)	(F) NET OUTPUT FAC (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURN (UNITS)	(J) FUEL HEAT VALUE (MMBTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH CENTS/KWH	(N) FUEL COST PER UNIT ($)
		31,416.82					#2	89,867	5.794	520,732	3,086,999	9.826	34.351
		66,520.18					GS	1,065,096	1.035	1,102,569	4,814,573	7.238	4.520
Bayboro Peaker	200	79,536.00	5			13,285				1,056,656	5,438,471	6.838	
		79,536.00					#2	181,414	5.825	1,056,656	5,438,471	6.838	29.978
Debary Peaker	644	514,800.00	9			13,888				7,149,320	35,065,769	6.812	
		194,492.17					#2	464,415	5.816	2,701,023	15,993,399	8.223	34.438
		320,307.83					GS	4,287,070	1.038	4,448,297	19,072,370	5.954	4.449
Higgins Peaker	126	71,776.00	7			16,688				1,197,832	5,154,938	7.182	
		0.00					#2	0	0.000	0	0	0.000	0.000
		71,776.00					GS	1,156,382	1.036	1,197,832	5,154,938	7.182	4.458
Hines Energy	506	3,034,621.00	68			7,358				22,327,606	93,039,642	3.066	
		0.00					#2	0	0.000	0	920	0.000	0.000
		3,034,621.00					GS	21,529,211	1.037	22,327,606	93,038,722	3.066	4.322
Intercession City Peaker	1,017	811,377.00	9			13,124				10,648,753	50,036,423	6.167	
		200,595.24					#2	453,128	5.810	2,632,672	15,136,345	7.546	33.404
		610,781.76					GS	7,734,737	1.036	8,016,081	34,900,078	5.714	4.512
Rio Pinar Peaker	15	3,352.00	3			17,157				57,511	357,156	10.655	
		3,352.00					#2	9,897	5.811	57,511	357,156	10.655	36.087
Suwannee Peaker	173	119,783.00	8			14,061				1,684,324	7,880,916	6.579	
		37,468.66					#2	90,113	5.847	526,864	2,956,073	7.889	32.804
		82,314.34					GS	1,125,606	1.028	1,157,460	4,924,843	5.983	4.375
Tiger Bay Cogen	215	1,412,706.00	75			7,777				10,987,103	40,871,588	2.893	
		1,412,706.00					GS	10,592,735	1.037	10,987,103	40,871,588	2.893	3.858
Turner Peaker	166	48,715.00	3			15,453				752,789	4,462,752	9.161	
		48,715.00					#2	129,538	5.811	752,789	4,462,752	9.161	34.451
Univ of Florida Cogen	48	368,346.00	88			10,296				3,765,100	13,232,329	3.592	
		368,346.00					GS	3,652,534	1.031	3,765,100	13,232,329	3.592	3.623
TOTAL	3,371	6,588,419.00				9,364				61,669,794	265,413,368	4.028	
SYSTEM TOTAL	8,066	34,481,079.00				9,842				339,350,427	855,890,122	2.482	

NOTE: Includes the following aerial survey adjustment:

FLORIDA POWER CORPORATION

SYSTEM NET GENERATION AND FUEL COST

Schedule A-4

(A) PLANT	(B) NET CAP (MW)	(C) NET GENERATION (MWH)	(D) CAP FAC (%)	(E) EQUIV AVAIL FAC (%)	(F) NET OUTPUT FAC (%)	(G) AVG NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURN (UNITS)	(J) FUEL HEAT VALUE (MMBTU/UNIT)	(K) FUEL BURNED (MMBTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH CENTS/KWH	(N) FUEL COST PER UNIT ($)
Plant	Tons	Dollars		MMBTU									
Crystal River 4 & 5	2,703	157,922.98		66,088.35									

FLORIDA POWER CORPORATION
SYSTEM GENERATION FUEL COST
Schedule A-5

			Actual	Estimated	Difference	Difference (%)
HEAVY OIL	1	PURCHASES				
	2	Units (BBL)	9,736,801	9,994,584	-257,783	-2.6%
	3	Unit Cost ($/BBL)	23.42	20.53	2.88	14.0%
	4	Amount ($)	228,002,071	205,229,504	22,772,567	11.1%
	5	BURNED				
	6	Units (BBL)	9,850,631	9,994,584	-143,953	-1.4%
	7	Unit Cost ($/BBL)	22.44	21.06	1.38	6.5%
	8	Amount ($)	221,008,292	210,464,501	10,543,791	5.0%
	9	ADJUSTMENTS				
	10	Units (BBL)	-8,026			
	11	Amount ($)	-592,108			
	12	ENDING INVENTORY				
	13	Units (BBL)	1,090,585	800,000	290,585	36.3%
	14	Unit Cost ($/BBL)	25.38	20.99	4.39	20.9%
	15	Amount ($)	27,675,746	16,792,128	10,883,618	64.8%
	16					
	17	DAYS SUPPLY	0	0	0	0.0%
LIGHT OIL	18	PURCHASES				
	19	Units (BBL)	1,552,026	1,638,169	-86,143	-5.3%
	20	Unit Cost ($/BBL)	33.20	34.20	-1.00	-2.9%
	21	Amount ($)	51,528,840	56,028,333	-4,499,493	-8.0%
	22	BURNED				
	23	Units (BBL)	1,547,027	1,638,169	-91,142	-5.6%
	24	Unit Cost ($/BBL)	33.90	34.22	-0.32	-0.9%
	25	Amount ($)	52,447,821	56,055,260	-3,607,439	-6.4%
	26	ADJUSTMENTS				
	27	Units (BBL)	28,703			
	28	Amount ($)	-61,579			
	29	ENDING INVENTORY				
	30	Units (BBL)	867,360	550,000	317,360	57.7%
	31	Unit Cost ($/BBL)	32.10	34.63	-2.53	-7.3%
	32	Amount ($)	27,843,099	19,048,288	8,794,811	46.2%
	33					
	34	DAYS SUPPLY	0	0	0	0.0%

FLORIDA POWER CORPORATION
SYSTEM GENERATION FUEL COST
Schedule A-5

			Actual	Estimated	Difference	Difference (%)
COAL	35	PURCHASES				
	36	Units (TON)	5,737,237	5,900,000	-162,763	-2.8%
	37	Unit Cost ($/TON)	58.53	63.53	-5.00	-7.9%
	38	Amount ($)	335,794,771	374,803,580	-39,008,809	-10.4%
	39	BURNED				
	40	Units (TON)	5,564,857	5,703,539	-138,682	-2.4%
	41	Unit Cost ($/TON)	57.96	63.23	-5.28	-8.3%
	42	Amount ($)	322,518,187	360,647,177	-38,128,990	-10.6%
	43	ADJUSTMENTS				
	44	Units (TON)	0			
	45	Amount ($)	-112			
	46	ENDING INVENTORY				
	47	Units (TON)	954,685	809,368	145,317	18.0%
	48	Unit Cost ($/TON)	58.11	63.77	-5.66	-8.9%
	49	Amount ($)	55,476,745	51,617,251	3,859,494	7.5%
	50					
	51	DAYS SUPPLY	0	0	0	0.0%
OTHER	52					
	53					
	54					
	55					
	56					
	57					
	58					
	59					
	60					
	61					
	62					
	63					
	64					
	65					

FLORIDA POWER CORPORATION
SYSTEM GENERATION FUEL COST
Schedule A-5

			Actual	Estimated	Difference	Difference (%)
GAS	66	BURNED				
	67	Units (MCF)	56,163,957	40,339,721	15,824,236	39.2%
	68	Unit Cost ($/MCF)	4.23	4.94	-0.71	-14.3%
	69	Amount ($)	237,581,107	199,094,514	38,486,593	19.3%
NUCLEAR	70	BURNED				
	71	Units (MM BTU)	68,947,790	63,001,964	5,945,826	9.4%
	72	Unit Cost ($/MM BTU)	0.32	0.36	-0.03	-9.6%
	73	Amount ($)	22,334,715	22,567,698	-232,983	-1.0%

NOTE: Purchase dollars and units do not include plant to plant transfers. See schedule A-5, Attachment #1 for detail of adjustments.

FLORIDA POWER CORPORATION
SCHEDULE A6

POWER SOLD
FOR THE MONTH OF:
DEC 2002

(1) SOLD TO	(2) TYPE & SCHEDULE	(3) TOTAL KWH SOLD (000)	(4) KWH WHEELED FROM OTHER SYSTEMS (000)	(5) KWH FROM OWN GENERATION (000)	(5a) FUEL COST C/KWH	(5b) TOTAL COST C/KWH	(7) FUEL ADJ. TOTAL $	(8) TOTAL COST $	(9) 80% GAIN ON ECONOMY ENERGY SALES $	(10) NONFUEL AMOUNT FOR FUEL ADJ $
ESTIMATED		100,321	0	100,321	3.42	3.42	3,430,946	3,430,946	0	234,681
ACTUAL:										
0	0	0	0				-	-		-
Entergy Services, Inc.	Schedule C	100	0	100	1.642	2.971	1,641.92	2,971.26	Not Applicable	1,329.34
The Energy Authority	Schedule C	25	0	25	1.597	3.472	399.26	868.01	"	468.75
0	0	0	0	-	-	-	-	-	"	-
SubTotal - Gain on Economy Energy Sales		125		125			2,041.19	3,839.28	-	1,798.09
0	0	0	-				-	-		
SEMINOLE	LOAD FOLLOWING	4,052	-	4,052	7.38	7.38	298,848.20	298,848.20	Not Applicable	-
Cargill Power Markets, LLC	MR-1	2,934	-	2,934	2.09	2.81	61,326.96	82,440.72	"	21,113.76
City of New Smyrna Beach, FL	Schedule H	0	-	-	-	-	-	-	"	-
City of New Smyrna Beach, FL	Schedule I	0	-	-	-	-	6,926.64	6,926.64	"	-
City of New Smyrna Beach, FL	Schedule OS	179	-	179	3.49	4.75	6,247.28	8,504.10	"	2,256.82
City of Tallahassee, FL	Schedule OS	120	-	120	1.61	2.88	1,936.41	3,455.71	"	1,519.30
Duke Energy Trading & Market	Schedule OS	499	-	499	3.12	4.73	15,580.51	23,603.58	"	8,023.07
Florida Municipal Power Agenc	CR-1	1,780	-	1,780	2.75	3.90	48,988.29	69,423.14	"	20,434.85
Florida Power & Light Company	*Contract*	500	-	500	2.16	3.56	10,782.19	17,800.19	"	7,018.00
Florida Power & Light Company	CR-1	1,800	-	1,800	1.57	1.88	28,265.33	33,798.66	"	5,533.33
Florida Power & Light Company	Schedule OS	21,925	-	21,925	1.82	2.17	399,950.05	474,876.96	"	74,926.92
LG & E Energy Marketing, Inc.	Schedule OS	6,350	-	6,350	2.54	4.34	161,567.57	275,669.87	"	114,102.30
Morgan Stanley Capital Group,	MR-1	600	-	600	1.07	1.54	6,427.51	9,259.51	"	2,832.00
Oglethorpe Power Corporation	MR-1	2,185	-	2,185	2.48	3.74	54,280.07	81,634.77	"	27,354.70
Oglethorpe Power Corporation	Schedule R	205	-	205	2.94	4.43	6,034.54	9,075.59	"	3,041.05
Orlando Utilities Commission	Schedule OS	4,815	-	4,815	2.35	2.80	113,336.50	134,968.31	"	21,631.81
Reedy Creek Improvement Dist	Schedule OS	6,550	-	6,550	1.62	2.19	106,058.54	143,456.90	"	37,398.36
Seminole Electric Cooperative,	CR-1	50,354	-	50,354	2.40	3.35	1,210,370.26	1,687,752.56	"	477,382.30
Seminole Electric Cooperative,	Schedule J	4,735	-	4,735	2.44	3.66	115,382.76	173,295.79	"	57,913.03
Southern Company Services, Ir	MR-1	4,536	-	4,536	2.63	4.73	119,457.55	214,439.99	"	94,982.44
Tampa Electric Company	CR-1	58,227	-	58,227	2.55	3.71	1,484,796.23	2,158,794.31	"	673,998.08
Tennessee Valley Authority	MR-1	600	-	600	2.44	3.48	14,622.99	20,868.99	"	6,246.00
The Energy Authority	MR-1	4,835	-	4,835	2.66	3.23	128,631.56	156,157.00	"	27,525.44
The Energy Authority	*Schedule OS*	2,703	-	2,703	2.98	4.20	80,430.48	113,562.58	"	33,132.10
0	0	0	-	-	-	-	-	-	"	-
ADJUSTMENTS										
0	0	0	-	-	-	-	-	-	0	-
Cargill Power Markets, LLC	MR-1	100	-	100	3.57	1.60	3,570.00	1,600.00	"	(1,970.00)
LG & E Energy Marketing, Inc.	Schedule OS	30	-	30	2.97	5.00	891.00	1,500.00	"	609.00
Oglethorpe Power Corporation	Schedule J	-30	-	(30)	2.97	5.00	(891.00)	(1,500.00)	"	(609.00)
0	0	0	-	-	-	-	-	-	"	-
SubTotal - Gain on Other Power Sales		180,584		180,584			4,483,818.42	6,200,214.08	-	1,716,395.66
CURRENT MONTH TOTAL		180,709		180,709	2.482	3.433	4,485,859.61	6,204,053.36	-	1,718,193.75
DIFFERENCE		80,388		80,388	-0.938	0.013	1,054,913.61	2,773,107.36	-	1,483,512.75
DIFFERENCE %		80.10%		80.10%	-27.40%	0.40%	30.70%	80.80%	0.00%	632.10%
CUMULATIVE ACTUAL		1,006,540		1,006,540	2.547	3.106	25,637,249.83	31,265,836.07	-	5,628,586.24
CUMULATIVE ESTIMATED		1,035,000		1,035,000	3.291	3.291	34,059,150.00	34,059,150.00	-	4,765,728.00
CUMULATIVE DIFFERENCE		(28,460)		(28,460)	-0.744	-0.185	(8,421,900.17)	(2,793,313.93)	-	862,858.24
CUMULATIVE DIFFERENCE %		-2.75%		-2.75%	-22.61%	-5.62%	-24.73%	-8.20%	0.00%	

FLORIDA POWER CORPORATION
SCHEDULE A7

PURCHASED POWER
EXCLUSIVE OF ECONOMY PURCHASES
FOR THE MONTH OF:
DEC 2002

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
PURCHASED FROM	TYPE & SCHEDULE	TOTAL KWH PURCHASED (000)	KWH FOR OTHER UTILITIES (000)	KWH FOR INTERRUPTIBLE (000)	KWH FOR FIRM (000)	FUEL COST C/KWH	TOTAL COST C/KWH	TOTAL AMOUNT FOR FUEL ADJ $	FUEL COST $
ESTIMATED		284,493			284,493	1.799	1.799	5,117,369	5,117,369
ACTUAL									
0	0	-	-	-	-	-	0.000	-	-
Glades	Firm	8	-	-	8	8.640	8.640	691.20	691.20
Southern Company Services, Ir	Southern UPS	249,771	-	-	249,771	1.654	1.654	4,130,669.07	4,130,669.07
Tampa Electric Company	TECO AR1	15,780	-	-	15,780	3.288	3.288	518,846.40	518,846.40
0	0	-	-	-	-	-	0.000	-	-
ADJUSTMENTS									
0	0	-	0	-	-	0.000	0.000	-	-
Southern Company Services, Ir	Southern UPS	-	0	-	-	0.000	0.000	(232,552.96)	(232,552.96)
TECO Energy	TECO AR1	-	0	-	-	0.000	0.000	108,870.00	108,870.00
0	0	-	0	-	-	0.000	0.000	-	-
CURRENT MONTH TOTAL		265,559			265,559	1.705	1.705	4,526,523.71	4,526,523.71
DIFFERENCE		(18,934)			(18,934)	(0.094)	(0.094)	(590,845.29)	(590,845.29)
DIFFERENCE %		(6.7)			(6.7)	(5.2)	(5.2)	(11.5)	(11.5)
CUMULATIVE ACTUAL		3,202,373			3,202,373	1.804	1.804	57,767,866.25	57,767,866.25
CUMULATIVE ESTIMATED		3,319,365			3,319,365	1.786	1.786	59,300,213.00	59,300,213.00
CUMULATIVE DIFFERENCE		(116,992)			(116,992)	0.018	0.018	(1,532,346.75)	(1,532,346.75)
CUMULATIVE DIFFERENCE %		(3.5)			(3.5)	1.0	1.0	(2.6)	(2.6)

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FLORIDA POWER CORPORATION
SCHEDULE A8

ENERGY PAYMENT TO QUALIFYING FACILITIES
FOR THE MONTH OF:
DEC 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL KWH PURCHASED (000)	(4) KWH FOR OTHER UTILITIES (000)	(5) KWH FOR INTERRUPTIBLE (000)	(6) KWH FOR FIRM (000)	(7) ENERGY COST C/KWH	(8) TOTAL COST C/KWH	(9) TOTAL AMOUNT FOR FUEL ADJ $
ESTIMATED		505,740			505,740	2.443	2.443	12,357,123
ACTUAL								
AUBURNDALE (EL DORADO)	CO-GEN	83,514			83,514	2.935	2.935	2,451,164.26
ADJ		0			0			13,999.26
AUBURNDALE LFC POWER SYSTEMS	CO-GEN	8,303			8,303	2.179	2.179	180,930.43
ADJ		0			0			(12,208.46)
BAY COUNTY	CO-GEN	6,157			6,157	2.089	2.089	128,619.73
ADJ		0			0			(12,549.69)
CARGILL FERTILIZER	CO-GEN	8,723			8,723	1.452	1.452	126,657.96
ADJ		0			0			49,166.45
CENTRAL POWER & LIME (FLACRUSH)	CO-GEN	0			0	0.000	0.000	0.00
ADJ		0			0			0.00
CITRUS WORLD	CO-GEN	21			21	4.302	4.302	901.27
ADJ		2			2			(110.28)
JEFFERSON POWER	CO-GEN	802			802	0.000	0.000	0.00
ADJ		0			0			0.00
LAKE COUNTY	CO-GEN	7,684			7,684	2.131	2.131	163,746.04
ADJ		120			120			(14,954.62)
LAKE ORDER COGEN LIMITED	CO-GEN	52,638			52,638	3.110	3.110	1,637,041.80
ADJ		0			0			(83,319.89)
METRO-DADE COUNTY	CO-GEN	29,219			29,219	3.084	3.084	901,132.08
ADJ		0			0			101,310.24
ORANGE COGEN	CO-GEN	40,077			40,077	3.081	3.081	1,234,865.01
ADJ		0			0			(273,287.13)
ORLANDO COGEN	CO-GEN	60,359			60,359	3.090	3.090	1,865,380.60
ADJ		159			159			(85,684.90)
PASCO COGEN LIMITED	CO-GEN	49,073			49,073	1.965	1.965	964,284.45
ADJ		22			22			(145,274.38)
PASCO COUNTY RESOURCE RECOVERY	CO-GEN	17,757			17,757	2.125	2.125	377,336.25
ADJ		0			0			(32,367.22)
PCS PHOSPHATE	CO-GEN	297			297	4.402	4.402	13,072.18
ADJ		22			22			(5,595.94)
PERPETUAL ENERGY	CO-GEN	0			0	0.000	0.000	0.00
ADJ		0			0			0.00
PINELLAS COUNTY	CO-GEN	29,524			29,524	2.088	2.088	616,461.12
ADJ		0			0			(50,907.66)
POLK POWER - MULBERRY ENERGY	CO-GEN	33,854			33,854	2.384	2.384	807,071.49
ADJ		0			0			(97,699.52)
POLK POWER- ROYSTER ENERGY	CO-GEN	13,165			13,165	2.383	2.383	313,729.34
ADJ		0			0			(38,046.96)
ST. JOE PAPER	CO-GEN	0			0	0.000	0.000	0.00
ADJ		0			0			0.00
TIMBER ENERGY RESOURCES	CO-GEN	8,117			8,117	1.750	1.750	142,047.50
ADJ		0			0			0.00
U.S. AGRI-CHEMICALS	CO-GEN	3,389			3,389	4.270	4.270	144,710.30
ADJ		0			0			(20,009.53)
WHEELABRATOR RIDGE ENERGY	CO-GEN	10,258			10,258	3.312	3.312	339,744.96
ADJ		0			0			339,914.69
SUBTOTAL EXCLUDING TIGER BAY STIPULATED PAYMENTS								
CURRENT MONTH TOTAL		463,256			463,256	2.599	2.599	12,041,271.25
DIFFERENCE		(42,484)			(42,484)	0.156	0.156	(315,851.75)
DIFFERENCE %		(8.4)			(8.4)	6.4	6.4	(2.6)
TIGER BAY STIPULATED PAYMENTS								
TIGER BAY - ECOPEAT	CO-GEN	20,633			20,633	4.612	4.612	951,642.08
TIGER BAY - GENERAL PEAT	CO-GEN	88,204			88,204	2.136	2.136	1,884,182.17
TIGER BAY - TIMBER 2	CO-GEN	3,077			3,077	2.133	2.133	65,656.72
TIGER BAY - STEAM SALES	CO-GEN	0			0	0.000	0.000	(57,061.99)
TOTAL QF ENERGY PAYMENTS INCLUDING TIGER BAY								
CURRENT MONTH TOTAL		575,171			575,171	2.588	2.588	14,885,690.23
DIFFERENCE		69,431			69,431	0.145	0.145	2,528,567.23
DIFFERENCE %		13.7			13.7	5.9	5.9	20.5
CUMULATIVE ACTUAL		6,476,112			6,476,112	2.461	2.461	159,374,840.09
CUMULATIVE ESTIMATED		6,510,148			6,510,148	2.437	2.437	158,644,508.00
CUMULATIVE DIFFERENCE		(34,036)			(34,036)	0.024	0.024	730,332.09
CUMULATIVE DIFFERENCE %		(0.5)			(0.5)	1.0	1.0	0.5

FLORIDA POWER CORPORATION
SCHEDULE A9

ECONOMY ENERGY PURCHASES
INCLUDING LONG TERM PURCHASES
FOR THE MONTH OF:
DEC 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE		(3) TOTAL KWH PURCHASED (000)	(4) ENERGY COST C/KWH	(5) TOTAL AMOUNT FOR FUEL ADJ $	(6) COST IF GENERATED C/KWH	(7) COST IF GENERATED $	(8) FUEL SAVINGS $
ESTIMATED			42,139	3.200	1,348,448	3.200	1,348,448	0
ACTUAL								
	0	0	0	0	-	0	-	-
Subtotal - Energy Purchases (Broker)			-	-	0.00	-	0.00	0.00
	0	0	-		-	0.000	-	-
Southeastern Power Admin.	Hydro		3,624	1.813	65,695.67	1.813	65,695.67	-
SEMINOLE	LOAD FOLLOWING		1,270	4.892	62,128.54	4.892	62,128.54	-
Carolina Power & Light Company	Transmission Purchase		-	0.000	5,179.73	0.000	-	(5,179.73)
City of Tallahassee, FL	Transmission Purchase		-	0.000	12,606.72	0.000	-	(12,606.72)
Duke Energy Trading & Marketing, L. L. C.	Schedule OS		92	4.000	3,680.00	9.017	8,295.30	4,615.30
Duke Power Company	Transmission Purchase		-	0.000	234.91	0.000	-	(234.91)
Dynegy Power Marketing, Inc.	EEI		370	3.069	11,355.00	4.691	17,355.80	6,000.80
Exelon Generation Company, LLC	EEI		202	3.772	7,620.00	6.932	14,003.31	6,383.31
Florida Power & Light Company	Schedule OS		400	5.525	22,100.00	7.410	29,640.00	7,540.00
Florida Power & Light Company	Transmission Purchase		-	0.000	10,448.87	0.000	-	(10,448.87)
Georgia Transmission Corporation	Transmission Purchase		-	0.000	11,755.90	0.000	-	(11,755.90)
Jacksonville Electric Authority	Transmission Purchase		-	0.000	177,462.27	0.000	-	(177,462.27)
LG & E Energy Marketing, Inc.	Schedule OS		1,156	3.274	37,853.00	5.645	65,259.96	27,406.96
Seminole Electric Cooperative, Inc.	Schedule J		75	2.600	1,950.00	3.048	2,286.00	336.00
Seminole Electric Cooperative, Inc.	Transmission Purchase		-	0.000	5,399.90	0.000	-	(5,399.90)
South Carolina Electric & Gas Company	EEI		264	3.002	7,924.00	5.298	13,985.41	6,061.41
South Carolina Public Service Authority	Transmission Purchase		-	0.000	154.50	0.000	-	(154.50)
Southern Company Services, Inc.	MR-1		676	3.469	23,448.00	4.936	33,364.55	9,916.55
Southern Company Services, Inc.	Transmission Purchase		-	0.000	17,508.18	0.000	-	(17,508.18)
Tampa Electric Company	Transmission Purchase		-	0.000	938.22	0.000	-	(938.22)
	0	0	-	0.000	-	0.000	-	-
ADJUSTMENTS								
	0	0	-	-	-	-	-	-
Cargill Power Markets, LLC	MR-1		(1)	4.40	(44.00)	6.42	(64.16)	(20.16)
City of Tallahassee, FL	Transmission Purchase		-	-	1,010.36	-	-	(1,010.36)
Florida Power & Light Company	Transmission Purchase		-	-	1,485.01	-	-	(1,485.01)
Georgia Transmission Corporation	Transmission Purchase		-	-	7.83	-	-	(7.83)
Jacksonville Electric Authority	Transmission Purchase		-	-	1,309.43	-	-	(1,309.43)
Seminole Electric Cooperative, Inc.	Transmission Purchase		-	-	1.10	-	-	(1.10)
South Carolina Public Service Authority	Transmission Purchase		-	-	16.50	-	-	(16.50)
Southern Company Services, Inc.	Transmission Purchase		-	-	365.60	-	-	(365.60)
Tampa Electric Company	Transmission Purchase		-	-	(0.15)	-	-	0.15
	0	0	-	-	-	-	-	-
Subtotal - Energy Purchases (Non-Broker)			8,128	6.024	489,595.09	3.838	311,950.38	(177,644.71)
CURRENT MONTH TOTAL			8,128	6.024	489,595.09	3.838	311,950.38	(177,644.71)
DIFFERENCE			(34,011)	2.824	(858,852.91)	0.638	(1,036,497.62)	(177,644.71)
DIFFERENCE %			(80.7)	88.3	(63.7)	19.9	(76.9)	0.0
CUMULATIVE ACTUAL			774,522	5.190	40,195,372.80	6.095	47,208,646.25	7,013,273.45
CUMULATIVE ESTIMATED			678,000	2.966	20,107,161.00	2.966	20,107,161.00	
CUMULATIVE DIFFERENCE			96,522	2.224	20,088,211.80	3.129	27,101,485.25	7,013,273.45
CUMULATIVE DIFFERENCE %			14.2	75.0	99.9	105.5	134.8	

EXHIBIT 24

PROGRESS ENERGY FLORIDA
PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGEN PURCHASES)
ESTIMATED FOR THE PERIOD OF: JANUARY THROUGH DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
MONTH	NAME OF PURCHASE	TYPE & SCHEDULE	TOTAL KWH PURCHASED	KWH FOR OTHER UTILITIES	KWH FOR INTERRUPTIBLE	KWH FOR FIRM	C/KWH (A) FUEL COST	C/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJ (7) x (8)(B)
Jul-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	31,811,000			31,811,000	3.550	3.550	1,129,291
	UPS PURCHASE	UPS	247,008,000			247,008,000	1.550	1.550	3,828,624
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		278,819,000	0	0	278,819,000	1.778	1.778	4,957,915
Aug-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	37,134,000			37,134,000	3.550	3.550	1,318,257
	UPS PURCHASE	UPS	247,008,000			247,008,000	1.550	1.550	3,828,624
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		284,142,000	0	0	284,142,000	1.811	1.811	5,146,881
Sep-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	33,901,000			33,901,000	3.550	3.550	1,203,486
	UPS PURCHASE	UPS	239,040,000			239,040,000	1.550	1.550	3,705,120
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		272,941,000	0	0	272,941,000	1.798	1.798	4,908,606
Oct-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	26,093,000			26,093,000	3.550	3.550	926,302
	UPS PURCHASE	UPS	247,008,000			247,008,000	1.550	1.550	3,828,624
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		273,101,000	0	0	273,101,000	1.741	1.741	4,754,926
Nov-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	39,439,000			39,439,000	3.550	3.550	1,400,085
	UPS PURCHASE	UPS	239,040,000			239,040,000	1.550	1.550	3,705,120
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		278,479,000	0	0	278,479,000	1.833	1.833	5,105,205
Dec-04	EMERGENCY	A&B	0			0	0.000	0.000	0
	TECO	--	20,913,000			20,913,000	3.550	3.550	742,412
	UPS PURCHASE	UPS	247,008,000			247,008,000	1.550	1.550	3,828,624
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		267,921,000	0	0	267,921,000	1.706	1.706	4,571,036
Jan-04	EMERGENCY	A&B	0			0	0.000	0.000	0
THRU	TECO	--	339,905,000			339,905,000	3.550	3.550	12,066,632
Dec-04	UPS PURCHASE	UPS	2,915,973,000			2,915,973,000	1.550	1.550	45,197,582
	OTHER	--	0			0	0.000	0.000	0
	TOTAL		3,255,878,000	0	0	3,255,878,000	1.759	1.759	57,264,214

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 24
COMPANY/ FPUC
WITNESS: Sch. E7 pg 2 of 2 + pg. 2 of 5
DATE: 12-12-03

PROGRESS ENERGY FLORIDA
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED / ACTUAL TRUE-UP
For the Year 2003

Progress Energy Florida
Docket 030001-EI
Witness: Portuondo
Exhibit No.
Part D
Sheet 2 of 5

		Actual Jan-03	Actual Feb-03	Actual Mar-03	Actual Apr-03	Actual May-03	Actual Jun-03	Actual Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated Dec-03	Total 2003
	Base Production Level Capacity Charges:													
1	Payments to Qualifying Facilities	24,724,976	27,151,122	25,536,546	25,183,973	25,641,292	25,877,780	26,049,524	26,314,605	26,314,605	26,314,605	20,505,184	20,505,184	300,119,396
2	UPS Purchase (413 MW)	4,051,119	4,265,922	3,788,442	3,925,202	3,701,633	3,967,206	4,600,651	4,031,019	3,900,986	4,031,019	3,900,986	4,031,019	48,195,204
3	Incremental Security Costs	0	0	0	197,728	0	0	289,444	252,750	252,750	252,750	252,750	252,828	1,751,000
4	Subtotal - Base Level Capacity Charges	28,776,095	31,417,044	29,324,988	29,306,903	29,342,925	29,844,986	30,939,619	30,598,374	30,468,341	30,598,374	24,658,920	24,789,031	350,065,600
5	Base Production Jurisdictional %	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%	95.957%
6	Base Level Jurisdictional Capacity Charges	27,612,677	30,146,853	28,139,379	28,122,025	28,156,591	28,638,353	29,688,730	29,361,282	29,236,506	29,361,282	23,661,960	23,786,810	335,912,448
	Intermediate Production Level Capacity Charges:													
7	TECO Power Purchase	565,567	565,567	565,567	565,567	565,567	565,567	565,567	566,000	566,000	566,000	566,000	566,000	6,788,969
8	Capacity Sales	(3,593)	(3,245)	(3,593)	(3,477)	(3,593)	(3,477)	(3,593)	0	0	0	0	0	(24,571)
9	Subtotal - Intermediate Level Capacity Charges	561,974	562,322	561,974	562,090	561,974	562,090	561,974	566,000	566,000	566,000	566,000	566,000	6,764,398
10	Intermediate Production Jurisdictional %	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%	86.574%
11	Intermediate Level Jurisdictional Capacity Charg	486,523	486,825	486,523	486,624	486,523	486,624	486,523	490,009	490,009	490,009	490,009	490,009	5,856,210
	Peaking Production Level Capacity Charges:													
12	Peaking Purchases - Yearly	0	0	0	0	0	0	0	0	0	0	0	0	0
13	Peaking Purchases - Summer Peak	0	0	0	0	0	0	0	0	0	0	0	0	0
14	Peaking Purchases - Winter Peak	1,034,801	1,084,800	0	0	0	0	0	0	0	0	0	884,800	3,004,401
15	Subtotal - Peaking Level Capacity Charges	1,034,801	1,084,800	0	0	0	0	0	0	0	0	0	884,800	3,004,401
16	Peaking Production Jurisdictional %	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%	74.562%
17	Peaking Level Jurisdictional Capacity Charges	771,568	808,849	0	0	0	0	0	0	0	0	0	659,725	2,240,141
18	Transmission Revenues from Economy Sales	(361,936)	(835,914)	(182,755)	(113,525)	(48,143)	(26,384)	(13,938)	(92,398)	(96,091)	(79,991)	(152,485)	(177,352)	(2,180,912)
19	Jurisdictional Capacity Payments (Lines 6 + 11 + 17 + 18)	28,508,833	30,606,612	28,443,147	28,495,124	28,594,971	29,098,593	30,161,316	29,758,893	29,630,424	29,771,300	23,999,484	24,759,192	341,827,887
20	Capacity Cost Recovery Revenues	30,746,795	28,983,600	24,247,953	24,296,838	27,928,411	32,162,523	32,763,177	32,965,768	34,735,948	30,038,709	24,758,855	25,970,718	349,599,295
21	Prior Period True-Up Provision	(742,168)	(742,168)	(742,168)	(242,404)	(242,404)	(242,404)	(242,404)	(242,404)	(242,404)	(242,404)	(242,404)	(242,402)	(4,408,138)
22	Current Period Capacity Revenues (Lines 20+21)	30,004,627	28,241,432	23,505,785	24,054,434	27,686,007	31,920,119	32,520,773	32,723,364	34,493,544	29,796,305	24,516,451	25,728,316	345,191,157
23	Current Period Over/(Under) Rec. (Lines 22-19)	1,495,794	(2,365,180)	(4,937,362)	(4,440,690)	(908,964)	2,821,526	2,359,457	2,964,471	4,863,120	25,005	516,967	969,124	3,363,270
24	Interest Provision for Month	(3,510)	(3,132)	(5,957)	(9,999)	(12,542)	(10,448)	(7,252)	(4,791)	(1,263)	1,020	1,457	2,296	(54,121)
25	Current Cycle Balance	1,492,284	(876,029)	(5,819,348)	(10,270,037)	(11,191,543)	(8,380,464)	(6,028,259)	(3,068,579)	1,793,279	1,819,304	2,337,728	3,309,148	3,309,148
26	Plus: Prior Period Balance	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)	(4,408,138)
27	Plus: Cumulative True-Up Provision	742,168	1,484,336	2,226,504	2,468,908	2,711,312	2,953,716	3,196,120	3,438,524	3,680,928	3,923,332	4,165,736	4,408,138	4,408,138
28	End of Period Net True-Up (Lines 25+26+27)	(2,173,686)	(3,799,831)	(8,000,982)	(12,209,267)	(12,888,369)	(9,834,886)	(7,240,277)	(4,038,193)	1,066,069	1,334,498	2,095,326	3,309,148	3,309,148

42 - 13/Mwh

EXHIBIT
tabbies 25

ORIGINAL

Original Sheet No. 1

FERC NO. 2

FEDERAL ENERGY REGULATORY COMMISSION

WASHINGTON, D.C.

FILED
FEDERAL ENERGY
REGULATORY COMMISSION
02 MAR 11 PM 5:00
OFFICE OF THE SECRETARY

ELECTRIC RATE SCHEDULE

FILING PARTY Hardee Pwr. Partners Ltd.

OTHER PARTY Tampa Elec. Co.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 25
COMPANY/ FIPUG
WITNESS: Hardee Electric Rate Schedule
DATE: 11-12-03

Issued by: John T. Duff, Vice President, Operations
Issued on: March,11, 2002

Effective: February 1, 2001

Filed to comply with order of the Federal Energy Regulatory Commission, Docket No. ER01-3064-001, issued January 8, 2002.

Sheet Nos. 2 - 10
are reserved for future use.

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AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY

This Agreement is made and entered into as of this 27th day of July, 1989 by and between Tampa Electric Company, a Florida corporation ("Tampa"), and TECO Power Services Corporation, a Florida corporation ("Power Services").

W I T N E S S E T H

WHEREAS, Power Services will, subject to the provisions of this Agreement, have long-term capacity and energy available for sale to Tampa, and Tampa will have need for such capacity and energy,

WHEREAS, Power Services will construct, own and operate certain generating facilities to be located on a site to be acquired by Acuera Corp., a wholly-owned subsidiary of Seminole Electric Cooperative, Inc. ("Seminole") and leased to Power Services in Polk and Hardee Counties, Florida,

WHEREAS, Power Services proposes to construct these facilities in two stages, the first stage to consist of facilities (the "1993 Non-Coal Facilities") having a design net electrical capability of approximately 295 megawatts, and the second stage to be available in the year 2003 and to consist of additions (the "2003 Capacity Additions"), which would increase the capacity of the 1993 Non-Coal Facilities to a total design net electrical capability of approximately 440 megawatts,

WHEREAS, Power Services has entered into a turnkey construction contract with General Electric Company for construction of the 1993 Non-Coal Facilities,

WHEREAS, Power Services is selling a portion of the capacity and corresponding energy of the 1993 Non-Coal Facilities to Seminole and has agreed to make available to Seminole capacity and corresponding energy of the 2003 Capacity Additions primarily for Seminole's back-up needs, all pursuant to the Seminole Contract (as herein defined),

WHEREAS, Power Services is willing to make available and Tampa is willing to purchase capacity and corresponding energy of the 1993 Non-Coal Facilities,

WHEREAS, Power Services intends to construct the 2003 Capacity Additions and is willing to make available to Tampa capacity and corresponding energy from them,

NOW THEREFORE, in consideration of the foregoing premises and of the mutual benefits to be obtained from the covenants herein, the Parties hereby agree as follows:

ARTICLE I
DEFINITIONS

For all purposes of this Agreement, the terms defined in this section shall have the following meanings. Except where the context otherwise requires, definitions and other terms expressed in the singular shall include the plural and vice versa.

1.1. "1993 Non-Coal Facilities" shall mean those facilities to be available to Tampa on the Scheduled Date of Commercial Operation comprising the CC 1 and CT 2A and,

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to the extent appropriate in the context, all appurtenant common and supporting facilities owned by Power Services at the Site.

1.2. "2003 Capacity Additions" shall mean all or any portion of the following facilities that may be constructed pursuant to the terms of this Agreement: CT 2B, HRSG 2A, HRSG 2B, and ST 2 and, to the extent appropriate in the context, all appurtenant common and supporting facilities owned by HPP at the Site. [Fourth Amendment]

1.2.1. "2003 Capacity Additions Actual Availability" shall have the meaning and be calculated in the manner set forth in Appendix BB. [Fourth Amendment]

1.2.2. "2003 Capacity Additions Actual Net Electrical Output" shall mean the electrical capability after allowance for station service at which the first phase of the 2003 Capacity Additions can operate as determined pursuant to the 2003 Capacity Additions Performance Tests described in Appendices BB and CC. [Fourth Amendment]

1.2.3. "2003 Capacity Additions Actual Net Heat Rate" shall mean the heat rate after allowance for station service at which the first phase of the 2003 Capacity Additions can operate as determined pursuant to the 2003 Capacity Additions Performance Tests described in Appendices BB and CC. [Fourth Amendment]

1.2.4. "2003 Capacity Additions Capacity Charge" shall mean the component of the Monthly Capacity Charge as adjusted each month pursuant to Sections 6.4.9 and 6.4.10 that reflects Tampa's purchase of the capacity supplied through the construction of the 2003 Capacity Additions. [Fourth Amendment]

1.2.5. "2003 Capacity Additions Capacity Charge Adjustment Effective Date" shall mean the first day of the month following receipt of final approval of the modification of the conditions of certification to allow the construction and operation of the first phase of the 2003 Capacity Additions from the FDEP. [Fourth Amendment]

1.2.6. "2003 Capacity Additions Commercial Operation Date" shall mean the date HPP notifies Tampa of the occurrence of the date of Substantial Completion under the 2003 Capacity Additions Construction Contract and the achievement by the CT 2B of minimum net electrical output of eighty (80) megawatts on natural gas adjusted to 59 degrees site conditions, or as otherwise agreed by the Parties. [Fourth Amendment]

1.2.7. "2003 Capacity Additions Construction Contract" shall mean the Engineering, Procurement and Construction Agreement between TPS, National Energy Production Corporation and Enron Capital and Trade Resources Corp. dated as of June 17, 1999 relating to the construction of the first phase of the 2003 Capacity Additions. [Fourth Amendment]

1.2.8. "2003 Capacity Additions Construction Release" shall mean the date certified at the time in writing by HPP providing authorization to begin construction of the first phase of the 2003 Capacity Additions pursuant to the 2003 Capacity Additions Construction Contract. The date of the 2003 Capacity Additions Construction Release is currently scheduled for November 15, 1999. [Fourth Amendment]

1.2.9. "2003 Capacity Additions Contract Year" shall mean a one year period beginning on the first day of the month in which the 2003 Capacity Additions Commercial Operation Date occurs, except that the initial 2003 Capacity Additions Contract Year shall commence on the 2003 Commercial Operation Date and the final 2003 Capacity Additions Contract Year shall end on the date of termination of this Agreement. [Fourth Amendment]

1.2.10. "2003 Capacity Additions Correction Period" shall mean the period of time during which HPP continues to pay to Tampa delay damages pursuant to Section 8.3.1.1(a). [Fourth Amendment]

1.2.11. "2003 Capacity Additions Energy Charge" shall mean the monthly charges which are included in the Monthly Energy Charge pursuant to Section 6.5.4 which are the result of the Fixed Operation and Maintenance Costs and Variable Operation and Maintenance Costs associated solely with the 2003 Capacity Additions. [Fourth Amendment]

1.2.12. "2003 Capacity Additions Energy Charge Effective Date" shall mean the date which is ninety (90) days following the 2003 Capacity Additions Construction Release. [Fourth Amendment]

1.2.13. "2003 Capacity Additions Guaranteed Net Electrical Output" shall have the meaning set forth in Appendix BB. [Fourth Amendment]

1.2.14. "2003 Capacity Additions Guaranteed Net Heat Rate" shall have the meaning set forth in Appendix BB. [Fourth Amendment]

1.2.15. "2003 Capacity Additions Ongoing Guaranteed Availability" shall have the meaning set forth in Section 8.3.3.1(b). [Fourth Amendment]

1.2.16. "2003 Capacity Additions Ongoing Guaranteed Net Electrical Output" shall have the meaning set forth in Section 8.3.3.1(a). [Fourth Amendment]

1.2.17. "2003 Capacity Additions Ongoing Guaranteed Net Heat Rate" shall have the meaning set forth in Section 8.3.3.1(a). [Fourth Amendment]

1.2.18. "2003 Capacity Additions Performance Guarantees" shall have the meaning set forth in Section 8.3.2. [Fourth Amendment]

1.2.19. "2003 Capacity Additions Performance Tests" shall mean the performance tests to be performed on the first phase of the 2003 Capacity Additions as set forth in Appendix CC. [Fourth Amendment]

1.2.20. "Access Roads" shall mean Front Access Road and the Cooling Reservoir Access Road at the Site. [Third Amendment]

1.3. "Actual Availability" shall have the meaning and be calculated in the manner set forth in Appendix O.

1.4. "Actual Net Electrical Output" shall mean the electrical capability after allowance for station service at which the 1993 Non-Coal Facilities can operate as determined pursuant to the Performance and Demonstration Tests.

1.5. "Actual Net Heat Rate" shall mean the heat rate after allowance for station service at which the 1993 Non-Coal Facilities can operate as determined pursuant to the Performance and Demonstration Tests.

1.5.1. "Acuera" shall mean Acuera Corp., a Florida corporation.

1.6. "Affiliate" shall mean any entity owned by, owning, controlled by, controlling, or under common control or ownership with the entity in conjunction with which the term Affiliate is used.

1.7. "Agreement" shall mean this agreement between Power Services and Tampa, including the appendices hereto.

1.8. "Annual Planned Outage" shall mean the removal of a generating unit from service for inspection and/or general overhaul of major equipment components.

1.9. "Appraisal Procedure" shall mean a procedure whereby two independent appraisers, one chosen by Tampa and one by Power Services, shall mutually agree upon the determinations then the subject of appraisal. Tampa or Power Services, as the case may be, shall deliver a written notice to the other appointing its appraiser within fifteen (15) days after receipt from the other of a written notice appointing its appraiser. If within thirty (30) days after appointment of the two appraisers they are unable to agree upon the amount in question, a third independent appraiser shall be chosen within ten (10) days thereafter by the mutual consent of such first two appraisers or, if such first two appraisers fail to agree upon the appointment of a third appraiser, such appointment shall be made by the American Arbitration Association, or any organization successor thereto, and shall be a disinterested person qualified in the matter to be determined. The three appraisers shall make the determination in accordance with the rules of the American Arbitration Association or any such successor then in effect, and such determination shall be binding and conclusive on Tampa and Power Services. Each Party shall pay the costs of its own appraiser and shall share equally in the costs, if any, of a third appraiser.

1.10. "Banker" shall have the meaning set forth in Section 6.4.1.

1.11. "Benefits Derived from all Off-System Sales" shall mean the revenue obtained from any Off-System Sales less the Incremental Fuel Cost and Incremental Operation and Maintenance Cost associated with the Off-System Sales.

1.12. "Capacity and Corresponding Energy" shall mean the capacity and hourly energy generated by the CT/CC Facilities or the 2003 Capacity Additions, as appropriate given the context. [Fourth Amendment]

1.13. "Capacity Finance Rate" shall have the meaning set forth in Section 6.4.1.

1.14. "CC" shall mean a Combined Cycle Unit.

1.15. "CC 2 Efficiency Rights" shall have the meaning set forth in Section 10.2.2.1.

1.16. "Combined Cycle Units" shall mean the fossil-fired combination combustion turbine, heat recovery steam generator and associated steam turbine generating units, each with a nominal rating of 220 MW, to be or, with respect to the 2003 Capacity Additions, proposed to be constructed by Power Services on the Site and comprising the specific components described as follows:

1.16.1. "HRSG 1A" shall mean the heat recovery steam generator which receives waste heat from CT 1A and provides steam to ST 1.

1.16.2. "HRSG 1B" shall mean the heat recovery steam generator which receives waste heat from CT 1B and provides steam to ST 1.

(d) Insurer hereby waives all rights of subrogation against Tampa, its officers, directors and employees; and

(e) Notwithstanding any provision of this policy, if such insurance is cancelled for any reason whatsoever, including nonpayment of premium, or any substantial change is made in the coverage which affects the interest of Tampa as an additional insured, such cancellation or change shall not be effective as to Tampa, the additional insured, for sixty (60) days after written notice of such cancellation or change is sent by registered mail from such insurer to Tampa.

5.11.2.4. Certificates: Power Services shall cause its insurers or agents to provide Tampa with certificates of insurance evidencing the policies and endorsements listed above beginning the Date of Operation and at the time of renewal of any coverage and at such other times as Tampa may reasonably request. Failure of Tampa to obtain certificates of insurance shall not relieve Power Services of the insurance requirements set forth herein. Power Services shall also provide Tampa on a timely basis a copy of any information or reports that Power Services furnishes to the Lender concerning insurance coverage related to the CT/CC Facilities. Failure to obtain the insurance coverage required by this Section 5.11.2 shall in no way relieve or limit Power Services' obligations and liabilities under other provisions of this Agreement.

5.12. Application of Insurance Proceeds: All insurance proceeds received by Power Services on account of damage to the CT/CC Facilities after the Date of Operation, net of any cost of recovering the same, shall, to the extent not required by the Lender to prepay debt, be applied by Power Services, to the extent necessary, to repair of the facilities. Power Services shall not be obligated to use

funds other than such proceeds and amounts payable as part of the Monthly Energy Charge for such repair. In the event that insurance proceeds are required by the Lender to be applied to prepayment of debt, the Monthly CT/CC Capacity Charge shall be adjusted as provided in Section 6.4.7.

ARTICLE VI
CHARGES, BILLING, AND PAYMENTS

6.1. Billing and Payments: Power Services shall render bills for each month to Tampa as soon as practicable after the end of the month. Bills shall be due and payable within fourteen (14) days from the date of receipt. The payment date shall be the date of receipt by Power Services. All payments to Power Services shall be by wire or electronic transfer to Power Services' account in a domestic bank as directed in writing by Power Services. The bill for the first Monthly Charge under this Agreement shall reflect an estimated Monthly Energy Charge for the first Delivery Month. The bill for the second Delivery Month shall be based on the actual Monthly Energy Charge for the first Delivery Month and shall true-up the bill for the first Delivery Month to the actual Monthly Energy Charge for such first Delivery Month. The bill for the third and each succeeding Delivery Month shall be based on the actual Monthly Energy Charge for the previous Delivery Month. After the bill for the last Delivery Month is rendered on the basis of the Monthly Energy Charge for the previous Delivery Month, a final true-up statement for the entire period of service shall be issued and a bill or payment issued as necessary. The final true-up statement shall be in the amount of (1) a second bill for the last Delivery Month but based on the actual Monthly Energy Charge for the last Delivery Month less (2) the bill for

the first Delivery Month as adjusted (in the second Delivery Month) to the actual Monthly Energy Charge for the first Delivery Month.

6.2. Overdue Accounts: If either Party shall fail to make any payment when due under this Agreement, then such overdue amount shall accrue interest computed on the basis of a year of 360 days and actual days elapsed for any overdue period at an annual rate equal to 200 basis points over the then prime interest rate (or the equivalent) as published in The Wall Street Journal computed on a daily basis during such period.

6.3 Monthly Charge: Tampa shall pay HPP monthly during the period commencing with the Date of Operation and continuing to and including December 31, 2012 an amount (the "Monthly Charge") equal to the sum of the Monthly Capacity Charge and the Monthly Energy Charge for the CT/CC Facilities (adjusted for Off-System Sales pursuant to Section 6.6 and true-ups pursuant to Section 6.1) and the 2003 Capacity Additions. Effective upon the Date of Operation, Tampa shall pay the Monthly Charge with respect to the CT/CC Facilities in all events, whether or not the CT/CC Facilities generate and deliver the Capacity and Corresponding Energy sold to Tampa hereunder, or whether or not such Facilities are capable of generating and delivering such Capacity and Corresponding Energy, without regard to the cause of any failure or inability to generate and deliver such Capacity and Corresponding Energy, and such payments shall not be subject to any reduction, whether by offset or otherwise. Effective upon the 2003 Capacity Additions Commercial Operation Date, Tampa shall pay the Monthly Charge with respect to the first phase of the 2003 Capacity Additions in all events, whether or not the 2003 Capacity Additions generate and deliver the Capacity and Corresponding Energy sold to Tampa hereunder, or whether or not such 2003 Capacity Additions are capable of generating and delivering such Capacity and Corresponding Energy, without regard to the cause of any failure or inability to generate and deliver such Capacity and Corresponding Energy, and such payments shall not be subject to any reduction, whether by offset or otherwise. To the extent that no energy is generated and the calculation of any component of the Monthly Charge requires

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an allocation of expenses, such expenses shall be allocated as provided for in this Article VI. [Fourth Amendment]

6.4 Monthly Capacity Charge: The Monthly Capacity Charge shall be equal to the sum of the Monthly CT/CC Capacity Charge and the 2003 Capacity Additions Capacity Charge. For the Monthly CT/CC Capacity Charge, during the period from the Date of Operation to the earlier of (a) the last day of the tenth Contract Year and (b) December 31, 2003, the Monthly CT/CC Capacity Charge shall be $1,137,250. During the period from the end of the period described in the preceding sentence through the remaining term of this Agreement, the Monthly CT/CC Capacity Charge shall be $1,184,917. For the 2003 Capacity Additions Capacity Charge, during the period from the 2003 Capacity Additions Commercial Operation Date until December 31, 2012, the 2003 Capacity Additions Capacity Charge for the first phase shall be $451,550. To the extent that the 2003 Capacity Additions Commercial Operation Date occurs during the month, the 2003 Capacity Additions Capacity Charge for such month shall be the 2003 Capacity Additions Capacity Charge set forth above multiplied by a fraction, the numerator of which is the number of days of the month starting with and subsequent to the 2003 Capacity Additions Commercial Operation Date and the denominator of which is the total number of days in the month in which the 2003 Capacity Additions Commercial Operation Date occurs. The Monthly Capacity Charge described in this Section 6.4 shall be subject to adjustment only as expressly provided for in this Agreement. [Fourth Amendment]

6.4.1. Capacity Finance Rate Adjustments: The Monthly CT/CC Capacity Charge shall be adjusted upward or downward to the extent that the Capacity Finance Rate varies from 10.50 percent in order to reflect the effect of such variation on a levelized basis over a term of twenty years. The amount of the monthly adjustment shall be determined in accordance with the computation set forth in Appendix B. Except as provided in Section 6.4.1.1, the Capacity Finance Rate, expressed as a percentage, shall be the Long Term Finance Rate. The Long Term Finance Rate shall be determined by Power Services and Tampa by mutual agreement. If the Parties cannot agree, then, at the request of Power Services not earlier than six months prior to the Scheduled Date of Commercial Operation or, if the Long Term Finance Rate has not been set prior to the earlier of (a) six (6) months after the Date of Commercial Operation and (b) the date on which Power Services enters into a commitment letter for long-term financing of all or any part of the 1993 Non-Coal Facilities, at the request of either Party, the Long Term Finance Rate shall be determined in accordance with the Appraisal Procedure, with each appraiser to be from a nationally recognized investment banking firm with utility project financing

expertise (the "Bankers"). Both Parties will cooperate in providing the Bankers with relevant information necessary for the determination and such information shall also be provided to each Party. Both Parties will have an opportunity to consult with the Bankers in advance of the determination. The Bankers shall determine the market rate on an "all-in basis" (taking into account fees and other costs of financing including all legal, professional and other costs associated with the financing described below and any applicable capital adequacy or other reserve requirements) on the Applicable Date (as defined below) for long-term fixed rate project debt based upon actual facts and circumstances then existing with respect to the project, subject to the following assumptions: (i) a project capitalization of at least 22-1/2 percent common equity, (ii) non-recourse non-callable project debt for the balance with substantially level debt service over a term of 20 years, (iii) an average ratio of pre-tax cash flow to debt service during the term of the debt equal to the higher of the projected actual ratio and 1.3 to 1, (iv) the Seminole Contract is in full force and effect as originally executed or, to the extent approved by Tampa, as amended, (v) the 1993 Non-Coal Capacity has been completed on schedule and satisfies the Performance Guarantees, and (vi) such other assumptions as the Bankers consider necessary and reasonable. The Applicable Date shall be the next business day following the date the request to determine the Long Term Finance Rate is made by a Party, provided, that in the event Power Services is in the process of arranging and diligently proceeding to complete long term financing, the Applicable Date shall, at the request of Power Services, be deferred for not more than thirty (30) days in order to permit the Long Term Finance Rate to be determined substantially contemporaneously with the setting of the rate on such long term financing. In the event that

the Long Term Finance Rate has not been determined, the Capacity Finance Rate shall be the Short Term Rate determined in the manner provided in Section 6.4.1.1, provided that an adjustment shall be made when the Long Term Finance Rate is determined so that the Capacity Finance Rate equals the Long Term Finance Rate during any period subsequent to the short term financing period under Section 6.4.1.1.

6.4.1.1. Short Term Financing: If the Long Term Finance Rate determined pursuant to Section 6.4.1 exceeds 10.50 percent, Tampa shall have the option to cause the Capacity Finance Rate to be determined on a short term financing basis (the "Short Term Rate") for up to six consecutive six-month periods after the Date of Operation. The short term financing option may be extended if mutually agreeable. The Short Term Rate during each month of any short term financing period shall be a fixed number of basis points greater than an appropriate index. Such index and such number shall be determined prior to each six month period by mutual agreement of the Parties. If the Parties cannot agree then, at the request of either Party, such index and such number shall be determined by the Bankers in accordance with the Appraisal Procedure. The Bankers shall determine such index and such number with respect to the market rate for short term fixed rate project debt on the same basis, upon the same facts and subject to the same assumptions as the determination of the Long Term Finance Rate. Prior to the end of the third month of each six-month period for which Tampa exercises its short term financing option, Tampa and Power Services will have the Long Term Finance Rate determined in accordance with Section 6.4.1 as promptly as practicable. Power Services shall have the right to terminate the short term financing period at any time by establishing a Long Term Finance Rate

pursuant to Section 6.4.1 not exceeding 10.5 percent, provided, however, that Power Services may not terminate the short term financing period prior to having entered into a commitment letter for long term financing of all or any part of the 1993 Non-Coal Facilities.

6.4.1.2. Variable Rate Construction Interest: The Monthly CT/CC Capacity Charge has been determined based upon a projected fixed rate of interest during construction of 9.51 percent. To the extent that the actual amount of interest during construction differs from the amount used to set the Monthly CT/CC Capacity Charge, the Monthly CT/CC Capacity Charge shall be equitably adjusted in accordance with Appendix C.

6.4.2. State and Federal Income Tax Adjustment: The Monthly Capacity Charge shall be adjusted upward or downward for changes in the marginal combined state and federal corporate income tax rate (or any successor thereto) applicable to an entity the income of which consists solely of that derived by Power Services with respect to the Power Resources (as defined in the Seminole Contract). Such adjustment shall be effective on the date such change in rate is applicable to Power Services. Adjustments effective on other than the first day of the month shall be prorated. The amount of adjustment for each calendar year for each one percent that the rate differs from 37.63 percent is shown in Appendix D. To the extent the actual combined state and federal income tax rate is outside the bands described above, the adjustment will be calculated in a methodology consistent with Appendix D. Power Services shall include a notice of any adjustment made pursuant to this Section 6.4.2 in the first bill containing such adjustment, along with the calculations made to support such adjustment.

6.4.3. Property Tax Abatement: The Parties shall attempt to obtain from the appropriate authorities an abatement of the property taxes applicable to the 1993 Non-Coal Facilities. Tampa's annual share of such abatement shall be the product of (a) the assessed value of the 1993 Non-Coal Facilities, (b) the reduction of the applicable property tax rate due to such abatement, and (c) forty percent (40%). For any calendar year such abatement is applicable, Power Services shall credit Tampa's share thereof in the statement for the Monthly Capacity Charge that is rendered in the January invoice of the subsequent calendar year.

6.4.4. Regulatory Mandated Changes: If any environmental, labor or safety-related legislation, or any environmental regulation not presently proposed, applicable to the construction or operation of the CT/CC Facilities becomes effective after the date of this Agreement, or if any permit relating to the construction or operation of the 1993 Non-Coal Facilities is granted subject to or modified to impose conditions which Power Services could not reasonably have anticipated on the date of this Agreement, and such legislation, regulation or permit mandates modifications requiring capital additions or causes a delay which increases the capital cost to Power Services of performing this Agreement (a "Regulatory Mandated Change"), such modifications or delay shall be deemed to be a change for which Power Services shall be entitled to an equitable adjustment of the Monthly Capacity Charge pursuant to Section 6.4.8.

6.4.5. Delays: In the event that the Date of Commercial Operation is delayed beyond the Scheduled Date of Commercial Operation solely due to an act or omission of Tampa or its directors, officers, employees, agents or

6.4.9.4 Future Adjustments of HPS #3 or the 2003 Capacity Additions: If either HPS #3 or the 2003 Capacity Additions are reconfigured or adjusted in their nominal electrical capacity capability and/or in their use of the HPS Shared Common Facilities, the HPS Shared Common Facilities Capacity Charge Adjustment shall be equitably adjusted and HPP shall promptly file any necessary documents with the FERC to carry out the intent of the Parties under this Section. [Fourth Amendment]

6.4.10 Further Adjustments to 2003 Capacity Additions Capacity Charge: As of the 2003 Capacity Additions Commercial Operation Date, the 2003 Capacity Additions Capacity Charge shall be subject to adjustment as provided for in Sections 6.4.2 through 6.4.8, provided, however, that Tampa shall be entitled to one hundred percent (100%) of the reduction provided for in Section 6.4.7 and shall be responsible for one hundred percent (100%) of the cost increase provided for in Section 6.4.8. Upon notification by Tampa to HPP to complete construction of the second phase of the 2003 Capacity Additions pursuant to Section 10.2.1, the Parties shall make further adjustments to the 2003 Capacity Additions Capacity Charge and HPP shall promptly file any necessary documents with the FERC to carry out the intent of the Parties under this Section. [Fourth Amendment]

6.5. Monthly Energy Charge: The Monthly Energy Charge shall be comprised of (i) the Monthly Combustion Turbine Cost, (ii) the Monthly Combined Cycle Cost, (iii) the HPS Site Common Facilities Energy Charge, (iv) the 2003 Capacity Additions Energy Charge and (v) the HPS Plant

Common Facilities Energy Charge. Costs and allocations of costs shall be determined in accordance with the records and accounting system of HPP. Such records and accounting system will be kept according to generally accepted utility accounting practices, including the FERC Uniform System of Accounts. [Fourth Amendment]

6.5.1 Monthly Combustion Turbine Cost: During any period when any of the CT units is operated as a stand-alone combustion turbine, the Monthly Combustion Turbine Cost shall be the sum of:

(a) The Tampa portion of the cost of fuel consumed by any CT unit other than the CT 2B as part of the 2003 Capacity Additions during the Delivery Month, including transportation and handling costs, allocated to Tampa on an hourly basis according to type of fuel, fuel cost, hourly unit load, the demonstrated heat rate corresponding to average load level in each hour and Tampa's proportion of the hourly load. (See Appendix E). In addition, a monthly adjustment shall be added to the total of the hourly charges to compensate for off-line fuel consumption and variations in unit heat rate. Such adjustment shall be calculated by subtracting from the total actual fuel consumption for the 1993 Non-Coal Facilities for each month the Theoretical Total Fuel Consumption. The "Theoretical Total Fuel Consumption" shall be defined as the product of the hourly average loadings and the corresponding heat rates. The Tampa portion of such adjustment shall be determined by dividing the total MWh delivered to Tampa from such CT unit during the Delivery Month by the total

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MWh generated by such CT unit during the Delivery Month; and [Fourth Amendment]

(b) The sum of (i) forty percent (40%) of the Delivery Month Fixed Operation and Maintenance Costs (provided, however, that, upon the earlier to occur of (x) the HPS #3 Energy Charge Effective Date and (y) the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded and, upon the occurrence of the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs associated with the HPS Plant Common Facilities shall be excluded) allocated to any CT unit other than the CT 2B as part of the 2003 Capacity Additions as calculated pursuant to Appendix F; and (ii) the Tampa portion of the Delivery Month Variable Operation and Maintenance Costs (provided, however, that, upon the earlier to occur of (x) the HPS #3 Energy Charge Effective Date and (y) the 2003 Capacity Additions Energy Charge Effective Date, the Variable Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded and, upon the occurrence of the 2003 Capacity Additions Energy Charge Effective Date, the Variable Operation and Maintenance Costs associated with the HPS Plant Common Facilities shall be excluded) allocated to any CT unit other than the CT 2B as part of the 2003 Capacity Additions as calculated pursuant to Appendix G less any portion of such costs allocated to Off-System Sales, allocated to Tampa in the proportion that the energy generated by any CT unit other than the CT 2B as part of the 2003 Capacity Additions for Tampa during the previous twelve (12) month period ending

with the Delivery Month bears to the total net energy generated by such unit during the same twelve (12) month period (provided that such total net energy shall not include energy generated for Off-System Sales); [Fourth Amendment]

(c) Forty percent (40%) of the Delivery Month fixed charges for replaced property units of the CT 2A, as calculated pursuant to Appendix T; and [Fourth Amendment]

(d) Forty percent (40%) of the Delivery Month administrative and general expenses allocated to any CT unit, as calculated pursuant to Appendix H, until the occurrence of the 2003 Capacity Additions Energy Charge Effective Date at which time the percentage shall be fifty nine and seventy-seven one hundredths percent (59.77%) of the Delivery Month administrative and general expenses allocated to any CT unit, as calculated pursuant to Appendix H. [Fourth Amendment]

6.5.2 Monthly Combined Cycle Cost: The Monthly Combined Cycle Cost shall be the sum of:

(a) The Tampa portion of the cost of fuel consumed by the CC 1 during the Delivery Month, including transportation and handling costs, allocated to Tampa on an hourly basis according to type of fuel, fuel cost, hourly unit load, the demonstrated heat rate corresponding to average load level in each hour and Tampa's proportion of the hourly load. (See Appendix I). In addition, a monthly adjustment shall be added to the total of the hourly charges to compensate for off-line fuel consumption and variations in unit heat rate. Such adjustment shall be calculated by subtracting from the total actual fuel consumption for the 1993 Non-Coal Facilities for each month the Theoretical Total Fuel Consumption. The "Theoretical Total Fuel Consumption" shall be defined as the product of the hourly average loadings and the corresponding heat rates. The Tampa portion of such adjustment shall be determined by dividing the total MWh delivered to Tampa from the CC 1 during the Delivery Month by the total MWh generated by the CC 1 during the Delivery Month; and [Fourth Amendment]

(b) The sum of (i) forty percent (40%) of the Delivery Month Fixed Operation and Maintenance Costs (provided, however, that, upon the earlier to occur of (x) the HPS #3 Energy Charge Effective Date and (y) the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded and, upon the occurrence of the 2003 Capacity Additions Energy Charge

Effective Date, the Fixed Operation and Maintenance Costs associated with the HPS Plant Common Facilities shall be excluded) allocated to the CC 1 as calculated pursuant to Appendix J; and (ii) the Tampa portion of the Delivery Month Variable Operation and Maintenance Costs (provided, however, that, upon the earlier to occur of (x) the HPS #3 Energy Charge Effective Date and (y) the 2003 Capacity Additions Energy Charge Effective Date, the Variable Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded and, upon the occurrence of the 2003 Capacity Additions Energy Charge Effective Date, the Variable Operation and Maintenance Costs associated with the HPS Plant Common Facilities shall be excluded) associated with the CC 1 as calculated pursuant to Appendix K less any portion of such costs allocated to Off-System Sales, allocated to Tampa in the proportion that the energy generated by the CC 1 for Tampa during the previous twelve (12) month period ending with the Delivery Month bears to the total net energy generated by the CC 1 during the same twelve (12) month period (provided that such total net energy shall not include energy generated for Off-System Sales); and [Fourth Amendment]

(c) Forty percent (40%) of the Delivery Month fixed charges for replaced property units of the CC 1, as calculated pursuant to Appendix U; and [Fourth Amendment]

(d) Forty percent (40%) of the Delivery Month administrative and general expenses allocated to the Combined Cycle Units, as calculated pursuant to Appendix L, until the occurrence of the 2003 Capacity Additions Energy

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Charge Effective Date at which time the percentage shall be fifty nine and seventy-seven one hundredths percent (59.77%) of the Delivery Month administrative and general expenses allocated to the Combined Cycle Units, as calculated pursuant to Appendix L. [Fourth Amendment]

6.5.3. HPS Site Common Facilities Energy Charge: [Fourth Amendment]

(a) The HPS Site Common Facilities Energy Charge shall commence on the earlier of the HPS #3 Energy Charge Effective Date or the 2003 Capacity Additions Energy Charge Effective Date and shall continue through the remaining term of this Agreement. The HPS Site Common Facilities Energy Charge shall be calculated pursuant to Appendices X and Y and shall be subject to adjustment in accordance with Sections 6.4.9.1 through 6.4.9.4. The allocations in Appendix X are calculated on the assumption that the 2003 Capacity Additions Energy Charge Effective Date precedes the HPS #3 Energy Charge Effective Date. In the event that the sequencing of such effective dates shall occur other than as assumed, the allocations shall be recalculated to reflect the changes in sequencing of such effective dates and no other changes. [Fourth Amendment]

(b) Commencing on the HPS #3 Energy Charge Effective Date, the HPS Site Common Facilities Energy Charge to Tampa shall include an allocation to reflect Seminole's equitable share of the Delivery Month Fixed Operation and Maintenance Costs and the Delivery Month Variable Operation and Maintenance Costs associated with the utilization of the HPS Site Common Facilities for HPS

#3, as calculated pursuant to Appendices X and Y. [Fourth Amendment]

(c) Commencing on the 2003 Capacity Additions Energy Charge Effective Date, the HPS Site Common Facilities Energy Charge to Tampa shall include an allocation to reflect Tampa's equitable share of the Delivery Month Fixed Operation and Maintenance Costs and the Delivery Month Variable Operation and Maintenance Costs associated with the utilization of the HPS Site Common Facilities for the 2003 Capacity Additions, as calculated pursuant to Appendices X and Y. [Fourth Amendment]

6.5.4 2003 Capacity Additions Energy Charge: The 2003 Capacity Additions Energy Charge shall commence on the 2003 Capacity Additions Commercial Operation Date and shall continue through the remaining term of this Agreement. The 2003 Capacity Additions Energy Charge to Tampa shall be subject to adjustment in accordance with Sections 6.4.9.1 through 6.4.9.4. The 2003 Capacity Additions Energy Charge shall be the sum of: [Fourth Amendment]

(a) The total cost of fuel consumed by the 2003 Capacity Additions during the Delivery Month, including transportation and handling costs; and [Fourth Amendment]

(b) The Delivery Month Fixed Operation and Maintenance Costs and Delivery Month Variable Operation and Maintenance Costs (but excluding the Delivery Month Fixed Operation and Maintenance Costs and the Delivery Month Variable Operation and Maintenance Costs associated with the HPS Shared Common Facilities) allocated to the 2003

Capacity Additions as calculated pursuant to Appendix Z; and [Fourth Amendment]

(c) The Delivery Month fixed charges for replaced property units of the 2003 Capacity Additions, as calculated pursuant to Appendix AA. [Fourth Amendment]

6.5.5 HPS Plant Common Facilities Energy Charge: The HPS Plant Common Facilities Energy Charge shall commence on the 2003 Capacity Additions Energy Charge Effective Date and shall continue through the remaining term of this Agreement. The HPS Plant Common Facilities Energy Charge to Tampa shall include an amount to reflect Tampa's equitable share of the Delivery Month Fixed Operation and Maintenance Costs and the Delivery Month Variable Operation and Maintenance Costs associated with the utilization of the HPS Plant Common Facilities as a result of the construction by HPP of all or part of the 2003 Capacity Additions as calculated pursuant to Appendices V and W. The HPS Plant Common Facilities Energy Charge shall also be subject to adjustment in accordance with Sections 6.4.9.1 through 6.4.9.4. [Fourth Amendment]

6.6 Interchange Sales: Except as provided for in Section 6.6.4, Tampa shall be entitled to forty percent (40%) of the Benefits Derived from all Off-System Sales of Capacity and Corresponding Energy. Sales and payments for or recovery of the attributable costs and benefits shall be made in the following manner. [Fourth Amendment]

6.6.1. Economy Interchange Sales: The Operating Agent shall determine the Incremental Fuel Cost and Incremental Operation and Maintenance Cost associated with Off-System Economy Interchange Sales, quote prices to potential buyers and make such sales pursuant to Section 4.1, invoice buyers and receive payment directly. Each month Power Services shall pay Tampa forty percent (40%) of the excess of revenues from such sales over the Incremental Fuel Cost and

Incremental Operation and Maintenance Cost associated with such sales during the previous month in the form of a credit reflected in the Monthly Charge with respect to such previous month.

6.6.2. Schedule A Interchange Sales: Prior to the beginning of each month Power Services shall estimate the fuel and operations and maintenance costs associated with Off-System Sales of Schedule A Interchange Service and shall provide that information to Tampa. Tampa may quote prices for such sales to potential buyers, make such sales in accordance with Section 4.1, invoice buyers and receive payment directly for sales made by Tampa. At the end of each month Tampa shall inform Power Services of Tampa's revenues from such sales of Schedule A Interchange Service during such month. Power Services shall calculate the Incremental Fuel Cost and the Incremental Operation and Maintenance Cost of such sales according to methods developed by the Operating Committee. Such costs and sixty percent (60%) of the excess of the revenues from such sales over such costs shall be recovered by Power Services in the form of a debit reflected in the Monthly Charge with respect to such month. Power Services shall also calculate the excess of revenues from similar sales of Schedule A Interchange Service made by Seminole during such month over the Incremental Fuel Cost and Incremental Operation and Maintenance Cost associated with such sales. Power Services shall pay forty percent (40%) of such excess to Tampa in the form of a credit reflected in the Monthly Charge with respect to such month.

6.6.3. Schedule B Interchange Sales: Prior to the beginning of each month Power Services shall estimate the fuel and operations and maintenance costs associated with Off-System Sales of Schedule B Interchange Service and shall provide that information to Tampa. Tampa may quote prices to

potential buyers and make such sales in accordance with Section 4.1, invoice buyers and receive payment directly for sales made by Tampa. At the end of each month Tampa shall inform Power Services of Tampa's revenues from such sales of Schedule B Interchange Service during such month. Power Services shall calculate the Incremental Fuel Cost and Incremental Operation and Maintenance Cost of such sales according to methods developed by the Operating Committee. Such costs and sixty percent (60%) of the excess of the revenues from such sales over such costs shall be recovered by Power Services in the form of a debit reflected in the Monthly Charge with respect to such month. Power Services shall also calculate the excess of revenues from similar sales of Schedule B Interchange Service made by Seminole during such month over the Incremental Fuel Cost and Incremental Operation and Maintenance Cost associated with such sales. Power Services shall pay forty percent (40%) of such excess to Tampa in the form of a credit reflected in the Monthly Charge with respect to such month.

6.6.4 Interchange Sales from the 2003 Capacity Additions: Notwithstanding the foregoing, Tampa shall be entitled to one hundred (100%) of the Benefits Derived from all Off-System Sales of Capacity and Corresponding Energy made from the 2003 Capacity Additions. [Fourth Amendment]

6.7. Test and Pre-Operation Fuel and Energy:

6.7.1 Test Fuel: Tampa shall pay HPP forty percent (40%) of the cost of all fuel use associated with Test Operation of the 1993 Non-Coal Facilities and one hundred percent (100%) of the cost of all fuel use associated with the activities in connection with the check-out, testing and start-up of the 2003 Capacity Additions, including transportation and handling cost. [Fourth Amendment]

6.7.2. Test Energy: Power Services shall cause the Operating Agent to sell any energy produced by the 1993 Non-Coal Facilities during Test Operation. Power Services shall pay Tampa forth percent (40%) of all revenues from such sales. Such payment shall be in the form of a credit to Tampa's liability for fuel cost pursuant to this Section 6.7. If after reasonable efforts the Operating Agent is unable to sell such energy, Tampa shall purchase such energy as reasonably necessary to allow Test Operation.

6.7.3 Test Energy from 2003 Capacity Additions: Tampa shall purchase any energy produced by the 2003 Capacity Additions during test operation. If, after reasonable efforts, Tampa is unable to purchase such energy as reasonably necessary to allow test operation, HPP shall cause the Operating Agent to sell any such energy. HPP shall pay Tampa one hundred percent (100%) of all revenues

from such sales from the 2003 Capacity Additions. Such payment shall be in the form of a credit to Tampa's liability for fuel cost pursuant to this Section 6.7. [Fourth Amendment]

APPENDIX F

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY
BETWEEN
HARDEE POWER PARTNERS LIMITED
(ASSIGNEE OF TECO POWER SERVICES CORPORATION)
AND
TAMPA ELECTRIC COMPANY

1993 Non-Coal Facilities

COMBUSTION TURBINE
FIXED OPERATION AND MAINTENANCE COST

For purposes of this Agreement, the "Delivery Month Fixed Operation and Maintenance Costs" excluding fuel, identified in Section 6.5.1 (b) shall be determined as follows:

Line	Account	Description	Resource
1	513	Maintenance of Electric Plant	See Note 3
2	546	Operation Supervision & Engineering	See Note 1
3	548	Generation Expense	See Note 1
4	549	Misc. Other Power Generation Expense	See Note 1
5	550	Rents	See Note 2
6	551	Maintenance Supervision & Engineering	See Note 1
7	552	Maintenance of Structures	All Resources
8	553	Maintenance of Generation & Electric Plant	See Note 3
9	554	Maintenance of Misc. Other Power Generation	See Note 3
10	555	Purchased Power	See Note 1
11	562	Station Expense	See Note 1
12	569	Maintenance of Structures (Transmission)	All Resources
13	570	Maintenance of Station Equipment	See Note 3
14	571	Maintenance of Overhead Lines	See Note 3
15	Total Delivery Month Fixed Operation and Maintenance Associated With 1993 Non-Coal Facilities (Sum of Lines 1 Through 14; See Note 4)		

16 Percent Allocable to Tampa: 40% for all accounts except Account 550. See Note 2 for Account 550 percentage.

17 TOTAL FIXED OPERATION AND MAINTENANCE EXPENSE ALLOCABLE TO TAMPA FOR 1993 Non-Coal Facilities (Line 15 x Line 16)

Note 1: Resources 00, 01, 02, 04, 08, 09, 10, 14, 15, 18, 37, 39, and 47.

Note 2: Resources 03 and 33. Tampa's allocation for the portion of this account that is for the annual site lease costs is 59.77%. Tampa's allocation for the remaining portion of this account shall be 40%.

Note 3: Resources 00, 01, 02 (except overtime payroll), 04, 08, 09, 10, 14, 15, 18, 37, 39, and 47.

Note 4: Amounts in lines 1 through 14 shall include only those direct expenses which provide a benefit to the CT unit (provided that, upon the earlier to occur of (x) the HPS #3 Energy Charge Effective Date and (y) the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded and, upon the occurrence of the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs associated with the HPS Plant Common Facilities shall be excluded). These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred. A description of resource codes currently in effect is provided in Appendix M.

APPENDIX G

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

1993 Non-Coal Facilities

COMBUSTION TURBINE VARIABLE OPERATION AND MAINTENANCE COST

For purposes of this Agreement, the "Delivery Month Variable Operation and Maintenance Costs" excluding fuel, identified in Section 6.5.1 (b) shall be determined as follows:

Line	Account	Description
1	513	Maintenance of Electric Plant
2	546	Operation Supervision & Engineering
3	548	Generation Expense
4	549	Misc. Other Power Generation Expense
5	550	Rents
6	551	Maintenance Supervision & Engineering
7	552	Maintenance of Structures
8	553	Maintenance of Generation & Electric Equipment
9	554	Maintenance of Misc. Other Power Generation
10	555	Purchased Power
11	562	Station Expense
12	569	Maintenance of Structures (Transmission)
13	570	Maintenance of Station Equipment
14	571	Maintenance of Overhead Lines
15	Total Operation and Maintenance Associated With 1993 Non-Coal Facilities (Lines 1 Through 14; See Note 1)	
16	Less: Total Fixed Operation and Maintenance For 1993 Non-Coal Facilities (Appendix F, Line 15)	

17 Total Variable Operation & Maintenance For 1993 Non-Coal Facilities (Line 15 – Line 16)

18 Operation & Maintenance Allocated to Off-System Sales

19 Total Variable O&M For 1993 Non-Coal Facilities To Be Allocated (Line 17 – Line 18)

20 Energy Generated by the CT Unit for Tampa During the Previous Twelve Month Period Ending With the Delivery Month

21 Total Energy Generated By the CT Unit During the Previous Twelve Month Period Ending With the Delivery Month

22 Energy Generated by the CT Unit for Off-System Sales During the Previous Twelve Month Period Ending With the Delivery Month

23 Total Net Energy Generated By the CT Unit Exclusive of Energy Generated for Off-System Sales (Line 21 – Line 22)

24 Percent of Energy Generated for Tampa During the Previous Twelve Months (Line 20 divided by Line 23)

25 Total Variable O&M Allocable to Tampa Associated With Tampa's Sales of Schedules A and B Interchange Service

26 TOTAL VARIABLE O&M ALLOCABLE TO TAMPA FOR 1993 Non-Coal Facilities ((Line 19 x Line 24) + Line 25)

Note 1: Amounts in lines 1 through 14 shall include only those direct expenses which provide a benefit to the CT unit (provided that, upon the earlier to occur of (x) the HPS #3 Energy Charge Effective Date and (y) the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation an Maintenance Costs and the Variable Operation and Maintenance Costs associated with the HPS Site Common Facilities shall be excluded and, upon the occurrence of the 2003 Capacity Additions Energy Charge Effective Date, the Fixed Operation and Maintenance Costs and the Variable Operation and Maintenance Costs associated with the HPS Plant Common Facilities shall be excluded). These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, unless the price charged by such associated company was established through a bidding process, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred.

APPENDIX H

AGREEMENT FOR SALE AND PURCHASE OF CAPACITY AND ENERGY BETWEEN HARDEE POWER PARTNERS LIMITED (ASSIGNEE OF TECO POWER SERVICES CORPORATION) AND TAMPA ELECTRIC COMPANY

COMBUSTION TURBINE ADMINISTRATIVE AND GENERAL EXPENSES

For purposes of this Agreement, the "Delivery Month Administrative and General Expenses Allocated to the CT Unit," identified in Section 6.5.1 (d) shall be determined as follows:

Line	Description
1	920-932 Administrative & General Expenses
2	Less: Production Property Insurance Included in Account 924
3	920-932 Administrative & General Expenses Excluding Production Property Insurance (Line 1 – Line 2) (See Note 1)
4	CT Unit MW Capacity
5	Total CT/CC Facilities MW Capacity
6	Percent Allocable to CT Unit (Line 4 divided by Line 5)
7	A&G Allocable to CT Unit (Line 3 x Line 6)
8	Percent Allocable to Tampa: 40% Commencing on the 2003 Capacity Additions Energy Charge Effective Date, percentage allocable to Tampa: 59.77%
9	A&G Expense Allocable to Tampa (Line 7 x Line 8)

Note 1: Included only those expenses directly charged to the CT/CC Facilities, the 2003 Capacity Additions and Allocable Costs from TECO Energy, Inc. per Appendix S. Administrative and General services by TECO Energy subsidiaries will be provided at cost. Direct charges shall include only those expenses which provide a benefit to the CT/CC Facilities and the 2003 Capacity Additions. These expenses must be supportable by documentation such as invoices, monthly time sheets, and salary allocations (but only to the extent such salary allocations are reviewed on at least an annual basis.) These expenses may include charges from TECO Energy's associated companies, however, in no event shall such expenses include profits or markups to such associated companies other than associated payroll allocations of pension, benefits, taxes and insurance. Such charges from

TECO Energy's associated companies shall be pursuant to written agreements with HPP and subject to acceptance by Tampa pursuant to the provisions of Section 7.4 of this Agreement.

The formula described above reflects the organizational structure, accounting policies, the capitalization and units of property policies, and the lease versus ownership practices currently in effect at the time this Agreement is entered into. If a material change occurs in any practice or policy that results in the above formula no longer reflecting accurately the costs recoverable pursuant to such formula as of the date of this Agreement, then the Operating Committee shall review and if required modify the formula to result in a just, fair and reasonable recovery of the actual expenses incurred.

A. Summary of Significant Accounting Policies

Organization -- Hardee Power Partners Limited (Hardee Power), a limited partnership, was organized under the provisions of the Florida Revised Uniform Limited Partnership Act as amended. Hardee Power was formed Mar. 21, 1990 for the purpose of constructing, owning and operating Hardee Power Station, a 295-megawatt combined cycle and combustion turbine generating facility in Hardee County, Florida. On Jan. 1, 1993, Hardee Power Station began commercial operation providing 440 megawatts of backup power to Seminole Electric Cooperative (Seminole) and 295 megawatts of peaking and intermediate capacity to Tampa Electric Company (Tampa Electric), an affiliated company, for a twenty year period. During the first ten years, Tampa Electric will sell limited use of 145 megawatts of capacity from its coal-fired Big Bend Four generating unit to Hardee Power for resale to Seminole. Hardee Power increased the existing 295 MW station to 370 MW during 2000. The commercial operation date for the 75 MW expansion was May 17, 2000. This expansion is the first since Hardee Power went into commercial operation in 1993. The total cost of the project was approximately $41.6 million. In 1999, Hardee Power entered into a sale-leaseback of certain equipment at the Hardee Power Station, as discussed in footnote E.

Basis of accounting -- Hardee Power maintains its accounts in accordance with recognized policies prescribed or permitted by the Federal Energy Regulatory Commission (FERC). These policies conform with generally accepted accounting principles in all material respects. Hardee Power's wholesale business is regulated by the FERC.

Revenue recognition – Revenues derived from power generation are recognized upon output, product delivery or satisfaction of specific targets, all as specified as contract terms.

Depreciation -- Hardee Power provides for depreciation primarily by the straight-line method at annual rates that amortize the original cost of depreciable property over the estimated service life. The provision for plant in service, expressed as a percentage of the original cost of depreciable property, was 3.0% for 2001 and 2000. Depreciation expense for 2001 and 2000 was approximately $5.9 million and $6.9 million, respectively.

Interest capitalized -- Interest costs for the construction of Hardee Power Station were capitalized and will be amortized over the service lives of the related property. No interest was capitalized during 2001 and 2000.

Income taxes -- No provision is made for income taxes in the financial statements of Hardee Power since earnings are reported by the individual partners.

Cash and cash equivalents -- Cash equivalents are highly liquid, high-quality debt instruments purchased with an original maturity of three months or less. The carrying amount of cash equivalents approximated fair market value because of the short maturity of these instruments.

Property, plant and equipment -- Property, plant and equipment is stated at original cost. Capitalized amounts include appropriate administrative and general costs, payroll-related costs, taxes and other benefits, and interest during construction.

Asset impairment -- Hardee Power periodically assesses whether there has been a permanent impairment of its long-lived assets and certain intangibles held and used by it, in accordance with FAS 121, Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of. No write-down of assets due to impairment was required in 2001 or 2000.

In August 2001, the Financial Accounting Standards Board issued FAS 144, Accounting for the Impairment or Disposal of Long-Lived Assets. FAS 144 addresses accounting and reporting for the impairment or disposal of long-lived assets, including the disposal of a segment of a business, and supersedes FAS 121. FAS 144 is effective for fiscal years beginning after December 15, 2001.

Deferred charges -- Debt issuance costs are amortized on a straight-line basis, which approximates the effective interest method, over the term of the related debt. Power sales agreement negotiation costs are amortized on a straight-line basis over the term of the agreement.

Use of estimates -- The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Reclassification – Certain prior year amounts were reclassified to conform with current year presentation.

B. Partnership Agreement

Formation -- Hardee Power was formed Mar. 21, 1990 between Hardee Power I, Inc. (HP I), the general partner, and Hardee Power II, Inc. (HP II), the limited partner. Both HP I and HP II are wholly owned subsidiaries of TECO Power Services, which is a wholly owned subsidiary of TECO Energy, Inc.

Allocation of profits and losses -- Profits and losses are to be allocated between the partners based on each partner's contributions to capital, 25% to HP I and 75% to HP II.

Related parties -- TECO Power Services provides Hardee Power administrative support in the areas of contract administration, fuel procurement and environmental compliance. TPS Operations Co., a wholly owned subsidiary of TECO Power Services, provides Hardee Power all operating and maintenance support functions. Accordingly, Hardee Power has no employees. In 2001, Hardee Power reimbursed TECO Power Services and TPS Operations Co. $1.7 million and $8.2 million, respectively. In 2000,

Hardee Power reimbursed TECO Power Services and TPS Operations Co. $1.1 million and $3.0 million, respectively.

Effective on Jun. 1, 1999, the TECO Peoples Gas transportation capacity contract was extended through 2002. TECO Peoples Gas, an affiliated company, assumed the role of delivery point operator with the upstream natural gas pipeline. This change allows Hardee Power to balance its monthly actual natural gas usage with TECO Peoples Gas instead of the Florida Gas Transmission Company pipeline. This transportation contract will expire around the time a second pipeline may be in use in Central Florida. Hardee Power charges under the capacity contract were $3.3 million and $2.0 million in 2001 and 2000, respectively.

During 2000, Hardee Power began purchasing natural gas for Tampa Electric, an affiliated company, for their Polk power station. Hardee Power acted only as a pass through entity for the transactions. As of Apr. 30, 2001, Hardee Power discontinued the purchasing of natural gas at the request of Tampa Electric. Hardee Power purchased $6.5 million and $8.8 million of natural gas for Tampa Electric in 2001 and 2000, respectively. In 2001, Tampa Electric paid Hardee for all Polk purchases and the affiliate receivable was zero at Dec. 31, 2001. There was no income statement effect as a result of the transactions.

C. Long-Term Debt

Hardee Power's long-term debt consists of $165 million of 20 year non-recourse secured facilities notes, Series A, bearing interest at 7.8%. The notes are collateralized by the facility. These long-term debt agreements contain various restrictive covenants, including provisions related to the debt service coverage ratio, maximum levels of debt to total capitalization and an annual requirement of a certificate by an Independent Engineer evaluating the plant performance.

Maturities of the Series A notes for the years 2003, 2004, 2005 and 2006 are $8.1 million, $8.8 million, $9.5 million and $10.2 million, respectively. At Dec. 31, 2001, the notes had a carrying amount of $118.6 million and an estimated fair market value of $127.2 million. The estimated fair market value of the notes was based on the current rates offered for debt of the same remaining maturities. The carrying amount of long-term debt due within one year approximated fair market value because of the short maturity of these instruments.

D. Commitments and Contingencies

Hardee Power estimates that capital expenditures for ongoing business during 2002 will be approximately $550,000 and approximately $1.2 million for the years 2003 through 2006.

E. Operating Leases

Hardee Power has a 22-year lease for approximately 1,300 acres of land in Hardee and Polk counties, Florida which is the site for Hardee Power Station. The lease is renewable for up to five consecutive four-year terms. Rental expense related to the lease was capitalized during the construction of the generating facility. For the years ended Dec. 31, 2001 and 2000, total lease payments made were approximately $175 thousand and $177 thousand, respectively.

Hardee Power completed a transaction on December 29, 2000, where certain equipment at the Hardee Power Station was sold to a third party and leased back under an operating lease agreement with an initial term of 12 years. The proceeds received by Hardee Power were approximately $42.4 million, which resulted in a deferred gain of approximately $1.4 million. For the years ended Dec. 31, 2001 and 2000, total lease payments were $3.3 million and zero, respectively.

Total future minimum lease payments are approximately as follows (in thousands):

Year ending Dec. 31:

2002	$ 3,589
2003	3,585
2004	3,581
2005	3,577
2006	3,573
Thereafter to 2012	21,358
Total minimum lease payments	$39,263

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Hardee Power Partners Limited	(1) [X] An Original (2) [ ] A Resubmission	04/30/2002	Dec. 31, 2001

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another Utility column (i, k, m, o) in a similar manner to a utility department. Spread the amount(s) over Lines 02 thru 24 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7,9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.
4. Use pages 122-123 for important notes regarding the statement of income or any account thereof.
5. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301	123,655,417	128,284,914
3	Operating Expenses			
4	Operation Expenses (401)	320-323	84,837,904	90,320,837
5	Maintenance Expenses (402)	320-323	5,234,568	2,863,528
6	Depreciation Expense (403)	336-337	5,880,154	6,853,082
7	Amort. & Depl. of Utility Plant (404-405)	336-337	357,487	73,065
8	Amort. of Utility Plant Acq. Adj. (406)	336-337		
9	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)			
10	Amort. of Conversion Expenses (407)			
11	Regulatory Debits (407.3)			
12	(Less) Regulatory Credits (407.4)			
13	Taxes Other Than Income Taxes (408.1)	262-263	3,026,925	2,440,246
14	Income Taxes - Federal (409.1)	262-263		
15	- Other (409.1)	262-263		
16	Provision for Deferred Income Taxes (410.1)	234, 272-277		
17	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277		
18	Investment Tax Credit Adj. - Net (411.4)	266		
19	(Less) Gains from Disp. of Utility Plant (411.6)			
20	Losses from Disp. of Utility Plant (411.7)			
21	(Less) Gains from Disposition of Allowances (411.8)			
22	Losses from Disposition of Allowances (411.9)			
23	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		99,337,038	102,550,758
24	Net Util Oper Inc (Enter Tot line 2 less 23) Carry fwd to P117,line 25		24,318,379	25,734,156

LTD 120935239
Eq 47257721
168192960
Wallace 190445632

over 22
ROR =
12.769 (no taxes shown)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Hardee Power Partners Limited	(1) [X] An Original (2) [ ] A Resubmission	04/30/2002	Dec. 31, 2001

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).

. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Tampa Electric Company (1)	LU	2			
2	Seminole Electric Cooperative	LU	1			
3						
4						
5						
6	(1) Subsidiary of parent holding					
7	company, TECO Energy, Inc.					
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.

AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	REVENUE Energy Charges ($) (i)	REVENUE Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
940,400	19,451,507	45,141,417		64,592,924	1
684,424	33,845,111	24,582,636		58,427,747	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
1,624,824	53,296,618	69,724,053	0	123,020,671	
1,624,824	**53,296,618**	**69,724,053**	**0**	**123,020,671**	

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Calculation of Incremental Hedging Expenses		
	Actual Expenses	
	2001	2002
Payroll and Fringe Benefits	$ 159,723	$ 252,939
Travel Costs	2,500	-
Training	6,930	-
Total	$ 169,153	$ 252,939
2002 Incremental Hedging Costs (2002 Expenses Less 2001 'Base Year' Expenses)	**$ 83,786**	

FLORIDA PUBLIC SERVICE COMMISSION
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COMPANY/ TEC
WITNESS: JTW-1
DATE: 11-12-03

DOCUMENT NUMBER-DATE
03073 APR-1 8
FPSC-COMMISSION CLERK

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2002 TRANSPORTATION BENCHMARK CALCULATION

Average Rail Mileage to Tampa		1,146	miles	(Note 1)
x	Average of Lowest Two Publicly Available Florida Rail Rates	1.93	¢ / ton mile	(Note 2)
+	Costs of Privately Owned Rail Cars	$ 1.75	per ton	(Note 3)
Transportation Benchmark for the Year Ended 12/31/02		$ 23.87	per ton	(Note 4)

Notes

1/ Weighted average domestic rail miles from all Tampa Electric waterborne coal supplies to plants. Rail miles for imported coal sources are measured from port of entry.

2/ Cents per ton-mile for publicly available Florida utility rail coal transportation rates including discounts for volume and private rail cars. The current publicly available rail rates to Florida utilities on a cents per ton-mile basis for 2001 are as follows:

JEA	¢	2.52
Orlando	¢	1.99
Lakeland	¢	1.89
Gainesville	¢	1.98
* Average of Lowest Two	¢	1.93

3/ The cost of private rail cars was approved in the original stipulation as $2.00 per ton. Subsequent negotiation between Tampa Electric and Public Service Commission Staff resulted in an agreed upon estimated cost of $1.75 per ton.

4/ Calculated by multiplying average domestic rail mileage to Tampa by Florida rail coal market costs (cents per ton-mile), then adding the costs of privately-owned rail cars.

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REDACTED

2002 TRANSPORTATION MARKET PRICE APPLICATION

Tampa Electric Weighted Average per ton Water Transportation Price from All Tampa Electric Coal Sources [redacted] divided by 6,440,178.97 tons	[redacted]
Transportation Benchmark	$23.87
Over/(Under) Benchmark	[redacted]
Total Tons Transported in 2002	6,440,178.97
Total Transportation Cost in 2002	[redacted]
Total Amount Allowable for Recovery Using Benchmark ($23.87 x 6,440,178.97 tons)	$153,727,072.01
Total Cost Over/(Under) Benchmark – 2002	[redacted]
Prior Year's Cumulative Benefit (1988-2001)	[redacted]
Net Benefit for 1988 – 2002	[redacted]

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Updated Transportation Services Solicitation Schedule

Step	Tasks to Establish Transportation Contract	Estimated Completion Date
1.	Complete evaluation of proposals	Week of September 22
2.	Notify transportation provider that submitted the winning proposal and begin contract negotiations	Week of September 22
3.	Complete transportation contract negotiations	Week of October 24
4.	Execute new transportation contract	Week of November 3
5.	Notify unsuccessful bidders that contract has been awarded	Week of November 3

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Tampa Electric Company
2004 Projected Incremental O&M Hedging Costs

Incremental O&M Hedging Costs

Labor and related charges	$	80,847
System development		100,000
Consultant fees		100,000
Total	**$**	**280,847**

TAMPA ELECTRIC COMPANY
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TAMPA ELECTRIC COMPANY

FUEL AND PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 28
COMPANY/ TECO
WITNESS. JDJ-1
DATE 11-12-03

DOCUMENT NUMBER-DATE
03071 APR-1 8
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FUEL AND PURCHASED POWER COST RECOVERY

AND

CAPACITY COST RECOVERY

INDEX

DOCUMENT NO.	TITLE	PAGE
1	Final Capacity Over/ (Under) Recovery for January 2002 - December 2002	13
2	Final Fuel and Purchased Power Over/ (Under) Recovery for January 2002 - December 2002	18
3	Actual Fuel and Purchased Power True-up *vs.* Original Estimates	20
4	Final Fuel and Purchased Power Recovery January 2002 - December 2002 Schedules A1 through A9	22

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EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 1

FINAL CAPACITY OVER/(UNDER) RECOVERY FOR

JANUARY 2002 - DECEMBER 2002

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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2002 THROUGH DECEMBER 2002

1.	End-of-Period True-up: Over/(Under) Recovery	($1,842,516)
2.	Less: Actual/Estimated Over/(Under) Recovery Approved at the November 2002 Fuel Hearings for the January 2002 through December 2002 period	(1,528,054)
3.	Net True-up: Over/(Under) Recovery to be carried forward to the January 2004 through December 2004 period	**($314,462)**

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2002 THROUGH DECEMBER 2002

	Actual Jan-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	Total
1 UNIT POWER CAPACITY CHARGES	1,849,662	1,651,854	1,651,854	1,651,854	1,651,854	1,651,854	1,651,854	1,651,854	1,312,284	1,617,897	1,456,634	2,329,868	20,129,323
2 CAPACITY PAYMENTS TO COGENERATORS	1,275,735	1,275,735	1,275,735	1,532,415	1,532,415	1,532,415	1,532,415	1,532,415	1,537,065	1,537,065	1,537,065	1,537,065	17,637,540
3 EMERGENCY CAPACITY CHARGES	1,753,279	1,446,664	1,251,885	1,064,359	1,295,042	1,754,591	1,836,009	1,836,771	1,159,791	1,854,984	1,173,755	1,310,809	17,737,939
4 INCREMENTAL SECURITY O&M COSTS	0	0	0	0	0	0	0	0	0	0	0	816,076	816,076
5 (CAPACITY REVENUES)	(66,339)	(54,354)	(35,774)	(86,329)	(310,072)	142,068	(95,334)	(116,347)	(92,262)	14,174	(34,872)	(37,775)	(773,216)
6 TOTAL CAPACITY DOLLARS	4,812,337	4,319,899	4,143,701	4,162,299	4,169,239	5,080,928	4,924,944	4,904,692	3,916,878	5,024,120	4,132,582	5,956,043	55,547,663
7 JURISDICTIONAL PERCENTAGE	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	0.9189189	
8 JURISDICTIONAL CAPACITY DOLLARS	4,422,147	3,969,637	3,807,725	3,824,815	3,831,192	4,668,961	4,525,624	4,507,015	3,599,294	4,616,759	3,797,508	5,473,120	51,043,797
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	4,231,917	3,557,714	3,514,105	4,056,855	4,668,632	4,817,528	4,765,906	4,960,801	5,010,618	5,007,012	4,020,593	3,775,360	52,387,041
10 PRIOR PERIOD TRUE-UP PROVISION	(463,342)	(463,342)	(463,342)	(463,342)	(463,342)	(463,342)	(463,342)	(463,342)	(463,342)	(463,342)	(463,342)	(463,341)	(5,560,103)
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	3,768,575	3,094,372	3,050,763	3,593,513	4,205,290	4,354,186	4,302,564	4,497,459	4,547,276	4,543,670	3,557,251	3,312,019	46,826,938
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	(653,572)	(875,265)	(756,962)	(231,302)	374,098	(314,775)	(223,060)	(9,556)	947,982	(73,089)	(240,257)	(2,161,101)	(4,216,859)
13 INTEREST PROVISION FOR PERIOD	(4,793)	(5,210)	(5,775)	(5,829)	(5,012)	(4,295)	(3,961)	(3,416)	(2,116)	(796)	(314)	(1,072)	(42,589)
14 TRUE-UP AND INT. PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(3,143,171)	(3,338,194)	(3,755,327)	(4,054,722)	(3,828,511)	(2,996,083)	(2,851,811)	(2,615,490)	(2,165,120)	(755,912)	(366,455)	(143,684)	(3,143,171)
15 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	463,342	463,342	463,342	463,342	463,342	463,342	463,342	463,342	463,342	463,342	463,342	463,341	5,560,103
16 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 15)	(3,338,194)	(3,755,327)	(4,054,722)	(3,828,511)	(2,996,083)	(2,851,811)	(2,615,490)	(2,165,120)	(755,912)	(366,455)	(143,684)	(1,842,516)	**(1,842,516)**

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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD JANUARY 2002 THROUGH DECEMBER 2002

	Actual Jan-02	Actual Feb-02	Actual Mar-02	Actual Apr-02	Actual May-02	Actual Jun-02	Actual Jul-02	Actual Aug-02	Actual Sep-02	Actual Oct-02	Actual Nov-02	Actual Dec-02	Total
1 BEGINNING TRUE-UP AMOUNT	(3,143,171)	(3,338,194)	(3,755,327)	(4,054,722)	(3,828,511)	(2,996,083)	(2,851,811)	(2,615,490)	(2,165,120)	(755,912)	(366,455)	(143,684)	(3,143,171)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(3,333,401)	(3,750,117)	(4,048,947)	(3,822,682)	(2,991,071)	(2,847,516)	(2,611,529)	(2,161,704)	(753,796)	(365,659)	(143,370)	(1,841,444)	(1,799,927)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	(6,476,572)	(7,088,311)	(7,804,274)	(7,877,404)	(6,819,582)	(5,843,599)	(5,463,340)	(4,777,194)	(2,918,916)	(1,121,571)	(509,825)	(1,985,128)	(4,943,098)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(3,238,286)	(3,544,156)	(3,902,137)	(3,938,702)	(3,409,791)	(2,921,800)	(2,731,670)	(2,388,597)	(1,459,458)	(560,786)	(254,913)	(992,564)	(2,471,549)
5 INTEREST RATE % - 1ST DAY OF MONTH	1.780	1.770	1.750	1.800	1.750	1.770	1.750	1.730	1.710	1.760	1.650	1.300	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	1.770	1.750	1.800	1.750	1.770	1.750	1.730	1.710	1.760	1.650	1.300	1.290	NA
7 TOTAL (LINE 5 + LINE 6)	3.550	3.520	3.550	3.550	3.520	3.520	3.480	3.440	3.470	3.410	2.950	2.590	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	1.775	1.760	1.775	1.775	1.760	1.760	1.740	1.720	1.735	1.705	1.475	1.295	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.148	0.147	0.148	0.148	0.147	0.147	0.145	0.143	0.145	0.142	0.123	0.108	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(4,793)	(5,210)	(5,775)	(5,829)	(5,012)	(4,295)	(3,961)	(3,416)	(2,116)	(796)	(314)	(1,072)	(42,589)

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EXHIBIT NO._____
DOCKET NO. 030001-EI
TAMPA ELECTRIC COMPANY
(JDJ-1)
DOCUMENT NO. 1
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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD JANUARY 2002 THROUGH DECEMBER 2002

	(1) ACTUAL	(2) ACTUAL/ ESTIMATED	(3) VARIANCE (1) - (2)	(4) % CHANGE (3)/(2)
1 UNIT POWER CAPACITY CHARGES	$20,129,323	$39,016,852	($18,887,529)	-48.41%
2 CAPACITY PAYMENTS TO COGENERATORS	17,637,540	$17,653,850	(16,310)	-0.09%
3 EMERGENCY CAPACITY CHARGES	17,737,939	0	17,737,939	0.00%
4 INCREMENTAL SECURITY O&M COSTS	816,076	0	816,076	0.00%
5 (CAPACITY REVENUES)	(773,216)	($996,000)	222,784	-22.37%
6 TOTAL CAPACITY DOLLARS	$55,547,663	$55,674,702	($127,039)	-0.23%
7 JURISDICTIONAL PERCENTAGE	91.89189%	91.89189%	0.00000%	0.00%
8 JURISDICTIONAL CAPACITY DOLLARS	$51,043,797	$51,160,536	($116,739)	-0.23%
9 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	52,387,041	52,826,605	(439,564)	-0.83%
10 PRIOR PERIOD TRUE-UP PROVISION	(5,560,103)	(5,560,103)	0	0.00%
11 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	$46,826,938	$47,266,502	($439,564)	-0.93%
12 TRUE-UP PROVISION FOR PERIOD OVER/(UNDER) RECOVERY (Line 11 - Line 8)	($4,216,859)	($3,894,034)	($322,825)	8.29%
13 INTEREST PROVISION FOR PERIOD	(42,589)	(50,952)	8,363	-16.41%
14 TRUE-UP AND INT. PROVISION BEGINNING OF PERIOD - OVER/(UNDER) RECOVERY	(3,143,171)	(3,143,171)	0	0.00%
15 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS PERIOD	5,560,103	5,560,103	0	0.00%
16 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 12 - 15)	($1,842,516)	($1,528,054)	($314,462)	20.58%

EXHIBIT NO. _____
DOCKET NO. 030001-EI
TAMPA ELECTRIC COMPANY
(JDJ-1)
DOCUMENT NO. 2

EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 2

FINAL FUEL AND PURCHASED POWER OVER/(UNDER) RECOVERY

FOR

JANUARY 2002 - DECEMBER 2002

EXHIBIT NO._____
DOCKET NO. 030001-EI
TAMPA ELECTRIC COMPANY
(JDJ-1)
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PAGE 1 OF 1

TAMPA ELECTRIC COMPANY
FINAL FUEL OVER/(UNDER)-RECOVERY
FOR THE PERIOD
JANUARY 2002 THROUGH DECEMBER 2002

1	TOTAL FUEL COSTS FOR THE PERIOD	$523,259,217
2	JURISDICTIONAL FUEL COSTS (INCL. PEABODY AND ALL ADJUSTMENTS)	512,067,602
3	JURISDICTIONAL FUEL REVENUES APPLICABLE TO THE PERIOD	490,205,204
4	ACTUAL OVER/(UNDER)-RECOVERED FUEL COSTS FOR THE PERIOD (*LINE 3 - LINE 2*)	(21,862,398)
5	INTEREST	(981,360)
6	TRUE-UP COLLECTED	88,672,735
7	PRIOR PERIOD TRUE-UP (ACTUAL ENDING 12/01)	(97,656,895)
8	ACTUAL OVER/(UNDER)-RECOVERY FOR THE PERIOD (LINE 4 + LINE 5 + LINE 6 + LINE 7)	(31,827,918)
9	*PROJECTED UNDER-RECOVERY PER PROJECTION FILED 9/20/02* (SCHEDULE E1-A LINE 3)	(3,165,591)
10	**FINAL FUEL OVER/(UNDER)-RECOVERY (LINE 8 - LINE 9)**	**($28,662,327)**

EXHIBIT NO. _____
DOCKET NO. 030001-EI
TAMPA ELECTRIC COMPANY
(JDJ-1)
DOCUMENT NO. 3

EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 3

ACTUAL FUEL AND PURCHASED POWER TRUE-UP

VS.

ORIGINAL ESTIMATES

JANUARY 2002 - DECEMBER 2002

EXHIBIT NO._____
DOCKET NO. 030001-EI
TAMPA ELECTRIC COMPANY
(JDJ-1)
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TAMPA ELECTRIC COMPANY
CALCULATION OF TRUE-UP AMOUNT
ACTUAL vs. ORIGINAL ESTIMATES
FOR THE PERIOD:
JANUARY 2002 THROUGH DECEMBER 2002

		ACTUAL	ESTIMATED	VARIANCE AMOUNT	%
A	1. FUEL COST OF SYSTEM NET GENERATION	$356,592,326	$392,688,455	($36,096,129)	(9.2)
	2. FUEL COST OF POWER SOLD	14,537,254	18,634,100	(4,096,846)	(22.0)
	2a. GAINS FROM MARKET BASED SALES	131,309	3,150,500	(3,019,191)	(95.8)
	3. FUEL COST OF PURCHASED POWER	169,929,890	143,368,600	26,561,290	18.5
	3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0
	3b. PAYMENT TO QUALIFIED FACILITIES	11,416,463	10,762,700	653,763	6.1
	4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0
	6a. ADJ. TO FUEL COST (FT. MEADE/WAUCHULA)	(69,826)	(48,000)	(21,826)	45.5
	6b. ADJ. TO FUEL COST	(24,859)	0	(24,859)	0.0
	6c. RISK MANAGEMENT O&M	83,786	0	83,786	0.0
	7. ADJUSTED TOTAL FUEL & NET PWR.TRANS. SUM OF LINES A1 THRU 6c	$523,259,217	$524,987,155	($1,727,938)	(0.3)
C	1. JURISDICTIONAL FUEL REVENUE	$579,972,895	$585,250,619	($5,277,724)	(0.9)
	2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0
	a. TRUE-UP PROVISION	(88,672,735)	(88,672,735)	0	0.0
	b. INCENTIVE PROVISION	(1,094,956)	(1,094,956)	0	0.0
	3. JURIS. FUEL REVENUE APPL. TO PERIOD (Sum of Lines C1 through C2b)	490,205,204	495,482,928	(5,277,724)	(1.1)
	6B.JURISDICTIONAL FUEL COST	508,803,680	492,466,467	16,337,213	3.3
	6D.PEABODY CONTRACT BUY OUT AMORT. JURISD.	3,518,281	3,390,659	127,622	3.8
	6E.1999 REVENUE REFUND ADJ.	(254,359)	0	(254,359)	0.0
	6F.OTHER	0	0	0	0.0
	6G.OTHER	0	0	0	0.0
	6H.JURISD. TOTAL FUEL & NET PWR. TRANS. (INCL. PEABODY AND ALL ADJUSTMENTS)	512,067,602	495,857,126	16,210,476	3.3
	7. TRUE-UP PROV.- THIS PER. (LINE C3-C6H)	(21,862,398)	(374,198)	(21,488,200)	5,742.5
	8. INTEREST PROVISION - THIS PERIOD	(981,360)	(1,657,379)	676,019	(40.8)
	9.TOTAL TRUE-UP AMOUNT FOR PERIOD	($22,843,758)	($2,031,577)	($20,812,181)	1,024.4
	10.TRUE-UP & INT. PROV. BEG. OF PERIOD (Beginning January 2002)	(97,656,895)	(88,672,735)	(8,984,160)	10.1
	11.TRUE-UP COLLECTED (REFUNDED)	88,672,735	88,672,735	0	0.0
	12.END OF PERIOD TOTAL NET TRUE-UP (LINE C9 through C11)	($31,827,918)	($2,031,577)	($29,796,341)	1,466.7

Line numbers reference Schedule A-2 included in Document No. 4

EXHIBIT NO. _____
DOCKET NO. 030001-EI
TAMPA ELECTRIC COMPANY
(JDJ-1)
DOCUMENT NO. 4

EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 4

FUEL AND PURCHASED POWER COST RECOVERY

JANUARY 2002 - DECEMBER 2002

SCHEDULES A1 THROUGH A9

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

JANUARY 2002

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY

MONTH OF: JANUARY 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	30,886,176	31,558,471	(672,295)	-2.1%	1,370,467	1,487,466	(116,999)	-7.9%	2.25370	2.12163	0.13207	6.2%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. *Coal Car Investment*	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(4,538)	(4,000)	(538)	13.5%	1,370,467 (a)	1,487,466 (a)	(116,999)	-7.9%	(0.00033)	(0.00027)	(0.00006)	23.1%
4b. Adjustments to Fuel Cost (1)	(477)	0	(477)	0.0%	1,370,467 (a)	1,487,466 (a)	(116,999)	-7.9%	(0.00003)	0.00000	(0.00003)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	1,370,467 (a)	1,487,466 (a)	(116,999)	-7.9%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**30,881,161**	**31,554,471**	**(673,310)**	**-2.1%**	**1,370,467**	**1,487,466**	**(116,999)**	**-7.9%**	**2.25333**	**2.12136**	**0.13197**	**6.2%**
6. Fuel Cost of Purchased Power - Firm (A7)	7,646,400	6,118,500	1,527,900	25.0%	120,294	105,976	14,318	13.5%	6.35643	5.77348	0.58295	10.1%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	791,923	849,700	(57,777)	-6.8%	40,276	39,069	1,207	3.1%	1.96624	2.17487	(0.20863)	-9.6%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**8,438,323**	**6,968,200**	**1,470,123**	**21.1%**	**160,570**	**145,045**	**15,525**	**10.7%**	**5.25523**	**4.80416**	**0.45107**	**9.4%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,531,037**	**1,632,511**	**(101,474)**	**-6.2%**				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	70,285	93,700	(23,415)	-25.0%	3,663	6,206	(2,543)	-41.0%	1.91878	1.50983	0.40895	27.1%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	769	0	769	0.0%	25	0	25	0.0%	3.07600	0.00000	3.07600	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	643,936	1,297,000	(653,064)	-50.4%	24,846	53,940	(29,094)	-53.9%	2.59171	2.40452	0.18719	7.8%
21. Fuel Cost of Market Base Sales (A6)	285,653	316,100	(30,447)	-9.6%	14,989	15,027	(38)	-0.3%	1.90575	2.10355	(0.19780)	-9.4%
21a. Gains on Market Based Sales	31,489	135,800	(104,311)	-76.8%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 +21a)	**1,032,132**	**1,842,600**	**(810,468)**	**-44.0%**	**43,523**	**75,173**	**(31,650)**	**-42.1%**	**2.37148**	**2.45115**	**(0.07968)**	**-3.3%**
23. Net Inadvertant Interchange					1,320	0	1,320	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					(13)	0	(13)	0.0%				
25. Interchange and Wheeling Losses					362	1,100	(738)	-67.1%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	**38,287,352**	**36,680,071**	**1,607,281**	**4.4%**	**1,488,459**	**1,556,238**	**(67,779)**	**-4.4%**	**2.57228**	**2.35697**	**0.21531**	**9.1%**
27. Net Unbilled	(461,905) (a)	(139,321) (a)	(322,584)	231.5%	(17,957)	(5,911)	(12,046)	203.8%	2.57228	2.35698	0.21531	9.1%
28. Company Use	99,161 (a)	96,636 (a)	2,525	2.6%	3,855	4,100	(245)	-6.0%	2.57227	2.35698	0.21529	9.1%
29. T & D Losses	1,380,749 (a)	542,390 (a)	838,359	154.6%	53,678	23,012	30,666	133.3%	2.57228	2.35697	0.21531	9.1%
30. System KWH Sales	38,287,352	36,680,071	1,607,281	4.4%	1,448,883	1,535,037	(86,154)	-5.6%	2.64254	2.38952	0.25302	10.6%
31. Wholesale KWH Sales	(624,751)	(2,253,440)	1,628,689	-72.3%	(23,642)	(94,305)	70,663	-74.9%	2.64255	2.38952	0.25302	10.6%
32. Jurisdictional KWH Sales	37,662,601	34,426,631	3,235,970	9.4%	1,425,241	1,440,732	(15,491)	-1.1%	2.64254	2.38952	0.25302	10.6%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	37,687,458	34,449,353	3,238,105	9.4%	1,425,241	1,440,732	(15,491)	-1.1%	2.64429	2.39110	0.25319	10.6%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	310,079	295,857	14,222	4.8%	1,425,241	1,440,732	(15,491)	-1.1%	0.02176	0.02054	0.00122	5.9%
35a. Adjustment	0	0	0	0.0%	1,425,241	1,440,732	(15,491)	-1.1%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	1,425,241	1,440,732	(15,491)	-1.1%	0.00000	0.00000	0.00000	0.0%
36. True-up *	7,389,395	7,389,395	0	0.0%	1,425,241	1,440,732	(15,491)	-1.1%	0.51847	0.51289	0.00557	1.1%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	45,386,932	42,134,605	3,252,327	7.7%	1,425,241	1,440,732	(15,491)	-1.1%	3.18451	2.92453	0.25998	8.9%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.18680	2.92663	0.26017	8.9%
40. GPIF * (Already Adjusted for Taxes)	91,246	91,246	0	0.0%	1,425,241	1,440,732	(15,491)	-1.1%	0.00640	0.00633	0.00007	1.1%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**45,478,178**	**42,225,851**	**3,252,327**	**7.7%**	**1,425,241**	**1,440,732**	**(15,491)**	**-1.1%**	**3.19320**	**2.93296**	**0.26024**	**8.9%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.193**	**2.933**	**0.260**	**8.9%**

* Based on Jurisdictional Sales (a) Included for Informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY

PERIOD TO DATE THROUGH: JANUARY 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	30,886,176	31,558,471	(672,295)	-2.1%	1,370,467	1,487,466	(116,999)	-7.9%	2.25370	2.12163	0.13207	6.2%
2. *Spent Nuclear Fuel Disposal Cost*	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(4,538)	(4,000)	(538)	13.5%	1,370,467 (a)	1,487,466 (a)	(116,999)	-7.9%	(0.00033)	(0.00027)	(0.00006)	23.1%
4b. Adjustments to Fuel Cost (1)	(477)	0	(477)	0.0%	1,370,467 (a)	1,487,466 (a)	(116,999)	-7.9%	(0.00003)	0.00000	(0.00003)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	1,370,467 (a)	1,487,466 (a)	(116,999)	-7.9%	0.00000	0.00000	0.00000	0.0%
5. *TOTAL COST OF GENERATED POWER (Lines 1 through 4c)*	***30,881,161***	***31,554,471***	***(673,310)***	***-2.1%***	**1,370,467**	**1,487,466**	**(116,999)**	**-7.9%**	**2.25333**	**2.12136**	**0.13197**	**6.2%**
6. Fuel Cost of Purchased Power - Firm (A7)	7,646,400	6,118,500	1,527,900	25.0%	120,294	105,976	14,318	13.5%	6.35643	5.77348	0.58295	10.1%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	791,923	849,700	(57,777)	-6.8%	40,276	39,069	1,207	3.1%	1.96624	2.17487	(0.20863)	-9.6%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**8,438,323**	**6,968,200**	**1,470,123**	**21.1%**	**160,570**	**145,045**	**15,525**	**10.7%**	**5.25523**	**4.80416**	**0.45107**	**9.4%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,531,037**	**1,632,511**	**(101,474)**	**-6.2%**				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	70,285	93,700	(23,415)	-25.0%	3,663	6,206	(2,543)	-41.0%	1.91878	1.50983	0.40895	27.1%
18. Fuel Cost of Sch. G Jurisd. Sales (A6)	769	0	769	0.0%	25	0	25	0.0%	3.07600	0.00000	3.07600	0.0%
19. Fuel Cost of FMPA D Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	643,936	1,297,000	(653,064)	-50.4%	24,846	53,940	(29,094)	-53.9%	2.59171	2.40452	0.18719	7.8%
21. Fuel Cost of Market Base Sales (A6)	285,653	316,100	(30,447)	-9.6%	14,989	15,027	(38)	-0.3%	1.90575	2.10355	(0.19780)	-9.4%
21a. Gains on Market Based Sales	31,489	135,800	(104,311)	-76.8%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES *(LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)*	**1,032,132**	**1,842,600**	**(810,468)**	**-44.0%**	**43,523**	**75,173**	**(31,650)**	**-42.1%**	**2.37146**	**2.45115**	**(0.07968)**	**-3.3%**
23. Net Inadvertant Interchange					1,320	0	1,320	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					(13)	0	(13)	0.0%				
25. Interchange and Wheeling Losses					362	1,100	(738)	-67.1%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	**38,287,352**	**36,680,071**	**1,607,281**	**4.4%**	**1,488,459**	**1,556,238**	**(67,779)**	**-4.4%**	**2.57228**	**2.35697**	**0.21531**	**9.1%**
27. Net Unbilled	(461,905) (a)	(139,321) (a)	(322,584)	231.5%	(17,957)	(5,911)	(12,046)	203.8%	2.57228	2.35698	0.21531	9.1%
28. Company Use	99,161 (a)	96,636 (a)	2,525	2.6%	3,855	4,100	(245)	-6.0%	2.57227	2.35698	0.21529	9.1%
29. T & D Losses	1,380,749 (a)	542,390 (a)	838,359	154.6%	53,678	23,012	30,666	133.3%	2.57228	2.35697	0.21531	9.1%
30. System KWH Sales	38,287,352	36,680,071	1,607,281	4.4%	1,448,883	1,535,037	(86,154)	-5.6%	2.64254	2.38952	0.25302	10.6%
31. Wholesale KWH Sales	(624,751)	(2,253,440)	1,628,689	-72.3%	(23,642)	(94,305)	70,663	-74.9%	2.64255	2.38952	0.25302	10.6%
32. Jurisdictional KWH Sales	37,662,601	34,426,631	3,235,970	9.4%	1,425,241	1,440,732	(15,491)	-1.1%	2.64254	2.38952	0.25302	10.6%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	37,687,458	34,449,353	3,238,105	9.4%	1,425,241	1,440,732	(15,491)	-1.1%	2.64429	2.39110	0.25319	10.6%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	*310,079*	*295,857*	*14,222*	*4.8%*	1,425,241	1,440,732	(15,491)	-1.1%	0.02176	0.02054	0.00122	5.9%
35a. Adjustment	0	0	0	0.0%	1,425,241	1,440,732	(15,491)	-1.1%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	1,425,241	1,440,732	(15,491)	-1.1%	0.00000	0.00000	0.00000	0.0%
36. True-up *	7,389,395	7,389,395	0	0.0%	1,425,241	1,440,732	(15,491)	-1.1%	0.51847	0.51289	0.00557	1.1%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	45,366,932	42,134,605	3,252,327	7.7%	1,425,241	1,440,732	(15,491)	-1.1%	3.18451	2.92453	0.25998	8.9%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.18680	2.92663	0.26017	8.9%
40. GPIF * (Already Adjusted for Taxes)	91,246	91,246	0	0.0%	1,425,241	1,440,732	(15,491)	-1.1%	0.00640	0.00633	0.00007	1.1%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**45,478,178**	**42,225,851**	**3,252,327**	**7.7%**	**1,425,241**	**1,440,732**	**(15,491)**	**-1.1%**	**3.19320**	**2.93296**	**0.26024**	**8.9%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.193**	**2.933**	**0.260**	**8.9%**

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	30,886,176	31,558,471	(672,295)	-2.1%	30,886,176	31,558,471	(672,295)	-2.1%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	1,000,643	1,706,800	(706,157)	-41.4%	1,000,643	1,706,800	(706,157)	-41.4%
2a. GAINS FROM MARKET BASED SALES	31,489	135,800	(104,311)	-76.8%	31,489	135,800	(104,311)	-76.8%
3. FUEL COST OF PURCHASED POWER	7,646,400	6,118,500	1,527,900	25.0%	7,646,400	6,118,500	1,527,900	25.0%
3a. *DEMAND & NONFUEL COST OF PUR. PWR.*	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	791,923	849,700	(57,777)	-6.8%	791,923	849,700	(57,777)	-6.8%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	38,292,367	36,684,071	1,608,296	4.4%	38,292,367	36,684,071	1,608,296	4.4%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(4,538)	(4,000)	(538)	13.5%	(4,538)	(4,000)	(538)	13.5%
6b. ADJ.TO FUEL COST	(477)	0	(477)	0.0%	(477)	0	(477)	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	38,287,352	36,680,071	1,607,281	4.4%	38,287,352	36,680,071	1,607,281	4.4%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,425,241	1,440,732	(15,491)	-1.1%	1,425,241	1,440,732	(15,491)	-1.1%
2. NONJURISDICTIONAL SALES	23,642	94,305	(70,663)	-74.9%	23,642	94,305	(70,663)	-74.9%
3. TOTAL SALES	1,448,883	1,535,037	(86,154)	-5.6%	1,448,883	1,535,037	(86,154)	-5.6%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9836826	0.9385650	0.0451176	4.8%	0.9836826	0.9385650	0.0451176	4.8%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	46,632,310	47,489,807	(857,497)	-1.8%	46,632,310	47,489,807	(857,497)	-1.8%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(7,389,395)	(7,389,395)	0	0.0%	(7,389,395)	(7,389,395)	0	0.0%
2b. INCENTIVE PROVISION	(91,246)	(91,246)	0	0.0%	(91,246)	(91,246)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	39,151,669	40,009,166	(857,497)	-2.1%	39,151,669	40,009,166	(857,497)	-2.1%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	38,287,352	36,680,071	1,607,281	4.4%	38,287,352	36,680,071	1,607,281	4.4%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9836826	0.9385650	0.0451176	4.8%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	37,662,601	34,426,631	3,235,970	9.4%	37,662,601	34,426,631	3,235,970	9.4%
6a. JURISDIC. LOSS MULTIPLIER	1.00066	1.00066	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	37,687,458	34,449,353	3,238,105	9.4%	37,687,458	34,449,353	3,238,105	9.4%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	315,223	315,223	0	0.0%	315,223	315,223	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	310,079	295,857	14,222	4.8%	310,079	295,857	14,222	4.8%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	37,997,537	34,745,210	3,252,327	9.4%	37,997,537	34,745,210	3,252,327	9.4%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	1,154,132	5,263,956	(4,109,824)	-78.1%	1,154,132	5,263,956	(4,109,824)	-78.1%
8. INTEREST PROVISION FOR THE MONTH	(138,210)	(274,212)	136,002	-49.6%	(138,210)	(274,212)	136,002	-49.6%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(97,656,895)	(88,672,735)	(8,984,160)	10.1%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	7,389,395	7,389,395	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(89,251,578)	(76,293,596)	(12,957,982)	17.0%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT [1] (LINE C9)	(97,656,895)	(88,672,735)	(8,984,160)	10.1%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(89,113,368)	(76,019,384)	(13,093,984)	17.2%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(186,770,263)	(164,692,119)	(22,078,144)	13.4%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(93,385,132)	(82,346,060)	(11,039,072)	13.4%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.780	4.000	(2)	-55.5%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.770	4.000	(2)	-55.8%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	3.550	8.000	(4)	-55.6%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.775	4.000	(2)	-55.6%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.148	0.333	(0)	-55.6%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(138,210)	(274,212)	136,002	-49.6%	NOT APPLICABLE			

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GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	155,366	267,340	(111,974)	-41.9%	155,366	267,340	(111,974)	-41.9%
2	LIGHT OIL	515,034	999,295	(484,261)	-48.5%	515,034	999,295	(484,261)	-48.5%
3	COAL	30,069,217	29,484,272	584,945	2.0%	30,069,217	29,484,272	584,945	2.0%
4	NATURAL GAS	146,559	807,564	(661,005)	-81.9%	146,559	807,564	(661,005)	-81.9%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	30,886,176	31,558,471	(672,295)	-2.1%	30,886,176	31,558,471	(672,295)	-2.1%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	3,609	5,837	(2,228)	-38.2%	3,609	5,837	(2,228)	-38.2%
9	LIGHT OIL	10,314	16,255	(5,941)	-36.5%	10,314	16,255	(5,941)	-36.5%
10	COAL	1,353,227	1,449,147	(95,920)	-6.6%	1,353,227	1,449,147	(95,920)	-6.6%
11	NATURAL GAS	3,317	16,227	(12,910)	-79.6%	3,317	16,227	(12,910)	-79.6%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,370,467	1,487,466	(116,999)	-7.9%	1,370,467	1,487,466	(116,999)	-7.9%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	5,821	8,696	(2,875)	-33.1%	5,821	8,696	(2,875)	-33.1%
16	LIGHT OIL (BBL)	19,028	28,598	(9,570)	-33.5%	19,028	28,598	(9,570)	-33.5%
17	COAL (TON)	630,957	643,239	(12,282)	-1.9%	630,957	643,239	(12,282)	-1.9%
18	NATURAL GAS (MCF)	35,753	165,088	(129,335)	-78.3%	35,753	165,088	(129,335)	-78.3%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	36,521	54,600	(18,080)	-33.1%	36,521	54,600	(18,080)	-33.1%
22	LIGHT OIL	108,009	160,876	(52,867)	-32.9%	108,009	160,876	(52,867)	-32.9%
23	COAL	14,725,987	15,012,355	(286,368)	-1.9%	14,725,987	15,012,355	(286,368)	-1.9%
24	NATURAL GAS	37,791	169,726	(131,935)	-77.7%	37,791	169,726	(131,935)	-77.7%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	14,908,308	15,397,557	(489,249)	-3.2%	14,908,308	15,397,557	(489,249)	-3.2%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.26%	0.39%	(0.00)	-	0.26%	0.39%	(0.00)	-
29	LIGHT OIL	0.75%	1.09%	(0.00)	-	0.75%	1.09%	(0.00)	-
30	COAL	98.74%	97.42%	0.01	-	98.74%	97.42%	0.01	-
31	NATURAL GAS	0.24%	1.09%	(0.01)	-	0.24%	1.09%	(0.01)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	26.69	30.74	(4.05)	-13.2%	26.69	30.74	(4.05)	-13.2%
36	LIGHT OIL ($/BBL)	27.07	34.94	(7.88)	-22.5%	27.07	34.94	(7.88)	-22.5%
37	COAL ($/TON)	47.66	45.84	1.82	4.0%	47.66	45.84	1.82	4.0%
38	NATURAL GAS ($/MCF)	4.10	4.89	(0.79)	-16.2%	4.10	4.89	(0.79)	-16.2%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	4.25	4.90	(0.64)	-13.1%	4.25	4.90	(0.64)	-13.1%
42	LIGHT OIL	4.77	6.21	(1.44)	-23.2%	4.77	6.21	(1.44)	-23.2%
43	COAL	2.04	1.96	0.08	4.0%	2.04	1.96	0.08	4.0%
44	NATURAL GAS	3.88	4.76	(0.88)	-18.5%	3.88	4.76	(0.88)	-18.5%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.07	2.05	0.02	1.1%	2.07	2.05	0.02	1.1%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	10,119	9,354	765	8.2%	10,119	9,354	765	8.2%
49	LIGHT OIL	10,472	9,897	575	5.8%	10,472	9,897	575	5.8%
50	COAL	10,882	10,359	523	5.0%	10,882	10,359	523	5.0%
51	NATURAL GAS	11,393	10,459	934	8.9%	11,393	10,459	934	8.9%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	10,878	10,352	526	5.1%	10,878	10,352	526	5.1%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	4.30	4.58	(0.28)	-6.1%	4.30	4.58	(0.28)	-6.1%
56	LIGHT OIL	4.99	6.15	(1.16)	-18.9%	4.99	6.15	(1.16)	-18.9%
57	COAL	2.22	2.03	0.19	9.4%	2.22	2.03	0.19	9.4%
58	NATURAL GAS	4.42	4.98	(0.56)	-11.2%	4.42	4.98	(0.56)	-11.2%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.25	2.12	0.13	6.1%	2.25	2.12	0.13	6.1%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: JANUARY 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	32	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	32	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	32	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	41	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	52	-188	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-188**	**---**	**---**	**---**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	35,443	41.8	83.6	63.8	12,428	COAL	18,799	23,432,000	440,498.2	921,938	2.60	49.04
GAN.#2	98	23,260	31.9	52.3	67.2	12,658	COAL	12,816	22,974,000	294,434.8	628,521	2.70	49.04
GAN.#3	155	58,009	50.3	91.5	62.6	12,346	COAL	39,008	18,360,000	716,186.9	1,913,026	3.30	49.04
GAN.#4	159	40,730	34.4	64.0	65.7	13,537	COAL	28,783	19,156,000	551,367.1	1,411,573	3.47	49.04
GAN.#5	217	72,050	44.6	57.0	69.6	11,519	COAL	35,228	23,560,000	829,971.7	1,727,648	2.40	49.04
GAN.#6	392	153,653	52.7	70.8	69.0	10,831	COAL	70,890	23,476,000	1,664,213.6	3,476,579	2.26	49.04
GANNON STATION	**1,135**	**383,145**	**45.4**	**69.7**	**67.1**	**11,736**	**COAL**	**205,524**	**21,879,062**	**4,496,672.3**	**10,079,285**	**2.63**	**49.04**
B.B.#1	426	179,770	56.7	71.8	73.1	10,722	COAL	78,744	24,478,940	1,927,569.7	3,592,546	2.00	45.62
B.B.#2	426	227,352	71.7	84.4	79.0	10,480	COAL	96,725	24,633,840	2,382,708.2	4,412,894	1.94	45.62
B.B.#3	433	160,327	49.8	59.6	63.9	10,764	COAL	70,360	24,526,740	1,725,711.5	3,210,041	2.00	45.62
B.B. 1 - 3	1,285	567,449	59.4	71.9	72.0	10,637	COAL	245,829	24,553,569	6,035,989.4	11,215,481	1.98	45.62
B.B.#4	447	246,026	74.0	90.1	80.7	10,296	COAL	116,973	21,655,523	2,533,105.7	6,208,516	2.52	53.08
B.B. STATION	**1,732**	**813,475**	**63.1**	**76.6**	**74.2**	**10,534**	**COAL**	**362,802**	**23,619,197**	**8,569,095.1**	**17,423,997**	**2.14**	**48.03**
SEB-PHIL. #1(HVY OIL)	17	1,703	13.5	100.0	74.1	9,618	HVY.OIL	2,611	6,273,540	16,379.9	69,689	4.09	26.69
SEB-PHIL. #2(HVY OIL)	17	2,094	16.6	100.0	92.9	9,618	HVY.OIL	3,210	6,273,540	20,140.6	85,677	4.09	26.69
SEB-PHILLIPS TOTAL	**34**	**3,797**	**15.0**	**100.0**	**83.5**	**9,618**	**HVY.OIL**	**5,821**	**6,273,540**	**36,520.5**	**155,366**	**4.09**	**26.69**
POLK #1 GASIFIER	250	156,607	84.2	87.4	90.6	10,601	COAL	62,631	26,508,000	1,660,219.9	2,565,935	1.64	40.97
POLK #1 CT (OIL)	245	5,466	3.0	89.8	74.2	7,917	LGT.OIL	7,876	5,789,821	43,277.0	208,770	3.82	26.51
POLK #1 TOTAL	**250**	**162,073**	**87.1**	**84.3**	**89.9**	**10,511**	**-**	**-**	**-**	**1,703,496.9**	**2,774,705**	**1.71**	**-**
POLK #2 CT (GAS)	160	2,696	2.3	98.8	82.4	11,617	GAS	29,630	972,290	31,319.0	111,941	4.15	3.78
POLK #2 CT (OIL)	180	3,305	2.5	91.9	63.8	12,657	LGT.OIL	7,225	5,789,827	41,832.6	191,514	5.79	26.51
POLK #2 TOTAL	**170**	**6,001**	**5.0**	**100.0**	**71.0**	**12,190**	**-**	**-**	**-**	**73,151.6**	**303,455**	**5.06**	**-**
POLK STATION TOTA	**420**	**168,074**	**53.8**	**90.6**	**80.6**	**10,571**	**-**	**-**	**-**	**1,776,648.5**	**3,078,160**	**1.83**	**-**
B.B.C.T.#1	17	47	0.4	100.0	55.3	19,962	LGT.OIL	161	5,829,139	938.2	4,704	10.01	29.22
B.B.C.T.#2	80	1,320	2.2	100.0	50.0	16,559	LGT.OIL	3,748	5,831,172	21,857.8	109,520	8.30	29.22
B.B.C.T.#3	80	176	0.3	100.0	73.3	587	LGT.OIL	18	5,832,863	103.3	526	0.30	29.22
C.T. TOTAL	**177**	**1,543**	**1.2**	**100.0**	**61.1**	**14,841**	**LGT.OIL**	**3,927**	**5,831,097**	**22,899.3**	**114,750**	**7.44**	**29.22**
CITY OF TAMPA	**6**	**621**	**0.0**	**0.0**	**0.0**	**10,422**	**GAS**	**6,123**	**972,290**	**6,472.0**	**34,618**	**5.57**	**5.65**
TOT. COAL (GN,BB,POLK)	**3,117**	**1,353,227**	**58.4**	**74.9**	**72.9**	**10,882**	**COAL**	**630,957**	**23,339,128**	**14,725,987.3**	**30,069,217**	**2.22**	**47.66**
SYSTEM	**3,504**	**1,370,467**	**52.7**	**77.5**	**72.1**	**10,877**	**-**	**-**	**-**	**14,908,307.7**	**30,886,176**	**2.25**	**-**

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT
B.B. = BIG BEND
GAN. = GANNON
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	10,954	8,696	2,258	26.0%	10,954	8,696	2,258	26.0%
3 UNIT COST ($/BBL)	23.90	31.61	(7.70)	-24.4%	23.90	31.61	(7.70)	-24.4%
4 AMOUNT ($)	261,843	274,865	(13,022)	-4.7%	261,843	274,865	(13,022)	-4.7%
5 BURNED:								
6 UNITS (BBL)	5,821	8,696	(2,875)	-33.1%	5,821	8,696	(2,875)	-33.1%
7 UNIT COST ($/BBL)	26.69	30.74	(4.05)	-13.2%	26.69	30.74	(4.05)	-13.2%
8 AMOUNT ($)	155,366	267,340	(111,974)	-41.9%	155,366	267,340	(111,974)	-41.9%
9 ENDING INVENTORY:								
10 UNITS (BBL)	70,398	59,129	11,269	19.1%	70,398	59,129	11,269	19.1%
11 UNIT COST ($/BBL)	26.13	26.59	(0.45)	-1.7%	26.13	26.59	(0.45)	-1.7%
12 AMOUNT ($)	1,839,688	1,572,062	267,626	17.0%	1,839,688	1,572,062	267,626	17.0%
13								
14 DAYS SUPPLY:	210	176	34	19.3%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	26,341	40,288	(13,947)	-34.6%	26,341	40,288	(13,947)	-34.6%
17 UNIT COST ($/BBL)	19.08	35.65	(16.57)	-46.5%	19.08	35.65	(16.57)	-46.5%
18 AMOUNT ($)	502,588	1,436,371	(933,783)	-65.0%	502,588	1,436,371	(933,783)	-65.0%
19 BURNED:								
20 UNITS (BBL)	19,028	28,598	(9,570)	-33.5%	19,028	28,598	(9,570)	-33.5%
21 UNIT COST ($/BBL)	27.07	34.94	(7.88)	-22.5%	27.07	34.94	(7.88)	-22.5%
22 AMOUNT ($)	515,034	999,295	(484,261)	-48.5%	515,034	999,295	(484,261)	-48.5%
23 ENDING INVENTORY:								
24 UNITS (BBL)	105,107	113,465	(8,358)	-7.4%	105,107	113,465	(8,358)	-7.4%
25 UNIT COST ($/BBL)	28.17	34.47	(6.30)	-18.3%	28.17	34.47	(6.30)	-18.3%
26 AMOUNT ($)	2,960,652	3,910,931	(950,279)	-24.3%	2,960,652	3,910,931	(950,279)	-24.3%
27								
28 DAYS SUPPLY: NORMAL	69	75	(6)	-8.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	15	16	(1)	-7.4%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	434,718	608,000	(173,282)	-28.5%	434,718	608,000	(173,282)	-28.5%
32 UNIT COST ($/TON)	49.09	46.51	2.58	5.5%	49.09	46.51	2.58	5.5%
33 AMOUNT ($)	21,341,662	28,281,027	(6,939,365)	-24.5%	21,341,662	28,281,027	(6,939,365)	-24.5%
34 BURNED:								
35 UNITS (TONS)	630,957	643,239	(12,282)	-1.9%	630,957	643,239	(12,282)	-1.9%
36 UNIT COST ($/TON)	47.66	45.84	1.82	4.0%	47.66	45.84	1.82	4.0%
37 AMOUNT ($)	30,069,217	29,484,272	584,945	2.0%	30,069,217	29,484,272	584,945	2.0%
38 ENDING INVENTORY:								
39 UNITS (TONS)	429,241	941,581	(512,340)	-54.4%	429,241	941,581	(512,340)	-54.4%
40 UNIT COST ($/TON)	45.70	45.65	0.06	0.1%	45.70	45.65	0.06	0.1%
41 AMOUNT ($)	19,617,345	42,979,973	(23,362,628)	-54.4%	19,617,345	42,979,973	(23,362,628)	-54.4%
42								
43 DAYS SUPPLY:	25	54	(29)	-53.7%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	35,753	165,088	(129,335)	-78.3%	35,753	165,088	(129,335)	-78.3%
46 UNIT COST ($/MCF)	4.07	4.89	(0.82)	-16.8%	4.07	4.89	(0.82)	-16.8%
47 AMOUNT ($)	145,586	807,564	(661,978)	-82.0%	145,586	807,564	(661,978)	-82.0%
48 BURNED:								
49 UNITS (MCF)	35,753	165,088	(129,335)	-78.3%	35,753	165,088	(129,335)	-78.3%
50 UNIT COST ($/MCF)	4.10	4.89	(0.79)	-16.2%	4.10	4.89	(0.79)	-16.2%
51 AMOUNT ($)	146,559	807,564	(661,005)	-81.9%	146,559	807,564	(661,005)	-81.9%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

* Includes adjustment of $973

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	8,702
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	8,702

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(10,596)	(308,086)
OTHER USAGE	(512)	(14,845)
TOTAL	(11,108)	(322,931)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	34,453
IGNITION #2 OIL	299,384
IGNITION PROPANE	1,982
AERIAL SURVEY ADJ.	0
ADDITIVES	41,222
GREEN FUEL	0
TOTAL	377,041

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2002

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. -D	6,206.0	0.0	6,206.0	1.510	1.510	93,700.00	93,700.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	53,940.0	0.0	53,940.0	2.405	3.453	1,297,000.00	1,862,300.00	
VARIOUS	JURISDIC.	MKT. BASE	15,027.0	0.0	15,027.0	2.104	2.104	316,100.00	316,100.00	135,800.00
TOTAL			75,173.0	0.0	75,173.0	2.270	3.022	1,706,800.00	2,272,100.00	135,800.00
ACTUAL:										
FLA. PWR. & LIGHT	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR PARTNERS	SEP. CONTR.	SCH. -D	24,846.0	0.0	24,846.0	2.551	3.284	633,821.46	815,942.64	
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. -D	2,611.1	26.4	2,584.7	2.015	2.015	52,074.47	52,074.47	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. -D	1,078.4	0.0	1,078.4	1.689	1.689	18,210.75	18,210.75	
FLA. PWR. CORP.		SCH. -MA	907.0	0.0	907.0	1.872	2.571	16,982.18	23,317.13	4,022.10
FLA. PWR. & LIGHT		SCH. -MA	8,775.0	0.0	8,775.0	1.852	2.185	162,471.98	191,711.94	6,863.71
CITY OF LAKELAND		SCH. -MA	3,688.0	0.0	3,688.0	2.055	2.487	75,778.49	91,732.66	6,549.77
ORLANDO UTIL. COMM.		SCH. -MA	275.0	0.0	275.0	2.051	2.662	5,639.50	7,319.84	979.09
REEDY CREEK		SCH. -MA	20.0	0.0	20.0	2.020	2.850	403.90	570.06	115.16
THE ENERGY AUTHORITY		SCH. -MA	281.0	0.0	281.0	2.147	2.649	6,032.63	7,443.36	694.18
AQUILA		SCH. -MA	989.0	0.0	989.0	1.753	3.230	17,340.22	31,943.74	12,081.57
DUKE ENERGY		SCH. -MA	54.0	0.0	54.0	1.859	2.454	1,003.98	1,324.96	183.28
AUBURNDALE POWER PARTNERS		SCH. -OATT	10.0	0.0	10.0	3.450	3.450	344.95	344.95	
CARGILL ALLIANT		SCH. -OATT	15.0	0.0	15.0	2.829	2.829	424.30	424.30	
ADJUSTMENTS TO PREV. MONTHS										
HARDEE PWR PARTNERS EST.	Dec. 2001	CONTRACT	(16,314.0)	0.0	(16,314.0)	2.489	3.225	(406,055.46)	(526,126.50)	
HARDEE PWR PARTNERS ACT.	Dec. 2001	CONTRACT	16,314.0	0.0	16,314.0	2.551	3.279	416,170.14	534,936.06	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD			3,689.5	26.4	3,663.1	1.919	1.919	70,285.22	70,285.22	
SUB-TOTAL SCHEDULE D POWER SALES-SEPARATED			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEP.			24,846.0	0.0	24,846.0	2.592	3.319	643,936.14	824,752.20	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD			14,989.0	0.0	14,989.0	1.906	2.371	285,652.88	355,363.69	31,488.86
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD			25.0	0.0	25.0	3.077	3.077	769.25	769.25	
TOTAL			43,549.5	26.4	43,523.1	2.299	2.875	1,000,643.49	1,251,170.36	31,488.86
CURRENT MONTH:										
DIFFERENCE			(31,623.5)	26.4	(31,649.9)	0.029	(0.147)	(706,156.51)	(1,020,929.64)	(104,311.14)
DIFFERENCE %			-42.1%	0.0%	-42.1%	1.3%	-4.9%	-41.4%	-44.9%	-76.8%
PERIOD TO DATE:										
ACTUAL			43,549.5	26.4	43,523.1	2.299	2.875	1,000,643.49	1,251,170.36	31,488.86
ESTIMATED			75,173.0	0.0	75,173.0	2.270	3.022	1,706,800.00	2,272,100.00	135,800.00
DIFFERENCE			(31,623.5)	26.4	(31,649.9)	0.029	(0.147)	(706,156.51)	(1,020,929.64)	(104,311.14)
DIFFERENCE %			-42.1%	0.0%	-42.1%	1.3%	-4.9%	-41.4%	-44.9%	-76.8%

* No Sales to Hardee Pwr Partners for Others in the month of January 2002.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH.-J	2,664.0	0.0	1,772.0	892.0	5.807	5.807	51,800.00
HARDEE POWER PARTNERS		IPP	67,561.0	0.0	0.0	67,561.0	5.217	5.217	3,524,800.00
VARIOUS		OTHER	24,494.0	0.0	0.0	24,494.0	6.700	6.700	1,641,100.00
VARIOUS		MKT. BASE	13,029.0	0.0	0.0	13,029.0	6.914	6.914	900,800.00
TOTAL			**107,748.0**	**0.0**	**1,772.0**	**105,976.0**	**5.773**	**5.773**	**6,118,500.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	58,697.0	0.0	0.0	58,697.0	3.869	3.869	2,270,774.02
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH.-J	7,877.0	0.0	50.0	7,827.0	3.133	3.133	245,192.00
FLA. POWER & LIGHT		SCH.-J	23,978.0	0.0	1,389.2	22,588.8	4.362	4.362	985,222.42
CITY OF LAKELAND		SCH.-J	4,110.0	0.0	250.0	3,860.0	4.334	4.334	167,282.50
ORLANDO UTIL. COMM.		SCH.-J	800.0	0.0	0.0	800.0	6.525	6.525	52,200.00
THE ENERGY AUTHORITY		SCH.-J	544.0	0.0	100.0	444.0	4.468	4.468	19,838.00
REEDY CREEK		SCH.-J	50.0	0.0	0.0	50.0	3.750	3.750	1,875.00
TALLAHASSEE		SCH.-J	74.0	0.0	0.0	74.0	2.492	2.492	1,844.00
CARGILL ALLIANT		SCH.-J	1,037.0	0.0	0.0	1,037.0	4.321	4.321	44,811.00
AXIA		SCH.-J	675.0	0.0	311.7	363.3	9.004	9.004	32,709.97
CORAL POWER		SCH.-J	1,499.0	0.0	0.0	1,499.0	3.712	3.712	55,638.00
DUKE ENERGY		SCH.-J	3,233.0	0.0	169.3	3,063.7	4.344	4.344	133,074.82
RINGHAVER		SCH.-J	350.0	0.0	0.0	350.0	8.219	8.219	28,767.80
OKEELANTA		SCH.-D	40.0	0.0	0.0	40.0	7.500	7.500	3,000.00
FLA. POWER CORP.		SCH.-D	19,600.0	0.0	0.0	19,600.0	3.135	3.135	614,460.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Dec-01	IPP	(20,355.0)	0.0	0.0	(20,355.0)	19.042	19.042	(3,876,091.99)
HARDEE PWR. PART.-NATIVE	Dec-01	IPP	20,355.0	0.0	0.0	20,355.0	19.710	19.710	4,011,870.72
THE ENERGY AUTH.	Apr-01	SCH.-Ja [1]	(3,940.0)	0.0	(1,378.3)	(2,561.7)	7.652	7.652	(196,022.69)
THE ENERGY AUTH.	Apr-01	SCH.-Ja	3,940.0	0.0	1,378.3	2,561.7	9.604	9.604	246,022.69
THE ENERGY AUTH.	Apr-01	SCH.-Jc [1]	(12,615.0)	0.0	0.0	(12,615.0)	1.695	1.695	(213,882.88)
THE ENERGY AUTH.	Apr-01	SCH.-Jc	12,615.0	0.0	0.0	12,615.0	8.037	8.037	1,013,882.88
CARGILL ALLIANT	Apr-01	SCH.-Jc [1]	(49,079.0)	0.0	0.0	(49,079.0)	2.590	2.590	(1,271,321.00)
CARGILL ALLIANT	Apr-01	SCH.-Jc	49,079.0	0.0	0.0	49,079.0	6.665	6.665	3,271,321.00
KOCH ENERGY TRAD	Jan-01	SCH.-Jc [2]	(19,554.0)	0.0	0.0	(19,554.0)	15.798	15.798	(3,089,214.69)
KOCH ENERGY TRAD	Jan-01	SCH.-Jc	19,554.0	0.0	0.0	19,554.0	15.745	15.745	3,078,697.69
KOCH ENERGY TRAD	Apr-01	SCH.-Ja	(5,678.0)	0.0	(1,944.7)	(3,733.3)	8.647	8.647	(322,802.00)
KOCH ENERGY TRAD	Apr-01	SCH.-Ja	5,678.0	0.0	1,944.7	3,733.3	8.724	8.724	325,708.00
KOCH ENERGY TRAD	Apr-01	SCH.-Jc	(30,460.0)	0.0	0.0	(30,460.0)	6.676	6.676	(2,033,573.80)
KOCH ENERGY TRAD	Apr-01	SCH.-Jc	30,460.0	0.0	0.0	30,460.0	6.713	6.713	2,044,777.30
KOCH ENERGY TRAD	Oct-00	SCH.-Ja	(99.0)	0.0	0.0	(99.0)	6.121	6.121	(6,060.00)
KOCH ENERGY TRAD	Oct-00	SCH.-Ja	99.0	0.0	0.0	99.0	5.735	5.735	5,677.50
ENRON	Jun-01	SCH.-Jc	(4,772.0)	0.0	0.0	(4,772.0)	7.175	7.175	(342,411.50)
ENRON	Jun-01	SCH.-Jc	4,772.0	0.0	0.0	4,772.0	7.179	7.179	342,581.50
ENRON	Apr-01	SCH.-Jc	(2,031.0)	0.0	0.0	(2,031.0)	7.496	7.496	(152,246.60)
ENRON	Apr-01	SCH.-Jc	2,031.0	0.0	0.0	2,031.0	7.523	7.523	152,798.60
TOTAL			**122,564.0**	**0.0**	**2,270.2**	**120,293.8**	**6.356**	**6.356**	**7,646,400.26**
CURRENT MONTH:									
DIFFERENCE			14,816.0	0.0	498.2	14,317.8	0.583	0.583	1,527,900.26
DIFFERENCE %			13.8%	0.0%	28.1%	13.5%	10.1%	10.1%	25.0%
PERIOD TO DATE:									
ACTUAL			122,564.0	0.0	2,270.2	120,293.8	6.356	6.356	7,646,400.26
ESTIMATED			107,748.0	0.0	1,772.0	105,976.0	5.773	5.773	6,118,500.00
DIFFERENCE			14,816.0	0.0	498.2	14,317.8	0.583	0.583	1,527,900.26
DIFFERENCE %			13.8%	0.0%	28.1%	13.5%	10.1%	10.1%	25.0%

[1] Originally adjusted in May 2001
[2] Originally adjusted in February 2001

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	39,069.0	0.0	0.0	39,069.0	2.175	2.175	849,700.00
TOTAL		**39,069.0**	**0.0**	**0.0**	**39,069.0**	**2.175**	**2.175**	**849,700.00**
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.0
McKAY BAY REFUSE	COGEN.	12,724.0	0.0	0.0	12,724.0	1.894	1.894	240,952.0
MULBERRY PHOSPHATES INC.	COGEN	0.0	0.0	0.0	0.0	0.000	0.000	0.0
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.0
IMC-AGRICO-NEW WALES	COGEN.	517.0	0.0	0.0	517.0	2.667	2.667	13,790.0
HILLSBOROUGH COUNTY	COGEN.	18,111.0	0.0	0.0	18,111.0	1.893	1.893	342,919.6
CARGILL MILLPOINT	COGEN.	39.0	0.0	0.0	39.0	6.508	6.508	2,538.1
CF INDUSTRIES INC.	COGEN.	908.0	0.0	0.0	908.0	3.243	3.243	29,445.7
FARMLAND HYDRO LP	COGEN.	1.0	0.0	0.0	1.0	1.995	1.995	20.0
IMC-AGRICO-S. PIERCE	COGEN.	1,580.0	0.0	0.0	1,580.0	2.715	2.715	42,890.9
AUBURNDALE POWER PARTNERS	COGEN.	918.0	0.0	0.0	918.0	2.401	2.401	22,037.4
ORANGE COGENERATION L.P.	COGEN.	4.0	0.0	0.0	4.0	1.808	1.808	72.3
CUTRALE CITRUS	COGEN.	5,474.0	0.0	0.0	5,474.0	1.856	1.856	101,582.8
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.0
SUB-TOTAL FOR JANUARY 2002		40,276.0	0.0	0.0	40,276.0	1.977	1.977	796,248.62
ADJUSTMENTS FOR THE MONTH OF: NOVEMBER 2001								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	(10,679.0)	0.0	0.0	(10,679.0)	1.782	1.782	(190,307.73)
		10,679.0	0.0	0.0	10,679.0	1.771	1.771	189,172.94
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
HILLSBOROUGH COUNTY	COGEN.	(19,092.0)	0.0	0.0	(19,092.0)	1.799	1.799	(343,468.06)
		19,092.0	0.0	0.0	19,092.0	1.787	1.787	341,207.68
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
FARMLAND HYDRO LP	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ORANGE COGENERATION L.P.	COGEN.	(5,496.0)	0.0	0.0	(5,496.0)	1.770	1.770	(97,255.86)
		5,496.0	0.0	0.0	5,496.0	1.753	1.753	96,325.48
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF: NOVEMBER 2001		0.0	0.0	0.0	0.0	0.000	0.000	(4,325.55)
GRAND TOTAL		**40,276.0**	**0.0**	**0.0**	**40,276.0**	**1.966**	**1.966**	**791,923.07**
CURRENT MONTH:								
DIFFERENCE		1,207.0	0.0	0.0	1,207.0	(0.209)	(0.209)	(57,776.93)
DIFFERENCE %		3.1%	0.0%	0.0%	3.1%	-9.6%	-9.6%	-6.8%
PERIOD TO DATE:								
ACTUAL		40,276.0	0.0	0.0	40,276.0	1.966	1.966	791,923.07
ESTIMATED		39,069.0	0.0	0.0	39,069.0	2.175	2.175	849,700.00
DIFFERENCE		1,207.0	0.0	0.0	1,207.0	(0.209)	(0.209)	(57,776.93)
DIFFERENCE %		3.1%	0.0%	0.0%	3.1%	-9.6%	-9.6%	-6.8%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: JANUARY 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		0.0	0.000	0.00	0.000	0.00	0.00
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

FEBRUARY 2002

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY

MONTH OF: FEBRUARY 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	21,294,367	27,148,168	(5,853,801)	-21.6%	1,114,734	1,270,634	(155,900)	-12.3%	1.91026	2.13658	(0.22632)	-10.6%
2. *Spent Nuclear Fuel Disposal Cost*	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(3,773)	(4,000)	227	-5.7%	1,114,734 (a)	1,270,634 (a)	(155,900)	-12.3%	(0.00034)	(0.00031)	(0.00002)	7.5%
4b. Adjustments to Fuel Cost (1)	(406)	0	(406)	0.0%	1,114,734 (a)	1,270,634 (a)	(155,900)	-12.3%	(0.00004)	0.00000	(0.00004)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	1,114,734 (a)	1,270,634 (a)	(155,900)	-12.3%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**21,290,188**	**27,144,168**	**(5,853,980)**	**-21.6%**	**1,114,734**	**1,270,634**	**(155,900)**	**-12.3%**	**1.90989**	**2.13627**	**(0.22638)**	**-10.6%**
6. Fuel Cost of Purchased Power - Firm (A7)	2,002,284	9,145,800	(7,143,516)	-78.1%	95,768	169,080	(73,312)	-43.4%	2.09077	5.40916	(3.31839)	-61.3%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	606,408	701,900	(95,492)	-13.6%	31,276	34,868	(3,592)	-10.3%	1.93889	2.01302	(0.07413)	-3.7%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**2,608,692**	**9,847,700**	**(7,239,008)**	**-73.5%**	**127,044**	**203,948**	**(76,904)**	**-37.7%**	**2.05338**	**4.82853**	**(2.77516)**	**-57.5%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,241,778**	**1,474,582**	**(232,804)**	**-15.8%**				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	59,280	90,800	(31,520)	-34.7%	2,990	6,118	(3,128)	-51.1%	1.98261	1.48415	0.49846	33.6%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	650	0	650	0.0%	22	0	22	0.0%	2.95455	0.00000	2.95455	0.0%
19. *Fuel Cost of Other Sales (A6)*	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	491,473	1,221,000	(729,527)	-59.7%	19,128	48,720	(29,592)	-60.7%	2.56939	2.50616	0.06323	2.5%
21. Fuel Cost of Market Base Sales (A6)	41,739	340,300	(298,561)	-87.7%	2,082	16,375	(14,293)	-87.3%	2.00476	2.07817	(0.07341)	-3.5%
21a. Gains on Market Based Sales	(278)	151,800	(152,078)	-100.2%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES *(LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 +21a)*	**592,864**	**1,803,900**	**(1,211,036)**	**-67.1%**	**24,222**	**71,213**	**(46,991)**	**-66.0%**	**2.44763**	**2.53310**	**(0.08548)**	**-3.4%**
23. Net Inadvertant Interchange					(368)	0	(368)	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					2,300	0	2,300	0.0%				
25. Interchange and Wheeling Losses					165	1,000	(835)	-83.5%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS *(LINE 5 + 12 - 22 + 23 + 24 - 25)*	**23,306,016**	**35,187,968**	**(11,881,952)**	**-33.8%**	**1,219,323**	**1,402,369**	**(183,046)**	**-13.1%**	**1.91139**	**2.50918**	**(0.59779)**	**-23.8%**
27. Net Unbilled	(1,768,227) (a)	(1,787,289) (a)	19,062	-1.1%	(92,510)	(71,230)	(21,280)	29.9%	1.91139	2.50918	(0.59779)	-23.8%
28. Company Use	65,809 (a)	102,876 (a)	(37,067)	-36.0%	3,443	4,100	(657)	-16.0%	1.91139	2.50917	(0.59779)	-23.8%
29. T & D Losses	983,398 (a)	2,195,177 (a)	(1,231,779)	-56.1%	50,403	87,486	(37,083)	-42.4%	1.91139	2.50918	(0.59779)	-23.8%
30. System KWH Sales	23,306,016	35,187,968	(11,881,952)	-33.8%	1,257,987	1,382,013	(124,026)	-9.0%	1.85264	2.54614	(0.69349)	-27.2%
31. Wholesale KWH Sales	(219,058)	(2,021,890)	1,802,834	-89.2%	(11,824)	(79,410)	67,586	-85.1%	1.85264	2.54614	(0.69350)	-27.2%
32. Jurisdictional KWH Sales	23,086,960	33,166,078	(10,079,118)	-30.4%	1,246,163	1,302,603	(56,440)	-4.3%	1.85264	2.54614	(0.69349)	-27.2%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	23,102,197	33,187,968	(10,085,771)	-30.4%	1,246,163	1,302,603	(56,440)	-4.3%	1.85387	2.54782	(0.69395)	-27.2%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	*309,753*	*294,725*	*15,028*	*5.1%*	*1,246,163*	1,302,603	(56,440)	-4.3%	0.02486	0.02263	0.00223	9.9%
35a. Adjustment	0	0	0	0.0%	1,246,163	1,302,603	(56,440)	-4.3%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	1,246,163	1,302,603	(56,440)	-4.3%	0.00000	0.00000	0.00000	0.0%
36. True-up *	7,389,395	7,389,395	0	0.0%	1,246,163	1,302,603	(56,440)	-4.3%	0.59297	0.56728	0.02569	4.5%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	30,801,345	40,872,088	(10,070,743)	-24.6%	1,246,163	1,302,603	(56,440)	-4.3%	2.47169	3.13772	(0.66603)	-21.2%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.47347	3.13998	(0.66651)	-21.2%
40. GPIF * (Already Adjusted for Taxes)	91,246	91,246	0	0.0%	1,246,163	1,302,603	(56,440)	-4.3%	0.00732	0.00700	0.00032	4.5%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**30,892,591**	**40,963,334**	**(10,070,743)**	**-24.6%**	**1,246,163**	**1,302,603**	**(56,440)**	**-4.3%**	**2.48079**	**3.14698**	**(0.66619)**	**-21.2%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**2.481**	**3.147**	**(0.666)**	**-21.2%**

* Based on Jurisdictional Sales (a) Included for Informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: FEBRUARY 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	52,180,543	58,706,639	(6,526,096)	-11.1%	2,485,201	2,758,100	(272,899)	-9.9%	2.09965	2.12852	(0.02887)	-1.4%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(8,311)	(8,000)	(311)	3.9%	2,485,201 (a)	2,758,100 (a)	(272,899)	-9.9%	(0.00033)	(0.00029)	(0.00004)	15.3%
4b. Adjustments to Fuel Cost (1)	(883)	0	(883)	0.0%	2,485,201 (a)	2,758,100 (a)	(272,899)	-9.9%	(0.00004)	0.00000	(0.00004)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	2,485,201 (a)	2,758,100 (a)	(272,899)	-9.9%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**52,171,349**	**58,698,639**	**(6,527,290)**	**-11.1%**	**2,485,201**	**2,758,100**	**(272,899)**	**-9.9%**	**2.09928**	**2.12823**	**(0.02895)**	**-1.4%**
6. Fuel Cost of Purchased Power - Firm (A7)	9,648,684	15,264,300	(5,615,616)	-36.8%	216,062	275,056	(58,994)	-21.4%	4.46570	5.54952	(1.08382)	-19.5%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,398,331	1,551,600	(153,269)	-9.9%	71,552	73,937	(2,385)	-3.2%	1.95429	2.09854	(0.14426)	-6.9%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**11,047,015**	**16,815,900**	**(5,768,885)**	**-34.3%**	**287,614**	**348,993**	**(61,379)**	**-17.6%**	**3.84092**	**4.81841**	**(0.97749)**	**-20.3%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**2,772,815**	**3,107,093**	**(334,278)**	**-10.8%**				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	129,565	184,500	(54,935)	-29.8%	6,653	12,324	(5,671)	-46.0%	1.94747	1.49708	0.45039	30.1%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	1,419	0	1,419	0.0%	47	0	47	0.0%	3.01915	0.00000	3.01915	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	1,135,409	2,518,000	(1,382,591)	-54.9%	43,974	102,860	(58,686)	-57.2%	2.58200	2.45276	0.12924	5.3%
21. Fuel Cost of Market Base Sales (A6)	327,392	656,400	(329,008)	-50.1%	17,071	31,402	(14,331)	-45.6%	1.91783	2.09031	(0.17249)	-8.3%
21a. Gains on Market Based Sales	31,211	287,600	(256,389)	-89.1%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 +21a)	**1,624,996**	**3,646,500**	**(2,021,504)**	**-55.4%**	**67,745**	**146,386**	**(78,641)**	**-53.7%**	**2.39870**	**2.49102**	**(0.09232)**	**-3.7%**
23. Net Inadvertant Interchange					952	0	952	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					2,287	0	2,287	0.0%				
25. Interchange and Wheeling Losses					527	2,100	(1,573)	-74.9%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	**61,593,368**	**71,868,039**	**(10,274,671)**	**-14.3%**	**2,707,782**	**2,958,607**	**(250,825)**	**-8.5%**	**2.27468**	**2.42912**	**(0.15444)**	**-6.4%**
27. Net Unbilled	(2,230,132) (a)	(1,926,610) (a)	(303,522)	15.8%	(110,467)	(77,141)	(33,326)	43.2%	2.01882	2.49752	(0.47870)	-19.2%
28. Company Use	164,970 (a)	199,512 (a)	(34,542)	-17.3%	7,298	8,200	(902)	-11.0%	2.26048	2.43307	(0.17259)	-7.1%
29. T & D Losses	2,344,147 (a)	2,737,567 (a)	(393,420)	-14.4%	104,081	110,498	(6,417)	-5.8%	2.25223	2.47748	(0.22525)	-9.1%
30. System KWH Sales	61,593,368	71,868,039	(10,274,671)	-14.3%	2,706,870	2,917,050	(210,180)	-7.2%	2.27545	2.46372	(0.18828)	-7.6%
31. Wholesale KWH Sales	(843,807)	(4,275,330)	3,431,523	-80.3%	(35,466)	(173,715)	138,249	-79.6%	2.37920	2.46112	(0.08192)	-3.3%
32. Jurisdictional KWH Sales	60,749,561	67,592,709	(6,843,148)	-10.1%	2,671,404	2,743,335	(71,931)	-2.6%	2.27407	2.46389	(0.18982)	-7.7%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	60,789,655	67,637,321	(6,847,666)	-10.1%	2,671,404	2,743,335	(71,931)	-2.6%	2.27557	2.46551	(0.18994)	-7.7%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	619,832	590,582	29,250	5.0%	2,671,404	2,743,335	(71,931)	-2.6%	0.02320	0.02153	0.00167	7.8%
35a. Adjustment	0	0	0	0.0%	2,671,404	2,743,335	(71,931)	-2.6%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	2,671,404	2,743,335	(71,931)	-2.6%	0.00000	0.00000	0.00000	0.0%
36. True-up *	14,778,790	14,778,790	0	0.0%	2,671,404	2,743,335	(71,931)	-2.6%	0.55322	0.53872	0.01451	2.7%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	76,188,277	83,006,693	(6,818,416)	-8.2%	2,671,404	2,743,335	(71,931)	-2.6%	2.85199	3.02576	(0.17376)	-5.7%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									2.85405	3.02794	(0.17389)	-5.7%
40. GPIF * (Already Adjusted for Taxes)	182,492	182,492	0	0.0%	2,671,404	2,743,335	(71,931)	-2.6%	0.00683	0.00665	0.00018	2.7%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**76,370,769**	**83,189,185**	**(6,818,416)**	**-8.2%**	**2,671,404**	**2,743,335**	**(71,931)**	**-2.6%**	**2.86088**	**3.03459**	**(0.17371)**	**-5.7%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**2.861**	**3.035**	**(0.174)**	**-5.7%**

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	21,294,367	27,148,168	(5,853,801)	-21.6%	52,180,543	58,706,639	(6,526,096)	-11.1%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	593,142	1,652,100	(1,058,958)	-64.1%	1,593,785	3,358,900	(1,765,115)	-52.6%
2a. GAINS FROM MARKET BASED SALES	(278)	151,800	(152,078)	-100.2%	31,211	287,600	(256,389)	-89.1%
3. FUEL COST OF PURCHASED POWER	2,002,284	9,145,800	(7,143,516)	-78.1%	9,648,684	15,264,300	(5,615,616)	-36.8%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	606,408	701,900	(95,492)	-13.6%	1,398,331	1,551,600	(153,269)	-9.9%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. *TOTAL FUEL & NET POWER TRANSACTION*	23,310,195	35,191,968	(11,881,773)	-33.8%	61,602,562	71,876,039	(10,273,477)	-14.3%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(3,773)	(4,000)	227	-5.7%	(8,311)	(8,000)	(311)	3.9%
6b. ADJ.TO FUEL COST	(406)	0	(406)	0.0%	(883)	0	(883)	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	23,306,016	35,187,968	(11,881,952)	-33.8%	61,593,368	71,868,039	(10,274,671)	-14.3%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,246,163	1,302,603	(56,440)	-4.3%	2,671,404	2,743,335	(71,931)	-2.6%
2. NONJURISDICTIONAL SALES	11,824	79,410	(67,586)	-85.1%	35,466	173,715	(138,249)	-79.6%
3. TOTAL SALES	1,257,987	1,382,013	(124,026)	-9.0%	2,706,870	2,917,050	(210,180)	-7.2%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9906009	0.9425403	0.0480606	5.1%	0.9868978	0.9404484	0.0464494	4.9%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: FEBRUARY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	40,772,286	42,923,095	(2,150,809)	-5.0%	87,404,596	90,412,902	(3,008,306)	-3.3%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(7,389,395)	(7,389,395)	0	0.0%	(14,778,790)	(14,778,790)	0	0.0%
2b. INCENTIVE PROVISION	(91,246)	(91,246)	0	0.0%	(182,492)	(182,492)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	33,291,645	35,442,454	(2,150,809)	-6.1%	72,443,314	75,451,620	(3,008,306)	-4.0%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	23,306,016	35,187,968	(11,881,952)	-33.8%	61,593,368	71,868,039	(10,274,671)	-14.3%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9906009	0.9425403	0.0480606	5.1%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	23,086,960	33,166,078	(10,079,118)	-30.4%	60,749,561	67,592,709	(6,843,148)	-10.1%
6a. JURISDIC. LOSS MULTIPLIER	1.00066	1.00066	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	23,102,197	33,187,968	(10,085,771)	-30.4%	60,789,655	67,637,321	(6,847,666)	-10.1%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	312,692	312,692	0	0.0%	627,915	627,915	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	309,753	294,725	15,028	5.1%	619,832	590,582	29,250	5.0%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	23,411,950	33,482,693	(10,070,743)	-30.1%	61,409,487	68,227,903	(6,818,416)	-10.0%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	9,879,695	1,959,761	7,919,934	404.1%	11,033,827	7,223,717	3,810,110	52.7%
8. INTEREST PROVISION FOR THE MONTH	(118,507)	(238,491)	119,984	-50.3%	(256,717)	(512,703)	255,986	-49.9%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(89,251,578)	(76,293,596)	(12,957,982)	17.0%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	7,389,395	7,389,395	0	0.0%	NOT APPLICABLE			
11. *END OF PERIOD TOTAL NET TRUE-UP* (LINE C7 through C10)	(72,100,995)	(67,182,931)	(4,918,064)	7.3%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(89,251,578)	(76,293,596)	(12,957,982)	17.0%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(71,982,488)	(66,944,440)	(5,038,048)	7.5%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(161,234,066)	(143,238,036)	(17,996,030)	12.6%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(80,617,033)	(71,619,018)	(8,998,015)	12.6%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.770	4.000	(2)	-55.8%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.750	4.000	(2)	-56.3%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	3.520	8.000	(4)	-56.0%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.760	4.000	(2)	-56.0%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.147	0.333	(0)	-55.9%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(118,507)	(238,491)	119,984	-50.3%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	31,108	293,929	(262,821)	-89.4%	186,474	561,269	(374,795)	-66.8%
2	LIGHT OIL	293,173	1,013,913	(720,740)	-71.1%	808,207	2,013,208	(1,205,001)	-59.9%
3	COAL	20,900,507	25,370,267	(4,469,760)	-17.6%	50,969,724	54,854,539	(3,884,815)	-7.1%
4	NATURAL GAS	69,579	470,059	(400,480)	-85.2%	216,138	1,277,623	(1,061,485)	-83.1%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	21,294,367	27,148,168	(5,853,801)	-21.6%	52,180,543	58,706,639	(6,526,096)	-11.1%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	400	6,278	(5,878)	-93.6%	4,009	12,115	(8,106)	-66.9%
9	LIGHT OIL	6,621	15,647	(9,026)	-57.7%	16,935	31,902	(14,967)	-46.9%
10	COAL	1,106,824	1,237,658	(130,834)	-10.6%	2,460,051	2,686,805	(226,754)	-8.4%
11	NATURAL GAS	889	11,051	(10,162)	-92.0%	4,206	27,278	(23,072)	-84.6%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,114,734	1,270,634	(155,900)	-12.3%	2,485,201	2,758,100	(272,899)	-9.9%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	1,113	9,353	(8,240)	-88.1%	6,934	18,049	(11,115)	-61.6%
16	LIGHT OIL (BBL)	10,972	29,183	(18,211)	-62.4%	30,000	57,781	(27,781)	-48.1%
17	COAL (TON)	513,599	547,442	(33,843)	-6.2%	1,144,556	1,190,681	(46,125)	-3.9%
18	NATURAL GAS (MCF)	12,504	110,200	(97,696)	-88.7%	48,257	275,288	(227,031)	-82.5%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	6,981	58,728	(51,748)	-88.1%	43,501	113,328	(69,827)	-61.6%
22	LIGHT OIL	59,302	164,510	(105,208)	-64.0%	167,311	325,386	(158,075)	-48.6%
23	COAL	11,950,934	12,839,818	(888,884)	-6.9%	26,676,921	27,852,173	(1,175,252)	-4.2%
24	NATURAL GAS	13,242	113,314	(100,072)	-88.3%	51,033	283,040	(232,007)	-82.0%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	12,030,459	13,176,370	(1,145,911)	-8.7%	26,938,767	28,573,927	(1,635,160)	-5.7%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.04%	0.49%	(0.00)	-	0.16%	0.44%	(0.00)	-
29	LIGHT OIL	0.59%	1.23%	(0.01)	-	0.68%	1.16%	(0.00)	-
30	COAL	99.29%	97.40%	0.02	-	98.99%	97.42%	0.02	-
31	NATURAL GAS	0.08%	0.87%	(0.01)	-	0.17%	0.99%	(0.01)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	27.95	31.43	(3.48)	-11.1%	26.89	31.10	(4.20)	-13.5%
36	LIGHT OIL ($/BBL)	26.72	34.74	(8.02)	-23.1%	26.94	34.84	(7.90)	-22.7%
37	COAL ($/TON)	40.69	46.34	(5.65)	-12.2%	44.53	46.07	(1.54)	-3.3%
38	NATURAL GAS ($/MCF)	5.56	4.27	1.30	30.5%	4.48	4.64	(0.16)	-3.5%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	4.46	5.00	(0.55)	-11.0%	4.29	4.95	(0.67)	-13.4%
42	LIGHT OIL	4.94	6.16	(1.22)	-19.8%	4.83	6.19	(1.36)	-21.9%
43	COAL	1.75	1.98	(0.23)	-11.5%	1.91	1.97	(0.06)	-3.0%
44	NATURAL GAS	5.25	4.15	1.11	26.7%	4.24	4.51	(0.28)	-6.2%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	1.77	2.06	(0.29)	-14.1%	1.94	2.05	(0.12)	-5.7%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	17,451	9,355	8,096	86.5%	10,851	9,354	1,497	16.0%
49	LIGHT OIL	8,957	10,514	(1,557)	-14.8%	9,880	10,200	(320)	-3.1%
50	COAL	10,798	10,374	424	4.1%	10,844	10,366	478	4.6%
51	NATURAL GAS	14,895	10,254	4,641	45.3%	12,133	10,376	1,757	16.9%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	10,792	10,370	422	4.1%	10,840	10,360	480	4.6%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	7.78	4.68	3.10	66.2%	4.65	4.63	0.02	0.4%
56	LIGHT OIL	4.43	6.48	(2.05)	-31.6%	4.77	6.31	(1.54)	-24.4%
57	COAL	1.89	2.05	(0.16)	-7.8%	2.07	2.04	0.03	1.5%
58	NATURAL GAS	7.83	4.25	3.58	84.2%	5.14	4.68	0.46	9.8%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	1.91	2.14	(0.23)	-10.7%	2.10	2.13	(0.03)	-1.4%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: FEBRUARY 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	32	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	32	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	32	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	41	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	52	-163	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-163**	**---**	**---**	**---**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	32,948	43.0	94.9	57.3	11,955	COAL	16,768	23,490,200	393,883.7	584,856	1.78	34.88
GAN.#2	98	18,304	27.8	44.3	78.7	12,935	COAL	10,057	23,542,000	236,761.9	350,781	1.92	34.88
GAN.#3	155	47,989	46.1	98.5	52.2	14,050	COAL	31,844	21,174,000	674,264.9	1,110,696	2.31	34.88
GAN.#4	159	41,861	39.2	72.7	64.7	12,267	COAL	26,747	19,198,000	513,488.9	932,916	2.23	34.88
GAN.#5	217	34,488	23.7	31.1	64.8	9,606	COAL	15,952	20,768,000	331,291.1	556,394	1.61	34.88
GAN.#6	392	169,401	64.3	86.7	69.3	10,830	COAL	78,708	23,310,000	1,834,683.5	2,745,279	1.62	34.88
GANNON STATION	**1,135**	**344,991**	**45.2**	**72.9**	**65.1**	**11,549**	**COAL**	**180,076**	**22,126,069**	**3,984,374.0**	**6,280,922**	**1.82**	**34.88**
B.B.#1	426	105,397	36.8	46.7	68.8	10,750	COAL	47,043	24,084,300	1,132,997.7	1,936,838	1.84	41.17
B.B.#2	426	89,239	31.2	39.0	75.6	10,402	COAL	39,069	23,759,720	928,268.5	1,608,536	1.80	41.17
B.B.#3	433	189,583	65.2	81.3	72.2	10,520	COAL	81,526	24,464,140	1,994,452.2	3,356,561	1.77	41.17
B.B. 1 - 3	1,285	384,219	44.5	55.8	72.3	10,556	COAL	167,638	24,193,378	4,055,718.4	6,901,935	1.80	41.17
B.B.#4	447	253,321	84.3	95.3	86.8	10,324	COAL	117,504	22,257,112	2,615,294.1	6,161,847	2.43	52.44
B.B. STATION	**1,732**	**637,540**	**54.8**	**66.0**	**76.0**	**10,464**	**COAL**	**285,142**	**23,395,463**	**6,671,012.5**	**13,063,782**	**2.05**	**45.82**
SEB-PHIL. #1(HVY OIL)	17	163	1.4	100.0	35.3	12,399	HVY.OIL	322	6,273,540	2,021.0	9,000	5.52	27.95
SEB-PHIL. #2(HVY OIL)	17	400	3.5	100.0	86.6	12,399	HVY.OIL	791	6,273,540	4,959.5	22,108	5.53	27.95
SEB-PHILLIPS TOTAL	**34**	**563**	**2.5**	**100.0**	**60.9**	**12,399**	**HVY.OIL**	**1,113**	**6,273,540**	**6,980.5**	**31,108**	**5.53**	**27.95**
POLK #1 GASIFIER	250	124,293	74.0	78.9	93.8	10,423	COAL	48,381	26,778,000	1,295,547.5	1,555,803	1.25	32.16
POLK #1 CT (OIL)	245	6,359	3.9	80.6	70.5	8,539	LGT.OIL	10,112	5,749,366	54,301.5	268,366	4.22	26.54
POLK #1 TOTAL	**250**	**130,652**	**77.6**	**80.6**	**92.3**	**10,332**	**-**	**-**	**-**	**1,349,849.0**	**1,824,169**	**1.40**	**-**
POLK #2 CT (GAS)	160	683	0.6	96.6	52.4	15,735	GAS	10,148	972,290	10,747.0	57,433	8.41	5.66
POLK #2 CT (OIL)	180	0	0.0	96.2	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**170**	**683**	**0.6**	**97.7**	**52.4**	**15,735**	**-**	**-**	**-**	**10,747.0**	**57,433**	**8.41**	**-**
POLK STATION TOTAL	**420**	**131,335**	**46.5**	**87.5**	**74.9**	**10,360**	**-**	**-**	**-**	**1,360,596.0**	**1,881,602**	**1.43**	**-**
B.B.C.T.#1	17	51	0.4	100.0	75.0	17,761	LGT.OIL	156	5,799,347	905.8	4,500	8.82	28.85
B.B.C.T.#2	80	204	0.4	100.0	51.0	17,936	LGT.OIL	629	5,814,859	3,659.0	18,144	8.89	28.85
B.B.C.T.#3	80	7	0.0	100.0	8.8	62,300	LGT.OIL	75	5,814,667	436.1	2,163	30.90	28.84
C.T. TOTAL	**177**	**262**	**0.2**	**100.0**	**34.2**	**19,087**	**LGT.OIL**	**860**	**5,812,026**	**5,000.9**	**24,807**	**9.47**	**28.85**
CITY OF TAMPA	**6**	**206**	**0.0**	**0.0**	**0.0**	**12,112**	**GAS**	**2,356**	**972,290**	**2,495.0**	**12,146**	**5.90**	**5.16**
TOT. COAL (GN,BB,POLK)	**3,117**	**1,106,824**	**52.8**	**69.5**	**73.5**	**10,798**	**COAL**	**513,599**	**23,269,028**	**11,950,934.0**	**20,900,507**	**1.89**	**40.69**
SYSTEM	**3,504**	**1,114,734**	**47.4**	**72.9**	**70.1**	**10,791**	**-**	**-**	**-**	**12,030,458.9**	**21,294,367**	**1.91**	**-**

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT B.B. = BIG BEND
GAN. = GANNON C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	611	9,353	(8,742)	-93.5%	11,565	18,049	(6,484)	-35.9%
3 UNIT COST ($/BBL)	(12.67)	31.47	(44.14)	-140.2%	21.97	31.54	(9.57)	-30.3%
4 AMOUNT ($)	(7,740)	294,382	(302,122)	-102.6%	254,103	569,247	(315,144)	-55.4%
5 BURNED:								
6 UNITS (BBL)	1,113	9,353	(8,240)	-88.1%	6,934	18,049	(11,115)	-61.6%
7 UNIT COST ($/BBL)	27.95	31.43	(3.48)	-11.1%	26.89	31.10	(4.20)	-13.5%
8 AMOUNT ($)	31,108	293,929	(262,821)	-89.4%	186,474	561,269	(374,795)	-66.8%
9 ENDING INVENTORY:								
10 UNITS (BBL)	69,896	59,129	10,767	18.2%	69,896	59,129	10,767	18.2%
11 UNIT COST ($/BBL)	25.82	26.74	(0.92)	-3.4%	25.82	26.74	(0.92)	-3.4%
12 AMOUNT ($)	1,804,482	1,580,955	223,527	14.1%	1,804,482	1,580,955	223,527	14.1%
13								
14 DAYS SUPPLY:	212	180	32	18.0%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	15,877	36,178	(20,301)	-56.1%	42,218	76,466	(34,248)	-44.8%
17 UNIT COST ($/BBL)	25.71	34.98	(9.27)	-26.5%	21.57	35.34	(13.76)	-38.9%
18 AMOUNT ($)	408,196	1,265,671	(857,475)	-67.7%	910,784	2,702,042	(1,791,258)	-66.3%
19 BURNED:								
20 UNITS (BBL)	10,972	29,183	(18,211)	-62.4%	30,000	57,781	(27,781)	-48.1%
21 UNIT COST ($/BBL)	26.72	34.74	(8.02)	-23.1%	26.94	34.84	(7.90)	-22.7%
22 AMOUNT ($)	293,173	1,013,913	(720,740)	-71.1%	808,207	2,013,208	(1,205,001)	-59.9%
23 ENDING INVENTORY:								
24 UNITS (BBL)	103,203	113,465	(10,262)	-9.0%	103,203	113,465	(10,262)	-9.0%
25 UNIT COST ($/BBL)	27.90	34.57	(6.67)	-19.3%	27.90	34.57	(6.67)	-19.3%
26 AMOUNT ($)	2,879,630	3,922,736	(1,043,106)	-26.6%	2,879,630	3,922,736	(1,043,106)	-26.6%
27								
28 DAYS SUPPLY: NORMAL	69	76	(7)	-8.8%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	15	16	(1)	-7.9%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	740,504	790,000	(49,496)	-6.3%	1,175,222	1,398,000	(222,778)	-15.9%
32 UNIT COST ($/TON)	41.28	47.05	(5.77)	-12.3%	44.17	46.82	(2.65)	-5.7%
33 AMOUNT ($)	30,571,190	37,172,730	(6,601,540)	-17.8%	51,912,852	65,453,757	(13,540,905)	-20.7%
34 BURNED:								
35 UNITS (TONS)	513,599	547,442	(33,843)	-6.2%	1,144,556	1,190,681	(46,125)	-3.9%
36 UNIT COST ($/TON)	40.69	46.34	(5.65)	-12.2%	44.53	46.07	(1.54)	-3.3%
37 AMOUNT ($)	20,900,507	25,370,267	(4,469,760)	-17.6%	50,969,724	54,854,539	(3,884,815)	-7.1%
38 ENDING INVENTORY:								
39 UNITS (TONS)	656,146	1,184,139	(527,993)	-44.6%	656,146	1,184,139	(527,993)	-44.6%
40 UNIT COST ($/TON)	43.02	46.58	(3.55)	-7.6%	43.02	46.58	(3.55)	-7.6%
41 AMOUNT ($)	28,230,044	55,152,409	(26,922,365)	-48.8%	28,230,044	55,152,409	(26,922,365)	-48.8%
42								
43 DAYS SUPPLY:	35	64	(29)	-44.5%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	12,504	110,200	(97,696)	-88.7%	48,257	275,288	(227,031)	-82.5%
46 UNIT COST ($/MCF)	5.56	4.27	1.30	30.5%	4.46	4.64	(0.18)	-3.9%
47 AMOUNT ($)	69,579	470,059	(400,480)	-85.2%	215,165	1,277,623	(1,062,458)	-83.2%
48 BURNED:								
49 UNITS (MCF)	12,504	110,200	(97,696)	-88.7%	48,257	275,288	(227,031)	-82.5%
50 UNIT COST ($/MCF)	5.56	4.27	1.30	30.5%	4.48	4.64	(0.16)	-3.5%
51 AMOUNT ($)	69,579	470,059	(400,480)	-85.2%	216,138	1,277,623	(1,061,485)	-83.1%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

* Includes adjustment of ($20,665)

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	3,642
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	3,642

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(6,204)	(178,637)
OTHER USAGE	(605)	(17,408)
TOTAL	(6,809)	(196,045)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	48,038
IGNITION #2 OIL	174,995
IGNITION PROPANE	4,250
AERIAL SURVEY ADJ.	(1,318,394)
ADDITIVES	33,127
GREEN FUEL	0
TOTAL	(1,057,984)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2002

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. -D	6,116.0	0.0	6,116.0	1.484	1.484	90,800.00	90,800.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	48,720.0	0.0	48,720.0	2.506	3.554	1,221,000.00	1,731,600.00	
VARIOUS	JURISDIC.	MKT. BASE	16,375.0	0.0	16,375.0	2.078	2.078	340,300.00	340,300.00	151,800.00
TOTAL			71,213.0	0.0	71,213.0	2.320	3.037	1,652,100.00	2,162,700.00	151,800.00
ACTUAL:										
FLA. PWR. & LIGHT	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR PARTNERS	SEP. CONTR.	SCH. -D	19,128.0	0.0	19,128.0	2.559	3.324	489,485.52	635,814.72	
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. -D	2,261.7	4.1	2,257.6	2.058	2.058	46,451.91	46,451.91	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. -D	732.1	0.0	732.1	1.752	1.752	12,828.15	12,828.15	
FLA. PWR. CORP.		SCH. -MA	100.0	0.0	100.0	1.804	2.467	1,804.44	2,467.24	348.80
FLA. PWR. & LIGHT		SCH. -MA	50.0	0.0	50.0	1.679	2.033	839.33	1,016.48	20.15
CITY OF LAKELAND		SCH. -MA	288.0	0.0	288.0	1.960	2.449	5,645.84	7,051.74	501.58
AQUILA		SCH. -MA	800.0	0.0	800.0	2.433	2.476	19,462.21	19,810.66	(2,163.55)
DUKE ENERGY		SCH. -MA	844.0	0.0	844.0	2.068	2.837	17,455.57	23,941.63	3,835.90
CARGILL ALLIANT		SCH. -OATT	22.0	0.0	22.0	2.952	2.952	649.52	649.52	
ADJUSTMENTS TO PREV. MONTHS										
HARDEE PWR PARTNERS EST.	Jan. 2001	CONTRACT	(24,846.0)	0.0	(24,846.0)	2.551	3.284	(633,821.46)	(815,942.64)	
HARDEE PWR PARTNERS ACT.	Jan. 2001	CONTRACT	24,846.0	0.0	24,846.0	2.559	3.324	635,809.14	825,881.04	
CITY OF LAKELAND	Jan. 2001	SCH. -MA	(3,688.0)	0.0	(3,688.0)	2.055	2.487	(75,778.49)	(91,732.66)	(6,549.77)
CITY OF LAKELAND	Jan. 2001	SCH. -MA	3,688.0	0.0	3,688.0	1.897	2.335	69,979.72	86,132.89	6,748.77
ORLANDO UTIL. COMM.	Jan. 2001	SCH. -MA	(275.0)	0.0	(275.0)	2.051	2.662	(5,639.50)	(7,319.84)	(979.09)
ORLANDO UTIL. COMM.	Jan. 2001	SCH. -MA	275.0	0.0	275.0	1.923	2.534	5,288.45	6,968.79	979.09
AQUILA	Jan. 2001	SCH. -MA	(989.0)	0.0	(989.0)	1.753	3.230	(17,340.22)	(31,943.74)	(12,081.57)
AQUILA	Jan. 2001	SCH. -MA	989.0	0.0	989.0	2.058	3.230	20,356.12	31,943.74	9,065.67
DUKE ENERGY	Jan. 2001	SCH. -MA	(54.0)	0.0	(54.0)	1.859	2.454	(1,003.98)	(1,324.96)	(183.28)
DUKE ENERGY	Jan. 2001	SCH. -MA	54.0	0.0	54.0	1.865	2.454	1,007.27	1,324.96	179.99
THE ENERGY AUTHORITY	Jan. 2001	SCH. -MA	(281.0)	0.0	(281.0)	2.147	2.649	(6,032.63)	(7,443.36)	(694.18)
THE ENERGY AUTHORITY	Jan. 2001	SCH. -MA	281.0	0.0	281.0	2.039	2.541	5,730.00	7,140.73	694.18
REEDY CREEK	Jan. 2001	SCH. -MA	(20.0)	0.0	(20.0)	2.020	2.850	(403.90)	(570.06)	(115.16)
REEDY CREEK	Jan. 2001	SCH. -MA	20.0	0.0	20.0	1.844	2.675	368.74	534.90	115.16
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD			2,993.8	4.1	2,989.7	1.983	1.983	59,280.06	59,280.06	
SUB-TOTAL SCHEDULE D POWER SALES-SEPARATED			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEP.			19,128.0	0.0	19,128.0	2.569	3.376	491,473.20	645,753.12	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD			2,082.0	0.0	2,082.0	2.005	2.305	41,738.97	47,999.14	(277.31)
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD			22.0	0.0	22.0	2.952	2.952	649.52	649.52	
TOTAL			24,225.8	4.1	24,221.7	2.449	3.112	593,141.75	753,681.84	(277.31)
CURRENT MONTH:										
DIFFERENCE			(46,987.2)	4.1	(46,991.3)	0.129	0.075	(1,058,958.25)	(1,409,018.16)	(152,077.31)
DIFFERENCE %			-66.0%	0.0%	-66.0%	5.6%	2.5%	-64.1%	-65.2%	-100.2%
PERIOD TO DATE:										
ACTUAL			67,775.3	30.5	67,744.8	2.353	2.959	1,593,785.24	2,004,852.20	31,211.55
ESTIMATED			146,386.0	0.0	146,386.0	2.295	3.030	3,358,900.00	4,434,800.00	287,600.00
DIFFERENCE			(78,610.7)	30.5	(78,641.2)	0.058	(0.071)	(1,765,114.76)	(2,429,947.80)	(256,388.45)
DIFFERENCE %			-53.7%	0.0%	-53.7%	2.5%	-2.3%	-52.6%	-54.8%	-89.1%

* No Sales to Hardee Pwr Partners for Others in the month of February 2002.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH.-J	2,577.0	0.0	1,638.0	939.0	5.804	5.804	54,500.00
HARDEE POWER PARTNERS		IPP	57,292.0	0.0	0.0	57,292.0	5.222	5.222	2,991,900.00
VARIOUS		OTHER	35,292.0	0.0	0.0	35,292.0	6.906	6.906	2,437,300.00
VARIOUS		MKT. BASE	75,557.0	0.0	0.0	75,557.0	4.847	4.847	3,662,100.00
TOTAL			**170,718.0**	**0.0**	**1,638.0**	**169,080.0**	**5.409**	**5.409**	**9,145,800.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	34,705.0	0.0	0.0	34,705.0	0.845	0.845	293,186.59
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH.-J	22,287.0	0.0	62.8	22,224.2	2.419	2.419	537,557.05
FLA. POWER & LIGHT		SCH.-J	9,897.0	0.0	0.0	9,897.0	2.814	2.814	278,539.00
CITY OF LAKELAND		SCH.-J	6,439.0	0.0	27.0	6,412.0	2.512	2.512	161,053.00
THE ENERGY AUTHORITY		SCH.-J	221.0	0.0	49.0	172.0	6.833	6.833	11,753.00
OKEELANTA		SCH.-J	1,370.0	0.0	0.0	1,370.0	3.453	3.453	47,311.00
AQUILLA		SCH.-J	1,629.0	0.0	0.0	1,629.0	4.249	4.249	69,209.00
CARGILL ALLIANT		SCH.-J	1,995.0	0.0	0.0	1,995.0	0.179	0.179	3,575.00
AXIA		SCH.-J	147.0	0.0	0.0	147.0	9.694	9.694	14,250.00
DUKE ENERGY		SCH.-J	3,717.0	0.0	157.0	3,560.0	3.624	3.624	129,022.25
RINGHAVER		SCH.-J	7.0	0.0	0.0	7.0	198.328	198.328	13,882.93
FLA. POWER CORP.		SCH.-D	13,650.0	0.0	0.0	13,650.0	4.232	4.232	577,616.50
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Jan. 2001	*IPP*	*(58,697.0)*	*0.0*	0.0	(58,697.0)	3.869	3.869	(2,270,774.02)
HARDEE PWR. PART.-NATIVE	Jan. 2001	IPP	58,697.0	0.0	0.0	58,697.0	3.559	3.559	2,089,049.62
FLA. POWER CORP.	Jan. 2001	SCH.-D	(19,600.0)	0.0	0.0	(19,600.0)	3.135	3.135	(614,460.00)
FLA. POWER CORP.	Jan. 2001	SCH.-D	19,600.0	0.0	0.0	19,600.0	3.375	3.375	661,512.98
TOTAL			***96,064.0***	***0.0***	***295.8***	***95,768.2***	**2.091**	**2.091**	**2,002,283.90**
CURRENT MONTH:									
DIFFERENCE			(74,654.0)	0.0	(1,342.2)	(73,311.8)	(3.318)	(3.318)	(7,143,516.10)
DIFFERENCE %			-43.7%	0.0%	-81.9%	-43.4%	-61.3%	-61.3%	-78.1%
PERIOD TO DATE:									
ACTUAL			218,628.0	0.0	2,566.0	216,062.0	4.466	4.466	9,648,684.16
ESTIMATED			278,466.0	0.0	3,410.0	275,056.0	5.550	5.550	15,264,300.00
DIFFERENCE			(59,838.0)	0.0	(844.0)	(58,994.0)	(1.084)	(1.084)	(5,615,615.84)
DIFFERENCE %			-21.5%	0.0%	-24.8%	-21.4%	-19.5%	-19.5%	-36.8%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	34,868.0	0.0	0.0	34,868.0	2.013	2.013	701,900.00
TOTAL			**34,868.0**	**0.0**	**0.0**	**34,868.0**	**2.013**	**2.013**	**701,900.00**
ACTUAL:									
IMC-AGRICO-NICHOLS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.0
McKAY BAY REFUSE		COGEN.	12,329.0	0.0	0.0	12,329.0	1.892	1.892	233,293.3
MULBERRY PHOSPHATES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.0
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.0
IMC-AGRICO-NEW WALES		COGEN.	228.0	0.0	0.0	228.0	2.046	2.046	4,664.2
HILLSBOROUGH COUNTY		COGEN.	11,603.0	0.0	0.0	11,603.0	1.897	1.897	220,132.5
CARGILL MILLPOINT		COGEN.	79.0	0.0	0.0	79.0	2.040	2.040	1,611.9
CF INDUSTRIES INC.		COGEN.	298.0	0.0	0.0	298.0	2.401	2.401	7,156.3
FARMLAND HYDRO LP		COGEN.	1,184.0	0.0	0.0	1,184.0	2.335	2.335	27,652.0
IMC-AGRICO-S. PIERCE		COGEN.	492.0	0.0	0.0	492.0	2.257	2.257	11,105.9
AUBURNDALE POWER PARTNERS		COGEN.	26.0	0.0	0.0	26.0	2.133	2.133	554.7
ORANGE COGENERATION L.P.		COGEN.	5,037.0	0.0	0.0	5,037.0	1.954	1.954	98,440.1
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.0
AS AVAILABLE ASSIGNMENT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.0
SUB-TOTAL FOR FEBRUARY 2002			31,276.0	0.0	0.0	31,276.0	1.933	1.933	604,610.94
ADJUSTMENTS FOR THE MONTH OF:	**DECEMBER 2001**								
IMC-AGRICO-NICHOLS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE		COGEN.	(13,696.0)	0.0	0.0	(13,696.0)	1.841	1.841	(252,208.13
			13,696.0	0.0	0.0	13,696.0	1.846	1.846	252,803.52
MULBERRY PHOSPHATES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
HILLSBOROUGH COUNTY		COGEN.	(19,591.0)	0.0	0.0	(19,591.0)	1.842	1.842	(360,806.32
			19,591.0	0.0	0.0	19,591.0	1.846	1.846	361,655.05
CARGILL MILLPOINT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.		COGEN.	(1,034.0)	0.0	0.0	(1,034.0)	2.276	2.276	(23,530.01
			1,034.0	0.0	0.0	1,034.0	2.275	2.275	23,523.49
FARMLAND HYDRO LP		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
ORANGE COGENERATION L.P.		COGEN.	(5,704.0)	0.0	0.0	(5,704.0)	1.791	1.791	(102,164.46
			5,704.0	0.0	0.0	5,704.0	1.797	1.797	102,523.94
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
AS AVAILABLE ASSIGNMENT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**DECEMBER 2001**		0.0	0.0	0.0	0.0	0.000	0.000	1,797.08
GRAND TOTAL			**31,276.0**	**0.0**	**0.0**	**31,276.0**	**1.938**	**1.939**	**606,408.02**
CURRENT MONTH:									
DIFFERENCE			(3,592.0)	0.0	0.0	(3,592.0)	(0.074)	(0.074)	(95,491.98
DIFFERENCE %			-10.3%	0.0%	0.0%	-10.3%	-3.7%	-3.7%	-13.6%
PERIOD TO DATE:									
ACTUAL			71,552.0	0.0	0.0	71,552.0	1.954	1.954	1,398,331.09
ESTIMATED			73,937.0	0.0	0.0	73,937.0	2.099	2.099	1,551,600.00
DIFFERENCE			(2,385.0)	0.0	0.0	(2,385.0)	(0.144)	(0.144)	(153,268.91
DIFFERENCE %			-3.2%	0.0%	0.0%	-3.2%	(0.069)	(0.069)	-9.9%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: FEBRUARY 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-6
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

MARCH 2002

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	25,606,559	27,978,239	(2,371,680)	-8.5%	1,183,064	1,246,354	(63,290)	-5.1%	2.16443	2.24481	(0.08038)	-3.6%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(4,566)	(4,000)	(566)	14.2%	1,183,064 (a)	1,246,354 (a)	(63,290)	-5.1%	(0.00039)	(0.00032)	(0.00007)	20.3%
4b. Adjustments to Fuel Cost (1)	(1,370)	0	(1,370)	0.0%	1,183,064 (a)	1,246,354 (a)	(63,290)	-5.1%	(0.00012)	0.00000	(0.00012)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	1,183,064 (a)	1,246,354 (a)	(63,290)	-5.1%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**25,600,623**	**27,974,239**	**(2,373,616)**	**-8.5%**	**1,183,064**	**1,246,354**	**(63,290)**	**-5.1%**	**2.16393**	**2.24449**	**(0.08056)**	**-3.6%**
6. Fuel Cost of Purchased Power - Firm (A7)	12,545,183	11,220,700	1,324,483	11.8%	249,956	215,608	34,348	15.9%	5.01896	5.20421	(0.18526)	-3.6%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	892,119	805,100	87,019	10.8%	39,090	39,069	21	0.1%	2.28222	2.06071	0.22150	10.7%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**13,437,302**	**12,025,800**	**1,411,502**	**11.7%**	**289,046**	**254,677**	**34,369**	**13.5%**	**4.64885**	**4.72198**	**(0.07314)**	**-1.5%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,472,110**	**1,501,031**	**(28,921)**	**-1.9%**				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	72,172	93,700	(21,528)	-23.0%	2,822	6,205	(3,383)	-54.5%	2.55748	1.51007	1.04740	69.4%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	2,347	0	2,347	0.0%	55	0	55	0.0%	4.26727	0.00000	4.26727	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	669,227	1,643,200	(973,973)	-59.3%	27,955	64,728	(36,773)	-56.8%	2.39394	2.53862	(0.14468)	-5.7%
21. Fuel Cost of Market Base Sales (A6)	25,191	772,900	(747,709)	-96.7%	1,146	25,086	(23,940)	-95.4%	2.19817	3.08100	(0.88283)	-28.7%
21a. Gains on Market Based Sales	6,526	433,500	(426,974)	-98.5%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 +21a)	**775,463**	**2,943,300**	**(2,167,837)**	**-73.7%**	**31,978**	**96,019**	**(64,041)**	**-66.7%**	**2.42499**	**3.06533**	**(0.64034)**	**-20.9%**
23. Net Inadvertant Interchange					(305)	0	(305)	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					2,217	0	2,217	0.0%				
25. Interchange and Wheeling Losses					160	1,400	(1,240)	-88.6%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	**38,262,462**	**37,056,739**	**1,205,723**	**3.3%**	**1,441,884**	**1,403,612**	**38,272**	**2.7%**	**2.65364**	**2.64010**	**0.01355**	**0.5%**
27. Net Unbilled	2,697,827 (a)	1,396,269 (a)	1,301,558	93.2%	101,665	52,887	48,778	92.2%	2.65364	2.64010	0.01355	0.5%
28. Company Use	98,636 (a)	108,244 (a)	(9,608)	-8.9%	3,717	4,100	(383)	-9.3%	2.65365	2.64010	0.01355	0.5%
29. T & D Losses	2,171,132 (a)	(1,406,548) (a)	3,577,680	-254.4%	81,817	(53,276)	135,093	-253.6%	2.65364	2.64010	0.01355	0.5%
30. System KWH Sales	38,262,462	37,056,739	1,205,723	3.3%	1,254,685	1,399,901	(145,216)	-10.4%	3.04957	2.64710	0.40247	15.2%
31. Wholesale KWH Sales	(917,252)	(3,242,772)	2,325,520	-71.7%	(30,078)	(122,503)	92,425	-75.4%	3.04958	2.64710	0.40248	15.2%
32. Jurisdictional KWH Sales	37,345,210	33,813,967	3,531,243	10.4%	1,224,607	1,277,398	(52,791)	-4.1%	3.04957	2.64710	0.40247	15.2%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	37,369,858	33,836,284	3,533,574	10.4%	1,224,607	1,277,398	(52,791)	-4.1%	3.05158	2.64884	0.40274	15.2%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	302,726	283,019	19,707	7.0%	1,224,607	1,277,398	(52,791)	-4.1%	0.02472	0.02216	0.00256	11.6%
35a. Adjustment	0	0	0	0.0%	1,224,607	1,277,398	(52,791)	-4.1%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	1,224,607	1,277,398	(52,791)	-4.1%	0.00000	0.00000	0.00000	0.0%
36. True-up *	7,389,395	7,389,395	0	0.0%	1,224,607	1,277,398	(52,791)	-4.1%	0.60341	0.57847	0.02494	4.3%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	45,061,979	41,508,698	3,553,281	8.6%	1,224,607	1,277,398	(52,791)	-4.1%	3.67971	3.24947	0.43024	13.2%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.68236	3.25181	0.43055	13.2%
40. GPIF * (Already Adjusted for Taxes)	91,246	91,246	0	0.0%	1,224,607	1,277,398	(52,791)	-4.1%	0.00745	0.00714	0.00031	4.3%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**45,153,225**	**41,599,944**	**3,553,281**	**8.5%**	**1,224,607**	**1,277,398**	**(52,791)**	**-4.1%**	**3.68981**	**3.25895**	**0.43086**	**13.2%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.690**	**3.259**	**0.431**	**13.2%**

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: MARCH 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	77,787,102	86,684,878	(8,897,776)	-10.3%	3,668,265	4,004,454	(336,189)	-8.4%	2.12054	2.16471	(0.04417)	-2.0%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(12,877)	(12,000)	(877)	7.3%	3,668,265 (a)	4,004,454 (a)	(336,189)	-8.4%	(0.00035)	(0.00030)	(0.00005)	17.1%
4b. Adjustments to Fuel Cost (1)	(2,253)	0	(2,253)	0.0%	3,668,265 (a)	4,004,454 (a)	(336,189)	-8.4%	(0.00006)	0.00000	(0.00006)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	3,668,265 (a)	4,004,454 (a)	(336,189)	-8.4%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**77,771,972**	**86,672,878**	**(8,900,906)**	**-10.3%**	**3,668,265**	**4,004,454**	**(336,189)**	**-8.4%**	**2.12013**	**2.16441**	**(0.04428)**	**-2.0%**
6. Fuel Cost of Purchased Power - Firm (A7)	22,193,867	26,485,000	(4,291,133)	-16.2%	466,018	490,664	(24,646)	-5.0%	4.76245	5.39779	(0.63534)	-11.8%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	2,290,450	2,356,700	(66,250)	-2.8%	110,642	113,006	(2,364)	-2.1%	2.07015	2.08546	(0.01532)	-0.7%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**24,484,317**	**28,841,700**	**(4,357,383)**	**-15.1%**	**576,660**	**603,670**	**(27,010)**	**-4.5%**	**4.24588**	**4.77773**	**(0.53184)**	**-11.1%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**4,244,925**	**4,608,124**	**(363,199)**	**-7.9%**				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	201,737	278,200	(76,463)	-27.5%	9,475	18,529	(9,054)	-48.9%	2.12915	1.50143	0.62772	41.8%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	3,766	0	3,766	0.0%	102	0	102	0.0%	3.69216	0.00000	3.69216	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	1,804,636	4,161,200	(2,356,564)	-56.6%	71,929	167,388	(95,459)	-57.0%	2.50891	2.48596	0.02295	0.9%
21. Fuel Cost of Market Base Sales (A6)	352,583	1,429,300	(1,076,717)	-75.3%	18,217	56,488	(38,271)	-67.8%	1.93546	2.53027	(0.59481)	-23.5%
21a. Gains on Market Based Sales	37,737	721,100	(683,363)	-94.8%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 +21a)	**2,400,459**	**6,589,800**	**(4,189,341)**	**-63.6%**	**99,723**	**242,405**	**(142,682)**	**-58.9%**	**2.40713**	**2.71851**	**(0.31138)**	**-11.5%**
23. Net Inadvertant Interchange					647	0	647	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					4,504	0	4,504	0.0%				
25. Interchange and Wheeling Losses					687	3,500	(2,813)	-80.4%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	**99,855,830**	**108,924,778**	**(9,068,948)**	**-8.3%**	**4,149,666**	**4,362,219**	**(212,553)**	**-4.9%**	**2.40636**	**2.49700**	**(0.09065)**	**-3.6%**
27. Net Unbilled	467,695 (a)	(530,341) (a)	998,036	-188.2%	(8,802)	(24,254)	15,452	-63.7%	(5.31351)	2.18661	(7.50012)	-343.0%
28. Company Use	263,606 (a)	307,756 (a)	(44,150)	-14.3%	11,015	12,300	(1,285)	-10.4%	2.39315	2.50208	(0.10893)	-4.4%
29. T & D Losses	4,515,279 (a)	1,331,019 (a)	3,184,260	239.2%	185,898	57,222	128,676	224.9%	2.42890	2.32608	0.10282	4.4%
30. System KWH Sales	99,855,830	108,924,778	(9,068,948)	-8.3%	3,961,555	4,316,951	(355,396)	-8.2%	2.52062	2.52319	(0.00257)	-0.1%
31. Wholesale KWH Sales	(1,761,059)	(7,518,102)	5,757,043	-76.6%	(65,544)	(296,218)	230,674	-77.9%	2.68683	2.53603	0.14880	5.9%
32. Jurisdictional KWH Sales	98,094,771	101,406,676	(3,311,905)	-3.3%	3,896,011	4,020,733	(124,722)	-3.1%	2.51783	2.52209	(0.00427)	-0.2%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	98,159,513	101,473,605	(3,314,092)	-3.3%	3,896,011	4,020,733	(124,722)	-3.1%	2.51949	2.52376	(0.00427)	-0.2%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	922,558	873,601	48,957	5.6%	3,896,011	4,020,733	(124,722)	-3.1%	0.02368	0.02173	0.00195	9.0%
35a. Adjustment	0	0	0	0.0%	3,896,011	4,020,733	(124,722)	-3.1%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	3,896,011	4,020,733	(124,722)	-3.1%	0.00000	0.00000	0.00000	0.0%
36. True-up *	22,168,185	22,168,185	0	0.0%	3,896,011	4,020,733	(124,722)	-3.1%	0.56900	0.55135	0.01765	3.2%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	121,250,256	124,515,391	(3,265,135)	-2.6%	3,896,011	4,020,733	(124,722)	-3.1%	3.11216	3.09683	0.01533	0.5%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.11440	3.09906	0.01534	0.5%
40. GPIF * (Already Adjusted for Taxes)	273,738	273,738	0	0.0%	3,896,011	4,020,733	(124,722)	-3.1%	0.00703	0.00681	0.00022	3.2%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**121,523,994**	**124,789,129**	**(3,265,135)**	**-2.6%**	**3,896,011**	**4,020,733**	**(124,722)**	**-3.1%**	**3.12143**	**3.10587**	**0.01556**	**0.5%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.121**	**3.106**	**0.015**	**0.5%**

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CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	25,606,559	27,978,239	(2,371,680)	-8.5%	77,787,102	86,684,878	(8,897,776)	-10.3%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	768,937	2,509,800	(1,740,863)	-69.4%	2,362,722	5,868,700	(3,505,978)	-59.7%
2a. GAINS FROM MARKET BASED SALES	6,526	433,500	(426,974)	-98.5%	37,737	721,100	(683,363)	-94.8%
3. FUEL COST OF PURCHASED POWER	12,545,183	11,220,700	1,324,483	11.8%	22,193,867	26,485,000	(4,291,133)	-16.2%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	892,119	805,100	87,019	10.8%	2,290,450	2,356,700	(66,250)	-2.8%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	38,268,398	37,060,739	1,207,659	3.3%	99,870,960	108,936,778	(9,065,818)	-8.3%
6a. ADJUSTMENTS TO FUEL COST	(4,566)	(4,000)	(566)	14.2%	(12,877)	(12,000)	(877)	7.3%
(FT. MEADE/WAUCHULA WHEELING LOSSES) 6b. ADJ.TO FUEL COST	(1,370)	0	(1,370)	0.0%	(2,253)	0	(2,253)	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	38,262,462	37,056,739	1,205,723	3.3%	99,855,830	108,924,778	(9,068,948)	-8.3%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,224,607	1,277,398	(52,791)	-4.1%	3,896,011	4,020,733	(124,722)	-3.1%
2. NONJURISDICTIONAL SALES	30,078	122,503	(92,425)	-75.4%	65,544	296,218	(230,674)	-77.9%
3. TOTAL SALES	1,254,685	1,399,901	(145,216)	-10.4%	3,961,555	4,316,951	(355,396)	-8.2%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9760274	0.9124917	0.0635357	7.0%	0.9834550	0.9313826	0.0520724	5.6%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: MARCH 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	39,901,595	42,086,698	(2,185,103)	-5.2%	127,306,191	132,499,600	(5,193,409)	-3.9%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(7,389,395)	(7,389,395)	0	0.0%	(22,168,185)	(22,168,185)	0	0.0%
2b. INCENTIVE PROVISION	(91,246)	(91,246)	0	0.0%	(273,738)	(273,738)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	32,420,954	34,606,057	(2,185,103)	-6.3%	104,864,268	110,057,677	(5,193,409)	-4.7%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	38,262,462	37,056,739	1,205,723	3.3%	99,855,830	108,924,778	(9,068,948)	-8.3%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9760274	0.9124917	0.0635357	7.0%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	37,345,210	33,813,967	3,531,243	10.4%	98,094,771	101,406,676	(3,311,905)	-3.3%
6a. JURISDIC. LOSS MULTIPLIER	1.00066	1.00066	0.00000	0.0%	NA	NA	-	0.0%
6b. *(LINE C6 x LINE C6a)*	37,369,858	33,836,284	3,533,574	10.4%	98,159,513	101,473,605	(3,314,092)	-3.3%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	310,161	310,161	0	0.0%	938,076	938,076	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	302,726	283,019	19,707	7.0%	922,558	873,601	48,957	5.6%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	37,672,584	34,119,303	3,553,281	10.4%	99,082,071	102,347,206	(3,265,135)	-3.2%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(5,251,630)	486,754	(5,738,384)	-1178.9%	5,782,197	7,710,471	(1,928,274)	-25.0%
8. INTEREST PROVISION FOR THE MONTH	(105,128)	(210,605)	105,477	-50.1%	(361,845)	(723,308)	361,463	-50.0%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(72,100,995)	(67,182,931)	(4,918,064)	7.3%	----------NOT APPLICABLE----------			
10. TRUE-UP COLLECTED (REFUNDED)	7,389,395	7,389,395	0	0.0%	----------NOT APPLICABLE----------			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(70,068,358)	(59,517,387)	(10,550,971)	17.7%	----------NOT APPLICABLE----------			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(72,100,995)	(67,182,931)	(4,918,064)	7.3%	----------NOT APPLICABLE----------			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(69,963,230)	(59,306,782)	(10,656,448)	18.0%	----------NOT APPLICABLE----------			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(142,064,225)	(126,489,713)	(15,574,512)	12.3%	----------NOT APPLICABLE----------			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(71,032,113)	(63,244,857)	(7,787,256)	12.3%	----------NOT APPLICABLE----------			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.750	4.000	(2)	-56.3%	----------NOT APPLICABLE----------			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.800	4.000	(2)	-55.0%	----------NOT APPLICABLE----------			
7. TOTAL (LINE D5 + LINE D6)	3.550	8.000	(4)	-55.6%	----------NOT APPLICABLE----------			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.775	4.000	(2)	-55.6%	----------NOT APPLICABLE----------			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.148	0.333	(0)	-55.6%	----------NOT APPLICABLE----------			
10. INT. PROVISION (LINE D4 x LINE D9)	(105,128)	(210,605)	105,477	-50.1%	----------NOT APPLICABLE----------			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	353,754	423,881	(70,127)	-16.5%	540,228	985,150	(444,922)	-45.2%
2	LIGHT OIL	1,766,815	1,441,938	324,877	22.5%	2,575,022	3,455,146	(880,124)	-25.5%
3	COAL	22,669,949	24,835,472	(2,165,523)	-8.7%	73,639,673	79,690,011	(6,050,338)	-7.6%
4	NATURAL GAS	816,041	1,276,948	(460,907)	-36.1%	1,032,179	2,554,571	(1,522,392)	-59.6%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	25,606,559	27,978,239	(2,371,680)	-8.5%	77,787,102	86,684,878	(8,897,776)	-10.3%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	9,010	9,235	(225)	-2.4%	13,019	21,350	(8,331)	-39.0%
9	LIGHT OIL	40,293	22,340	17,953	80.4%	57,228	54,242	2,986	5.5%
10	COAL	1,115,161	1,185,003	(69,842)	-5.9%	3,575,212	3,871,808	(296,596)	-7.7%
11	NATURAL GAS	18,600	29,776	(11,176)	-37.5%	22,806	57,054	(34,248)	-60.0%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,183,064	1,246,354	(63,290)	-5.1%	3,668,265	4,004,454	(336,189)	-8.4%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	14,154	13,760	394	2.9%	21,088	31,809	(10,721)	-33.7%
16	LIGHT OIL (BBL)	63,060	42,088	20,972	49.8%	93,060	99,869	(6,809)	-6.8%
17	COAL (TON)	524,327	529,065	(4,738)	-0.9%	1,668,883	1,719,746	(50,863)	-3.0%
18	NATURAL GAS (MCF)	199,913	299,642	(99,729)	-33.3%	248,170	574,930	(326,760)	-56.8%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	88,796	86,394	2,402	2.8%	132,297	199,722	(67,425)	-33.8%
22	LIGHT OIL	362,987	238,704	124,283	52.1%	530,298	564,090	(33,792)	-6.0%
23	COAL	12,216,410	12,387,401	(170,991)	-1.4%	38,893,331	40,239,574	(1,346,243)	-3.3%
24	NATURAL GAS	210,109	308,076	(97,967)	-31.8%	261,142	591,116	(329,974)	-55.8%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	12,878,302	13,020,575	(142,273)	-1.1%	39,817,069	41,594,502	(1,777,433)	-4.3%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.76%	0.74%	0.00	-	0.35%	0.53%	(0.00)	-
29	LIGHT OIL	3.41%	1.79%	0.02	-	1.56%	1.35%	0.00	-
30	COAL	94.26%	95.08%	(0.01)	-	97.46%	96.69%	0.01	-
31	NATURAL GAS	1.57%	2.39%	(0.01)	-	0.62%	1.42%	(0.01)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	24.99	30.81	(5.81)	-18.9%	25.62	30.97	(5.35)	-17.3%
36	LIGHT OIL ($/BBL)	28.02	34.26	(6.24)	-18.2%	27.67	34.60	(6.93)	-20.0%
37	COAL ($/TON)	43.24	46.94	(3.71)	-7.9%	44.13	46.34	(2.21)	-4.8%
38	NATURAL GAS ($/MCF)	4.08	4.26	(0.18)	-4.2%	4.16	4.44	(0.28)	-6.4%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	3.98	4.91	(0.92)	-18.8%	4.08	4.93	(0.85)	-17.2%
42	LIGHT OIL	4.87	6.04	(1.17)	-19.4%	4.86	6.13	(1.27)	-20.7%
43	COAL	1.86	2.00	(0.15)	-7.4%	1.89	1.98	(0.09)	-4.4%
44	NATURAL GAS	3.88	4.14	(0.26)	-6.3%	3.95	4.32	(0.37)	-8.5%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	1.99	2.15	(0.16)	-7.5%	1.95	2.08	(0.13)	-6.3%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,855	9,355	500	5.3%	10,162	9,355	807	8.6%
49	LIGHT OIL	9,009	10,685	(1,676)	-15.7%	9,266	10,400	(1,134)	-10.9%
50	COAL	10,955	10,453	502	4.8%	10,879	10,393	486	4.7%
51	NATURAL GAS	11,296	10,346	950	9.2%	11,451	10,361	1,090	10.5%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	10,886	10,447	439	4.2%	10,854	10,387	467	4.5%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	3.93	4.59	(0.66)	-14.4%	4.15	4.61	(0.46)	-10.0%
56	LIGHT OIL	4.38	6.45	(2.07)	-32.1%	4.50	6.37	(1.87)	-29.4%
57	COAL	2.03	2.10	(0.07)	-3.3%	2.06	2.06	0.00	0.0%
58	NATURAL GAS	4.39	4.29	0.10	2.3%	4.53	4.48	0.05	1.1%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.16	2.24	(0.08)	-3.6%	2.12	2.16	(0.04)	-1.9%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: MARCH 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	32	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	32	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	32	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	41	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	52	-173	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-173**	—	—	—	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	53,089	62.6	90.0	67.5	12,276	COAL	27,679	23,546,000	651,729.7	1,058,450	1.99	38.24
GAN.#2	98	49,384	67.7	88.4	75.9	12,640	COAL	26,475	23,578,000	624,227.6	1,012,409	2.05	38.24
GAN.#3	155	71,380	61.9	83.9	71.2	12,745	COAL	44,769	20,320,000	909,706.1	1,711,974	2.40	38.24
GAN.#4	159	1,726	1.5	2.5	58.0	14,810	COAL	1,335	19,148,000	25,562.6	51,051	2.96	38.24
GAN.#5	217	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GAN.#6	392	153,458	52.6	62.6	70.4	11,224	COAL	73,058	23,576,460	1,722,449.0	2,793,750	1.82	38.24
GANNON STATION	**1,135**	**329,037**	**39.0**	**50.1**	**55.5**	**11,955**	**COAL**	**173,316**	**22,696,549**	**3,933,675.0**	**6,627,634**	**2.01**	**38.24**
B.B.#1	426	210,314	66.4	78.0	77.8	10,714	COAL	93,895	23,998,400	2,253,329.8	3,918,157	1.86	41.73
B.B.#2	426	172,920	54.6	60.3	72.7	10,544	COAL	76,491	23,837,240	1,823,334.3	3,191,903	1.85	41.73
B.B.#3	433	7,905	2.5	3.2	76.0	9,008	COAL	2,951	24,128,000	71,208.2	123,142	1.56	41.73
B.B. 1 - 3	1,285	391,139	40.9	46.9	75.5	**10,605**	COAL	173,337	23,929,489	4,147,872.3	7,233,202	1.85	41.73
B.B.#4	447	292,678	88.0	97.8	88.0	10,288	COAL	135,503	22,222,263	3,011,178.7	7,217,512	2.47	53.26
B.B. STATION	**1,732**	**683,817**	**53.1**	**60.1**	**78.7**	**10,469**	**COAL**	**308,840**	**23,180,448**	**7,159,051.0**	**14,450,714**	**2.11**	**46.79**
SEB-PHIL. #1(HVY OIL)	17	4,398	34.8	100.0	85.8	9,670	HVY.OIL	6,779	6,273,540	42,527.1	169,429	3.85	24.99
SEB-PHIL. #2(HVY OIL)	17	4,785	37.8	96.3	94.9	9,670	HVY.OIL	7,375	6,273,540	46,269.3	184,325	3.85	24.99
SEB-PHILLIPS TOTAL	**34**	**9,183**	**36.3**	**98.2**	**90.4**	**9,670**	**HVY.OIL**	**14,154**	**6,273,540**	**88,796.4**	**353,754**	**3.85**	**24.99**
POLK #1 GASIFIER	250	102,307	55.0	62.8	87.4	10,983	COAL	42,171	26,646,000	1,123,683.7	1,591,601	1.56	37.74
POLK #1 CT (OIL)	245	35,398	19.4	99.2	73.0	8,190	LGT.OIL	50,469	5,749,370	289,911.6	1,414,396	4.00	28.03
POLK #1 TOTAL	**250**	**137,705**	**74.0**	**98.4**	**83.2**	**10,265**	-	-	-	**1,413,595.3**	**3,005,997**	**2.18**	-
POLK #2 CT (GAS)	160	17,276	14.5	96.5	78.7	11,401	GAS	187,408	972,290	196,966.0	737,351	4.27	3.93
POLK #2 CT (OIL)	180	1,335	1.0	94.6	84.6	11,201	LGT.OIL	2,601	5,749,379	14,953.1	72,889	5.46	28.02
POLK #2 TOTAL	**170**	**18,611**	**15.6**	**96.5**	**79.1**	**11,387**	-	-	-	**211,919.1**	**810,240**	**4.35**	-
POLK STATION TOTAL	**420**	**156,316**	**50.0**	**97.6**	**79.6**	**10,399**	-	-	-	**1,625,514.4**	**3,816,237**	**2.44**	-
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	17	229	1.8	100.0	80.2	17,032	LGT.OIL	670	5,817,498	3,900.4	18,747	8.19	27.98
B.B.C.T.#2	80	3,248	5.5	100.0	54.3	16,483	LGT.OIL	9,202	5,817,807	53,537.9	257,481	7.93	27.98
B.B.C.T.#3	80	83	0.1	100.0	64.0	8,242	LGT.OIL	118	5,817,672	684.1	3,302	3.98	27.98
C.T. TOTAL	**177**	**3,560**	**2.7**	**100.0**	**61.2**	**16,327**	**LGT.OIL**	**9,990**	**5,817,784**	**58,122.4**	**279,530**	**7.85**	**27.98**
CITY OF TAMPA	**6**	**1,324**	**0.0**	**0.0**	**0.0**	**9,927**	**GAS**	**12,505**	**972,290**	**13,142.8**	**78,690**	**5.94**	**6.29**
TOT. COAL (GN,BB,POLK)	**3,117**	**1,115,161**	**48.1**	**56.7**	**71.0**	**10,955**	**COAL**	**524,327**	**23,299,225**	**12,216,409.7**	**22,669,949**	**2.03**	**43.24**
SYSTEM	**3,504**	**1,183,064**	**45.5**	**63.7**	**70.5**	**10,884**	-	-	-	**12,878,302.0**	**25,606,559**	**2.16**	-

* *Hookers Point limited to 90 MW*

LEGEND:

H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	2,274	13,760	(11,486)	-83.5%	13,839	31,809	(17,970)	-56.5%
3 UNIT COST ($/BBL)	19.58	29.64	(10.06)	-33.9%	21.58	30.72	(9.14)	-29.8%
4 AMOUNT ($)	44,533	407,901	(363,368)	-89.1%	298,636	977,148	(678,512)	-69.4%
5 BURNED:								
6 UNITS (BBL)	14,154	13,760	394	2.9%	21,088	31,809	(10,721)	-33.7%
7 UNIT COST ($/BBL)	24.99	30.81	(5.81)	-18.9%	25.62	30.97	(5.35)	-17.3%
8 AMOUNT ($)	353,754	423,881	(70,127)	-16.5%	540,228	985,150	(444,922)	-45.2%
9 ENDING INVENTORY:								
10 UNITS (BBL)	58,016	59,129	(1,113)	-1.9%	58,016	59,129	(1,113)	-1.9%
11 UNIT COST ($/BBL)	26.02	26.64	(0.62)	-2.3%	26.02	26.64	(0.62)	-2.3%
12 AMOUNT ($)	1,509,736	1,575,440	(65,704)	-4.2%	1,509,736	1,575,440	(65,704)	-4.2%
13								
14 DAYS SUPPLY:	156	159	(3)	-1.7%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	51,452	49,891	1,561	3.1%	93,670	126,357	(32,687)	-25.9%
17 UNIT COST ($/BBL)	28.18	33.73	(5.55)	-16.5%	25.20	34.70	(9.50)	-27.4%
18 AMOUNT ($)	1,449,831	1,682,764	(232,933)	-13.8%	2,360,615	4,384,806	(2,024,191)	-46.2%
19 BURNED:								
20 UNITS (BBL)	63,060	42,088	20,972	49.8%	93,060	99,869	(6,809)	-6.8%
21 UNIT COST ($/BBL)	28.02	34.26	(6.24)	-18.2%	27.67	34.60	(6.93)	-20.0%
22 AMOUNT ($)	1,766,815	1,441,938	324,877	22.5%	2,575,022	3,455,146	(880,124)	-25.5%
23 ENDING INVENTORY:								
24 UNITS (BBL)	84,893	113,465	(28,572)	-25.2%	84,893	113,465	(28,572)	-25.2%
25 UNIT COST ($/BBL)	27.99	34.35	(6.36)	-18.5%	27.99	34.35	(6.36)	-18.5%
26 AMOUNT ($)	2,375,908	3,897,476	(1,521,568)	-39.0%	2,375,908	3,897,476	(1,521,568)	-39.0%
27								
28 DAYS SUPPLY: NORMAL	52	69	(17)	-24.9%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	12	16	(4)	-24.2%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	759,255	712,000	47,255	6.6%	1,934,477	2,110,000	(175,523)	-8.3%
32 UNIT COST ($/TON)	43.52	46.56	(3.04)	-6.5%	43.92	46.73	(2.81)	-6.0%
33 AMOUNT ($)	33,041,507	33,147,962	(106,455)	-0.3%	84,954,359	98,601,719	(13,647,360)	-13.8%
34 BURNED:								
35 UNITS (TONS)	524,327	529,065	(4,738)	-0.9%	1,668,883	1,719,746	(50,863)	-3.0%
36 UNIT COST ($/TON)	43.24	46.94	(3.71)	-7.9%	44.13	46.34	(2.21)	-4.8%
37 AMOUNT ($)	22,669,949	24,835,472	(2,165,523)	-8.7%	73,639,673	79,690,011	(6,050,338)	-7.6%
38 ENDING INVENTORY:								
39 UNITS (TONS)	891,074	1,367,074	(476,000)	-34.8%	891,074	1,367,074	(476,000)	-34.8%
40 UNIT COST ($/TON)	42.67	46.71	(4.04)	-8.7%	42.67	46.71	(4.04)	-8.7%
41 AMOUNT ($)	38,022,023	63,859,797	(25,837,774)	-40.5%	38,022,023	63,859,797	(25,837,774)	-40.5%
42								
43 DAYS SUPPLY:	46	71	(25)	-35.0%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	199,913	299,642	(99,729)	-33.3%	248,170	574,930	(326,760)	-56.8%
46 UNIT COST ($/MCF)	4.08	4.26	(0.18)	-4.2%	4.16	4.44	(0.29)	-6.5%
47 AMOUNT ($)	816,041	1,276,948	(460,907)	-36.1%	1,031,206	2,554,571	(1,523,365)	-59.6%
48 BURNED:								
49 UNITS (MCF)	199,913	299,642	(99,729)	-33.3%	248,170	574,930	(326,760)	-56.8%
50 UNIT COST ($/MCF)	4.08	4.26	(0.18)	-4.2%	4.16	4.44	(0.28)	-6.4%
51 AMOUNT ($)	816,041	1,276,948	(460,907)	-36.1%	1,032,179	2,554,571	(1,522,392)	-59.6%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	14,475
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	14,475

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(5,678)	(158,115)
OTHER USAGE	(1,024)	(28,623)
TOTAL	(6,702)	(186,738)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	38,743
IGNITION #2 OIL	143,640
IGNITION PROPANE	3,707
AERIAL SURVEY ADJ.	(795,956)
ADDITIVES	30,287
GREEN FUEL	0
TOTAL	(579,579)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2002

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. -D	6,205.0	0.0	6,205.0	1.510	1.510	93,700.00	93,700.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	64,728.0	0.0	64,728.0	2.539	3.587	1,643,200.00	2,321,600.00	
VARIOUS	JURISDIC.	MKT. BASE	25,086.0	0.0	25,086.0	3.081	3.081	772,900.00	772,900.00	433,500.00
TOTAL			96,019.0	0.0	96,019.0	2.614	3.320	2,509,800.00	3,188,200.00	433,500.00
ACTUAL:										
FLA. PWR. & LIGHT	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR PARTNERS	SEP. CONTR.	SCH. -D	27,955.0	0.0	27,955.0	2.461	3.229	687,972.55	902,666.95	
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. -D	2,428.3	209.7	2,218.6	2.739	2.739	60,773.58	60,773.58	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. -D	603.1	0.0	603.1	1.890	1.890	11,398.35	11,398.35	
FLA. PWR. CORP.		SCH. -MA	100.0	0.0	100.0	2.276	2.701	2,276.43	2,700.74	110.31
FLA. PWR. & LIGHT		SCH. -MA	125.0	0.0	125.0	2.696	3.559	3,369.77	4,448.90	686.63
ORLANDO UTIL. COMM.		SCH. -MA	250.0	0.0	250.0	1.945	2.505	4,862.85	6,262.61	614.76
REEDY CREEK		SCH. -MA	40.0	0.0	40.0	2.598	2.971	1,039.20	1,188.52	23.72
THE ENERGY AUTHORITY		SCH. -MA	125.0	0.0	125.0	2.818	2.966	3,522.93	3,707.81	(207.62)
DUKE ENERGY		SCH. -MA	506.0	0.0	506.0	2.000	3.361	10,120.47	17,007.53	5,298.22
AUBURNDALE POWER PARTNERS		SCH. -OATT	2.0	0.0	2.0	4.943	4.950	98.86	99.00	
DUKE ENERGY		SCH. -OATT	3.0	0.0	3.0	7.770	7.781	233.10	233.43	
CARGILL ALLIANT		SCH. -OATT	50.0	0.0	50.0	4.030	4.035	2,014.75	2,017.64	
ADJ. TO PREV. MONTHS										
HARDEE PWR PARTNERS EST.	Feb. 2002	CONTRACT	(19,128.0)	0.0	(19,128.0)	2.559	3.324	(489,485.52)	(635,814.72)	
HARDEE PWR PARTNERS ACT.	Feb. 2002	CONTRACT	19,128.0	0.0	19,128.0	2.461	3.229	470,740.08	617,643.12	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD			3,031.4	209.7	2,821.7	2.558	2.558	72,171.93	72,171.93	
SUB-TOTAL SCHEDULE D POWER SALES-SEPARATED			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEP.			27,955.0	0.0	27,955.0	2.394	3.164	669,227.11	884,495.35	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD			1,146.0	0.0	1,146.0	2.198	3.082	25,191.65	35,316.11	6,526.02
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD			55.0	0.0	55.0	4.267	4.273	2,346.71	2,350.07	
TOTAL			32,187.4	209.7	31,977.7	2.405	3.109	768,837.40	994,333.46	6,526.02
CURRENT MONTH:										
DIFFERENCE			(63,831.6)	209.7	(64,041.3)	(0.209)	(0.211)	(1,740,862.60)	(2,193,866.54)	(426,973.98)
DIFFERENCE %			-66.5%	0.0%	-66.7%	-8.0%	-6.4%	-69.4%	-68.8%	-98.5%
PERIOD TO DATE:										
ACTUAL			99,962.7	240.2	99,722.5	2.369	3.008	2,362,722.64	2,999,185.66	37,737.57
ESTIMATED			242,405.0	0.0	242,405.0	2.421	3.145	5,868,700.00	7,623,000.00	721,100.00
DIFFERENCE			(142,442.3)	240.2	(142,682.5)	(0.052)	(0.137)	(3,505,977.36)	(4,623,814.34)	(683,362.43)
DIFFERENCE %			-58.8%	0.0%	-58.9%	-2.1%	-4.4%	-59.7%	-60.7%	-94.8%

* No Sales to Hardee Pwr Partners for Others in the month of March 2002.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FOR OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. J	7,249.0	0.0	4,339.0	2,910.0	5.808	5.808	169,000.00
HARDEE POWER PARTNERS		IPP	62,608.0	0.0	0.0	62,608.0	5.143	5.143	3,219,800.00
VARIOUS		OTHER	55,705.0	0.0	0.0	55,705.0	5.862	5.862	3,265,200.00
VARIOUS		MKT. BASE	94,385.0	0.0	0.0	94,385.0	4.838	4.838	4,566,700.00
TOTAL			219,947.0	0.0	4,339.0	215,608.0	5.204	5.204	11,220,700.00
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	57,309.0	0.0	0.0	57,309.0	8.938	8.938	5,122,180.17
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH.-J	29,329.0	0.0	1,274.6	28,054.4	3.320	3.320	931,429.85
FLA. POWER & LIGHT		SCH.-J	21,836.0	0.0	1,796.8	20,039.2	3.640	3.640	729,484.29
LAKELAND		SCH.-J	16,140.0	0.0	2,781.5	13,358.5	4.711	4.711	629,275.74
THE ENERGY AUTHORITY		SCH.-J	12,998.0	0.0	2,398.4	10,599.6	4.265	4.265	452,069.81
REEDY CREEK		SCH.-J	20.0	0.0	0.0	20.0	3.600	3.600	720.00
OKEELANTA		SCH.-J	3,974.0	0.0	0.0	3,974.0	3.889	3.889	154,529.25
AQUILA		SCH.-J	13,734.0	0.0	386.4	13,347.6	3.738	3.738	498,867.48
CARGILL ALLIANT		SCH.-J	14,008.0	0.0	897.4	13,110.6	5.400	5.400	707,925.17
AUBURNDALE POWER PARTNERS		SCH.-J	48.0	0.0	0.0	48.0	4.500	4.500	2,160.00
KOCH ENERGY		SCH.-J	2,148.0	0.0	1,438.8	709.2	4.716	4.716	33,448.36
RELIANT		SCH.-J	4,432.0	0.0	1,924.5	2,507.5	7.155	7.155	179,399.27
DUKE ENERGY		SCH.-J	19,379.0	0.0	825.0	18,554.0	4.082	4.082	757,297.95
DYNEGY POWER MKTG.		SCH.-J	4,153.0	0.0	0.0	4,153.0	3.291	3.291	136,679.00
RINGHAVER		SCH.-J	437.0	0.0	0.0	437.0	0.222	0.222	969.72
OKEELANTA		SCH.-D	6,869.0	0.0	0.0	6,869.0	4.723	4.723	324,437.60
FLA. POWER CORP.		SCH.-D	56,750.0	0.0	0.0	56,750.0	3.298	3.298	1,871,823.50
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Feb. 2002	IPP	(34,705.0)	0.0	0.0	(34,705.0)	0.845	0.845	(293,186.59)
HARDEE PWR. PART.-NATIVE	Feb. 2002	IPP	34,705.0	0.0	0.0	34,705.0	0.490	0.490	170,004.49
FLA. POWER CORP.	Feb. 2002	SCH.-D	(13,650.0)	0.0	0.0	(13,650.0)	4.232	4.232	(577,618.50)
FLA. POWER CORP.	Feb. 2002	SCH.-D	13,650.0	0.0	0.0	13,650.0	4.370	4.370	596,503.50
DUKE ENERGY	Feb. 2002	SCH.-J	(3,717.0)	0.0	(157.0)	(3,560.0)	3.624	3.624	(129,022.25)
DUKE ENERGY	Feb. 2002	SCH.-J	3,716.0	0.0	156.0	3,560.0	3.621	3.621	128,922.25
CARGILL ALLIANT	Feb. 2002	SCH.-J	(1,995.0)	0.0	0.0	(1,995.0)	0.179	0.179	(3,575.00)
CARGILL ALLIANT	Feb. 2002	SCH.-J	1,995.0	0.0	0.0	1,995.0	6.038	6.038	120,456.00
KOCH ENERGY TRAD.	Jan. 2001	SCH.-Jc	(19,554.0)	0.0	0.0	(19,554.0)	15.798	15.798	(3,089,214.69)
KOCH ENERGY TRAD.	Jan. 2001	SCH.-Jc	19,553.0	0.0	0.0	19,553.0	15.799	15.799	3,089,214.69
KOCH ENERGY TRAD.	Apr. 2001	SCH.-Ja	(5,678.0)	0.0	(1,944.7)	(3,733.3)	8.647	8.647	(322,802.00)
KOCH ENERGY TRAD.	Apr. 2001	SCH.-Ja	5,712.0	0.0	1,944.7	3,767.3	8.569	8.569	322,802.00
KOCH ENERGY TRAD.	Apr. 2001	SCH.-Jc	(30,460.0)	0.0	0.0	(30,460.0)	6.676	6.676	(2,033,573.80)
KOCH ENERGY TRAD.	Apr. 2001	SCH.-Jc	30,533.0	0.0	0.0	30,533.0	6.660	6.660	2,033,573.80
ENRON	Apr. 2001	SCH.-Jc	(2,031.0)	0.0	0.0	(2,031.0)	7.496	7.496	(152,246.60)
ENRON	Apr. 2001	SCH.-Jc	2,037.0	0.0	0.0	2,037.0	7.474	7.474	152,246.60
ENRON	Mar. 2001	SCH.-Jc	(4,157.0)	0.0	0.0	(4,157.0)	5.798	5.798	(241,027.67)
ENRON	Mar. 2001	SCH.-Jc	4,160.0	0.0	0.0	4,160.0	5.794	5.794	241,027.67
TOTAL			263,678.0	0.0	13,722.4	249,955.6	5.019	5.019	12,545,183.06
CURRENT MONTH:									
DIFFERENCE			43,731.0	0.0	9,383.4	34,347.6	(0.185)	(0.185)	1,324,483.06
DIFFERENCE %			19.9%	0.0%	216.3%	15.9%	-3.6%	-3.6%	11.8%
PERIOD TO DATE:									
ACTUAL			482,306.0	0.0	16,288.4	466,017.6	4.762	4.762	22,193,867.22
ESTIMATED			498,413.0	0.0	7,749.0	490,664.0	5.398	5.398	26,485,000.00
DIFFERENCE			(16,107.0)	0.0	8,539.4	(24,646.4)	(0.636)	(0.636)	(4,291,132.78)
DIFFERENCE %			-3.2%	0.0%	110.2%	-5.0%	-11.8%	-11.8%	-16.2%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	39,069.0	0.0	0.0	39,069.0	2.061	2.061	805,100.00
TOTAL			39,069.0	0.0	0.0	39,069.0	2.061	2.061	805,100.00
ACTUAL:									
IMC-AGRICO-NICHOLS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE		COGEN.	13,625.0	0.0	0.0	13,625.0	2.203	2.203	300,151.54
MULBERRY PHOSPHATES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	92.0	0.0	0.0	92.0	3.147	3.147	2,894.90
HILLSBOROUGH COUNTY		COGEN.	17,343.0	0.0	0.0	17,343.0	2.210	2.210	383,317.13
CARGILL MILLPOINT		COGEN.	114.0	0.0	0.0	114.0	2.684	2.684	3,059.44
CF INDUSTRIES INC.		COGEN.	356.0	0.0	0.0	356.0	2.851	2.851	10,149.06
CUTRALE CITRUS		COGEN.	2.0	0.0	0.0	2.0	2.026	2.026	40.52
FARMLAND HYDRO LP		COGEN.	1,245.0	0.0	0.0	1,245.0	3.474	3.474	43,256.94
IMC-AGRICO-S. PIERCE		COGEN.	398.0	0.0	0.0	398.0	3.186	3.186	12,679.71
AUBURNDALE POWER PARTNERS		COGEN.	257.0	0.0	0.0	257.0	4.328	4.328	11,122.73
ORANGE COGENERATION L.P.		COGEN.	5,658.0	0.0	0.0	5,658.0	2.090	2.090	118,280.26
AS AVAILABLE ASSIGNMENT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR MARCH 2002			39,090.0	0.0	0.0	39,090.0	2.264	2.264	884,952.23
ADJUSTMENTS FOR THE MONTH OF:	**JANUARY 2002**								
IMC-AGRICO-NICHOLS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE		COGEN.	(12,724.0)	0.0	0.0	(12,724.0)	1.894	1.894	(240,951.95)
			12,724.0	0.0	0.0	12,724.0	1.913	1.913	243,376.82
MULBERRY PHOSPHATES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
HILLSBOROUGH COUNTY		COGEN.	(18,111.0)	0.0	0.0	(18,111.0)	1.893	1.893	(342,919.56)
			18,111.0	0.0	0.0	18,111.0	1.912	1.912	346,270.79
CARGILL MILLPOINT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
FARMLAND HYDRO LP		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
ORANGE COGENERATION L.P.		COGEN.	(5,474.0)	0.0	0.0	(5,474.0)	1.856	1.856	(101,582.76)
			5,474.0	0.0	0.0	5,474.0	1.881	1.881	102,973.05
AS AVAILABLE ASSIGNMENT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**JANUARY 2002**		0.0	0.0	0.0	0.0	0.000	0.000	7,166.39
GRAND TOTAL			39,090.0	0.0	0.0	39,090.0	2.282	2.282	892,118.62
CURRENT MONTH:									
DIFFERENCE			21.0	0.0	0.0	21.0	0.222	0.222	87,018.62
DIFFERENCE %			0.1%	0.0%	0.0%	0.1%	10.7%	10.7%	10.8%
PERIOD TO DATE:									
ACTUAL			110,642.0	0.0	0.0	110,642.0	2.070	2.070	2,290,449.71
ESTIMATED			113,006.0	0.0	0.0	113,006.0	2.085	2.085	2,356,700.00
DIFFERENCE			(2,364.0)	0.0	0.0	(2,364.0)	(0.015)	(0.015)	(66,250.29)
DIFFERENCE %			-2.1%	0.0%	0.0%	-2.1%	(0.007)	(0.007)	-2.8%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: MARCH 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

APRIL 2002

COMPARISON OF ESTIMATED AND ACTUAL,
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2002

**REVISED WITH MAY 2002 FUEL FILING

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	27,156,196	27,602,299	(446,103)	-1.6%	1,159,571	1,186,903	(27,332)	-2.3%	2.34192	2.32557	0.01634	0.7%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(4,812)	(4,000)	(812)	20.3%	1,159,571 (a)	1,186,903 (a)	(27,332)	-2.3%	(0.00041)	(0.00034)	(0.00008)	23.1%
4b. Adjustments to Fuel Cost (1)	(1,498)	0	(1,498)	0.0%	1,159,571 (a)	1,186,903 (a)	(27,332)	-2.3%	(0.00013)	0.00000	(0.00013)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	1,159,571 (a)	1,186,903 (a)	(27,332)	-2.3%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	27,149,886	27,598,299	(448,413)	-1.6%	1,159,571	1,186,903	(27,332)	-2.3%	2.34137	2.32524	0.01614	0.7%
6. Fuel Cost of Purchased Power - Firm (A7)	18,377,400	14,887,000	3,490,400	23.4%	372,821	279,500	93,321	33.4%	4.92928	5.32630	(0.39701)	-7.5%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,202,121	851,500	350,621	41.2%	46,884	39,704	7,180	18.1%	2.56403	2.14462	0.41941	19.6%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	19,579,521	15,738,500	3,841,021	24.4%	419,705	319,204	100,501	31.5%	4.66507	4.93055	(0.26548)	-5.4%
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,579,276	1,506,107	73,169	4.9%				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6) **	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	110,571	83,000	27,571	33.2%	3,495	5,884	(2,389)	-40.6%	3.16369	1.41061	1.75309	124.3%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	4,390	0	4,390	0.0%	88	0	88	0.0%	4.98864	0.00000	4.98864	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	1,378,979	1,598,700	(219,721)	-13.7%	54,690	62,640	(7,950)	-12.7%	2.52145	2.55220	(0.03076)	-1.2%
21. Fuel Cost of Market Base Sales (A6) **	2,510	227,600	(225,090)	-98.9%	110	10,926	(10,816)	-99.0%	2.28182	2.08310	0.19871	9.5%
21a. Gains on Market Based Sales **	242	169,800	(169,558)	-99.9%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	1,496,692	2,079,100	(582,408)	-28.0%	58,383	79,450	(21,067)	-26.5%	2.56358	2.61687	(0.05329)	-2.0%
23. Net Inadvertant Interchange					963	0	963	0.0%				
24. Wheeling Rec'd. less Wheeling Deliv'd.					(1,428)	0	(1,428)	0.0%				
25. Interchange and Wheeling Losses					94	1,200	(1,106)	-92.2%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	45,232,715	41,257,699	3,975,016	9.6%	1,520,334	1,425,457	94,877	6.7%	2.97518	2.89435	0.08083	2.8%
27. Net Unbilled	683,727 (a)	(1,325,843) (a)	2,009,570	-151.6%	22,981	(45,808)	68,789	-150.2%	2.97518	2.89435	0.08084	2.8%
28. Company Use	111,569 (a)	118,668 (a)	(7,099)	-6.0%	3,750	4,100	(350)	-8.5%	2.97517	2.89434	0.08083	2.8%
29. T & D Losses	2,376,159 (a)	1,437,363 (a)	938,796	65.3%	79,866	49,661	30,205	60.8%	2.97518	2.89435	0.08083	2.8%
30. System KWH Sales	45,232,715	41,257,699	3,975,016	9.6%	1,413,737	1,417,504	(3,767)	-0.3%	3.19951	2.91059	0.28893	9.9%
31. Wholesale KWH Sales	(1,606,602)	(3,193,466)	1,586,864	-49.7%	(50,214)	(109,719)	59,505	-54.2%	3.19951	2.91059	0.28892	9.9%
32. Jurisdictional KWH Sales	43,626,113	38,064,233	5,561,880	14.6%	1,363,523	1,307,785	55,738	4.3%	3.19951	2.91059	0.28893	9.9%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	43,654,906	38,089,355	5,565,551	14.6%	1,363,523	1,307,785	55,738	4.3%	3.20163	2.91251	0.28912	9.9%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	296,703	283,819	12,884	4.5%	1,363,523	1,307,785	55,738	4.3%	0.02176	0.02170	0.00006	0.3%
35a. Adjustment	0	0	0	0.0%	1,363,523	1,307,785	55,738	4.3%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	1,363,523	1,307,785	55,738	4.3%	0.00000	0.00000	0.00000	0.0%
36. True-up *	7,389,395	7,389,395	0	0.0%	1,363,523	1,307,785	55,738	4.3%	0.54193	0.56503	(0.02310)	-4.1%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	51,341,004	45,762,569	5,578,435	12.2%	1,363,523	1,307,785	55,738	4.3%	3.76532	3.49924	0.26608	7.6%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.76803	3.50176	0.26627	7.6%
40. GPIF * (Already Adjusted for Taxes)	91,246	91,246	0	0.0%	1,363,523	1,307,785	55,738	4.3%	0.00669	0.00698	(0.00029)	-4.1%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	51,432,250	45,853,815	5,578,435	12.2%	1,363,523	1,307,785	55,738	4.3%	3.77472	3.50874	0.26598	7.6%
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.775	3.509	0.266	7.6%

* Based on Jurisdictional Sales (a) Included for Informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: APRIL 2002

**REVISED WITH MAY 2002 FUEL FILING

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	104,943,298	114,287,177	(9,343,879)	-8.2%	4,827,836	5,191,357	(363,521)	-7.0%	2.17371	2.20149	(0.02778)	-1.3%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(17,689)	(16,000)	(1,689)	10.6%	4,827,836 (a)	5,191,357 (a)	(363,521)	-7.0%	(0.00037)	(0.00031)	(0.00006)	18.9%
4b. Adjustments to Fuel Cost (1)	(3,751)	0	(3,751)	0.0%	4,827,836 (a)	5,191,357 (a)	(363,521)	-7.0%	(0.00008)	0.00000	(0.00008)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	4,827,836 (a)	5,191,357 (a)	(363,521)	-7.0%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	104,921,858	114,271,177	(9,349,319)	-8.2%	4,827,836	5,191,357	(363,521)	-7.0%	2.17327	2.20118	(0.02791)	-1.3%
6. Fuel Cost of Purchased Power - Firm (A7)	40,571,267	41,372,000	(800,733)	-1.9%	836,839	770,164	68,675	8.9%	4.83660	5.37184	(0.53525)	-10.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	3,492,571	3,208,200	284,371	8.9%	157,526	152,710	4,816	3.2%	2.21714	2.10084	0.11629	5.5%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	44,063,838	44,580,200	(516,362)	-1.2%	996,365	922,874	73,491	8.0%	4.42246	4.83058	(0.40812)	-8.4%
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					5,824,201	6,114,231	(290,030)	-4.7%				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6) **	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	312,308	361,200	(48,892)	-13.5%	12,970	24,413	(11,443)	-46.9%	2.40793	1.47954	0.92839	62.7%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	8,156	0	8,156	0.0%	190	0	190	0.0%	4.29263	0.00000	4.29263	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	3,183,615	5,759,900	(2,576,285)	-44.7%	126,619	230,028	(103,409)	-45.0%	2.51433	2.50400	0.01033	0.4%
21. Fuel Cost of Market Base Sales (A6) **	355,093	1,656,900	(1,301,807)	-78.6%	18,327	67,414	(49,087)	-72.8%	1.93754	2.45780	(0.52026)	-21.2%
21a. Gains on Market Based Sales **	37,979	890,900	(852,921)	-95.7%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	3,897,151	8,668,900	(4,771,749)	-55.0%	158,106	321,855	(163,749)	-50.9%	2.46490	2.69342	(0.22852)	-8.5%
23. Net Inadvertant Interchange					1,610	0	1,610	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					3,076	0	3,076	0.0%				
25. Interchange and Wheeling Losses					781	4,700	(3,919)	-83.4%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	145,088,545	150,182,477	(5,093,932)	-3.4%	5,670,000	5,787,676	(117,676)	-2.0%	2.55888	2.59487	(0.03599)	-1.4%
27. Net Unbilled	1,151,422 (a)	(1,856,184) (a)	3,007,606	-162.0%	14,179	(70,062)	84,241	-120.2%	8.12061	2.64934	5.47127	206.5%
28. Company Use	375,175 (a)	426,424 (a)	(51,249)	-12.0%	14,765	16,400	(1,635)	-10.0%	2.54008	2.60015	(0.05917)	-2.3%
29. T & D Losses	6,891,438 (a)	2,768,391 (a)	4,123,047	148.9%	265,764	106,883	158,881	148.6%	2.59307	2.59011	0.00295	0.1%
30. System KWH Sales	145,088,545	150,182,477	(5,093,932)	-3.4%	5,375,292	5,734,455	(359,163)	-6.3%	2.69918	2.61895	0.08023	3.1%
31. Wholesale KWH Sales	(3,367,661)	(10,711,568)	7,343,907	-68.6%	(115,758)	(405,937)	290,179	-71.5%	2.90923	2.63873	0.27050	10.3%
32. Jurisdictional KWH Sales	141,720,884	139,470,909	2,249,975	1.6%	5,259,534	5,328,518	(68,984)	-1.3%	2.69455	2.61744	0.07711	2.9%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	141,814,419	139,562,960	2,251,459	1.6%	5,259,534	5,328,518	(68,984)	-1.3%	2.69633	2.61917	0.07716	2.9%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	1,219,261	1,157,420	61,841	5.3%	5,259,534	5,328,518	(68,984)	-1.3%	0.02318	0.02172	0.00146	6.7%
35a. Adjustment	0	0	0	0.0%	5,259,534	5,328,518	(68,984)	-1.3%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	5,259,534	5,328,518	(68,984)	-1.3%	0.00000	0.00000	0.00000	0.0%
36. True-up *	29,557,580	29,557,580	0	0.0%	5,259,534	5,328,518	(68,984)	-1.3%	0.56198	0.55471	0.00728	1.3%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	172,591,260	170,277,960	2,313,300	1.4%	5,259,534	5,328,518	(68,984)	-1.3%	3.28149	3.19560	0.08590	2.7%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.28385	3.19790	0.08596	2.7%
40. GPIF * (Already Adjusted for Taxes)	364,984	364,984	0	0.0%	5,259,534	5,328,518	(68,984)	-1.3%	0.00694	0.00685	0.00009	1.3%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	172,956,244	170,642,944	2,313,300	1.4%	5,259,534	5,328,518	(68,984)	-1.3%	3.29080	3.20475	0.08605	2.7%
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.291	3.205	0.086	2.7%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: APRIL 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	27,156,196	27,602,299	(446,103)	-1.6%	104,943,298	114,287,177	(9,343,879)	-8.2%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	1,496,450	1,909,300	(412,850)	-21.6%	3,859,172	7,778,000	(3,918,828)	-50.4%
2a. GAINS FROM MARKET BASED SALES	242	169,800	(169,558)	-99.9%	37,979	890,900	(852,921)	-95.7%
3. FUEL COST OF PURCHASED POWER	18,377,400	14,887,000	3,490,400	23.4%	40,571,267	41,372,000	(800,733)	-1.9%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,202,121	851,500	350,621	41.2%	3,492,571	3,208,200	284,371	8.9%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	45,239,025	41,261,699	3,977,326	9.6%	145,109,985	150,198,477	(5,088,492)	-3.4%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(4,812)	(4,000)	(812)	20.3%	(17,689)	(16,000)	(1,689)	10.6%
6b. ADJ.TO FUEL COST	(1,498)	0	(1,498)	0.0%	(3,751)	0	(3,751)	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	45,232,715	41,257,699	3,975,016	9.6%	145,088,545	150,182,477	(5,093,932)	-3.4%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,363,523	1,307,785	55,738	4.3%	5,259,534	5,328,518	(68,984)	-1.3%
2. NONJURISDICTIONAL SALES	50,214	109,719	(59,505)	-54.2%	115,758	405,937	(290,179)	-71.5%
3. TOTAL SALES	1,413,737	1,417,504	(3,767)	-0.3%	5,375,292	5,734,455	(359,163)	-6.3%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9644814	0.9225971	0.0418843	4.5%	0.9784648	0.9292109	0.0492539	5.3%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	44,583,810	43,095,971	1,487,839	3.5%	171,890,001	175,595,571	(3,705,570)	-2.1%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(7,389,395)	(7,389,395)	0	0.0%	(29,557,580)	(29,557,580)	0	0.0%
2b. INCENTIVE PROVISION	(91,246)	(91,246)	0	0.0%	(364,984)	(364,984)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	37,103,169	35,615,330	1,487,839	4.2%	141,967,437	145,673,007	(3,705,570)	-2.5%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	45,232,715	41,257,699	3,975,016	9.6%	145,088,545	150,182,477	(5,093,932)	-3.4%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9644814	0.9225971	0.0418843	4.5%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	43,626,113	38,064,233	5,561,880	14.6%	141,720,884	139,470,909	2,249,975	1.6%
6a. JURISDIC. LOSS MULTIPLIER	1.00066	1.00066	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	43,654,906	38,089,355	5,565,551	14.6%	141,814,419	139,562,960	2,251,459	1.6%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	307,630	307,630	0	0.0%	1,245,706	1,245,706	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	296,703	283,819	12,884	4.5%	1,219,261	1,157,420	61,841	5.3%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	43,951,609	38,373,174	5,578,435	14.5%	143,033,680	140,720,380	2,313,300	1.6%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(6,848,440)	(2,757,844)	(4,090,596)	148.3%	(1,066,243)	4,952,627	(6,018,870)	-121.5%
8. INTEREST PROVISION FOR THE MONTH	(103,301)	(190,481)	87,180	-45.8%	(465,146)	(913,789)	448,643	-49.1%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(70,068,358)	(59,517,387)	(10,550,971)	17.7%	----------NOT APPLICABLE----------			
10. TRUE-UP COLLECTED (REFUNDED)	7,389,395	7,389,395	0	0.0%	----------NOT APPLICABLE----------			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(69,630,704)	(55,076,317)	(14,554,387)	26.4%	----------NOT APPLICABLE----------			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(70,068,358)	(59,517,387)	(10,550,971)	17.7%	----------NOT APPLICABLE----------			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(69,527,403)	(54,885,836)	(14,641,567)	26.7%	----------NOT APPLICABLE----------			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(139,595,761)	(114,403,223)	(25,192,538)	22.0%	----------NOT APPLICABLE----------			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(69,797,881)	(57,201,612)	(12,596,269)	22.0%	----------NOT APPLICABLE----------			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.800	4.000	(2)	-55.0%	----------NOT APPLICABLE----------			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.750	4.000	(2)	-56.3%	----------NOT APPLICABLE----------			
7. TOTAL (LINE D5 + LINE D6)	3.550	8.000	(4)	-55.6%	----------NOT APPLICABLE----------			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.775	4.000	(2)	-55.6%	----------NOT APPLICABLE----------			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.148	0.333	(0)	-55.6%	----------NOT APPLICABLE----------			
10. INT. PROVISION (LINE D4 x LINE D9)	(103,301)	(190,481)	87,180	-45.8%	----------NOT APPLICABLE----------			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	193,457	216,472	(23,015)	-10.6%	733,685	1,201,622	(467,937)	-38.9%
2	LIGHT OIL	2,131,245	1,406,581	724,664	51.5%	4,706,267	4,861,727	(155,460)	-3.2%
3	COAL	22,430,591	23,547,417	(1,116,826)	-4.7%	96,070,264	103,237,428	(7,167,164)	-6.9%
4	NATURAL GAS	2,400,903	2,431,829	(30,926)	-1.3%	3,433,082	4,986,400	(1,553,318)	-31.2%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	27,156,196	27,602,299	(446,103)	-1.6%	104,943,298	114,287,177	(9,343,879)	-8.2%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	4,575	4,768	(193)	-4.0%	17,594	26,118	(8,524)	-32.6%
9	LIGHT OIL	41,049	18,434	22,615	122.7%	98,277	72,676	25,601	35.2%
10	COAL	1,051,340	1,117,966	(66,626)	-6.0%	4,626,552	4,989,774	(363,222)	-7.3%
11	NATURAL GAS	62,607	45,735	16,872	36.9%	85,413	102,789	(17,376)	-16.9%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,159,571	1,186,903	(27,332)	-2.3%	4,827,836	5,191,357	(363,521)	-7.0%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	7,493	7,097	396	5.6%	28,581	38,906	(10,325)	-26.5%
16	LIGHT OIL (BBL)	68,160	41,776	26,384	63.2%	161,220	141,645	19,575	13.8%
17	COAL (TON)	510,391	498,208	12,183	2.4%	2,179,274	2,217,954	(38,680)	-1.7%
18	NATURAL GAS (MCF)	671,525	461,959	209,566	45.4%	919,695	1,036,889	(117,194)	-11.3%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	47,009	44,562	2,447	5.5%	179,307	244,284	(64,977)	-26.6%
22	LIGHT OIL	396,940	238,271	158,669	66.6%	927,238	802,361	124,877	15.6%
23	COAL	11,928,329	11,630,052	298,277	2.6%	50,821,660	51,869,626	(1,047,966)	-2.0%
24	NATURAL GAS	707,115	474,940	232,175	48.9%	968,257	1,066,056	(97,799)	-9.2%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	13,079,393	12,387,825	691,568	5.6%	52,896,462	53,982,327	(1,085,865)	-2.0%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.39%	0.40%	(0.00)	-	0.36%	0.50%	(0.00)	-
29	LIGHT OIL	3.54%	1.55%	0.02	-	2.04%	1.40%	0.01	-
30	COAL	90.67%	94.19%	(0.04)	-	95.83%	96.12%	(0.00)	-
31	NATURAL GAS	5.40%	3.85%	0.02	-	1.77%	1.98%	(0.00)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	25.82	30.50	(4.68)	-15.4%	25.67	30.89	(5.21)	-16.9%
36	LIGHT OIL ($/BBL)	31.27	33.67	(2.40)	-7.1%	29.19	34.32	(5.13)	-15.0%
37	COAL ($/TON)	43.95	47.26	(3.32)	-7.0%	44.08	46.55	(2.46)	-5.3%
38	NATURAL GAS ($/MCF)	3.58	5.26	(1.69)	-32.1%	3.73	4.81	(1.08)	-22.4%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	4.12	4.86	(0.74)	-15.3%	4.09	4.92	(0.83)	-16.8%
42	LIGHT OIL	5.37	5.90	(0.53)	-9.0%	5.08	6.06	(0.98)	-16.2%
43	COAL	1.88	2.02	(0.14)	-7.1%	1.89	1.99	(0.10)	-5.0%
44	NATURAL GAS	3.40	5.12	(1.72)	-33.7%	3.55	4.68	(1.13)	-24.2%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.08	2.23	(0.15)	-6.8%	1.98	2.12	(0.13)	-6.3%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	10,275	9,346	929	9.9%	10,191	9,353	838	9.0%
49	LIGHT OIL	9,670	12,926	(3,256)	-25.2%	9,435	11,040	(1,605)	-14.5%
50	COAL	11,346	10,403	943	9.1%	10,985	10,395	590	5.7%
51	NATURAL GAS	11,295	10,385	910	8.8%	11,336	10,371	965	9.3%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	11,280	10,437	843	8.1%	10,957	10,399	558	5.4%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	4.23	4.54	(0.31)	-6.8%	4.17	4.60	(0.43)	-9.3%
56	LIGHT OIL	5.19	7.63	(2.44)	-32.0%	4.79	6.69	(1.90)	-28.4%
57	COAL	2.13	2.11	0.02	0.9%	2.08	2.07	0.01	0.5%
58	NATURAL GAS	3.83	5.32	(1.49)	-28.0%	4.02	4.85	(0.83)	-17.1%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.34	2.33	0.01	0.4%	2.17	2.20	(0.03)	-1.4%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: APRIL 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	0	-167	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-167**	—	—	—	**0**	HVY.OIL	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	48,902	59.7	79.5	71.8	13,734	COAL	25,049	26,812,000	671,613.8	995,904	2.04	39.76
GAN.#2	98	43,565	61.8	75.2	80.0	12,845	COAL	23,724	23,588,000	559,601.7	943,225	2.17	39.76
GAN.#3	145	75,890	72.8	90.6	78.4	12,746	COAL	48,833	19,808,000	967,284.1	1,941,514	2.56	39.76
GAN.#4	159	32,648	28.6	36.9	77.1	13,216	COAL	20,714	20,830,000	431,472.6	823,552	2.52	39.76
GAN.#5	217	573	0.4	1.7	21.4	20,261	COAL	559	20,768,000	11,609.3	22,225	3.88	39.76
GAN.#6	372	165,068	61.7	69.2	66.2	11,256	COAL	78,759	23,590,000	1,857,924.8	3,131,319	1.90	39.76
GANNON STATION	**1,105**	**366,646**	**46.1**	**55.7**	**62.4**	**12,272**	COAL	**197,638**	**22,766,403**	**4,499,506.3**	**7,857,739**	**2.14**	**39.76**
B.B.#1	416	195,388	65.3	76.7	72.5	11,337	COAL	90,717	24,417,980	2,215,125.9	3,943,046	2.02	43.47
B.B.#2	416	101,042	33.8	37.9	79.6	10,821	COAL	45,359	24,104,240	1,093,344.2	1,971,545	1.95	43.47
B.B.#3	433	2,533	0.8	1.6	34.9	11,373	COAL	1,194	24,128,000	28,808.8	51,898	2.05	43.47
B.B. 1 - 3	1,265	298,963	32.9	38.2	62.0	11,163	COAL	137,270	24,311,786	3,337,278.9	5,966,489	2.00	43.47
B.B.#4	442	275,996	86.8	96.5	86.8	10,552	COAL	131,149	22,206,376	2,912,337.4	6,932,278	2.51	52.86
B.B. STATION	**1,707**	**574,959**	**46.8**	**53.3**	**68.4**	**10,870**	COAL	**268,419**	**23,283,088**	**6,249,616.3**	**12,898,767**	**2.24**	**48.05**
SEB-PHIL. #1(HVY OIL)	17	5,019	41.1	82.9	93.0	9,366	HVY.OIL	7,493	6,273,540	47,009.3	193,457	3.85	25.82
SEB-PHIL. #2(HVY OIL)	17	-277	0.0	0.0	0.0	0	HVY.OIL	0	6,273,540	0.0	0	0.00	0.00
SEB-PHILLIPS TOTAL	**34**	**4,742**	**19.4**	**41.5**	**46.5**	**9,913**	HVY.OIL	**7,493**	**6,273,540**	**47,009.3**	**193,457**	**4.08**	**25.82**
POLK #1 GASIFIER	250	109,735	61.0	66.4	91.1	10,746	COAL	44,334	26,598,000	1,179,206.4	1,674,085	1.53	37.76
POLK #1 CT (OIL)	225	33,950	21.0	100.0	76.4	8,413	LGT.OIL	49,327	5,821,236	285,616.1	1,567,351	4.62	31.77
POLK #1 TOTAL	**250**	**143,685**	**79.9**	**96.1**	**87.2**	**10,195**	-	**-**	**-**	**1,464,822.5**	**3,241,436**	**2.26**	**-**
POLK #2 CT (GAS)	150	46,522	43.1	100.0	81.5	11,320	GAS	500,142	972,290	526,649.0	1,722,667	3.70	3.44
POLK #2 CT (OIL)	160	0	0.0	98.8	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**155**	**46,522**	**43.1**	**100.0**	**81.5**	**11,320**	-	**-**	**-**	**526,649.0**	**1,722,667**	**3.70**	**-**
POLK #3 CT (GAS)	150	14,195	36.2	99.3	59.7	11,352	GAS	153,037	972,290	161,148.0	568,047	4.00	3.71
POLK #3 CT (OIL)	160	2,132	2.9	100.0	33.8	13,119	LGT.OIL	4,493	6,225,381	27,970.2	142,762	6.70	31.77
POLK #3 TOTAL	**155**	**16,327**	**15.1**	**100.0**	**92.8**	**11,583**	-	**-**	**-**	**189,118.2**	**710,809**	**4.35**	**-**
POLK STATION TOTAL	**405**	**206,534**	**70.9**	**97.6**	**84.0**	**10,558**	-	**-**	**-**	**2,180,589.7**	**5,674,912**	**2.75**	**-**
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	681	7.9	89.8	113.5	16,825	LGT.OIL	1,975	5,800,860	11,457.8	58,001	8.52	29.37
B.B.C.T.#2	66	4,286	9.0	65.8	61.3	16,775	LGT.OIL	12,365	5,814,523	71,895.7	363,131	8.47	29.37
B.B.C.T.#3	66	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**144**	**4,967**	**4.8**	**83.5**	**37.5**	**16,781**	LGT.OIL	**14,340**	**5,812,600**	**83,353.5**	**421,132**	**8.48**	**29.37**
CITY OF TAMPA	**6**	**1,890**	**0.0**	**0.0**	**0.0**	**10,221**	GAS	**18,346**	**972,290**	**19,318.3**	**110,189**	**5.83**	**6.01**
TOT. COAL (GN,BB,POLK)	**3,062**	**1,051,340**	**47.8**	**55.2**	**68.1**	**11,346**	COAL	**510,391**	**23,370,958**	**11,928,329.0**	**22,430,591**	**2.13**	**43.95**
SYSTEM	**3,401**	**1,159,571**	**47.5**	**60.5**	**68.8**	**11,278**	-	**-**	**-**	**13,079,393.4**	**27,156,196**	**2.34**	**-**

* Hookers Point boiler limited to 90MW

LEGEND:

H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	2,698	7,097	(4,399)	-62.0%	16,537	38,906	(22,369)	-57.5%
3 UNIT COST ($/BBL)	25.87	29.44	(3.57)	-12.1%	22.28	30.49	(8.21)	-26.9%
4 AMOUNT ($)	69,786	208,939	(139,153)	-66.6%	368,422	1,186,087	(817,665)	-68.9%
5 BURNED:								
6 UNITS (BBL)	7,493	7,097	396	5.6%	28,581	38,906	(10,325)	-26.5%
7 UNIT COST ($/BBL)	25.82	30.50	(4.68)	-15.4%	25.67	30.89	(5.21)	-16.9%
8 AMOUNT ($)	193,457	216,472	(23,015)	-10.6%	733,685	1,201,622	(467,937)	-38.9%
9 ENDING INVENTORY:								
10 UNITS (BBL)	53,221	59,129	(5,908)	-10.0%	53,221	59,129	(5,908)	-10.0%
11 UNIT COST ($/BBL)	26.20	26.60	(0.40)	-1.5%	26.20	26.60	(0.40)	-1.5%
12 AMOUNT ($)	1,394,493	1,572,786	(178,293)	-11.3%	1,394,493	1,572,786	(178,293)	-11.3%
13								
14 DAYS SUPPLY:	99	110	(11)	-9.9%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	75,839	50,460	25,379	50.3%	169,509	176,817	(7,308)	-4.1%
17 UNIT COST ($/BBL)	33.67	32.38	1.29	4.0%	28.99	34.04	(5.05)	-14.8%
18 AMOUNT ($)	2,553,403	1,633,774	919,629	56.3%	4,914,018	6,018,580	(1,104,562)	-18.4%
19 BURNED:								
20 UNITS (BBL)	68,160	41,776	26,384	63.2%	161,220	141,645	19,575	13.8%
21 UNIT COST ($/BBL)	31.27	33.67	(2.40)	-7.1%	29.19	34.32	(5.13)	-15.0%
22 AMOUNT ($)	2,131,245	1,406,581	724,664	51.5%	4,706,267	4,861,727	(155,460)	-3.2%
23 ENDING INVENTORY:								
24 UNITS (BBL)	82,516	113,465	(30,949)	-27.3%	82,516	113,465	(30,949)	-27.3%
25 UNIT COST ($/BBL)	30.30	33.79	(3.49)	-10.3%	30.30	33.79	(3.49)	-10.3%
26 AMOUNT ($)	2,500,614	3,834,382	(1,333,768)	-34.8%	2,500,614	3,834,382	(1,333,768)	-34.8%
27								
28 DAYS SUPPLY: NORMAL	41	56	(15)	-26.8%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	12	16	(4)	-26.3%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	702,096	494,000	208,096	42.1%	2,636,573	2,604,000	32,573	1.3%
32 UNIT COST ($/TON)	44.32	46.55	(2.23)	-4.8%	44.02	46.70	(2.67)	-5.7%
33 AMOUNT ($)	31,117,540	22,993,885	8,123,655	35.3%	116,071,899	121,595,604	(5,523,705)	-4.5%
34 BURNED:								
35 UNITS (TONS)	510,391	498,208	12,183	2.4%	2,179,274	2,217,954	(38,680)	-1.7%
36 UNIT COST ($/TON)	43.95	47.26	(3.32)	-7.0%	44.08	46.55	(2.46)	-5.3%
37 AMOUNT ($)	22,430,591	23,547,417	(1,116,826)	-4.7%	96,070,264	103,237,428	(7,167,164)	-6.9%
38 ENDING INVENTORY:								
39 UNITS (TONS)	1,082,779	1,362,866	(280,087)	-20.6%	1,082,779	1,362,866	(280,087)	-20.6%
40 UNIT COST ($/TON)	42.89	46.76	(3.87)	-8.3%	42.89	46.76	(3.87)	-8.3%
41 AMOUNT ($)	46,441,533	63,730,263	(17,288,730)	-27.1%	46,441,533	63,730,263	(17,288,730)	-27.1%
42								
43 DAYS SUPPLY:	50	63	(13)	-20.5%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	671,525	461,959	209,566	45.4%	919,695	1,036,889	(117,194)	-11.3%
46 UNIT COST ($/MCF)	3.58	5.26	(1.69)	-32.1%	3.73	4.81	(1.08)	-22.4%
47 AMOUNT ($)	2,400,903	2,431,829	(30,926)	-1.3%	3,432,109	4,986,400	(1,554,291)	-31.2%
48 BURNED:								
49 UNITS (MCF)	671,525	461,959	209,566	45.4%	919,695	1,036,889	(117,194)	-11.3%
50 UNIT COST ($/MCF)	3.58	5.26	(1.69)	-32.1%	3.73	4.81	(1.08)	-22.4%
51 AMOUNT ($)	2,400,903	2,431,829	(30,926)	-1.3%	3,433,082	4,986,400	(1,553,318)	-31.2%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	8,428
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	8,428

(2) RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	(312)	(9,912)
IGNITION	(8,790)	(258,465)
OTHER USAGE	(954)	(29,075)
TOTAL	(10,056)	(297,452)

(3) RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	31,985
IGNITION #2 OIL	250,037
IGNITION PROPANE	6,452
AERIAL SURVEY ADJ.	(586,248)
ADDITIVES	30,335
GREEN FUEL	0
TOTAL	(267,439)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2002

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. -D	5,884.0	0.0	5,884.0	1.411	1.411	83,000.00	83,000.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	62,640.0	0.0	62,640.0	2.552	3.600	1,598,700.00	2,255,200.00	
VARIOUS	JURISDIC.	MKT. BASE	10,926.0	0.0	10,926.0	2.083	2.083	227,600.00	227,600.00	169,800.00
TOTAL			79,450.0	0.0	79,450.0	2.403	3.229	1,909,300.00	2,565,800.00	169,800.00
ACTUAL:										
FLA. PWR. & LIGHT	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR PARTNERS	SEP. CONTR.	SCH. -D	54,690.0	0.0	54,690.0	2.501	3.263	1,367,796.90	1,784,534.70	
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. -D	4,400.3	1,468.8	2,931.5	3.429	3.429	100,520.97	100,520.97	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. -D	563.8	0.0	563.8	1.782	1.782	10,049.60	10,049.60	
FLA. PWR. CORP.		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT		SCH. -MA	110.0	0.0	110.0	2.282	2.816	2,509.86	3,097.90	242.64
CITY OF LAKELAND		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
DUKE ENERGY		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
THE ENERGY AUTHORITY		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ENRON		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CARGILL ALLIANT		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CARGILL ALLIANT		SCH. -OATT	88.0	0.0	88.0	4.989	4.989	4,390.26	4,390.26	
ADJUSTMENTS TO PREV. MONTHS										
HARDEE PWR PARTNERS EST.	Mar. 2002	CONTRACT	(27,955.0)	0.0	(27,955.0)	2.461	3.229	(687,972.55)	(902,666.95)	
HARDEE PWR PARTNERS ACT.	Mar. 2002	CONTRACT	27,955.0	0.0	27,955.0	2.501	3.263	699,154.55	912,171.65	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD			4,964.1	1,468.8	3,495.3	3.163	3.163	110,570.57	110,570.57	
SUB-TOTAL SCHEDULE D POWER SALES-SEPARATED			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEP.			54,690.0	0.0	54,690.0	2.521	3.280	1,378,978.90	1,794,039.40	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD			110.0	0.0	110.0	2.282	2.816	2,509.86	3,097.90	242.64
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD			88.0	0.0	88.0	4.989	4.989	4,390.26	4,390.26	
TOTAL			59,852.1	1,468.8	58,383.3	2.563	3.275	1,496,449.59	1,912,098.13	242.64
CURRENT MONTH:										
DIFFERENCE			(19,597.9)	1,468.8	(21,066.7)	0.160	0.046	(412,850.41)	(653,701.87)	(169,557.36)
DIFFERENCE %			-24.7%	0.0%	-26.5%	6.7%	1.4%	-21.6%	-25.5%	-99.9%
PERIOD TO DATE:										
ACTUAL			159,814.8	1,709.0	158,105.8	2.441	3.106	3,859,172.23	4,911,283.79	37,980.21
ESTIMATED			321,855.0	0.0	321,855.0	2.417	3.166	7,778,000.00	10,188,800.00	890,900.00
DIFFERENCE			(162,040.2)	1,709.0	(163,749.2)	0.024	(0.060)	(3,918,827.77)	(5,277,516.21)	(852,919.79)
DIFFERENCE %			-50.3%	0.0%	-50.9%	1.0%	-1.9%	-50.4%	-51.8%	-95.7%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS FOR THE MONTH OF APRIL 2002.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. J	18,236.0	0.0	10,699.0	7,537.0	5.809	5.809	437,800.00
HARDEE POWER PARTNERS		IPP	59,240.0	0.0	0.0	59,240.0	4.777	4.777	2,829,800.00
VARIOUS		OTHER	62,614.0	0.0	0.0	62,614.0	6.060	6.060	3,794,400.00
VARIOUS		MKT. BASE	150,109.0	0.0	0.0	150,109.0	5.213	5.213	7,825,000.00
TOTAL			290,199.0	0.0	10,699.0	279,500.0	5.326	5.326	14,887,000.00
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	60,294.0	0.0	0.0	60,294.0	6.742	6.742	4,064,828.00
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH.-J	39,128.0	0.0	7,509.0	31,619.0	4.304	4.304	1,360,905.48
FLA. POWER & LIGHT		SCH.-J	39,977.0	0.0	10,825.5	29,151.5	5.005	5.005	1,459,078.82
CITY OF LAKELAND		SCH.-J	33,735.0	0.0	11,408.6	22,326.4	5.680	5.680	1,268,226.49
ORLANDO UTIL. COMM.		SCH.-J	42,650.0	0.0	5,670.0	36,980.0	6.614	6.614	2,446,033.88
THE ENERGY AUTHORITY		SCH.-J	27,089.0	0.0	7,810.3	19,278.7	5.338	5.338	1,029,083.81
REEDY CREEK		SCH.-J	610.0	0.0	31.3	578.7	6.036	6.036	34,932.98
OKEELANTA		SCH.-J	2,230.0	0.0	0.0	2,230.0	4.646	4.646	103,616.10
TALLAHASSEE		SCH.-J	2,108.0	0.0	278.1	1,829.9	5.697	5.697	104,251.37
AQUILA		SCH.-J	5,662.0	0.0	1,846.6	3,815.4	5.738	5.738	218,917.13
CARGILL ALLIANT		SCH.-J	42,918.0	0.0	2,501.1	40,416.9	5.184	5.184	2,095,209.83
AUBURNDALE POWER PART.		SCH.-J	3,991.0	0.0	0.0	3,991.0	3.200	3.200	127,712.00
KOCH ENERGY TRAD.		SCH.-J	845.0	0.0	0.0	845.0	3.897	3.897	32,925.80
RELIANT		SCH.-J	1,156.0	0.0	0.0	1,156.0	5.192	5.192	60,020.00
LOUISVILLE		SCH.-J	4,304.0	0.0	0.0	4,304.0	3.693	3.693	158,958.00
HOMESTEAD		SCH.-J	395.0	0.0	30.0	365.0	7.592	7.592	27,712.20
DUKE ENERGY		SCH.-J	31,940.0	0.0	5,643.0	26,297.0	5.781	5.781	1,520,289.35
DYNEGY POWER MKT.		SCH.-J	4,113.0	0.0	0.0	4,113.0	3.295	3.295	135,522.50
RINGHAVER		SCH.-J	1,533.0	0.0	0.0	1,533.0	3.514	3.514	53,867.36
FLA. POWER CORP.		SCH.-D	82,050.0	0.0	0.0	82,050.0	3.118	3.118	2,558,408.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Mar. 2002	IPP	(57,309.0)	0.0	0.0	(57,309.0)	8.938	8.938	(5,122,180.17)
HARDEE PWR. PART.-NATIVE	Mar. 2002	IPP	57,309.0	0.0	0.0	57,309.0	8.242	8.242	4,723,531.91
FLA. POWER CORP.	Mar. 2002	SCH.-D	(56,750.0)	0.0	0.0	(56,750.0)	3.298	3.298	(1,871,823.50)
FLA. POWER CORP.	Mar. 2002	SCH.-D	56,452.0	0.0	0.0	56,452.0	3.144	3.144	1,774,781.00
DUKE ENERGY	Mar. 2002	SCH.-J	(19,379.0)	0.0	(825.0)	(18,554.0)	4.082	4.082	(757,297.95)
DUKE ENERGY	Mar. 2002	SCH.-J	19,379.0	0.0	881.8	18,497.2	4.090	4.090	756,454.95
THE ENERGY AUTH.	Mar. 2002	SCH.-J	(12,998.0)	0.0	(2,398.4)	(10,599.6)	4.265	4.265	(452,069.81)
THE ENERGY AUTH.	Mar. 2002	SCH.-J	12,999.0	0.0	2,398.4	10,600.6	4.268	4.268	452,389.81
CITY OF LAKELAND	Mar. 2002	SCH.-J	(16,140.0)	0.0	(2,781.5)	(13,358.5)	4.711	4.711	(629,275.74)
CITY OF LAKELAND	Mar. 2002	SCH.-J	16,140.0	0.0	2,781.5	13,358.5	4.712	4.712	629,475.74
RELIANT	Mar. 2002	SCH.-J	(4,432.0)	0.0	(1,924.5)	(2,507.5)	7.155	7.155	(179,399.27)
RELIANT	Mar. 2002	SCH.-J	4,432.0	0.0	1,924.5	2,507.5	7.681	7.681	192,597.67
CARGILL ALLIANT	Mar. 2002	SCH.-J	(14,008.0)	0.0	(897.4)	(13,110.6)	5.400	5.400	(707,925.17)
CARGILL ALLIANT	Mar. 2002	SCH.-J	14,008.0	0.0	897.4	13,110.6	5.397	5.397	707,641.17
TOTAL			426,431.0	0.0	53,610.4	372,820.7	4.929	4.929	18,377,399.74
CURRENT MONTH:									
DIFFERENCE			136,232.0	0.0	42,911.4	93,320.7	(0.397)	(0.397)	3,490,399.74
DIFFERENCE %			46.9%	0.0%	401.1%	33.4%	-7.5%	-7.5%	23.4%
PERIOD TO DATE:									
ACTUAL			908,737.0	0.0	69,898.8	838,838.3	4.837	4.837	40,571,266.96
ESTIMATED			788,612.0	0.0	18,448.0	770,164.0	5.372	5.372	41,372,000.00
DIFFERENCE			120,125.0	0.0	51,450.8	68,674.3	(0.535)	(0.535)	(800,733.04)
DIFFERENCE %			15.2%	0.0%	278.9%	8.9%	-10.0%	-10.0%	-1.9%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	39,704.0	0.0	0.0	39,704.0	2.145	2.145	851,500.00
TOTAL		39,704.0	0.0	0.0	39,704.0	2.145	2.145	851,500.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	13,093.0	0.0	0.0	13,093.0	2.268	2.268	296,904.02
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	282.0	0.0	0.0	282.0	3.903	3.903	11,006.37
HILLSBOROUGH COUNTY	COGEN.	18,077.0	0.0	0.0	18,077.0	2.268	2.268	409,968.79
CARGILL MILLPOINT	COGEN.	118.0	0.0	0.0	118.0	4.372	4.372	5,159.04
CF INDUSTRIES INC.	COGEN.	350.0	0.0	0.0	350.0	3.250	3.250	11,375.01
FARMLAND HYDRO LP	COGEN.	1,993.0	0.0	0.0	1,993.0	3.475	3.475	69,250.88
IMC-AGRICO-S. PIERCE	COGEN.	1,390.0	0.0	0.0	1,390.0	3.988	3.988	55,427.36
AUBURNDALE POWER PARTNERS	COGEN.	3,991.0	0.0	0.0	3,991.0	4.554	4.554	181,759.15
ORANGE COGENERATION L.P.	COGEN.	7,590.0	0.0	0.0	7,590.0	2.175	2.175	165,114.36
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR APRIL 2002		46,884.0	0.0	0.0	46,884.0	2.572	2.572	1,205,964.98
ADJUSTMENTS FOR THE MONTH OF:	**FEBRUARY 2002**							
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	(12,329.0)	0.0	0.0	(12,329.0)	1.892	1.892	(233,293.30)
		12,329.0	0.0	0.0	12,329.0	1.882	1.882	231,974.89
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
HILLSBOROUGH COUNTY	COGEN.	(11,603.0)	0.0	0.0	(11,603.0)	1.897	1.897	(220,132.53)
		11,603.0	0.0	0.0	11,603.0	1.886	1.886	218,841.37
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
FARMLAND HYDRO LP	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ORANGE COGENERATION L.P.	COGEN.	(5,037.0)	0.0	0.0	(5,037.0)	1.954	1.954	(98,440.13)
		5,037.0	0.0	0.0	5,037.0	1.930	1.930	97,206.00
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**FEBRUARY 2002**	0.0	0.0	0.0	0.0	0.000	0.000	(3,843.70)
GRAND TOTAL		46,884.0	0.0	0.0	46,884.0	2.564	2.564	1,202,121.28
CURRENT MONTH:								
DIFFERENCE		7,180.0	0.0	0.0	7,180.0	0.419	0.419	350,621.28
DIFFERENCE %		18.1%	0.0%	0.0%	18.1%	19.6%	19.6%	41.2%
PERIOD TO DATE:								
ACTUAL		157,526.0	0.0	0.0	157,526.0	2.217	2.217	3,492,570.99
ESTIMATED		152,710.0	0.0	0.0	152,710.0	2.101	2.101	3,208,200.00
DIFFERENCE		4,816.0	0.0	0.0	4,816.0	0.116	0.116	284,370.99
DIFFERENCE %		3.2%	0.0%	0.0%	3.2%	0.055	0.055	8.9%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: APRIL 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

MAY 2002

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	36,816,875	33,060,389	3,756,486	11.4%	1,562,604	1,471,502	91,102	6.2%	2.35612	2.24671	0.10941	4.9%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(8,475)	(4,000)	(4,475)	111.9%	1,562,604 (a)	1,471,502 (a)	91,102	6.2%	(0.00054)	(0.00027)	(0.00027)	99.5%
4b. Adjustments to Fuel Cost (1)	(1,726)	0	(1,726)	0.0%	1,562,604 (a)	1,471,502 (a)	91,102	6.2%	(0.00011)	0.00000	(0.00011)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	1,562,604 (a)	1,471,502 (a)	91,102	6.2%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	36,806,674	33,056,389	3,750,285	11.3%	1,562,604	1,471,502	91,102	6.2%	2.35547	2.24644	0.10903	4.9%
6. Fuel Cost of Purchased Power - Firm (A7)	9,791,045	6,535,500	3,255,545	49.8%	238,033	129,576	108,457	83.7%	4.11331	5.04376	(0.93044)	-18.4%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,014,948	940,200	74,748	8.0%	42,737	41,027	1,710	4.2%	2.37487	2.29166	0.08321	3.6%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	10,805,993	7,475,700	3,330,293	44.5%	280,770	170,603	110,167	64.6%	3.84870	4.38193	(0.53323)	-12.2%
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,843,374	1,642,105	201,269	12.3%				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	161,846	88,700	73,146	82.5%	6,453	6,055	398	6.6%	2.50807	1.46491	1.04317	71.2%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	4,952	0	4,952	0.0%	176	0	176	0.0%	2.81364	0.00000	2.81364	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	1,258,657	980,400	278,257	28.4%	48,470	37,758	10,712	28.4%	2.59678	2.59654	0.00024	0.0%
21. Fuel Cost of Market Base Sales (A6)	139,057	508,300	(369,243)	-72.6%	6,496	23,257	(16,761)	-72.1%	2.14066	2.18558	(0.04492)	-2.1%
21a. Gains on Market Based Sales	23,547	248,700	(225,153)	-90.5%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	1,588,059	1,828,100	(238,041)	-13.0%	61,595	67,070	(5,475)	-8.2%	2.57823	2.72268	(0.14445)	-5.3%
23. Net Inadvertant Interchange					(686)	0	(686)	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					3,003	0	3,003	0.0%				
25. Interchange and Wheeling Losses					280	1,000	(720)	-72.0%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	46,024,608	38,705,989	7,318,619	18.9%	1,783,816	1,574,035	209,781	13.3%	2.58012	2.45903	0.12109	4.9%
27. Net Unbilled	1,650,606 (a)	3,722,332 (a)	(2,071,726)	-55.7%	63,974	151,374	(87,400)	-57.7%	2.58012	2.45903	0.12109	4.9%
28. Company Use	108,907 (a)	100,820 (a)	8,087	8.0%	4,221	4,100	121	3.0%	2.58012	2.45902	0.12110	4.9%
29. T & D Losses	1,723,185 (a)	(2,901,212) (a)	4,624,397	-159.4%	66,787	(117,982)	184,769	-156.6%	2.58012	2.45903	0.12109	4.9%
30. System KWH Sales	46,024,608	38,705,989	7,318,619	18.9%	1,648,834	1,536,543	112,291	7.3%	2.79134	2.51903	0.27231	10.8%
31. Wholesale KWH Sales	(1,426,823)	(2,556,867)	1,130,044	-44.2%	(51,116)	(101,502)	50,386	-49.6%	2.79134	2.51903	0.27231	10.8%
32. Jurisdictional KWH Sales	44,597,785	36,149,122	8,448,663	23.4%	1,597,718	1,435,041	162,677	11.3%	2.79134	2.51903	0.27231	10.8%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	44,627,220	36,172,980	8,454,240	23.4%	1,597,718	1,435,041	162,677	11.3%	2.79319	2.52069	0.27249	10.8%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	295,641	284,945	10,696	3.8%	1,597,718	1,435,041	162,677	11.3%	0.01850	0.01986	(0.00135)	-6.8%
35a. Adjustment	0	0	0	0.0%	1,597,718	1,435,041	162,677	11.3%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	1,597,718	1,435,041	162,677	11.3%	0.00000	0.00000	0.00000	0.0%
36. True-up *	7,389,395	7,389,395	0	0.0%	1,597,718	1,435,041	162,677	11.3%	0.46250	0.51493	(0.05243)	-10.2%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	52,312,256	43,847,320	8,464,936	19.3%	1,597,718	1,435,041	162,677	11.3%	3.27419	3.05548	0.21871	7.2%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.27654	3.05768	0.21886	7.2%
40. GPIF * (Already Adjusted for Taxes)	91,246	91,246	0	0.0%	1,597,718	1,435,041	162,677	11.3%	0.00571	0.00636	(0.00065)	-10.2%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	52,403,502	43,938,566	8,464,936	19.3%	1,597,718	1,435,041	162,677	11.3%	3.28225	3.06404	0.21821	7.1%
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.282	3.064	0.218	7.1%

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: MAY 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	141,760,173	147,347,566	(5,587,393)	-3.8%	6,390,440	6,662,859	(272,419)	-4.1%	2.21832	2.21148	0.00684	0.3%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(26,164)	(20,000)	(6,164)	30.8%	6,390,440 (a)	6,662,859 (a)	(272,419)	-4.1%	(0.00041)	(0.00030)	(0.00011)	36.4%
4b. Adjustments to Fuel Cost (1)	(5,477)	0	(5,477)	0.0%	6,390,440 (a)	6,662,859 (a)	(272,419)	-4.1%	(0.00009)	0.00000	(0.00009)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	6,390,440 (a)	6,662,859 (a)	(272,419)	-4.1%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	141,728,532	147,327,566	(5,599,034)	-3.8%	6,390,440	6,662,859	(272,419)	-4.1%	2.21782	2.21118	0.00664	0.3%
6. Fuel Cost of Purchased Power - Firm (A7)	50,362,312	47,907,500	2,454,812	5.1%	1,076,872	899,740	177,132	19.7%	4.67672	5.32459	(0.64787)	-12.2%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	4,507,519	4,148,400	359,119	8.7%	200,263	193,737	6,526	3.4%	2.25080	2.14125	0.10955	5.1%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	54,869,831	52,055,900	2,813,931	5.4%	1,277,135	1,093,477	183,658	16.8%	4.29632	4.76058	(0.46426)	-9.8%
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					7,667,575	7,756,336	(88,761)	-1.1%				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	474,154	449,900	24,254	5.4%	19,423	30,468	(11,045)	-36.3%	2.44120	1.47663	0.96457	65.3%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	13,108	0	13,108	0.0%	366	0	366	0.0%	3.58142	0.00000	3.58142	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of NPP Sch. D Separ. Sales (A6)	4,442,272	6,740,300	(2,298,028)	-34.1%	175,089	267,786	(92,697)	-34.6%	2.53715	2.51705	0.02010	0.8%
21. Fuel Cost of Market Base Sales (A6)	494,150	2,165,200	(1,671,050)	-77.2%	24,823	90,671	(65,848)	-72.6%	1.99069	2.38797	(0.39728)	-16.6%
21a. Gains on Market Based Sales	61,526	1,139,600	(1,078,074)	-94.6%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	5,485,210	10,495,000	(5,009,790)	-47.7%	219,701	388,925	(169,224)	-43.5%	2.49667	2.69846	(0.20179)	-7.5%
23. Net Inadvertant Interchange					924	0	924	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					6,079	0	6,079	0.0%				
25. Interchange and Wheeling Losses					1,061	5,700	(4,639)	-81.4%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	191,113,153	188,888,466	2,224,687	1.2%	7,453,816	7,361,711	92,105	1.3%	2.56396	2.56582	(0.00186)	-0.1%
27. Net Unbilled	2,802,028 (a)	1,866,148 (a)	935,880	50.2%	78,153	81,312	(3,159)	-3.9%	3.58531	2.29505	1.29026	56.2%
28. Company Use	484,082 (a)	527,244 (a)	(43,162)	-8.2%	18,986	20,500	(1,514)	-7.4%	2.54968	2.57192	(0.02224)	-0.9%
29. T & D Losses	8,614,623 (a)	(132,821) (a)	8,747,444	-6585.9%	332,551	(11,099)	343,650	-3096.2%	2.59047	1.19669	1.39378	116.5%
30. System KWH Sales	191,113,153	188,888,466	2,224,687	1.2%	7,024,126	7,270,998	(246,872)	-3.4%	2.72081	2.59783	0.12298	4.7%
31. Wholesale KWH Sales	(4,794,484)	(13,268,435)	8,473,951	-63.9%	(166,874)	(507,439)	340,565	-67.1%	2.87312	2.61478	0.25833	9.9%
32. Jurisdictional KWH Sales	186,318,669	175,620,031	10,698,638	6.1%	6,857,252	6,763,559	93,693	1.4%	2.71710	2.59656	0.12054	4.6%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	186,441,639	175,735,940	10,705,699	6.1%	6,857,252	6,763,559	93,693	1.4%	2.71890	2.59828	0.12062	4.6%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	1,514,902	1,442,365	72,537	5.0%	6,857,252	6,763,559	93,693	1.4%	0.02209	0.02133	0.00077	3.6%
35a. Adjustment	0	0	0	0.0%	6,857,252	6,763,559	93,693	1.4%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	6,857,252	6,763,559	93,693	1.4%	0.00000	0.00000	0.00000	0.0%
36. True-up *	36,946,975	36,946,975	0	0.0%	6,857,252	6,763,559	93,693	1.4%	0.53880	0.54627	(0.00746)	-1.4%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	224,903,516	214,125,280	10,778,236	5.0%	6,857,252	6,763,559	93,693	1.4%	3.27979	3.16587	0.11392	3.6%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.28215	3.16815	0.11400	3.6%
40. GPIF * (Already Adjusted for Taxes)	456,230	456,230	0	0.0%	6,857,252	6,763,559	93,693	1.4%	0.00665	0.00675	(0.00009)	-1.4%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	225,359,746	214,581,510	10,778,236	5.0%	6,857,252	6,763,559	93,693	1.4%	3.28880	3.17490	0.11391	3.6%
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.289	3.175	0.114	3.6%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	36,816,875	33,060,389	3,756,486	11.4%	141,760,173	147,347,566	(5,587,393)	-3.8%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	1,564,512	1,577,400	(12,888)	-0.8%	5,423,684	9,355,400	(3,931,716)	-42.0%
2a. GAINS FROM MARKET BASED SALES	23,547	248,700	(225,153)	-90.5%	61,526	1,139,600	(1,078,074)	-94.6%
3. FUEL COST OF PURCHASED POWER	9,791,045	6,535,500	3,255,545	49.8%	50,362,312	47,907,500	2,454,812	5.1%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,014,948	940,200	74,748	8.0%	4,507,519	4,148,400	359,119	8.7%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	46,034,809	38,709,989	7,324,820	18.9%	191,144,794	188,908,466	2,236,328	1.2%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(8,475)	(4,000)	(4,475)	111.9%	(26,164)	(20,000)	(6,164)	30.8%
6b. ADJ.TO FUEL COST	(1,726)	0	(1,726)	0.0%	(5,477)	0	(5,477)	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	46,024,608	38,705,989	7,318,619	18.9%	191,113,153	188,888,466	2,224,687	1.2%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,597,718	1,435,041	162,677	11.3%	6,857,252	6,763,559	93,693	1.4%
2. NONJURISDICTIONAL SALES	51,116	101,502	(50,386)	-49.6%	166,874	507,439	(340,565)	-67.1%
3. TOTAL SALES	1,648,834	1,536,543	112,291	7.3%	7,024,126	7,270,998	(246,872)	-3.4%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9689987	0.9339413	0.0350574	3.8%	0.9762427	0.9302105	0.0460322	4.9%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: MAY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	52,429,634	47,298,945	5,130,689	10.8%	224,319,635	222,894,516	1,425,119	0.6%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(7,389,395)	(7,389,395)	0	0.0%	(36,946,975)	(36,946,975)	0	0.0%
2b. INCENTIVE PROVISION	(91,246)	(91,246)	0	0.0%	(456,230)	(456,230)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	44,948,993	39,818,304	5,130,689	12.9%	186,916,430	185,491,311	1,425,119	0.8%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	46,024,608	38,705,989	7,318,619	18.9%	191,113,153	188,888,466	2,224,687	1.2%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9689987	0.9339413	0.0350574	3.8%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	44,597,785	36,149,122	8,448,663	23.4%	186,318,669	175,620,031	10,698,638	6.1%
6a. JURISDIC. LOSS MULTIPLIER	1.00066	1.00066	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	44,627,220	36,172,980	8,454,240	23.4%	186,441,639	175,735,940	10,705,699	6.1%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	305,099	305,099	0	0.0%	1,550,805	1,550,805	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	295,641	284,945	10,696	3.8%	1,514,902	1,442,365	72,537	5.0%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	44,922,861	36,457,925	8,464,936	23.2%	187,956,541	177,178,305	10,778,236	6.1%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	26,132	3,360,379	(3,334,247)	-99.2%	(1,040,111)	8,313,006	(9,353,117)	-112.5%
8. INTEREST PROVISION FOR THE MONTH	(96,907)	(165,506)	68,599	-41.4%	(562,053)	(1,079,295)	517,242	-47.9%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(69,630,704)	(55,076,317)	(14,554,387)	26.4%	----------NOT APPLICABLE----------			
10. TRUE-UP COLLECTED (REFUNDED)	7,389,395	7,389,395	0	0.0%	----------NOT APPLICABLE----------			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(62,312,084)	(44,492,049)	(17,820,035)	40.1%	----------NOT APPLICABLE----------			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(69,630,704)	(55,076,317)	(14,554,387)	26.4%	----------NOT APPLICABLE----------			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(62,215,177)	(44,326,543)	(17,888,634)	40.4%	----------NOT APPLICABLE----------			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(131,845,881)	(99,402,860)	(32,443,021)	32.6%	----------NOT APPLICABLE----------			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(65,922,941)	(49,701,430)	(16,221,511)	32.6%	----------NOT APPLICABLE----------			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.750	4.000	(2)	-56.3%	----------NOT APPLICABLE----------			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.770	4.000	(2)	-55.8%	----------NOT APPLICABLE----------			
7. TOTAL (LINE D5 + LINE D6)	3.520	8.000	(4)	-56.0%	----------NOT APPLICABLE----------			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.760	4.000	(2)	-56.0%	----------NOT APPLICABLE----------			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.147	0.333	(0)	-55.9%	----------NOT APPLICABLE----------			
10. INT. PROVISION (LINE D4 x LINE D9)	(96,907)	(165,506)	68,599	-41.4%	----------NOT APPLICABLE----------			

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GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	564,256	256,278	307,978	120.2%	1,297,941	1,457,900	(159,959)	-11.0%
2	LIGHT OIL	1,237,269	702,939	534,330	76.0%	5,943,536	5,564,666	378,870	6.8%
3	COAL	30,457,449	29,073,710	1,383,739	4.8%	126,527,713	132,311,138	(5,783,425)	-4.4%
4	NATURAL GAS	4,557,901	3,027,462	1,530,439	50.6%	7,990,983	8,013,862	(22,879)	-0.3%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	36,816,875	33,060,389	3,756,486	11.4%	141,760,173	147,347,566	(5,587,393)	-3.8%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	7,442	5,679	1,763	31.0%	25,036	31,797	(6,761)	-21.3%
9	LIGHT OIL	19,067	12,023	7,044	58.6%	117,344	84,699	32,645	38.5%
10	COAL	1,480,851	1,399,464	81,387	5.8%	6,107,403	6,389,238	(281,835)	-4.4%
11	NATURAL GAS	55,244	54,336	908	1.7%	140,657	157,125	(16,468)	-10.5%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,562,604	1,471,502	91,102	6.2%	6,390,440	6,662,859	(272,419)	-4.1%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	11,909	8,436	3,473	41.2%	40,490	47,342	(6,852)	-14.5%
16	LIGHT OIL (BBL)	38,963	21,042	17,921	85.2%	200,183	162,687	37,496	23.0%
17	COAL (TON)	698,423	617,782	80,641	13.1%	2,877,697	2,835,736	41,961	1.5%
18	NATURAL GAS (MCF)	598,446	557,896	40,550	7.3%	1,518,141	1,594,785	(76,644)	-4.8%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	74,712	52,969	21,743	41.0%	254,018	297,253	(43,235)	-14.5%
22	LIGHT OIL	226,022	116,797	109,225	93.5%	1,153,260	919,158	234,102	25.5%
23	COAL	16,329,769	14,543,621	1,786,148	12.3%	67,151,429	66,413,247	738,182	1.1%
24	NATURAL GAS	627,770	573,495	54,275	9.5%	1,596,028	1,639,551	(43,524)	-2.7%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	17,258,273	15,286,882	1,971,391	12.9%	70,154,735	69,269,209	885,526	1.3%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.48%	0.39%	0.00	-	0.39%	0.48%	(0.00)	-
29	LIGHT OIL	1.22%	0.82%	0.00	-	1.84%	1.27%	0.01	-
30	COAL	94.77%	95.10%	(0.00)	-	95.57%	95.89%	(0.00)	-
31	NATURAL GAS	3.54%	3.69%	(0.00)	-	2.20%	2.36%	(0.00)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	47.38	30.38	17.00	56.0%	32.06	30.80	1.26	4.1%
36	LIGHT OIL ($/BBL)	31.75	33.41	(1.65)	-4.9%	29.69	34.20	(4.51)	-13.2%
37	COAL ($/TON)	43.61	47.06	(3.45)	-7.3%	43.97	46.66	(2.69)	-5.8%
38	NATURAL GAS ($/MCF)	7.62	5.43	2.19	40.4%	5.26	5.03	0.24	4.7%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	7.55	4.84	2.71	56.1%	5.11	4.90	0.21	4.2%
42	LIGHT OIL	5.47	6.02	(0.54)	-9.0%	5.15	6.05	(0.90)	-14.9%
43	COAL	1.87	2.00	(0.13)	-6.7%	1.88	1.99	(0.11)	-5.4%
44	NATURAL GAS	7.26	5.28	1.98	37.5%	5.01	4.89	0.12	2.4%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.13	2.16	(0.03)	-1.4%	2.02	2.13	(0.11)	-5.0%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	10,039	9,327	712	7.6%	10,146	9,348	798	8.5%
49	LIGHT OIL	11,854	9,714	2,140	22.0%	9,828	10,852	(1,024)	-9.4%
50	COAL	11,027	10,392	635	6.1%	10,995	10,395	600	5.8%
51	NATURAL GAS	11,364	10,555	809	7.7%	11,347	10,435	912	8.7%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	11,045	10,389	656	6.3%	10,978	10,396	582	5.6%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	7.58	4.51	3.07	68.1%	5.18	4.59	0.59	12.9%
56	LIGHT OIL	6.49	5.85	0.64	10.9%	5.07	6.57	(1.50)	-22.8%
57	COAL	2.06	2.08	(0.02)	-1.0%	2.07	2.07	0.00	0.0%
58	NATURAL GAS	8.25	5.57	2.68	48.1%	5.68	5.10	0.58	11.4%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.36	2.25	0.11	4.9%	2.22	2.21	0.01	0.5%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: MAY 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	0	-177	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-177**	—	—	—	**0**	HVY.OIL	**0**	**0**	**0.0**	**209,599** **	**-118.42**	**0.00**
GAN.#1	114	45,994	54.2	76.5	67.2	12,216	COAL	23,440	23,970,000	561,856.8	936,829	2.04	39.97
GAN.#2	98	45,722	62.7	80.9	76.7	12,189	COAL	23,386	23,830,000	557,288.4	934,671	2.04	39.97
GAN.#3	145	71,839	66.6	87.5	74.0	12,196	COAL	46,645	18,784,000	876,179.7	1,864,265	2.60	39.97
GAN.#4	159	79,840	67.5	90.0	72.5	12,662	COAL	53,175	19,042,000	1,012,558.4	2,125,251	2.66	39.97
GAN.#5	217	99,739	61.8	77.1	78.7	10,656	COAL	44,909	23,666,000	1,062,816.4	1,794,882	1.80	39.97
GAN.#6	372	189,537	68.5	78.9	77.7	10,878	COAL	86,699	23,782,000	2,061,875.6	3,465,108	1.83	39.97
GANNON STATION	**1,105**	**532,671**	**64.8**	**81.2**	**75.5**	**11,513**	COAL	**278,254**	**22,039,487**	**6,132,575.3**	**11,121,006**	**2.09**	**39.97**
B.B.#1	416	185,181	59.8	69.1	73.8	10,760	COAL	81,260	24,521,100	1,992,584.6	3,540,725	1.91	43.57
B.B.#2	416	251,345	81.2	86.0	81.2	10,863	COAL	109,912	24,842,120	2,730,447.1	4,789,172	1.91	43.57
B.B.#3	433	164,896	51.2	32.5	73.5	10,560	COAL	71,298	24,422,900	1,741,292.0	3,106,652	1.88	43.57
B.B. 1 - 3	1,265	601,422	63.9	62.1	76.1	10,748	COAL	262,470	24,628,856	6,464,323.7	11,436,549	1.90	43.57
B.B.#4	442	258,891	78.7	90.8	78.7	10,662	COAL	121,741	22,674,033	2,760,358.6	6,531,712	2.52	53.65
B.B. STATION	**1,707**	**860,313**	**67.7**	**69.6**	**76.8**	**10,722**	COAL	**384,211**	**24,009,451**	**9,224,682.3**	**17,968,261**	**2.09**	**46.77**
SEB-PHIL. #1(HVY OIL)	17	4,579	36.2	100.0	79.3	9,806	HVY.OIL	7,157	6,273,540	44,901.4	213,140	4.65	29.78
SEB-PHIL. #2(HVY OIL)	17	3,040	24.0	68.6	82.0	9,806	HVY.OIL	4,752	6,273,540	29,810.1	141,517	4.66	29.78
SEB-PHILLIPS TOTAL	**34**	**7,619**	**30.1**	**84.3**	**80.7**	**9,806**	HVY.OIL	**11,909**	**6,273,540**	**74,711.5**	**354,657**	**4.65**	**29.78**
POLK #1 GASIFIER	250	67,867	47.2	50.5	84.8	11,068	COAL	35,958	27,046,000	972,510.9	1,368,182	1.56	38.05
POLK #1 CT (OIL)	225	7,452	4.5	73.7	60.7	9,739	LGT.OIL	12,602	5,758,744	72,574.4	413,531	5.55	32.81
POLK #1 TOTAL	**250**	**95,319**	**51.2**	**66.6**	**82.2**	**10,964**	-	-	-	**1,045,085.3**	**1,781,713**	**1.87**	-
POLK #2 CT (GAS)	150	25,128	22.5	99.4	78.4	11,581	GAS	277,425	972,290	291,019.0	1,978,753	7.87	7.13
POLK #2 CT (OIL)	160	4,538	3.8	99.9	77.0	11,721	LGT.OIL	9,125	5,828,982	53,191.5	299,434	6.60	32.81
POLK #2 TOTAL	**155**	**29,666**	**25.7**	**100.0**	**78.2**	**11,603**	-	-	-	**344,210.5**	**2,278,187**	**7.68**	-
POLK #3 CT (GAS)	150	28,436	25.5	94.9	78.2	11,268	GAS	305,461	972,290	320,429.0	2,472,946	8.70	8.10
POLK #3 CT (OIL)	160	2,274	1.9	95.4	96.3	9,494	LGT.OIL	3,704	5,828,991	21,588.6	121,530	5.34	32.81
POLK #3 TOTAL	**155**	**30,710**	**26.6**	**95.4**	**79.3**	**11,137**	-	-	-	**342,017.6**	**2,594,476**	**8.45**	-
POLK STATION TOTAL	**560**	**155,695**	**37.4**	**83.8**	**57.6**	**11,120**	-	-	-	**1,731,313.4**	**6,654,376**	**4.27**	-
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	344	3.9	98.7	104.8	17,360	LGT.OIL	1,030	5,800,874	5,972.0	30,657	8.91	29.76
B.B.C.T.#2	66	4,459	9.1	100.0	65.6	16,303	LGT.OIL	12,502	5,814,522	72,695.6	372,117	8.35	29.76
B.B.C.T.#3	66	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**144**	**4,803**	**4.5**	**99.9**	**38.8**	**16,379**	LGT.OIL	**13,532**	**5,813,484**	**78,667.6**	**402,774**	**8.39**	**29.76**
CITY OF TAMPA	**6**	**1,660**	**0.0**	**0.0**	**0.0**	**9,716**	GAS	**15,560**	**972,290**	**16,322.4**	**106,202**	**6.32**	**6.83**
TOT. COAL (GN,BB,POLK)	**3,062**	**1,480,851**	**65.0**	**72.2**	**77.0**	**11,027**	COAL	**698,423**	**23,380,944**	**16,329,768.5**	**30,457,449**	**2.06**	**43.61**
SYSTEM	**3,556**	**1,562,804**	**59.2**	**76.8**	**71.9**	**11,043**	-	-	-	**17,258,272.5**	**36,816,675**	**2.36**	-

* Hookers Point boiler limited to 90 MW
** Sale of Hookers Point #6 Oil Inventory

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	14,473	8,436	6,037	71.6%	31,010	47,342	(16,332)	-34.5%
3 UNIT COST ($/BBL)	28.43	29.06	(0.63)	-2.2%	25.15	30.23	(5.08)	-16.8%
4 AMOUNT ($)	411,518	245,182	166,336	67.8%	779,940	1,431,259	(651,329)	-45.5%
5 BURNED:								
6 UNITS (BBL)	11,909	8,436	3,473	41.2%	40,490	47,342	(6,852)	-14.5%
7 UNIT COST ($/BBL)	47.38	30.38	17.00	56.0%	32.06	30.80	1.26	4.1%
8 AMOUNT ($)	564,256	256,278	307,978	120.2%	1,297,941	1,457,900	(159,959)	-11.0%
9 ENDING INVENTORY:								
10 UNITS (BBL) (a)	8,169	59,129	(50,960)	-86.2%	8,169	59,129	(50,960)	-86.2%
11 UNIT COST ($/BBL)	28.92	26.54	2.38	9.0%	28.92	26.54	2.38	9.0%
12 AMOUNT ($) (a)	236,230	1,569,132	(1,332,902)	-84.9%	236,230	1,569,132	(1,332,902)	-84.9%
13								
14 DAYS SUPPLY:	12	87	(75)	-86.2%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	66,608	32,085	34,523	107.6%	236,117	208,902	27,215	13.0%
17 UNIT COST ($/BBL)	31.91	31.17	0.74	2.4%	29.81	33.60	(3.78)	-11.3%
18 AMOUNT ($)	2,125,453	1,000,107	1,125,346	112.5%	7,039,471	7,018,687	20,784	0.3%
19 BURNED:								
20 UNITS (BBL)	38,963	21,042	17,921	85.2%	200,183	162,687	37,496	23.0%
21 UNIT COST ($/BBL)	31.75	33.41	(1.65)	-4.9%	29.69	34.20	(4.51)	-13.2%
22 AMOUNT ($)	1,237,269	702,939	534,330	76.0%	5,943,536	5,564,666	378,870	6.8%
23 ENDING INVENTORY:								
24 UNITS (BBL)	103,648	113,465	(9,817)	-8.7%	103,648	113,465	(9,817)	-8.7%
25 UNIT COST ($/BBL)	30.81	33.21	(2.40)	-7.2%	30.81	33.21	(2.40)	-7.2%
26 AMOUNT ($)	3,193,538	3,768,008	(574,470)	-15.2%	3,193,538	3,768,008	(574,470)	-15.2%
27								
28 DAYS SUPPLY: NORMAL	42	46	(4)	-8.2%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	15	16	(1)	-7.5%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	572,626	608,000	(35,374)	-5.8%	3,209,199	3,212,000	(2,801)	-0.1%
32 UNIT COST ($/TON)	45.78	47.12	(1.34)	-2.8%	44.34	46.78	(2.44)	-5.2%
33 AMOUNT ($)	26,215,324	28,650,809	(2,435,485)	-8.5%	142,287,223	150,246,413	(7,959,190)	-5.3%
34 BURNED:								
35 UNITS (TONS)	698,423	617,782	80,641	13.1%	2,877,697	2,835,736	41,961	1.5%
36 UNIT COST ($/TON)	43.61	47.06	(3.45)	-7.3%	43.97	46.66	(2.69)	-5.8%
37 AMOUNT ($)	30,457,449	29,073,710	1,383,739	4.8%	126,527,713	132,311,138	(5,783,425)	-4.4%
38 ENDING INVENTORY:								
39 UNITS (TONS)	956,982	1,353,084	(396,102)	-29.3%	956,982	1,353,084	(396,102)	-29.3%
40 UNIT COST ($/TON)	43.75	47.15	(3.41)	-7.2%	43.75	47.15	(3.41)	-7.2%
41 AMOUNT ($)	41,864,480	63,801,273	(21,936,793)	-34.4%	41,864,480	63,801,273	(21,936,793)	-34.4%
42								
43 DAYS SUPPLY:	43	61	(18)	-29.2%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	598,446	557,896	40,550	7.3%	1,518,141	1,594,785	(76,644)	-4.8%
46 UNIT COST ($/MCF)	7.62	5.43	2.19	40.4%	5.26	5.03	0.24	4.7%
47 AMOUNT ($)	4,557,901	3,027,461	1,530,440	50.6%	7,990,010	8,013,861	(23,851)	-0.3%
48 BURNED:								
49 UNITS (MCF)	598,446	557,896	40,550	7.3%	1,518,141	1,594,785	(76,644)	-4.8%
50 UNIT COST ($/MCF)	7.62	5.43	2.19	40.4%	5.26	5.03	0.24	4.7%
51 AMOUNT ($)	4,557,901	3,027,462	1,530,439	50.6%	7,990,983	8,013,862	(22,879)	-0.3%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(a) Ending inventory includes sale of Hookers Point #6 oil of 47,616 bbls and $1,019,945.

(1) *RECONCILIATION - HEAVY OIL*

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	14,420
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	14,420

(2) *RECONCILIATION - LIGHT OIL*

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	(0)
IGNITION	(5,530)	(164,928)
OTHER USAGE	(983)	(30,332)
TOTAL	(6,513)	(195,260)

(3)

RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	45,138
IGNITION #2 OIL	150,508
IGNITION PROPANE	4,832
AERIAL SURVEY ADJ.	(586,248)
ADDITIVES	50,842
GREEN FUEL	0
TOTAL	(334,928)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2002

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. -D	6,055.0	0.0	6,055.0	1.465	1.465	88,700.00	88,700.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	37,758.0	0.0	37,758.0	2.597	3.645	980,400.00	1,376,100.00	
VARIOUS	JURISDIC.	SCH. -MB	23,257.0	0.0	23,257.0	2.186	2.186	508,300.00	508,300.00	248,700.00
TOTAL			67,070.0	0.0	67,070.0	2.352	2.942	1,577,400.00	1,973,100.00	248,700.00
ACTUAL:										
FLA. PWR. & LIGHT	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR PARTNERS	SEP. CONTR.	SCH. -D	48,470.0	0.0	48,470.0	2.546	3.332	1,234,046.20	1,615,020.40	
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. -D	5,707.8	201.4	5,506.4	2.603	2.603	143,320.42	143,320.42	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. -D	946.9	0.0	946.9	1.956	1.956	18,526.01	18,526.01	
FLA. PWR. CORP.		SCH. -MA	530.0	0.0	530.0	1.986	2.721	10,525.57	14,423.76	2,234.01
FLA. PWR. & LIGHT		SCH. -MA	5,297.0	0.0	5,297.0	2.133	2.743	112,993.51	145,284.07	15,657.98
CITY OF LAKELAND		SCH. -MA	95.0	0.0	95.0	2.255	3.113	2,142.60	2,957.74	516.84
ORLANDO UTIL. COMM.		SCH. -MA	150.0	0.0	150.0	2.109	3.035	3,163.92	4,552.88	917.96
THE ENERGY AUTHORITY		SCH. -MA	204.0	0.0	204.0	2.704	3.831	5,516.99	7,816.17	1,658.62
DUKE ENERGY		SCH. -MA	200.0	0.0	200.0	2.029	3.198	4,057.98	6,396.59	1,710.61
RELIANT		SCH. -MA	20.0	0.0	20.0	3.282	7.850	656.40	1,570.06	850.86
AUBURNDALE POWER PARTNERS		SCH. -OATT	101.0	0.0	101.0	0.726	0.726	733.55	733.55	
CARGILL ALLIANT		SCH. -OATT	80.0	0.0	80.0	5.273	5.273	4,218.27	4,218.27	
ADJUSTMENTS TO PREV. MONTHS										
HARDEE PWR PARTNERS EST.	Apr. 2002	CONTRACT	(54,690.0)	0.0	(54,690.0)	2.501	3.263	(1,367,796.90)	(1,784,534.70)	
HARDEE PWR PARTNERS ACT.	Apr. 2002	CONTRACT	54,690.0	0.0	54,690.0	2.546	3.332	1,392,407.40	1,822,270.80	
CARGILL ALLIANT	Apr. 2002	SCH. -OATT	(88.0)	0.0	(88.0)	4.989	4.989	(4,390.26)	(4,390.26)	
CARGILL ALLIANT	Apr. 2002	SCH. -OATT	88.0	0.0	88.0	5.289	5.289	4,390.26	4,390.26	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD			6,654.7	201.4	6,453.3	2.508	2.508	161,846.43	161,846.43	
SUB-TOTAL SCHEDULE D POWER SALES-SEPARATED			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEP.			48,470.0	0.0	48,470.0	2.597	3.410	1,258,656.70	1,652,756.50	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD			6,496.0	0.0	6,496.0	2.141	2.817	139,056.97	183,001.29	23,546.88
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD			176.0	0.0	176.0	2.814	2.814	4,951.82	4,951.82	
TOTAL			61,796.7	201.4	61,595.3	2.540	3.251	1,564,511.92	2,002,556.04	23,546.88
CURRENT MONTH:										
DIFFERENCE			(5,273.3)	201.4	(5,474.7)	0.188	0.309	(12,888.08)	29,456.04	(225,153.12)
DIFFERENCE %			-7.9%	0.0%	-8.2%	8.0%	10.5%	-0.8%	1.5%	-90.5%
PERIOD TO DATE:										
ACTUAL			221,611.5	1,910.4	219,701.1	2.469	3.147	5,423,684.15	6,913,839.83	61,527.09
ESTIMATED			388,925.0	0.0	388,925.0	2.405	3.127	9,355,400.00	12,161,900.00	1,139,600.00
DIFFERENCE			(167,313.5)	1,910.4	(169,223.9)	0.064	0.020	(3,931,715.85)	(5,248,060.17)	(1,078,072.91)
DIFFERENCE %			-43.0%	0.0%	-43.5%	2.7%	0.6%	-42.0%	-43.2%	-94.6%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS FOR THE MONTH OF MAY 2002.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH.-J	8,539.0	0.0	5,055.0	3,484.0	5.809	5.809	202,400.00
HARDEE POWER PARTNERS		IPP	74,341.0	0.0	0.0	74,341.0	4.322	4.322	3,213,300.00
VARIOUS		OTHER	24,800.0	0.0	0.0	24,800.0	4.950	4.950	1,227,600.00
VARIOUS		MKT. BASE	26,951.0	0.0	0.0	26,951.0	7.021	7.021	1,892,200.00
TOTAL			134,631.0	0.0	5,055.0	129,576.0	5.044	5.044	6,535,500.00
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	72,928.0	0.0	0.0	72,928.0	3.841	3.841	2,801,390.70
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH.-D	64,050.0	0.0	0.0	64,050.0	3.186	3.186	2,040,883.50
FLA. POWER CORP.		SCH.-J	14,226.0	0.0	900.0	13,326.0	3.460	3.460	461,076.00
FLA. POWER & LIGHT		SCH.-J	4,190.0	0.0	595.0	3,595.0	5.569	5.569	200,194.60
CITY OF LAKELAND		SCH.-J	6,385.0	0.0	1,052.1	5,332.9	6.935	6.935	369,825.77
ORLANDO UTIL. COMM.		SCH.-J	17,050.0	0.0	1,656.5	15,393.5	7.392	7.392	1,137,833.29
LAKE WORTH		SCH.-J	147.0	0.0	68.0	79.0	15.929	15.929	12,583.72
THE ENERGY AUTHORITY		SCH.-J	8,035.0	0.0	2,065.8	5,969.2	5.502	5.502	328,408.28
REEDY CREEK		SCH.-J	1,255.0	0.0	20.0	1,235.0	6.974	6.974	86,130.00
TALLAHASSEE		SCH.-J	5,009.0	0.0	272.1	4,736.9	5.455	5.455	258,408.92
AQUILA		SCH.-J	27,393.0	0.0	49.0	27,344.0	4.787	4.787	1,308,898.00
AUBURNDALE POWER PARTNERS		SCH.-J	3,848.0	0.0	0.0	3,848.0	4.500	4.500	173,160.00
CARGILL ALLIANT		SCH.-J	11,776.0	0.0	1,097.0	10,679.0	5.590	5.590	596,950.50
CALPINE		SCH.-J	335.0	0.0	0.0	335.0	4.355	4.355	14,590.00
HOMESTEAD		SCH.-J	24.0	0.0	5.0	19.0	7.681	7.681	1,459.39
DUKE ENERGY		SCH.-J	7,562.0	0.0	797.0	6,765.0	5.399	5.399	365,220.28
DYNEGY POWER MKT		SCH.-J	618.0	0.0	20.0	598.0	5.840	5.840	34,924.00
RINGHAVER		SCH.-J	1,776.0	0.0	0.0	1,776.0	7.693	7.693	136,620.54
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Apr. 2002	IPP	(60,294.0)	0.0	0.0	(60,294.0)	6.742	6.742	(4,064,828.00)
HARDEE PWR. PART.-NATIVE	Apr. 2002	IPP	60,294.0	0.0	0.0	60,294.0	5.826	5.826	3,512,458.10
FLA. POWER CORP.	Apr. 2002	SCH.-D	(82,050.0)	0.0	0.0	(82,050.0)	3.118	3.118	(2,558,408.00)
FLA. POWER CORP.	Apr. 2002	SCH.-D	82,050.0	0.0	0.0	82,050.0	3.137	3.137	2,573,997.50
DUKE ENERGY	Apr. 2002	SCH.-J	(31,940.0)	0.0	(5,643.0)	(26,297.0)	5.781	5.781	(1,520,289.35)
DUKE ENERGY	Apr. 2002	SCH.-J	31,945.0	0.0	5,643.0	26,302.0	5.781	5.781	1,520,403.35
THE ENERGY AUTH.	Apr. 2002	SCH.-J	(27,089.0)	0.0	(7,810.3)	(19,278.7)	5.338	5.338	(1,029,083.81)
THE ENERGY AUTH.	Apr. 2002	SCH.-J	27,079.0	0.0	7,810.3	19,268.7	5.353	5.353	1,031,384.81
CARGILL ALLIANT	Apr. 2002	SCH.-J	(42,918.0)	0.0	(2,501.1)	(40,416.9)	5.184	5.184	(2,095,209.83)
CARGILL ALLIANT	Apr. 2002	SCH.-J	42,946.0	0.0	2,501.1	40,444.9	5.173	5.173	2,092,062.83
TOTAL			246,630.0	0.0	8,597.5	238,032.5	4.113	4.113	9,791,045.09
CURRENT MONTH:									
DIFFERENCE			111,999.0	0.0	3,542.5	108,456.5	(0.931)	(0.931)	3,255,545.09
DIFFERENCE %			83.2%	0.0%	70.1%	83.7%	-18.5%	-18.5%	49.8%
PERIOD TO DATE:									
ACTUAL			1,155,367.0	0.0	78,496.3	1,076,870.8	4.677	4.677	50,362,312.05
ESTIMATED			923,243.0	0.0	23,503.0	899,740.0	5.325	5.325	47,907,500.00
DIFFERENCE			232,124.0	0.0	54,993.3	177,130.8	(0.648)	(0.648)	2,454,812.05
DIFFERENCE %			25.1%	0.0%	234.0%	19.7%	-12.2%	-12.2%	5.1%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	41,027.0	0.0	0.0	41,027.0	2.292	2.292	940,200.00
TOTAL			**41,027.0**	**0.0**	**0.0**	**41,027.0**	**2.292**	**2.292**	**940,200.00**
ACTUAL:									
IMC-AGRICO-NICHOLS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE		COGEN.	10,262.0	0.0	0.0	10,262.0	2.160	2.160	221,686.92
MULBERRY PHOSPHATES INC		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
HILLSBOROUGH COUNTY		COGEN.	19,044.0	0.0	0.0	19,044.0	2.168	2.168	412,951.77
CARGILL MILLPOINT		COGEN.	116.0	0.0	0.0	116.0	4.999	4.999	5,798.36
CF INDUSTRIES INC.		COGEN.	360.0	0.0	0.0	360.0	2.996	2.996	10,784.23
FARMLAND HYDRO LP		COGEN.	1,845.0	0.0	0.0	1,845.0	3.299	3.299	60,875.60
IMC-AGRICO-S. PIERCE		COGEN.	2,849.0	0.0	0.0	2,849.0	3.777	3.777	107,594.60
AUBURNDALE POWER PARTNERS		COGEN.	466.0	0.0	0.0	466.0	2.921	2.921	13,613.82
ORANGE COGENERATION L.P.		COGEN	7,797.0	0.0	0.0	7,797.0	2.210	2.210	172,277.06
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
AS AVAILABLE ASSIGNMENT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR MAY 2002			42,739.0	0.0	0.0	42,739.0	2.353	2.353	1,005,584.36
ADJUSTMENTS FOR THE MONTH OF:	**MARCH 2002**								
IMC-AGRICO-NICHOLS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE		COGEN	(13,625.0)	0.0	0.0	(13,625.0)	2.203	2.203	(300,151.54)
			13,625.0	0.0	0.0	13,625.0	2.228	2.228	303,569.09
MULBERRY PHOSPHATES INC		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD		COGEN	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
HILLSBOROUGH COUNTY		COGEN.	(17,343.0)	0.0	0.0	(17,343.0)	2.210	2.210	(383,317.13)
			17,343.0	0.0	0.0	17,343.0	2.236	2.236	387,759.22
CARGILL MILLPOINT		COGEN	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
FARMLAND HYDRO LP		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE		COGEN	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS		COGEN.	(257.0)	0.0	0.0	(257.0)	4.328	4.328	(11,122.73)
			255.0	0.0	0.0	255.0	4.332	4.332	11,045.84
ORANGE COGENERATION L.P.		COGEN.	(5,658.0)	0.0	0.0	(5,658.0)	2.090	2.090	(118,260.26)
			5,658.0	0.0	0.0	5,658.0	2.118	2.118	119,860.79
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
AS AVAILABLE ASSIGNMENT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**MARCH 2002**		(2.0)	0.0	0.0	(2.0)	(468.164)	(468.164)	9,363.28
GRAND TOTAL			**42,737.0**	**0.0**	**0.0**	**42,737.0**	**2.375**	**2.375**	**1,014,947.64**
CURRENT MONTH:									
DIFFERENCE			1,710.0	0.0	0.0	1,710.0	0.083	0.083	74,747.64
DIFFERENCE %			4.2%	0.0%	0.0%	4.2%	3.6%	3.6%	8.0%
PERIOD TO DATE:									
ACTUAL			200,263.0	0.0	0.0	200,263.0	2.251	2.251	4,507,518.63
ESTIMATED			193,737.0	0.0	0.0	193,737.0	2.141	2.141	4,148,400.00
DIFFERENCE			6,526.0	0.0	0.0	6,526.0	0.110	0.110	359,118.63
DIFFERENCE %			3.4%	0.0%	0.0%	3.4%	0.051	0.051	8.7%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: MAY 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		0.0	0.000	0.00	0.000	0.00	0.00
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

JUNE 2002

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY

MONTH OF: JUNE 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	33,085,162	38,316,729	(5,231,567)	-13.7%	1,417,458	1,607,652	(190,194)	-11.8%	2.33412	2.38340	(0.04928)	-2.1%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(7,655)	(4,000)	(3,655)	91.4%	1,417,458 (a)	1,607,652 (a)	(190,194)	-11.8%	(0.00054)	(0.00025)	(0.00029)	117.1%
4b. Adjustments to Fuel Cost (1)	(2,444)	0	(2,444)	0.0%	1,417,458 (a)	1,607,652 (a)	(190,194)	-11.8%	(0.00017)	0.00000	(0.00017)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	1,417,458 (a)	1,607,652 (a)	(190,194)	-11.8%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	33,075,063	38,312,729	(5,237,666)	-13.7%	1,417,458	1,607,652	(190,194)	-11.8%	2.33341	2.38315	(0.04974)	-2.1%
6. Fuel Cost of Purchased Power - Firm (A7)	11,531,754	12,912,400	(1,380,646)	-10.7%	320,997	229,061	91,936	40.1%	3.59248	5.63710	(2.04462)	-36.3%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	921,364	977,900	(56,536)	-5.8%	39,890	39,704	186	0.5%	2.30976	2.46298	(0.15321)	-6.2%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	12,453,118	13,890,300	(1,437,182)	-10.3%	360,887	268,765	92,122	34.3%	3.45070	5.16820	(1.71750)	-33.2%
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,778,345	1,876,417	(98,072)	-5.2%				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	153,383	92,700	60,683	65.5%	5,674	6,176	(302)	-4.9%	2.61122	1.50097	1.11025	74.0%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	(20,184)	0	(20,184)	0.0%	1,229	0	1,229	0.0%	(1.64231)	0.00000	(1.64231)	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	1,113,640	954,500	159,140	16.7%	43,380	36,540	6,840	18.7%	2.56717	2.61221	(0.04503)	-1.7%
21. Fuel Cost of Market Base Sales (A6)	17,441	593,200	(575,759)	-97.1%	825	25,608	(24,783)	-96.8%	2.11406	2.31646	(0.20240)	-8.7%
21a. Gains on Market Based Sales	484	463,400	(462,916)	-99.9%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	1,284,764	2,103,800	(839,036)	-39.9%	51,308	68,324	(17,016)	-24.9%	2.46504	3.07915	(0.61411)	-19.9%
23. Net Inadvertant Interchange					(328)	0	(328)	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					(2,436)	0	(2,436)	0.0%				
25. Interchange and Wheeling Losses					382	1,000	(618)	-61.8%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	44,263,417	50,099,229	(5,835,812)	-11.6%	1,723,891	1,807,093	(83,202)	-4.6%	2.56765	2.77237	(0.20472)	-7.4%
27. Net Unbilled	(78,005) (a)	1,182,109 (a)	(1,260,114)	-106.6%	(3,038)	42,639	(45,677)	-107.1%	2.56764	2.77237	(0.20472)	-7.4%
28. Company Use	107,944 (a)	113,667 (a)	(5,723)	-5.0%	4,204	4,100	104	2.5%	2.56765	2.77237	(0.20472)	-7.4%
29. T & D Losses	1,830,783 (a)	129,359 (a)	1,701,424	1315.3%	71,302	4,666	66,636	1428.1%	2.56765	2.77237	(0.20473)	-7.4%
30. System KWH Sales	44,263,417	50,099,229	(5,835,812)	-11.6%	1,651,423	1,755,688	(104,265)	-5.9%	2.68032	2.85354	(0.17322)	-6.1%
31. Wholesale KWH Sales	(1,247,259)	(3,381,072)	2,133,813	-63.1%	(46,534)	(118,487)	71,953	-60.7%	2.68032	2.85354	(0.17322)	-6.1%
32. Jurisdictional KWH Sales	43,016,158	46,718,157	(3,701,999)	-7.9%	1,604,889	1,637,201	(32,312)	-2.0%	2.68032	2.85354	(0.17322)	-6.1%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	43,044,549	46,748,991	(3,704,442)	-7.9%	1,604,889	1,637,201	(32,312)	-2.0%	2.68209	2.85542	(0.17333)	-6.1%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	294,042	282,148	11,894	4.2%	1,604,889	1,637,201	(32,312)	-2.0%	0.01832	0.01723	0.00109	6.3%
35a. Adjustment	0	0	0	0.0%	1,604,889	1,637,201	(32,312)	-2.0%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	1,604,889	1,637,201	(32,312)	-2.0%	0.00000	0.00000	0.00000	0.0%
36. True-up *	7,389,395	7,389,395	0	0.0%	1,604,889	1,637,201	(32,312)	-2.0%	0.46043	0.45134	0.00909	2.0%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	50,727,986	54,420,534	(3,692,548)	-6.8%	1,604,889	1,637,201	(32,312)	-2.0%	3.16084	3.32400	(0.16316)	-4.9%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.16312	3.32639	(0.16327)	-4.9%
40. GPIF * (Already Adjusted for Taxes)	91,246	91,246	0	0.0%	1,604,889	1,637,201	(32,312)	-2.0%	0.00569	0.00557	0.00011	2.0%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	50,819,232	54,511,780	(3,692,548)	-6.8%	1,604,889	1,637,201	(32,312)	-2.0%	3.16881	3.33196	(0.16316)	-4.9%
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.169	3.332	(0.163)	-4.9%

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY

PERIOD TO DATE THROUGH: JUNE 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	174,845,335	185,664,295	(10,818,960)	-5.8%	7,807,898	8,270,511	(462,613)	-5.6%	2.23934	2.24490	(0.00556)	-0.2%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (FLMeade/Wauch. Wheeling Losses)	(33,819)	(24,000)	(9,819)	40.9%	7,807,898 (a)	8,270,511 (a)	(462,613)	-5.6%	(0.00043)	(0.00029)	(0.00014)	49.3%
4b. Adjustments to Fuel Cost (1)	(7,921)	0	(7,921)	0.0%	7,807,898 (a)	8,270,511 (a)	(462,613)	-5.6%	(0.00010)	0.00000	(0.00010)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	7,807,898 (a)	8,270,511 (a)	(462,613)	-5.6%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	174,803,595	185,640,295	(10,836,700)	-5.8%	7,807,898	8,270,511	(462,613)	-5.6%	2.23880	2.24460	(0.00580)	-0.3%
6. Fuel Cost of Purchased Power - Firm (A7)	61,894,066	60,819,900	1,074,166	1.8%	1,397,869	1,128,801	269,068	23.8%	4.42774	5.38801	(0.96026)	-17.8%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	5,428,883	5,126,300	302,583	5.9%	240,153	233,441	6,712	2.9%	2.26059	2.19597	0.06462	2.9%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	67,322,949	65,946,200	1,376,749	2.1%	1,638,022	1,362,242	275,780	20.2%	4.11001	4.84100	(0.73099)	-15.1%
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					9,445,920	9,632,753	(186,833)	-1.9%				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	627,537	542,600	84,937	15.7%	25,297	36,644	(11,347)	-31.0%	2.48068	1.48073	0.99994	67.5%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	(7,076)	0	(7,076)	0.0%	1,595	0	1,595	0.0%	(0.44364)	0.00000	(0.44364)	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	5,555,912	7,694,800	(2,138,888)	-27.8%	218,469	304,326	(85,857)	-28.2%	2.54311	2.52847	0.01464	0.6%
21. Fuel Cost of Market Base Sales (A6)	511,591	2,758,400	(2,246,809)	-81.5%	25,648	116,279	(90,631)	-77.9%	1.99466	2.37223	(0.37756)	-15.9%
21a. Gains on Market Based Sales	62,010	1,603,000	(1,540,990)	-96.1%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	6,749,974	12,598,800	(5,848,826)	-46.4%	271,009	457,249	(186,240)	-40.7%	2.49068	2.75535	(0.26467)	-9.6%
23. Net Inadvertant Interchange					596	0	596	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					3,643	0	3,643	0.0%				
25. Interchange and Wheeling Losses					1,443	6,700	(5,257)	-78.5%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	235,376,570	238,987,695	(3,611,125)	-1.5%	9,177,707	9,168,804	8,903	0.1%	2.56466	2.60653	(0.04188)	-1.6%
27. Net Unbilled	2,724,023 (a)	3,048,257 (a)	(324,234)	-10.6%	75,115	123,951	(48,836)	-39.4%	3.62647	2.45924	1.16723	47.5%
28. Company Use	592,026 (a)	640,911 (a)	(48,885)	-7.6%	23,190	24,600	(1,410)	-5.7%	2.55294	2.60533	(0.05239)	-2.0%
29. T & D Losses	10,445,406 (a)	(3,462) (a)	10,448,868	-301815.9%	403,853	(6,433)	410,286	-6377.8%	2.58644	0.05382	2.53262	4706.1%
30. System KWH Sales	235,376,570	238,987,695	(3,611,125)	-1.5%	8,675,549	9,026,686	(351,137)	-3.9%	2.71310	2.64757	0.06553	2.5%
31. Wholesale KWH Sales	(6,041,743)	(16,649,507)	10,607,764	-63.7%	(213,408)	(625,926)	412,518	-65.9%	2.83108	2.65998	0.17110	6.4%
32. Jurisdictional KWH Sales	229,334,827	222,338,188	6,996,639	3.1%	8,462,141	8,400,760	61,381	0.7%	2.71013	2.64664	0.06348	2.4%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	229,486,188	222,484,931	7,001,257	3.1%	8,462,141	8,400,760	61,381	0.7%	2.71192	2.64839	0.06353	2.4%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	1,808,944	1,724,513	84,431	4.9%	8,462,141	8,400,760	61,381	0.7%	0.02138	0.02053	0.00085	4.1%
35a. Adjustment	0	0	0	0.0%	8,462,141	8,400,760	61,381	0.7%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	8,462,141	8,400,760	61,381	0.7%	0.00000	0.00000	0.00000	0.0%
36. True-up *	44,336,370	44,336,370	0	0.0%	8,462,141	8,400,760	61,381	0.7%	0.52394	0.52777	(0.00383)	-0.7%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	275,631,502	268,545,814	7,085,688	2.6%	8,462,141	8,400,760	61,381	0.7%	3.25723	3.19668	0.06055	1.9%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.25958	3.19899	0.06059	1.9%
40. GPIF * (Already Adjusted for Taxes)	547,476	547,476	0	0.0%	8,462,141	8,400,760	61,381	0.7%	0.00647	0.00652	(0.00005)	-0.7%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	276,178,978	269,093,290	7,085,688	2.6%	8,462,141	8,400,760	61,381	0.7%	3.26605	3.20551	0.06054	1.9%
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.266	3.206	0.060	1.9%

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CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	33,085,162	38,316,729	(5,231,567)	-13.7%	174,845,335	185,664,295	(10,818,960)	-5.8%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	1,264,280	1,640,400	(376,120)	-22.9%	6,687,964	10,995,800	(4,307,836)	-39.2%
2a. GAINS FROM MARKET BASED SALES	484	463,400	(462,916)	-99.9%	62,010	1,603,000	(1,540,990)	-96.1%
3. FUEL COST OF PURCHASED POWER	11,531,754	12,912,400	(1,380,646)	-10.7%	61,894,066	60,819,900	1,074,166	1.8%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	921,364	977,900	(56,536)	-5.8%	5,428,883	5,126,300	302,583	5.9%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	44,273,516	50,103,229	(5,829,713)	-11.6%	235,418,310	239,011,695	(3,593,385)	-1.5%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(7,655)	(4,000)	(3,655)	91.4%	(33,819)	(24,000)	(9,819)	40.9%
6b. ADJ.TO FUEL COST	(2,444)	0	(2,444)	0.0%	(7,921)	0	(7,921)	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	44,263,417	50,099,229	(5,835,812)	-11.6%	235,376,570	238,987,695	(3,611,125)	-1.5%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,604,889	1,637,201	(32,312)	-2.0%	8,462,141	8,400,760	61,381	0.7%
2. NONJURISDICTIONAL SALES	46,534	118,487	(71,953)	-60.7%	213,408	625,926	(412,518)	-65.9%
3. TOTAL SALES	1,651,423	1,755,688	(104,265)	-5.9%	8,675,549	9,026,686	(351,137)	-3.9%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9716219	0.9325125	0.0393094	4.2%	0.9754012	0.9306583	0.0447429	4.8%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: JUNE 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	53,016,439	53,998,121	(981,682)	-1.8%	277,336,074	276,892,637	443,437	0.2%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(7,389,395)	(7,389,395)	0	0.0%	(44,336,370)	(44,336,370)	0	0.0%
2b. INCENTIVE PROVISION	(91,246)	(91,246)	0	0.0%	(547,476)	(547,476)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	45,535,798	46,517,480	(981,682)	-2.1%	232,452,228	232,008,791	443,437	0.2%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	44,263,417	50,099,229	(5,835,812)	-11.6%	235,376,570	238,987,695	(3,611,125)	-1.5%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9718219	0.9325125	0.0393094	4.2%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	43,016,158	46,718,157	(3,701,999)	-7.9%	229,334,827	222,338,188	6,996,639	3.1%
6a. JURISDIC. LOSS MULTIPLIER	1.00066	1.00066	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	43,044,549	46,748,991	(3,704,442)	-7.9%	229,486,188	222,484,931	7,001,257	3.1%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	302,568	302,568	0	0.0%	1,853,373	1,853,373	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	294,042	282,148	11,894	4.2%	1,808,944	1,724,513	84,431	4.9%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	43,338,591	47,031,139	(3,692,548)	-7.9%	231,295,132	224,209,444	7,085,688	3.2%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	2,197,207	(513,659)	2,710,866	-527.8%	1,157,096	7,799,347	(6,642,251)	-85.2%
8. INTEREST PROVISION FOR THE MONTH	(84,553)	(136,710)	52,157	-38.2%	(646,606)	(1,216,005)	569,399	-46.8%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(62,312,084)	(44,492,049)	(17,820,035)	40.1%	----------NOT APPLICABLE----------			
10. TRUE-UP COLLECTED (REFUNDED)	7,389,395	7,389,395	0	0.0%	----------NOT APPLICABLE----------			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(52,810,035)	(37,753,023)	(15,057,012)	39.9%	----------NOT APPLICABLE----------			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: JUNE 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(62,312,084)	(44,492,049)	(17,820,035)	40.1%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(52,725,482)	(37,616,313)	(15,109,169)	40.2%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(115,037,566)	(82,108,362)	(32,929,204)	40.1%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(57,518,783)	(41,054,181)	(16,464,602)	40.1%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.770	4.000	(2)	-55.8%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.750	4.000	(2)	-56.3%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	3.520	8.000	(4)	-56.0%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.760	4.000	(2)	-56.0%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.147	0.333	(0)	-55.9%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(84,553)	(136,710)	52,157	-38.2%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	308,679	527,624	(218,945)	-41.5%	1,606,620	1,985,524	(378,904)	-19.1%
2	LIGHT OIL	1,050,206	1,827,418	(777,212)	-42.5%	6,993,742	7,392,084	(398,342)	-5.4%
3	COAL	28,198,973	31,017,189	(2,818,216)	-9.1%	154,726,686	163,328,327	(8,601,641)	-5.3%
4	NATURAL GAS	3,527,304	4,944,498	(1,417,194)	-28.7%	11,518,287	12,958,360	(1,440,073)	-11.1%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	33,085,162	38,316,729	(5,231,567)	-13.7%	174,845,335	185,664,295	(10,818,960)	-5.8%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	6,210	12,491	(6,281)	-50.3%	31,246	44,288	(13,042)	-29.4%
9	LIGHT OIL	21,946	25,010	(3,064)	-12.3%	139,290	109,709	29,581	27.0%
10	COAL	1,329,168	1,481,058	(151,890)	-10.3%	7,436,571	7,870,296	(433,725)	-5.5%
11	NATURAL GAS	60,134	89,093	(28,959)	-32.5%	200,791	246,218	(45,427)	-18.4%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,417,458	1,607,652	(190,194)	-11.8%	7,807,898	8,270,511	(462,613)	-5.6%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	10,034	18,613	(8,579)	-46.1%	50,524	65,955	(15,431)	-23.4%
16	LIGHT OIL (BBL)	33,612	57,069	(23,457)	-41.1%	233,795	219,756	14,039	6.4%
17	COAL (TON)	624,640	661,694	(37,054)	-5.6%	3,502,337	3,497,430	4,907	0.1%
18	NATURAL GAS (MCF)	640,296	911,496	(271,200)	-29.8%	2,158,437	2,506,281	(347,844)	-13.9%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	62,953	116,867	(53,914)	-46.1%	316,971	414,120	(97,149)	-23.5%
22	LIGHT OIL	195,578	325,999	(130,421)	-40.0%	1,348,839	1,245,157	103,682	8.3%
23	COAL	14,571,119	15,557,662	(986,543)	-6.3%	81,722,548	81,970,909	(248,361)	-0.3%
24	NATURAL GAS	671,670	937,026	(265,356)	-28.3%	2,267,698	2,576,577	(308,879)	-12.0%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	15,501,321	16,937,554	(1,436,233)	-8.5%	85,656,056	86,206,763	(550,708)	-0.6%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.44%	0.78%	(0.00)	-	0.40%	0.54%	(0.00)	-
29	LIGHT OIL	1.55%	1.56%	(0.00)	-	1.78%	1.33%	0.00	-
30	COAL	93.77%	92.13%	0.02	-	95.24%	95.16%	0.00	-
31	NATURAL GAS	4.24%	5.54%	(0.01)	-	2.57%	2.98%	(0.00)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	30.76	28.35	2.42	8.5%	31.80	30.10	1.69	5.6%
36	LIGHT OIL ($/BBL)	31.24	32.02	(0.78)	-2.4%	29.91	33.64	(3.72)	-11.1%
37	COAL ($/TON)	45.14	46.88	(1.73)	-3.7%	44.18	46.70	(2.52)	-5.4%
38	NATURAL GAS ($/MCF)	5.51	5.42	0.08	1.6%	5.34	5.17	0.17	3.2%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	4.90	4.51	0.39	8.6%	5.07	4.79	0.27	5.7%
42	LIGHT OIL	5.37	5.61	(0.24)	-4.2%	5.19	5.94	(0.75)	-12.7%
43	COAL	1.94	1.99	(0.06)	-2.9%	1.89	1.99	(0.10)	-5.0%
44	NATURAL GAS	5.25	5.28	(0.03)	-0.5%	5.08	5.03	0.05	1.0%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.13	2.26	(0.13)	-5.7%	2.04	2.15	(0.11)	-5.2%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	10,137	9,356	781	8.3%	10,144	9,351	793	8.5%
49	LIGHT OIL	8,912	13,035	(4,123)	-31.6%	9,684	11,350	(1,666)	-14.7%
50	COAL	10,963	10,504	459	4.4%	10,989	10,415	574	5.5%
51	NATURAL GAS	11,170	10,517	653	6.2%	11,294	10,465	829	7.9%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	10,936	10,536	400	3.8%	10,970	10,423	547	5.2%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	4.97	4.22	0.75	17.8%	5.14	4.48	0.66	14.7%
56	LIGHT OIL	4.79	7.31	(2.52)	-34.5%	5.02	6.74	(1.72)	-25.5%
57	COAL	2.12	2.09	0.03	1.4%	2.08	2.08	0.00	0.0%
58	NATURAL GAS	5.87	5.55	0.32	5.8%	5.74	5.26	0.48	9.1%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.33	2.38	(0.05)	-2.1%	2.24	2.24	0.00	0.0%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: JUNE 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	0	(175)	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**(175)**	—	—	—	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	42,306	51.5	70.8	69.0	11,437	COAL	20,366	23,758,000	483,855.4	854,508	2.02	41.96
GAN.#2	98	41,350	58.6	68.5	93.1	11,661	COAL	20,059	24,038,000	482,178.2	841,627	2.04	41.96
GAN.#3	145	17,829	17.1	21.6	78.8	12,697	COAL	12,372	18,298,000	226,382.9	519,099	2.91	41.96
GAN.#4	159	67,869	59.3	73.3	75.6	12,907	COAL	43,919	19,946,000	876,008.4	1,842,736	2.72	41.96
GAN.#5	217	110,417	70.7	81.5	85.6	10,272	COAL	47,836	23,710,000	1,134,191.6	2,007,084	1.82	41.96
GAN.#6	372	171,501	64.0	75.6	81.5	10,342	COAL	74,445	23,824,000	1,773,577.7	3,123,533	1.82	41.96
GANNON STATION	**1,105**	**451,272**	**56.7**	**68.2**	**79.7**	**11,027**	**COAL**	**218,997**	**22,722,659**	**4,976,194.2**	**9,168,587**	**2.04**	**41.96**
B.B.#1	416	164,010	54.8	63.8	70.2	10,936	COAL	75,140	23,870,040	1,793,594.8	3,356,650	2.05	44.67
B.B.#2	416	166,592	63.0	69.2	66.4	11,157	COAL	88,412	23,799,940	2,104,202.9	3,949,537	2.09	44.67
B.B.#3	433	137,274	44.0	51.1	75.3	10,467	COAL	59,195	24,272,520	1,436,807.7	2,644,356	1.93	44.67
B.B. 1 - 3	1,265	489,876	53.8	61.2	70.7	10,890	COAL	222,747	23,949,175	5,334,605.4	9,950,543	2.03	44.67
B.B.#4	442	254,361	79.9	90.8	79.9	10,466	COAL	123,663	21,527,900	2,662,206.2	6,875,514	2.70	55.60
B.B. STATION	**1,707**	**744,237**	**60.6**	**68.9**	**73.1**	**10,745**	**COAL**	**346,410**	**23,084,817**	**7,996,811.6**	**16,826,057**	**2.26**	**48.57**
SEB-PHIL. #1(HVY OIL)	17	1,785	14.6	53.1	71.1	9,860	HVY.OIL	2,805	6,273,540	17,599.3	86,291	4.83	30.76
SEB-PHIL. #2(HVY OIL)	17	4,600	37.6	96.5	82.9	9,860	HVY.OIL	7,229	6,273,540	45,353.9	222,388	4.83	30.76
SEB-PHILLIPS TOTAL	**34**	**6,385**	**26.1**	**74.8**	**77.0**	**9,860**	**HVY.OIL**	**10,034**	**6,273,540**	**62,953.2**	**308,679**	**4.83**	**30.76**
POLK #1 GASIFIER	250	133,659	74.3	84.2	81.2	11,957	COAL	59,233	26,980,000	1,598,113.4	2,184,329	1.63	36.88
POLK #1 CT (OIL)	225	17,456	10.8	99.3	120.2	7,654	LGT.OIL	22,928	5,827,534	133,612.3	722,948	4.14	31.53
POLK #1 TOTAL	**250**	**151,115**	**84.0**	**91.2**	**84.4**	**11,460**	**-**	**-**	**-**	**1,731,725.7**	**2,907,277**	**1.92**	**-**
POLK #2 CT (GAS)	150	21,565	20.0	98.8	77.6	11,425	GAS	234,876	972,290	246,385.0	1,257,177	5.83	5.35
POLK #2 CT (OIL)	160	2,787	2.4	98.8	79.2	11,700	LGT.OIL	5,595	5,827,528	32,607.0	176,430	6.33	31.53
POLK #2 TOTAL	**155**	**24,352**	**21.8**	**98.8**	**77.7**	**11,457**	**-**	**-**	**-**	**278,992.0**	**1,433,607**	**5.89**	**-**
POLK #3 CT (GAS)	150	36,541	33.8	98.7	77.6	11,070	GAS	385,597	972,290	404,491.0	2,142,690	5.86	5.56
POLK #3 CT (OIL)	160	1	0.0	98.7	1.2	399,600	LGT.OIL	69	5,827,621	399.6	2,162	216.20	31.33
POLK #3 TOTAL	**155**	**36,542**	**32.7**	**98.8**	**77.4**	**11,080**	**-**	**-**	**-**	**404,890.6**	**2,144,852**	**5.87**	**-**
POLK STATION TOTAL	**560**	**212,009**	**52.6**	**95.4**	**58.5**	**11,394**	**-**	**-**	**-**	**2,415,608.3**	**6,485,736**	**3.06**	**-**
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	21	0.2	100.0	87.5	18,238	LGT.OIL	66	5,828,641	383.0	1,955	9.31	29.62
B.B.C.T.#2	66	1,681	3.5	97.9	65.3	17,000	LGT.OIL	4,879	5,856,684	28,576.4	144,490	8.60	29.61
B.B.C.T.#3	66	0	0.0	7.6	0.0	0	LGT.OIL	75	0	0.0	2,221	0.00	29.61
C.T. TOTAL	**144**	**1,702**	**1.6**	**56.7**	**37.2**	**17,015**	**LGT.OIL**	**5,020**	**5,768,816**	**28,959.4**	**148,666**	**8.73**	**29.61**
CITY OF TAMPA	**6**	**2,028**	**0.0**	**0.0**	**0.0**	**10,254**	**GAS**	**19,823**	**972,290**	**20,794.3**	**127,437**	**6.28**	**6.43**
TOT. COAL (GN,BB,POLK)	**3,062**	**1,329,168**	**60.3**	**69.9**	**76.1**	**10,963**	**COAL**	**624,640**	**23,327,217**	**14,571,119.2**	**28,198,973**	**2.12**	**45.14**
SYSTEM	**3,556**	**1,417,458**	**55.5**	**72.4**	**71.4**	**10,935**	**-**	**-**	**-**	**15,501,321.0**	**33,085,162**	**2.33**	**-**

* Hookers Point boiler limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	14,248	18,613	(4,365)	-23.5%	45,258	65,955	(20,697)	-31.4%
3 UNIT COST ($/BBL)	32.70	26.69	6.01	22.5%	27.53	29.23	(1.70)	-5.8%
4 AMOUNT ($)	465,942	496,788	(30,846)	-6.2%	1,245,882	1,928,057	(682,175)	-35.4%
5 BURNED:								
6 UNITS (BBL)	10,034	18,613	(8,579)	-46.1%	50,524	65,955	(15,431)	-23.4%
7 UNIT COST ($/BBL)	30.76	28.35	2.42	8.5%	31.80	30.10	1.69	5.6%
8 AMOUNT ($)	308,679	527,624	(218,945)	-41.5%	1,606,620	1,985,524	(378,904)	-19.1%
9 ENDING INVENTORY:								
10 UNITS (BBL)	12,383	59,129	(46,746)	-79.1%	12,383	59,129	(46,746)	-79.1%
11 UNIT COST ($/BBL)	32.69	26.20	6.49	24.8%	32.69	26.20	6.49	24.8%
12 AMOUNT ($)	404,747	1,549,169	(1,144,422)	-73.9%	404,747	1,549,169	(1,144,422)	-73.9%
13								
14 DAYS SUPPLY:	16	77	(61)	-79.1%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	47,359	68,218	(20,859)	-30.6%	283,476	277,120	6,356	2.3%
17 UNIT COST ($/BBL)	29.72	30.29	(0.57)	-1.9%	29.80	32.78	(2.99)	-9.1%
18 AMOUNT ($)	1,407,577	2,066,664	(659,087)	-31.9%	8,447,048	9,085,351	(638,303)	-7.0%
19 BURNED:								
20 UNITS (BBL)	33,612	57,069	(23,457)	-41.1%	233,795	219,756	14,039	6.4%
21 UNIT COST ($/BBL)	31.24	32.02	(0.78)	-2.4%	29.91	33.64	(3.72)	-11.1%
22 AMOUNT ($)	1,050,206	1,827,418	(777,212)	-42.5%	6,993,742	7,392,084	(398,342)	-5.4%
23 ENDING INVENTORY:								
24 UNITS (BBL)	109,171	113,465	(4,294)	-3.8%	109,171	113,465	(4,294)	-3.8%
25 UNIT COST ($/BBL)	30.29	32.20	(1.91)	-5.9%	30.29	32.20	(1.91)	-5.9%
26 AMOUNT ($)	3,307,250	3,653,645	(346,395)	-9.5%	3,307,250	3,653,645	(346,395)	-9.5%
27								
28 DAYS SUPPLY: NORMAL	48	50	(2)	-3.3%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	16	16	(0)	-2.5%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	653,479	663,000	(9,521)	-1.4%	3,862,678	3,875,000	(12,322)	-0.3%
32 UNIT COST ($/TON)	45.39	45.88	(0.49)	-1.1%	44.52	46.62	(2.11)	-4.5%
33 AMOUNT ($)	29,662,004	30,419,414	(757,410)	-2.5%	171,949,227	180,665,827	(8,716,600)	-4.8%
34 BURNED:								
35 UNITS (TONS)	624,640	661,694	(37,054)	-5.6%	3,502,337	3,497,430	4,907	0.1%
36 UNIT COST ($/TON)	45.14	46.88	(1.73)	-3.7%	44.18	46.70	(2.52)	-5.4%
37 AMOUNT ($)	28,198,973	31,017,189	(2,818,216)	-9.1%	154,726,686	163,328,327	(8,601,641)	-5.3%
38 ENDING INVENTORY:								
39 UNITS (TONS)	985,821	1,354,390	(368,569)	-27.2%	985,821	1,354,390	(368,569)	-27.2%
40 UNIT COST ($/TON)	44.28	47.02	(2.74)	-5.8%	44.28	47.02	(2.74)	-5.8%
41 AMOUNT ($)	43,652,733	63,684,908	(20,032,175)	-31.5%	43,652,733	63,684,908	(20,032,175)	-31.5%
42								
43 DAYS SUPPLY:	45	61	(16)	-26.8%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	640,296	911,496	(271,200)	-29.8%	2,158,437	2,506,281	(347,844)	-13.9%
46 UNIT COST ($/MCF)	5.51	5.42	0.08	1.6%	5.34	5.17	0.17	3.2%
47 AMOUNT ($)	3,527,304	4,944,497	(1,417,193)	-28.7%	11,517,314	12,958,358	(1,441,044)	-11.1%
48 BURNED:								
49 UNITS (MCF)	640,296	911,496	(271,200)	-29.8%	2,158,437	2,506,281	(347,844)	-13.9%
50 UNIT COST ($/MCF)	5.51	5.42	0.08	1.6%	5.34	5.17	0.17	3.2%
51 AMOUNT ($)	3,527,304	4,944,498	(1,417,194)	-28.7%	11,518,287	12,958,360	(1,440,073)	-11.1%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%				

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	11,254
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	11,254

(2) RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(7,808)	(231,313)
OTHER USAGE	(416)	(12,346)
TOTAL	(8,224)	(243,659)

(3) RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	19,142
IGNITION #2 OIL	220,059
IGNITION PROPANE	2,228
AERIAL SURVEY ADJ.	0
ADDITIVES	83,793
GREEN FUEL	0
TOTAL	325,222

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2002

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. -D	6,176.0	0.0	6,176.0	1.501	1.501	92,700.00	92,700.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	36,540.0	0.0	36,540.0	2.612	3.660	954,500.00	1,337,400.00	
VARIOUS	JURISDIC.	SCH. -MB	25,608.0	0.0	25,608.0	2.316	2.316	593,200.00	593,200.00	463,400.0
TOTAL			68,324.0	0.0	68,324.0	2.401	2.961	1,640,400.00	2,023,300.00	463,400.00
ACTUAL:										
FLA. PWR. & LIGHT	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR PARTNERS	SEP. CONTR.	SCH. -D	43,380.0	0.0	43,380.0	2.556	3.341	1,108,792.80	1,449,325.80	
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. -D	5,503.7	464.2	5,039.5	2.724	2.724	137,298.41	137,298.41	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. -D	847.5	0.0	847.5	1.898	1.898	16,084.22	16,084.22	
FLA. PWR. CORP.		SCH. -MA		0.0	0.0	0.000	0.000			
FLA. PWR. & LIGHT		SCH. -MA	825.0	0.0	825.0	2.114	2.487	17,441.01	20,515.52	484.01
ORLANDO UTILITIES COMMISSION		SCH. -MA		0.0	0.0	0.000	0.000			
DUKE ENERGY		SCH. -MA		0.0	0.0	0.000	0.000			
THE ENERGY AUTHORITY		SCH. -MA		0.0	0.0	0.000	0.000			
CITY OF LAKE WORTH		SCH. -MA		0.0	0.0	0.000	0.000			
CARGILL ALLIANT		SCH. -MA		0.0	0.0	0.000	0.000			
AUBURNDALE POWER PARTNERS		SCH. -OATT	1,183.0	0.0	1,183.0	(1.814)	(1.814)	(21,464.81)	(21,464.81)	
CARGILL ALLIANT		SCH. -OATT	54.0	0.0	54.0	3.463	3.463	1,870.04	1,870.04	
ADJUSTMENTS TO PREV. MONTHS										
HARDEE PWR PARTNERS EST.	May 2002	CONTRACT	(48,470.0)	0.0	(48,470.0)	2.546	3.332	(1,234,046.20)	(1,615,020.40)	
HARDEE PWR PARTNERS ACT.	May 2002	CONTRACT	48,470.0	0.0	48,470.0	2.556	3.341	1,238,893.20	1,619,382.70	
SEMINOLE ELEC. PRECO-1	May 2002	SCH. -D	(5,707.8)	(201.4)	(5,506.4)	2.603	2.603	(143,320.42)	(143,320.42)	
SEMINOLE ELEC. PRECO-1	May 2002	SCH. -D	5,707.8	212.7	5,495.1	2.608	2.608	143,320.42	143,320.42	
SEMINOLE ELEC. PRECO-1	April 2002	SCH. -D	(4,400.3)	(1,468.8)	(2,931.5)	3.429	3.429	(100,520.97)	(100,520.97)	
SEMINOLE ELEC. PRECO-1	April 2002	SCH. -D	4,400.3	1,470.5	2,929.8	3.431	3.431	100,520.97	100,520.97	
AUBURNDALE POWER PARTNERS	May 2002	SCH. -OATT	(101.0)	0.0	(101.0)	0.726	0.726	(733.55)	(733.55)	
AUBURNDALE POWER PARTNERS	May 2002	SCH. -OATT	93.0	0.0	93.0	0.155	0.155	144.51	144.51	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISDICTIONAL			6,351.2	477.2	5,874.0	2.611	2.611	153,382.63	153,382.63	
SUB-TOTAL SCHEDULE D POWER SALES-SEPARATED			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEP.			43,380.0	0.0	43,380.0	2.567	3.351	1,113,639.80	1,453,688.10	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISDICTIONAL			825.0	0.0	825.0	2.114	2.487	17,441.01	20,515.52	484.01
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD			1,229.0	0.0	1,229.0	(1.642)	(1.642)	(20,183.81)	(20,183.81)	
TOTAL			51,785.2	477.2	51,308.0	2.464	3.133	1,264,279.63	1,607,402.44	484.01
CURRENT MONTH:										
DIFFERENCE			(16,538.8)	477.2	(17,016.0)	0.063	0.172	(376,120.37)	(415,897.56)	(462,915.99)
DIFFERENCE %			-24.2%	0.0%	-24.9%	2.6%	5.8%	-22.9%	-20.6%	-99.9%
PERIOD TO DATE:										
ACTUAL			273,396.7	2,387.6	271,009.1	2.468	3.144	6,687,963.78	8,521,242.27	62,011.10
ESTIMATED			457,249.0	0.0	457,249.0	2.405	3.102	10,995,800.00	14,185,200.00	1,603,000.00
DIFFERENCE			(183,852.3)	2,387.6	(186,239.9)	0.063	0.042	(4,307,836.22)	(5,663,957.73)	(1,540,988.90)
DIFFERENCE %			-40.2%	0.0%	-40.7%	2.6%	1.4%	-39.2%	-39.9%	-96.1%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF JUNE 2002.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH.-J	30,899.0	0.0	17,460.0	13,439.0	7.186	7.186	965,700.00
HARDEE POWER PARTNERS		IPP	113,091.0	0.0	0.0	113,091.0	4.409	4.409	4,986,300.00
VARIOUS		OTHER	31,036.0	0.0	0.0	31,036.0	6.313	6.313	1,959,300.00
VARIOUS		MKT. BASE	71,495.0	0.0	0.0	71,495.0	6.995	6.995	5,001,100.00
TOTAL			246,521.0	0.0	17,460.0	229,061.0	5.637	5.637	12,912,400.00
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	95,337.0	0.0	0.0	95,337.0	2.450	2.450	2,336,003.93
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH.-J	27,815.0	0.0	1,822.8	25,992.2	3.704	3.704	962,835.27
FLA. POWER & LIGHT		SCH.-J *	41,760.0	0.0	15,725.0	26,035.0	4.471	4.471	1,164,050.19
CITY OF LAKELAND		SCH.-J *	13,185.0	0.0	1,146.7	12,038.3	4.663	4.663	561,321.62
ORLANDO UTIL. COMM.		SCH.-J *	6,600.0	0.0	287.5	6,312.5	4.956	4.956	312,841.57
THE ENERGY AUTHORITY		SCH.-J *	6,390.0	0.0	645.0	5,745.0	4.011	4.011	230,439.62
REEDY CREEK		SCH.-J	180.0	0.0	0.0	180.0	3.933	3.933	7,080.00
OKEELANTA		SCH.-J	3,327.0	0.0	27.0	3,300.0	4.450	4.450	146,841.63
TALLAHASSEE		SCH.-J	226.0	0.0	0.0	226.0	2.843	2.843	6,426.00
AQUILA		SCH.-J	39,431.0	0.0	50.8	39,380.2	4.855	4.855	1,911,735.44
CARGILL ALLIANT		SCH.-J	14,165.0	0.0	1,236.1	12,928.9	3.735	3.735	482,954.63
CALPINE/AUBURNDALE PWR PART		SCH.-J	2,688.0	0.0	0.0	2,688.0	0.184	0.184	4,948.00
RELIANT		SCH.-J	14,679.0	0.0	2,624.8	12,054.2	4.599	4.599	554,416.02
DUKE ENERGY		SCH.-J *	9,864.0	0.0	1,172.5	8,691.5	3.391	3.391	294,690.82
DYNEGY POWER MARKETING		SCH.-J	3,139.0	0.0	1,284.6	1,854.4	4.741	4.741	87,915.43
RINGHAVER		SCH.-J	3,118.0	0.0	0.0	3,118.0	0.505	0.505	15,745.75
FLA. POWER CORP.		SCH.-D	64,200.0	0.0	0.0	64,200.0	3.525	3.525	2,262,882.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	May 2002	IPP	(72,928.0)	0.0	0.0	(72,928.0)	3.841	3.841	(2,801,390.70)
HARDEE PWR. PART.-NATIVE	May 2002	IPP	72,928.0	0.0	0.0	72,928.0	3.853	3.853	2,809,616.93
FLA. POWER CORP.	May 2002	SCH.-D	(64,050.0)	0.0	0.0	(64,050.0)	3.186	3.186	(2,040,883.50)
FLA. POWER CORP.	May 2002	SCH.-D	64,050.0	0.0	0.0	64,050.0	3.525	3.525	2,258,013.00
FLA. POWER & LIGHT	May 2002	SCH.-J	(4,190.0)	0.0	(595.0)	(3,595.0)	5.569	5.569	(200,194.60)
FLA. POWER & LIGHT	May 2002	SCH.-J *	6,590.0	0.0	2,995.0	3,595.0	4.194	4.194	150,761.35
THE ENERGY AUTH.	May 2002	SCH.-J	(8,035.0)	0.0	(2,065.8)	(5,969.2)	5.502	5.502	(328,408.28)
THE ENERGY AUTH.	May 2002	SCH.-J *	8,035.0	0.0	1,988.5	6,046.5	5.520	5.520	333,770.36
THE ENERGY AUTH.	Apr 2002	SCH.-J	(27,079.0)	0.0	(7,810.3)	(19,268.7)	5.353	5.353	(1,031,384.81)
THE ENERGY AUTH.	Apr 2002	SCH.-J *	27,079.0	0.0	7,810.3	19,268.7	5.354	5.354	1,031,595.81
CALPINE	May 2002	SCH.-J	(335.0)	0.0	0.0	(335.0)	4.355	4.355	(14,590.00)
CALPINE/AUBURNDALE PWR PART	May 2002	SCH.-J	1,074.0	0.0	0.0	1,074.0	1.358	1.358	14,590.00
CITY OF LAKELAND	May 2002	SCH.-J	(6,385.0)	0.0	(1,052.1)	(5,332.9)	6.935	6.935	(369,825.77)
CITY OF LAKELAND	May 2002	SCH.-J *	6,385.0	0.0	988.6	5,396.4	6.935	6.935	374,238.00
ORLANDO UTIL. COMM.	May 2002	SCH.-J	(17,050.0)	0.0	(1,656.5)	(15,393.5)	7.392	7.392	(1,137,833.29)
ORLANDO UTIL. COMM.	May 2002	SCH.-J *	17,050.0	0.0	1,627.5	15,422.5	7.390	7.390	1,139,715.91
DUKE ENERGY	May 2002	SCH.-J	(7,562.0)	0.0	(797.0)	(6,765.0)	5.399	5.399	(365,220.28)
DUKE ENERGY	May 2002	SCH.-J *	7,562.0	0.0	786.0	6,776.0	5.402	5.402	366,042.50
DUKE ENERGY	April 2002	SCH.-J	(31,945.0)	0.0	(5,643.0)	(26,302.0)	5.781	5.781	(1,520,403.35)
DUKE ENERGY	April 2002	SCH.-J *	31,945.0	0.0	5,646.8	26,298.2	5.781	5.781	1,520,396.97
TOTAL			349,243.0	0.0	28,245.8	320,997.2	3.592	3.592	11,531,754.17
CURRENT MONTH:									
DIFFERENCE			102,722.0	0.0	10,785.8	91,936.2	(2.045)	(2.045)	(1,380,645.83)
DIFFERENCE %			41.7%	0.0%	61.8%	40.1%	-36.3%	-36.3%	-10.7%
PERIOD TO DATE:									
ACTUAL			1,504,610.0	0.0	106,742.1	1,397,868.0	4.428	4.428	61,894,066.22
ESTIMATED			1,169,764.0	0.0	40,963.0	1,128,801.0	5.388	5.388	60,819,900.00
DIFFERENCE			334,846.0	0.0	65,779.1	269,067.0	(0.960)	(0.960)	1,074,166.22
DIFFERENCE %			28.6%	0.0%	160.6%	23.8%	-17.8%	-17.8%	1.8%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	39,704.0	0.0	0.0	39,704.0	2.463	2.463	977,900.00
TOTAL			39,704.0	0.0	0.0	39,704.0	2.463	2.463	977,900.00
ACTUAL:									
IMC-AGRICO-NICHOLS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.0
McKAY BAY REFUSE		COGEN.	12,661.0	0.0	0.0	12,661.0	2.263	2.263	286,480.5
MULBERRY PHOSPHATES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.0
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.0
IMC-AGRICO-NEW WALES		COGEN.	27.0	0.0	0.0	27.0	2.318	2.318	626.0
HILLSBOROUGH COUNTY		COGEN.	16,605.0	0.0	0.0	16,605.0	2.261	2.261	375,388.2
CARGILL MILLPOINT		COGEN.	27.0	0.0	0.0	27.0	3.301	3.301	891.3
CF INDUSTRIES INC.		COGEN.	672.0	0.0	0.0	672.0	3.630	3.630	24,390.9
FARMLAND HYDRO LP		COGEN.	1,934.0	0.0	0.0	1,934.0	3.389	3.389	65,548.9
IMC-AGRICO-S. PIERCE		COGEN.	928.0	0.0	0.0	928.0	4.159	4.159	38,591.3
AUBURNDALE POWER PARTNERS		COGEN.	3,828.0	0.0	0.0	3,828.0	4.053	4.053	155,148.1
ORANGE COGENERATION L.P.		COGEN.	7,199.0	0.0	0.0	7,199.0	2.265	2.265	163,037.6
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.0
AS AVAILABLE ASSIGNMENT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.0
SUB-TOTAL FOR JUNE 2002			43,881.0	0.0	0.0	43,881.0	2.530	2.530	1,110,102.66
ADJUSTMENTS FOR THE MONTH OF:	**APRIL 2002**								
IMC-AGRICO-NICHOLS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE		COGEN.	(13,093.0)	0.0	0.0	(13,093.0)	2.268	2.268	(296,904.02)
			13,093.0	0.0	0.0	13,093.0	2.254	2.254	295,167.21
MULBERRY PHOSPHATES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
HILLSBOROUGH COUNTY		COGEN.	(18,077.0)	0.0	0.0	(18,077.0)	2.268	2.268	(409,968.79)
			18,077.0	0.0	0.0	18,077.0	2.255	2.255	407,577.88
CARGILL MILLPOINT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
FARMLAND HYDRO LP		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS		COGEN.	(3,991.0)	0.0	0.0	(3,991.0)	4.554	4.554	(181,759.15)
			0.0	0.0	0.0	0.0	0.000	0.000	(1,671.01)
ORANGE COGENERATION L.P.		COGEN.	(7,590.0)	0.0	0.0	(7,590.0)	2.175	2.175	(165,114.36)
			7,590.0	0.0	0.0	7,590.0	2.160	2.160	163,933.22
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
AS AVAILABLE ASSIGNMENT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**APRIL 2002**		(3,991.0)	0.0	0.0	(3,991.0)	4.729	4.729	(188,739.02)
GRAND TOTAL			39,890.0	0.0	0.0	39,890.0	2.310	2.310	921,363.64
CURRENT MONTH:									
DIFFERENCE			186.0	0.0	0.0	186.0	(0.153)	(0.153)	(56,536.36)
DIFFERENCE %			0.5%	0.0%	0.0%	0.5%	-6.2%	-6.2%	-5.8%
PERIOD TO DATE:									
ACTUAL			240,153.0	0.0	0.0	240,153.0	2.261	2.261	5,428,882.27
ESTIMATED			233,441.0	0.0	0.0	233,441.0	2.196	2.196	5,126,300.00
DIFFERENCE			6,712.0	0.0	0.0	6,712.0	0.065	0.065	302,582.27
DIFFERENCE %			2.9%	0.0%	0.0%	2.9%	0.029	0.029	5.9%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: JUNE 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		0.0	0.000	0.00	0.000	0.00	0.00
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

JULY 2002

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	35,796,653	40,333,515	(4,536,862)	-11.2%	1,495,563	1,670,028	(174,465)	-10.4%	2.39352	2.41514	(0.02162)	-0.9%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(8,366)	(4,000)	(4,366)	109.2%	1,495,563 (a)	1,670,028 (a)	(174,465)	-10.4%	(0.00056)	(0.00024)	(0.00032)	133.5%
4b. Adjustments to Fuel Cost (1)	(2,203)	0	(2,203)	0.0%	1,495,563 (a)	1,670,028 (a)	(174,465)	-10.4%	(0.00015)	0.00000	(0.00015)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	1,495,563 (a)	1,670,028 (a)	(174,465)	-10.4%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	35,786,084	40,329,515	(4,543,431)	-11.3%	1,495,563	1,670,028	(174,465)	-10.4%	2.39282	2.41490	(0.02208)	-0.9%
6. Fuel Cost of Purchased Power - Firm (A7)	15,946,169	15,706,300	239,869	1.5%	360,671	242,730	117,941	48.6%	4.42125	6.47069	(2.04944)	-31.7%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,066,223	1,027,800	38,423	3.7%	42,215	41,027	1,188	2.9%	2.52570	2.50518	0.02052	0.8%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	17,012,392	16,734,100	278,292	1.7%	402,886	283,757	119,129	42.0%	4.22263	5.89733	(1.67470)	-28.4%
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,898,449	1,953,785	(55,336)	-2.8%				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	156,031	88,700	67,331	75.9%	5,728	6,054	(326)	-5.4%	2.72400	1.46515	1.25886	85.9%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	902	0	902	0.0%	(2,310)	0	(2,310)	0.0%	(0.03905)	0.00000	(0.03905)	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	1,395,551	997,300	398,251	39.9%	48,220	37,758	10,462	27.7%	2.89413	2.64129	0.25284	9.6%
21. Fuel Cost of Market Base Sales (A6)	36,021	593,200	(557,179)	-93.9%	1,590	22,659	(21,069)	-93.0%	2.26547	2.61794	(0.35247)	-13.5%
21a. Gains on Market Based Sales	8,321	552,700	(544,379)	-98.5%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	1,596,826	2,231,900	(635,074)	-28.5%	53,228	66,471	(13,243)	-19.9%	2.99997	3.35770	(0.35773)	-10.7%
23. Net Inadvertant Interchange					1,147	0	1,147	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					(2,479)	0	(2,479)	0.0%				
25. Interchange and Wheeling Losses					261	1,000	(739)	-73.9%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	51,201,650	54,831,715	(3,630,065)	-6.6%	1,843,628	1,886,314	(42,686)	-2.3%	2.77722	2.90682	(0.12960)	-4.5%
27. Net Unbilled	1,877,430 (a)	1,087,179 (a)	790,251	72.7%	67,601	37,401	30,200	80.7%	2.77722	2.90682	(0.12960)	-4.5%
28. Company Use	125,253 (a)	119,180 (a)	6,073	5.1%	4,510	4,100	410	10.0%	2.77723	2.90683	(0.12960)	-4.5%
29. T & D Losses	3,376,658 (a)	376,491 (a)	3,002,167	797.4%	121,656	12,952	108,704	839.3%	2.77722	2.90682	(0.12959)	-4.5%
30. System KWH Sales	51,201,650	54,831,715	(3,630,065)	-6.6%	1,649,861	1,831,861	(182,000)	-9.9%	3.10339	2.99322	0.11017	3.7%
31. Wholesale KWH Sales	(1,487,176)	(3,664,277)	2,177,101	-59.4%	(47,921)	(122,419)	74,498	-60.9%	3.10339	2.99323	0.11017	3.7%
32. Jurisdictional KWH Sales	49,714,474	51,167,438	(1,452,964)	-2.8%	1,601,940	1,709,442	(107,502)	-6.3%	3.10339	2.99322	0.11017	3.7%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	49,747,286	51,201,209	(1,453,923)	-2.8%	1,601,940	1,709,442	(107,502)	-6.3%	3.10544	2.99520	0.11024	3.7%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	291,322	279,986	11,336	4.0%	1,601,940	1,709,442	(107,502)	-6.3%	0.01819	0.01638	0.00181	11.0%
35a. Adjustment	0	0	0	0.0%	1,601,940	1,709,442	(107,502)	-6.3%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	1,601,940	1,709,442	(107,502)	-6.3%	0.00000	0.00000	0.00000	0.0%
36. True-up *	7,389,395	7,389,395	0	0.0%	1,601,940	1,709,442	(107,502)	-6.3%	0.46128	0.43227	0.02901	6.7%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	57,428,003	58,870,590	(1,442,587)	-2.5%	1,601,940	1,709,442	(107,502)	-6.3%	3.58490	3.44385	0.14106	4.1%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.58748	3.44633	0.14115	4.1%
40. GPIF * (Already Adjusted for Taxes)	91,246	91,246	0	0.0%	1,601,940	1,709,442	(107,502)	-6.3%	0.00570	0.00534	0.00036	6.7%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	57,519,249	58,961,836	(1,442,587)	-2.4%	1,601,940	1,709,442	(107,502)	-6.3%	3.59318	3.45167	0.14151	4.1%
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.593	3.452	0.141	4.1%

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: JULY 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	210,641,988	225,997,810	(15,355,822)	-6.8%	9,303,461	9,940,539	(637,078)	-6.4%	2.26413	2.27350	(0.00937)	-0.4%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(42,185)	(28,000)	(14,185)	50.7%	9,303,461 (a)	9,940,539 (a)	(637,078)	-6.4%	(0.00045)	(0.00028)	(0.00017)	61.0%
4b. Adjustments to Fuel Cost (1)	(10,124)	0	(10,124)	0.0%	9,303,461 (a)	9,940,539 (a)	(637,078)	-6.4%	(0.00011)	0.00000	(0.00011)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	9,303,461 (a)	9,940,539 (a)	(637,078)	-6.4%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**210,589,679**	**225,969,810**	**(15,380,131)**	**-6.8%**	**9,303,461**	**9,940,539**	**(637,078)**	**-6.4%**	**2.26356**	**2.27321**	**(0.00965)**	**-0.4%**
6. Fuel Cost of Purchased Power - Firm (A7)	77,840,235	76,526,200	1,314,035	1.7%	1,758,540	1,371,531	387,009	28.2%	4.42641	5.57962	(1.15321)	-20.7%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	6,495,106	6,154,100	341,006	5.5%	282,368	274,468	7,900	2.9%	2.30023	2.24219	0.05804	2.6%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**84,335,341**	**82,680,300**	**1,655,041**	**2.0%**	**2,040,908**	**1,645,999**	**394,909**	**24.0%**	**4.13225**	**5.02311**	**(0.89086)**	**-17.7%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**11,344,369**	**11,586,538**	**(242,169)**	**-2.1%**				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	783,568	631,300	152,268	24.1%	31,025	42,698	(11,673)	-27.3%	2.52560	1.47852	1.04708	70.8%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	(6,174)	0	(6,174)	0.0%	(715)	0	(715)	0.0%	0.86350	0.00000	0.86350	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	6,951,483	8,692,100	(1,740,637)	-20.0%	266,689	342,084	(75,395)	-22.0%	2.60658	2.54093	0.06565	2.6%
21. Fuel Cost of Market Base Sales (A6)	547,612	3,351,600	(2,803,988)	-83.7%	27,238	138,938	(111,700)	-80.4%	2.01047	2.41230	(0.40183)	-16.7%
21a. Gains on Market Based Sales	70,331	2,155,700	(2,085,369)	-96.7%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	**8,346,800**	**14,830,700**	**(6,483,900)**	**-43.7%**	**324,237**	**523,720**	**(199,483)**	**-38.1%**	**2.57429**	**2.83180**	**(0.25751)**	**-9.1%**
23. Net Inadvertant Interchange					1,743	0	1,743	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					1,164	0	1,164	0.0%				
25. Interchange and Wheeling Losses					1,704	7,700	(5,996)	-77.9%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	**286,578,220**	**293,819,410**	**(7,241,190)**	**-2.5%**	**11,021,335**	**11,055,118**	**(33,783)**	**-0.3%**	**2.60021**	**2.65777**	**(0.05755)**	**-2.2%**
27. Net Unbilled	4,601,453 (a)	4,135,436 (a)	466,017	11.3%	142,716	161,352	(18,636)	-11.5%	3.22420	2.56290	0.66121	25.8%
28. Company Use	717,279 (a)	760,091 (a)	(42,812)	-5.6%	27,700	28,700	(1,000)	-3.5%	2.58945	2.64840	(0.05895)	-2.2%
29. T & D Losses	13,824,064 (a)	373,029 (a)	13,451,035	3605.9%	525,509	6,519	518,990	7961.2%	2.63060	5.72221	(3.09161)	-54.0%
30. System KWH Sales	286,578,220	293,819,410	(7,241,190)	-2.5%	10,325,410	10,858,547	(533,137)	-4.9%	2.77547	2.70588	0.06958	2.6%
31. Wholesale KWH Sales	(7,528,919)	(20,313,784)	12,784,865	-62.9%	(261,329)	(748,345)	487,016	-65.1%	2.88101	2.71449	0.16652	6.1%
32. Jurisdictional KWH Sales	279,049,301	273,505,626	5,543,675	2.0%	10,064,081	10,110,202	(46,121)	-0.5%	2.77273	2.70524	0.06748	2.5%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	279,233,474	273,686,140	5,547,334	2.0%	10,064,081	10,110,202	(46,121)	-0.5%	2.77456	2.70703	0.06753	2.5%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	2,100,266	2,004,499	95,767	4.8%	10,064,081	10,110,202	(46,121)	-0.5%	0.02087	0.01983	0.00104	5.3%
35a. Adjustment	0	0	0	0.0%	10,064,081	10,110,202	(46,121)	-0.5%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	10,064,081	10,110,202	(46,121)	-0.5%	0.00000	0.00000	0.00000	0.0%
36. True-up *	51,725,765	51,725,765	0	0.0%	10,064,081	10,110,202	(46,121)	-0.5%	0.51396	0.51162	0.00234	0.5%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	333,059,505	327,416,404	5,643,101	1.7%	10,064,081	10,110,202	(46,121)	-0.5%	3.30939	3.23848	0.07091	2.2%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.31177	3.24081	0.07096	2.2%
40. GPIF * (Already Adjusted for Taxes)	638,722	638,722	0	0.0%	10,064,081	10,110,202	(46,121)	-0.5%	0.00635	0.00632	0.00003	0.5%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**333,698,227**	**328,055,126**	**5,643,101**	**1.7%**	**10,064,081**	**10,110,202**	**(46,121)**	**-0.5%**	**3.31812**	**3.24713**	**0.07099**	**2.2%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.318	3.247	0.071	2.2%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: JULY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	35,796,653	40,333,515	(4,536,862)	-11.2%	210,641,988	225,997,810	(15,355,822)	-6.8%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	1,588,505	1,679,200	(90,695)	-5.4%	8,276,469	12,675,000	(4,398,531)	-34.7%
2a. GAINS FROM MARKET BASED SALES	8,321	552,700	(544,379)	-98.5%	70,331	2,155,700	(2,085,369)	-96.7%
3. FUEL COST OF PURCHASED POWER	15,946,169	15,706,300	239,869	1.5%	77,840,235	76,526,200	1,314,035	1.7%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,066,223	1,027,800	38,423	3.7%	6,495,106	6,154,100	341,006	5.5%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	51,212,219	54,835,715	(3,623,496)	-6.6%	286,630,529	293,847,410	(7,216,881)	-2.5%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(8,366)	(4,000)	(4,366)	109.2%	(42,185)	(28,000)	(14,185)	50.7%
6b. ADJ.TO FUEL COST	(2,203)	0	(2,203)	0.0%	(10,124)	0	(10,124)	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	51,201,650	54,831,715	(3,630,065)	-6.6%	286,578,220	293,819,410	(7,241,190)	-2.5%
3. MWH SALES								
1. JURISDICTIONAL SALES	1,601,940	1,709,442	(107,502)	-6.3%	10,064,081	10,110,202	(46,121)	-0.5%
2. NONJURISDICTIONAL SALES	47,921	122,419	(74,498)	-60.9%	261,329	748,345	(487,016)	-65.1%
3. TOTAL SALES	1,649,861	1,831,861	(182,000)	-9.9%	10,325,410	10,858,547	(533,137)	-4.9%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9709545	0.9331723	0.0377822	4.0%	0.9746907	0.9310824	0.0436083	4.7%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: JULY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	52,048,829	56,387,401	(4,338,572)	-7.7%	329,384,903	333,280,038	(3,895,135)	-1.2%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(7,389,395)	(7,389,395)	0	0.0%	(51,725,765)	(51,725,765)	0	0.0%
2b. INCENTIVE PROVISION	(91,246)	(91,246)	0	0.0%	(638,722)	(638,722)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	44,568,188	48,906,760	(4,338,572)	-8.9%	277,020,416	280,915,551	(3,895,135)	-1.4%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	51,201,650	54,831,715	(3,630,065)	-6.6%	286,578,220	293,819,410	(7,241,190)	-2.5%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9709545	0.9331723	0.0377822	4.0%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	49,714,474	51,167,438	(1,452,964)	-2.8%	279,049,301	273,505,626	5,543,675	2.0%
6a. JURISDIC. LOSS MULTIPLIER	1.00066	1.00066	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	49,747,286	51,201,209	(1,453,923)	-2.8%	279,233,474	273,686,140	5,547,334	2.0%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	300,037	300,037	0	0.0%	2,153,410	2,153,410	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	291,322	279,986	11,336	4.0%	2,100,266	2,004,499	95,767	4.8%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	50,038,608	51,481,195	(1,442,587)	-2.8%	281,333,740	275,690,639	5,643,101	2.0%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(5,470,420)	(2,574,435)	(2,895,985)	112.5%	(4,313,324)	5,224,912	(9,538,236)	-182.6%
8. INTEREST PROVISION FOR THE MONTH	(75,183)	(117,701)	42,518	-36.1%	(721,789)	(1,333,706)	611,917	-45.9%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(52,810,035)	(37,753,023)	(15,057,012)	39.9%	----------NOT APPLICABLE----------			
10. TRUE-UP COLLECTED (REFUNDED)	7,389,395	7,389,395	0	0.0%	----------NOT APPLICABLE----------			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(50,966,243)	(33,055,764)	(17,910,479)	54.2%	----------NOT APPLICABLE----------			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
). *INTEREST PROVISION*								
1. *BEGINNING TRUE-UP AMOUNT (LINE C9)*	(52,810,035)	(37,753,023)	(15,057,012)	39.9%	----------NOT APPLICABLE----------			
2. ENDING TRUE-UP AMOUNT BEFORE INT. *(LINES C7 + C9 + C10)*	(50,891,060)	(32,938,063)	(17,952,997)	54.5%	----------NOT APPLICABLE----------			
3. *TOTAL BEG. & END. TRUE-UP AMOUNT*	(103,701,095)	(70,691,086)	(33,010,009)	46.7%	----------NOT APPLICABLE----------			
4. *AVG. TRUE-UP AMOUNT - (50% OF LINE D3)*	(51,850,548)	(35,345,543)	(16,505,005)	46.7%	----------NOT APPLICABLE----------			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.750	4.000	(2)	-56.3%	----------NOT APPLICABLE----------			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.730	4.000	(2)	-56.8%	----------NOT APPLICABLE----------			
7. TOTAL (LINE D5 + LINE D6)	3.480	8.000	(5)	-56.5%	----------NOT APPLICABLE----------			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.740	4.000	(2)	-56.5%	----------NOT APPLICABLE----------			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.145	0.333	(0)	-56.5%	----------NOT APPLICABLE----------			
10. INT. PROVISION (LINE D4 x LINE D9)	(75,183)	(117,701)	42,518	-36.1%	----------NOT APPLICABLE----------			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	483,312	573,919	(90,607)	-15.8%	2,089,932	2,559,443	(469,511)	-18.3%
2	LIGHT OIL	796,460	2,229,445	(1,432,985)	-64.3%	7,790,202	9,621,529	(1,831,327)	-19.0%
3	COAL	30,719,543	32,403,497	(1,683,954)	-5.2%	185,446,229	195,731,824	(10,285,595)	-5.3%
4	NATURAL GAS	3,797,338	5,126,654	(1,329,316)	-25.9%	15,315,625	18,085,014	(2,769,389)	-15.3%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	35,796,653	40,333,515	(4,536,862)	-11.2%	210,641,988	225,997,810	(15,355,822)	-6.8%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	9,964	14,661	(4,697)	-32.0%	41,210	58,949	(17,739)	-30.1%
9	LIGHT OIL	14,783	30,411	(15,628)	-51.4%	154,073	140,120	13,953	10.0%
10	COAL	1,419,728	1,533,022	(113,294)	-7.4%	8,856,299	9,403,318	(547,019)	-5.8%
11	NATURAL GAS	51,088	91,934	(40,846)	-44.4%	251,879	338,152	(86,273)	-25.5%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,495,563	1,670,028	(174,465)	-10.4%	9,303,461	9,940,539	(637,078)	-6.4%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	15,625	21,819	(6,194)	-28.4%	66,149	87,774	(21,625)	-24.6%
16	LIGHT OIL (BBL)	25,645	71,673	(46,028)	-64.2%	259,440	291,429	(31,989)	-11.0%
17	COAL (TON)	697,552	687,447	10,105	1.5%	4,199,889	4,184,877	15,012	0.4%
18	NATURAL GAS (MCF)	546,176	940,096	(393,920)	-41.9%	2,704,613	3,446,377	(741,764)	-21.5%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	98,021	137,001	(38,980)	-28.5%	414,993	551,121	(136,128)	-24.7%
22	LIGHT OIL	149,243	410,290	(261,047)	-63.6%	1,498,082	1,655,447	(157,365)	-9.5%
23	COAL	16,154,955	16,159,698	(4,743)	0.0%	97,877,503	98,130,607	(253,104)	-0.3%
24	NATURAL GAS	577,308	966,455	(389,147)	-40.3%	2,845,006	3,543,032	(698,026)	-19.7%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	16,979,528	17,673,444	(693,916)	-3.9%	102,635,583	103,880,207	(1,244,624)	-1.2%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.67%	0.88%	(0.00)	-	0.44%	0.59%	(0.00)	-
29	LIGHT OIL	0.99%	1.82%	(0.01)	-	1.66%	1.41%	0.00	-
30	COAL	94.93%	91.80%	0.03	-	95.19%	94.60%	0.01	-
31	NATURAL GAS	3.42%	5.50%	(0.02)	-	2.71%	3.40%	(0.01)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	30.93	26.30	4.63	17.6%	31.59	29.16	2.43	8.4%
36	LIGHT OIL ($/BBL)	31.06	31.11	(0.05)	-0.2%	30.03	33.02	(2.99)	-9.1%
37	COAL ($/TON)	44.04	47.14	(3.10)	-6.6%	44.16	46.77	(2.62)	-5.6%
38	NATURAL GAS ($/MCF)	6.95	5.45	1.50	27.5%	5.66	5.25	0.42	7.9%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	4.93	4.19	0.74	17.7%	5.04	4.64	0.39	8.4%
42	LIGHT OIL	5.34	5.43	(0.10)	-1.8%	5.20	5.81	(0.61)	-10.5%
43	COAL	1.90	2.01	(0.10)	-5.2%	1.89	1.99	(0.10)	-5.0%
44	NATURAL GAS	6.58	5.30	1.27	24.0%	5.38	5.10	0.28	5.5%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.11	2.28	(0.17)	-7.6%	2.05	2.18	(0.12)	-5.7%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,836	9,345	493	5.3%	10,070	9,349	721	7.7%
49	LIGHT OIL	10,096	13,491	(3,395)	-25.2%	9,723	11,814	(2,091)	-17.7%
50	COAL	11,379	10,541	838	7.9%	11,052	10,436	616	5.9%
51	NATURAL GAS	11,300	10,512	788	7.5%	11,295	10,478	817	7.8%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	11,353	10,583	770	7.3%	11,032	10,450	582	5.6%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	4.85	3.91	0.94	24.0%	5.07	4.34	0.73	16.8%
56	LIGHT OIL	5.39	7.33	(1.94)	-26.5%	5.06	6.87	(1.81)	-26.3%
57	COAL	2.16	2.11	0.05	2.4%	2.09	2.08	0.01	0.5%
58	NATURAL GAS	7.43	5.58	1.85	33.2%	6.08	5.35	0.73	13.6%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.39	2.42	(0.03)	-1.2%	2.26	2.27	(0.01)	-0.4%

SCHEDULE A4
PAGE 1 OF 1

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY
ACTUAL FOR MONTH OF: JULY 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	0	-178	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	90	-178	---	---	---	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN.#1	114	53,279	62.8	66.0	68.5	12,972	COAL	28,926	23,894,000	691,157.8	1,214,260	2.28	41.98
GAN.#2	98	48,092	66.0	78.3	81.6	13,675	COAL	28,006	23,482,000	657,636.9	1,175,641	2.44	41.98
GAN.#3	145	83,695	77.6	73.2	77.6	12,642	COAL	56,320	19,084,000	1,074,610.9	2,364,210	2.82	41.98
GAN.#4	159	75,796	64.1	82.3	70.0	13,625	COAL	55,026	18,768,000	1,032,728.0	2,309,891	3.05	41.98
GAN.#5	217	94,688	58.6	74.1	78.5	11,648	COAL	46,481	23,728,000	1,102,901.2	1,951,187	2.06	41.98
GAN.#6	372	154,914	56.0	65.0	81.6	11,343	COAL	73,356	23,954,000	1,757,169.6	3,079,350	1.99	41.98
GANNON STATION	1,105	510,464	62.1	76.5	77.4	12,374	COAL	288,115	21,923,206	6,316,404.4	12,094,539	2.37	41.98
B.B.#1	416	218,014	70.4	80.9	77.7	10,850	COAL	96,666	24,469,160	2,365,349.0	4,215,299	1.93	43.61
B.B.#2	416	190,833	61.7	67.1	78.0	10,612	COAL	82,611	24,515,080	2,025,209.6	3,600,362	1.89	43.58
B.B.#3	433	112,095	34.8	40.0	72.6	10,606	COAL	48,211	24,660,020	1,188,876.1	2,102,691	1.88	43.61
B.B. 1 - 3	1,265	520,942	55.4	62.4	76.0	10,710	COAL	227,487	24,526,284	5,579,434.7	9,918,352	1.90	43.60
B.B.#4	442	258,189	78.5	89.3	78.7	10,602	COAL	125,167	21,868,830	2,737,261.5	6,534,767	2.53	52.21
B.B. STATION	1,707	779,131	61.3	69.4	76.7	10,674	COAL	352,654	23,583,078	8,316,696.2	16,453,119	2.11	46.66
SEB-PHIL. #1(HVY OIL)	17	5,068	40.1	99.6	90.9	9,665	HVY.OIL	7,808	6,273,540	48,981.6	241,517	4.77	30.93
SEB-PHIL. #2(HVY OIL)	17	5,074	40.1	99.6	91.1	9,665	HVY.OIL	7,817	6,273,540	49,039.6	241,795	4.77	30.93
SEB-PHILLIPS TOTAL	34	10,142	40.1	99.6	91.0	9,665	HVY.OIL	15,625	6,273,540	98,021.2	483,312	4.77	30.93
POLK #1 GASIFIER	250	130,133	70.0	74.1	83.4	11,695	COAL	56,782	26,802,000	1,521,854.8	2,171,885	1.67	38.25
POLK #1 CT (OIL)	225	10,534	6.3	99.1	70.1	8,089	LGT.OIL	14,640	5,835,965	85,205.9	461,880	4.38	31.55
POLK #1 TOTAL	250	140,667	75.6	87.7	82.2	11,425	-	-	-	1,607,060.7	2,633,765	1.87	-
POLK #2 CT (GAS)	150	20,535	18.4	99.7	78.8	12,223	GAS	237,468	972,290	251,004.0	1,945,831	9.48	8.19
POLK #2 CT (OIL)	160	1,883	1.6	99.7	70.5	13,290	LGT.OIL	4,288	5,835,974	25,026.0	135,285	7.18	31.55
POLK #2 TOTAL	155	22,418	19.4	99.7	78.0	12,313	-	-	-	276,030.0	2,081,116	9.28	-
POLK #3 CT (GAS)	150	27,467	24.6	99.8	76.5	11,131	GAS	289,256	972,290	305,743.0	1,705,983	6.21	5.90
POLK #3 CT (OIL)	160	0	0.0	99.8	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	155	27,467	23.8	99.8	76.5	11,131	-	-	-	305,743.0	1,705,983	6.21	-
POLK STATION TOTAL	560	190,552	45.7	94.4	57.6	11,487	-	-	-	2,188,833.7	6,420,864	3.37	-
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	48	0.5	100.0	100.0	18,038	LGT.OIL	149	5,827,556	865.8	4,421	9.21	29.67
B.B.C.T.#2	66	2,318	4.7	100.0	65.0	16,456	LGT.OIL	6,568	5,807,716	38,145.6	194,874	8.41	29.67
B.B.C.T.#3	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	144	2,366	2.2	54.2	38.1	16,488	LGT.OIL	6,717	5,808,155	39,011.4	199,295	8.42	29.67
CITY OF TAMPA	6	3,086	0.0	0.0	0.0	6,663	GAS	19,452	972,290	20,560.8	145,524	4.72	7.48
TOT. COAL (GN,BB,POLK)	3,062	1,419,728	62.3	72.3	77.5	11,379	COAL	697,552	23,159,512	16,154,955.4	30,719,543	2.16	44.04
SYSTEM	3,556	1,495,563	56.6	75.2	72.5	11,352	-	-	-	16,979,527.7	35,796,653	2.39	-

* Hookers Point boiler limited to 90 MW

LEGEND:
H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	20,055	21,819	(1,764)	-8.1%	65,313	87,774	(22,461)	-25.6%
3 UNIT COST ($/BBL)	28.50	24.80	3.69	14.9%	27.83	28.13	(0.31)	-1.1%
4 AMOUNT ($)	571,515	541,216	30,299	5.6%	1,817,397	2,469,273	(651,876)	-26.4%
5 BURNED:								
6 UNITS (BBL)	15,625	21,819	(6,194)	-28.4%	66,149	87,774	(21,625)	-24.6%
7 UNIT COST ($/BBL)	30.93	26.30	4.63	17.6%	31.59	29.16	2.43	8.4%
8 AMOUNT ($)	483,312	573,919	(90,607)	-15.8%	2,089,932	2,559,443	(469,511)	-18.3%
9 ENDING INVENTORY:								
10 UNITS (BBL)	16,813	59,129	(42,316)	-71.6%	16,813	59,129	(42,316)	-71.6%
11 UNIT COST ($/BBL)	30.28	25.82	4.45	17.2%	30.28	25.82	4.45	17.2%
12 AMOUNT ($)	509,041	1,526,876	(1,017,835)	-66.7%	509,041	1,526,876	(1,017,835)	-66.7%
13								
14 DAYS SUPPLY:	26	76	(50)	-65.4%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	32,640	82,857	(50,217)	-60.6%	316,116	359,977	(43,861)	-12.2%
17 UNIT COST ($/BBL)	31.38	29.96	1.42	4.8%	29.96	32.13	(2.17)	-6.8%
18 AMOUNT ($)	1,024,240	2,482,034	(1,457,794)	-58.7%	9,471,288	11,567,385	(2,096,097)	-18.1%
19 BURNED:								
20 UNITS (BBL)	25,645	71,673	(46,028)	-64.2%	259,440	291,429	(31,989)	-11.0%
21 UNIT COST ($/BBL)	31.06	31.11	(0.05)	-0.2%	30.03	33.02	(2.99)	-9.1%
22 AMOUNT ($)	796,460	2,229,445	(1,432,985)	-64.3%	7,790,202	9,621,529	(1,831,327)	-19.0%
23 ENDING INVENTORY:								
24 UNITS (BBL)	106,463	113,465	(7,002)	-6.2%	106,463	113,465	(7,002)	-6.2%
25 UNIT COST ($/BBL)	30.49	31.39	(0.90)	-2.9%	30.49	31.39	(0.90)	-2.9%
26 AMOUNT ($)	3,246,048	3,562,022	(315,974)	-8.9%	3,246,048	3,562,022	(315,974)	-8.9%
27								
28 DAYS SUPPLY: NORMAL	54	61	(7)	-12.3%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	15	16	(1)	-4.9%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	630,149	699,000	(68,851)	-9.8%	4,492,827	4,574,000	(81,173)	-1.8%
32 UNIT COST ($/TON)	41.59	46.79	(5.20)	-11.1%	44.11	46.65	(2.54)	-5.5%
33 AMOUNT ($)	26,207,229	32,706,149	(6,498,920)	-19.9%	198,156,456	213,371,976	(15,215,520)	-7.1%
34 BURNED:								
35 UNITS (TONS)	697,552	687,447	10,105	1.5%	4,199,889	4,184,877	15,012	0.4%
36 UNIT COST ($/TON)	44.04	47.14	(3.10)	-6.6%	44.16	46.77	(2.62)	-5.6%
37 AMOUNT ($)	30,719,543	32,403,497	(1,683,954)	-5.2%	185,446,229	195,731,824	(10,285,595)	-5.3%
38 ENDING INVENTORY:								
39 UNITS (TONS)	918,418	1,365,943	(447,525)	-32.8%	918,418	1,365,943	(447,525)	-32.8%
40 UNIT COST ($/TON)	42.96	47.19	(4.23)	-9.0%	42.96	47.19	(4.23)	-9.0%
41 AMOUNT ($)	39,451,339	64,459,162	(25,007,823)	-38.8%	39,451,339	64,459,162	(25,007,823)	-38.8%
42								
43 DAYS SUPPLY:	44	67	(23)	-34.0%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	546,176	940,096	(393,920)	-41.9%	2,704,613	3,446,377	(741,764)	-21.5%
46 UNIT COST ($/MCF)	6.95	5.45	1.50	27.5%	5.66	5.25	0.41	7.9%
47 AMOUNT ($)	* 3,797,338	5,126,654	(1,329,316)	-25.9%	15,314,652	18,085,012	(2,770,360)	-15.3%
48 BURNED:								
49 UNITS (MCF)	546,176	940,096	(393,920)	-41.9%	2,704,613	3,446,377	(741,764)	-21.5%
50 UNIT COST ($/MCF)	6.95	5.45	1.50	27.5%	5.66	5.25	0.42	7.9%
51 AMOUNT ($)	* 3,797,338	5,126,654	(1,329,316)	-25.9%	15,315,625	18,085,014	(2,769,389)	-15.3%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%				

* Includes prior month adjustments to Polk ($318,943) and City of Tampa ($27,365)

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	16,091
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	16,091

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(7,685)	(227,982)
OTHER USAGE	(2,018)	(61,000)
TOTAL	(9,703)	(288,982)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	46,759
IGNITION PROPANE	518
IGNITION #2 OIL	211,891
AERIAL SURVEY ADJ.	0
ADDITIVES	51,752
GREEN FUEL	0
TOTAL	310,920

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2002

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. -D	6,054.0	0.0	6,054.0	1.465	1.465	88,700.00	88,700.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	37,758.0	0.0	37,758.0	2.641	3.690	997,300.00	1,393,100.00	
VARIOUS	JURISDIC.	SCH. -MB	22,659.0	0.0	22,659.0	2.618	2.618	593,200.00	593,200.00	552,700.00
TOTAL			66,471.0	0.0	66,471.0	2.526	3.122	1,679,200.00	2,075,000.00	552,700.00
ACTUAL:										
FLA. PWR. & LIGHT	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR PARTNERS	SEP. CONTR.	SCH. -D	48,220.0	0.0	48,220.0	2.734	3.442	1,318,334.80	1,659,732.40	
SEMINOLE ELEC. PRECO-1	*JURISDIC.*	*SCH. -D*	5,240.6	374.5	4,866.1	2.856	2.856	138,995.55	138,995.55	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. -D	854.3	0.0	854.3	1.994	1.994	17,035.05	17,035.05	
FLA. PWR. CORP.		SCH. -MA	225.0	0.0	225.0	2.491	3.713	5,604.06	8,354.99	2,044.43
FLA. PWR. & LIGHT		SCH. -MA	975.0	0.0	975.0	2.184	2.944	21,298.38	28,702.22	4,342.34
CITY OF LAKELAND		SCH. -MA	50.0	0.0	50.0	2.389	3.420	1,194.71	1,709.86	358.15
AQUILA		SCH. -MA	200.0	0.0	200.0	2.099	3.201	4,197.81	6,401.42	1,575.61
HARDEE PWR. PART. TO FLA. PWR. & LIGHT		SCH. -MA	140.0	0.0	140.0	2.662	3.137	3,726.35	4,391.98	
AUBURNDALE POWER PARTNERS		SCH. -OATT	56.0	0.0	56.0	1.611	1.611	902.34	902.34	
ADJUSTMENTS TO PREV. MONTHS										
HARDEE PWR PARTNERS EST.	*June 2002*	CONTRACT	(43,380.0)	0.0	(43,380.0)	2.556	3.341	(1,108,792.80)	(1,449,325.80)	
HARDEE PWR PARTNERS ACT.	June 2002	CONTRACT	43,380.0	0.0	43,380.0	2.734	3.442	1,186,009.20	1,493,139.60	
SEMINOLE ELEC. PRECO-1	June 2002	SCH. -D	(5,503.7)	(464.2)	(5,039.5)	2.724	2.724	(137,298.41)	(137,298.41)	
SEMINOLE ELEC. PRECO-1	June 2002	SCH. -D	5,511.7	464.2	5,047.5	2.720	2.720	137,298.41	137,298.41	
AUBURNDALE POWER PARTNERS	June 2002	SCH. -OATT	(1,183.0)	0.0	(1,183.0)	(1.814)	(1.814)	21,464.81	21,464.81	
AUBURNDALE POWER PARTNERS	June 2002	SCH. -OATT	(1,183.0)	0.0	(1,183.0)	1.814	1.814	(21,464.81)	(21,464.81)	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISDICTIONAL			6,102.9	374.5	5,728.4	2.724	2.724	156,030.60	156,030.60	
SUB-TOTAL SCHEDULE D POWER SALES-SEPARATED			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEP.			48,220.0	0.0	48,220.0	2.894	3.533	1,395,551.20	1,703,546.20	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISDICTIONAL			1,590.0	0.0	1,590.0	2.265	3.117	36,021.31	49,560.47	8,320.53
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISDICTIONAL			(2,310.0)	0.0	(2,310.0)	(0.039)	(0.039)	902.34	902.34	
TOTAL			53,602.9	374.5	53,228.4	2.984	3.588	1,588,505.45	1,910,039.61	8,320.53
CURRENT MONTH:										
DIFFERENCE			(12,868.1)	374.5	(13,242.6)	0.458	0.466	(90,694.55)	(164,960.39)	(544,379.47)
DIFFERENCE %			-19.4%	0.0%	-19.9%	18.1%	14.9%	-5.4%	-7.9%	-98.5%
PERIOD TO DATE:										
ACTUAL			326,999.6	2,762.1	324,237.5	2.553	3.217	8,276,469.23	10,431,281.88	70,331.63
ESTIMATED			523,720.0	0.0	523,720.0	2.420	3.105	12,675,000.00	16,260,200.00	2,155,700.00
DIFFERENCE			(196,720.4)	2,762.1	(199,482.5)	0.133	0.112	(4,398,530.77)	(5,828,918.12)	(2,085,368.37)
DIFFERENCE %			-37.6%	0.0%	-38.1%	5.5%	3.6%	-34.7%	-35.8%	-96.7%

* SALES TO HARDEE POWER PARTNERS FOR OTHERS INCLUDES TEC 40% PROFIT. SEC 60% PROFIT OR $998.44 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH.-J	37,701.0	0.0	18,935.0	18,766.0	10.596	10.596	1,988,500.00
HARDEE POWER PARTNERS		IPP	119,924.0	0.0	0.0	119,924.0	4.477	4.477	5,368,900.00
VARIOUS		OTHER	32,721.0	0.0	0.0	32,721.0	8.322	8.322	2,723,100.00
VARIOUS		MKT. BASE	71,319.0	0.0	0.0	71,319.0	7.888	7.888	5,625,800.00
TOTAL			261,665.0	0.0	18,935.0	242,730.0	6.471	6.471	15,706,300.00
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	96,160.0	0.0	0.0	96,160.0	2.907	2.907	2,795,228.06
HARDEE PWR. PART.-OTHERS		IPP	140.0	0.0	0.0	140.0	2.662	2.662	3,726.35
FLA. POWER CORP.		SCH.-J	37,360.0	0.0	998.2	36,361.8	3.508	3.508	1,275,696.11
FLA. POWER & LIGHT		SCH.-J	21,675.0	0.0	751.1	20,923.9	4.895	4.895	1,024,295.08
CITY OF LAKELAND		SCH.-J	32,802.0	0.0	2,548.1	30,253.9	3.828	3.828	1,158,088.21
ORLANDO UTIL. COMM.		SCH.-J	15,800.0	0.0	1,088.8	14,711.2	5.913	5.913	869,938.16
AUBURNDALE POWER PARTNERS		SCH.-J	1,494.0	0.0	0.0	1,494.0	2.026	2.026	30,262.00
THE ENERGY AUTHORITY		SCH.-J	6,316.0	0.0	992.6	5,323.4	4.611	4.611	245,451.68
REEDY CREEK		SCH.-J	185.0	0.0	5.0	180.0	4.131	4.131	7,435.00
OKEELANTA		SCH.-J	16,098.0	0.0	59.0	16,039.0	3.687	3.687	591,357.59
TALLAHASSEE		SCH.-J	192.0	0.0	163.0	29.0	11.259	11.259	3,265.04
AQUILA		SCH.-J	26,700.0	0.0	0.0	26,700.0	8.484	8.484	2,265,237.50
CALPINE/AUBURNDALE POWER PARTNERS		SCH.-J	820.0	0.0	60.0	760.0	4.863	4.863	36,960.00
CARGILL ALLIANT		SCH.-J	11,477.0	0.0	1,152.4	10,324.6	4.473	4.473	461,830.89
KOCH ENERGY		SCH.-J	1,200.0	0.0	0.0	1,200.0	4.233	4.233	50,800.00
RELIANT		SCH.-J	8,705.0	0.0	2,570.3	6,134.7	4.639	4.639	284,586.53
SEMINOLE ELECTRIC CO-OP		SCH.-J	3,014.0	0.0	400.0	2,614.0	3.301	3.301	86,297.00
DUKE ENERGY		SCH.-J	7,556.0	0.0	736.0	6,820.0	4.995	4.995	340,650.80
DYNEGY POWER MARKETING		SCH.-J	343.0	0.0	0.0	343.0	3.071	3.071	10,535.00
RINGHAVER		SCH.-J	3,407.0	0.0	0.0	3,407.0	3.266	3.266	111,278.02
OKEELANTA		SCH.-D	16,451.0	0.0	0.0	16,451.0	4.396	4.396	723,154.94
FLA. POWER CORP.		SCH.-D	64,300.0	0.0	0.0	64,300.0	4.100	4.100	2,636,496.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	June 2002	IPP	(95,337.0)	0.0	0.0	(95,337.0)	2.450	2.450	(2,336,003.93)
HARDEE PWR. PART.-NATIVE	June 2002	IPP	95,337.0	0.0	0.0	95,337.0	2.348	2.348	2,238,280.74
FLA. POWER CORP.	June 2002	SCH.-D	(64,200.0)	0.0	0.0	(64,200.0)	3.525	3.525	(2,262,882.00)
FLA. POWER CORP.	June 2002	SCH.-D	64,200.0	0.0	0.0	64,200.0	4.101	4.101	2,632,674.00
FLA. POWER CORP.	May 2002	SCH.-D	(64,050.0)	0.0	0.0	(64,050.0)	3.525	3.525	(2,258,013.00)
FLA. POWER CORP.	May 2002	SCH.-D	64,050.0	0.0	0.0	64,050.0	4.101	4.101	2,626,941.00
FLA. POWER CORP.	April 2002	SCH.-D	(82,050.0)	0.0	0.0	(82,050.0)	3.137	3.137	(2,573,997.50)
FLA. POWER CORP.	April 2002	SCH.-D	82,050.0	0.0	0.0	82,050.0	3.494	3.494	2,866,607.50
THE ENERGY AUTH.	June 2002	SCH.-J	(6,390.0)	0.0	(645.0)	(5,745.0)	4.011	4.011	(230,459.62)
THE ENERGY AUTH.	June 2002	SCH.-J	6,389.0	0.0	645.0	5,744.0	4.011	4.011	230,420.12
RELIANT	June 2002	SCH.-J	(14,679.0)	0.0	(2,624.8)	(12,054.2)	4.599	4.599	(554,416.02)
RELIANT	June 2002	SCH.-J	14,680.0	0.0	2,624.8	12,055.2	4.599	4.599	554,448.02
FLA. POWER & LIGHT	May 2002	SCH.-J	(6,590.0)	0.0	(2,995.0)	(3,595.0)	4.194	4.194	(150,761.35)
FLA. POWER & LIGHT	May 2002	SCH.-J	6,264.0	0.0	2,669.0	3,595.0	4.194	4.194	150,761.35
FLA. POWER & LIGHT	May 2002	SCH.-A	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER & LIGHT	May 2002	SCH.-A	475.0	0.0	475.0	0.0	0.000	0.000	0.00
TOTAL			372,344.0	0.0	11,673.5	360,670.5	4.421	4.421	15,946,169.27
CURRENT MONTH:									
DIFFERENCE			110,679.0	0.0	(7,261.5)	117,940.5	(2.050)	(2.050)	239,869.27
DIFFERENCE %			42.3%	0.0%	-38.3%	48.6%	-31.7%	-31.7%	1.5%
PERIOD TO DATE:									
ACTUAL			1,876,954.0	0.0	118,415.6	1,758,538.5	4.426	4.426	77,840,235.49
ESTIMATED			1,431,429.0	0.0	59,898.0	1,371,531.0	5.580	5.580	76,526,200.00
DIFFERENCE			445,525.0	0.0	58,517.6	387,007.5	(1.154)	(1.154)	1,314,035.49
DIFFERENCE %			31.1%	0.0%	97.7%	28.2%	-20.7%	-20.7%	1.7%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	41,027.0	0.0	0.0	41,027.0	2.505	2.505	1,027,800.00
TOTAL		**41,027.0**	**0.0**	**0.0**	**41,027.0**	**2.505**	**2.505**	**1,027,800.00**
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	13,018.0	0.0	0.0	13,018.0	2.409	2.409	313,642.42
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	27.0	0.0	0.0	27.0	3.669	3.669	990.54
HILLSBOROUGH COUNTY	COGEN.	17,900.0	0.0	0.0	17,900.0	2.408	2.408	431,053.46
CARGILL MILLPOINT	COGEN.	85.0	0.0	0.0	85.0	4.573	4.573	3,887.28
CF INDUSTRIES INC.	COGEN.	571.0	0.0	0.0	571.0	3.772	3.772	21,536.08
FARMLAND HYDRO LP	COGEN.	1,306.0	0.0	0.0	1,306.0	3.773	3.773	49,273.47
IMC-AGRICO-S. PIERCE	COGEN.	504.0	0.0	0.0	504.0	3.525	3.525	17,765.46
AUBURNDALE POWER PARTNERS	COGEN.	961.0	0.0	0.0	961.0	4.327	4.327	41,578.18
ORANGE COGENERATION L.P.	COGEN.	7,843.0	0.0	0.0	7,843.0	2.415	2.415	189,415.97
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR JULY 2002		42,215.0	0.0	0.0	42,215.0	2.533	2.533	1,069,142.86
ADJUSTMENTS FOR THE MONTH OF:	**MAY 2002**							
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	(10,262.0)	0.0	0.0	(10,262.0)	2.160	2.160	(221,688.92)
		10,262.0	0.0	0.0	10,262.0	2.154	2.154	221,082.13
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
HILLSBOROUGH COUNTY	COGEN.	(19,044.0)	0.0	0.0	(19,044.0)	2.168	2.168	(412,951.77)
		19,044.0	0.0	0.0	19,044.0	2.162	2.162	411,774.73
CARGILL MILLPOINT	COGEN.	(116.0)	0.0	0.0	(116.0)	4.999	4.999	(5,798.36)
		116.0	0.0	0.0	116.0	4.699	4.699	5,451.39
CF INDUSTRIES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
FARMLAND HYDRO LP	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AUBURNDALE POWER PARTNERS	COGEN.	(466.0)	0.0	0.0	(466.0)	0.000	0.000	0.00
		466.0	0.0	0.0	466.0	0.000	0.000	0.00
ORANGE COGENERATION L.P.	COGEN.	(7,797.0)	0.0	0.0	(7,797.0)	2.210	2.210	(172,277.06)
		7,797.0	0.0	0.0	7,797.0	2.199	2.199	171,488.31
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**MAY 2002**	0.0	0.0	0.0	0.0	0.000	0.000	(2,919.55)
GRAND TOTAL		**42,215.0**	**0.0**	**0.0**	**42,215.0**	**2.526**	**2.526**	**1,066,223.31**
CURRENT MONTH:								
DIFFERENCE		1,188.0	0.0	0.0	1,188.0	0.021	0.021	38,423.31
DIFFERENCE %		2.9%	0.0%	0.0%	2.9%	0.8%	0.8%	3.7%
PERIOD TO DATE:								
ACTUAL		282,368.0	0.0	0.0	282,368.0	2.300	2.300	6,495,105.58
ESTIMATED		274,468.0	0.0	0.0	274,468.0	2.242	2.242	6,154,100.00
DIFFERENCE		7,900.0	0.0	0.0	7,900.0	0.058	0.058	341,005.58
DIFFERENCE %		2.9%	0.0%	0.0%	2.9%	0.026	0.026	5.5%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: JULY 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		0.0	0.000	0.00	0.000	0.00	0.00
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

AUGUST 2002

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. *Fuel Cost of System Net Generation (A3)*	34,902,296	40,084,800	(5,182,504)	-12.9%	1,507,404	1,674,069	(166,665)	-10.0%	2.31539	2.39445	(0.07906)	-3.3%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(6,261)	(4,000)	(2,261)	56.5%	1,507,404 (a)	1,674,069 (a)	(166,665)	-10.0%	(0.00042)	(0.00024)	(0.00018)	73.8%
4b. *Adjustments to Fuel Cost (1)*	(3,130)	0	(3,130)	0.0%	1,507,404 (a)	1,674,069 (a)	(166,665)	-10.0%	(0.00021)	0.00000	(0.00021)	0.0%
4c. Adjustments to Fuel Cost (2)	8,125	0	8,125	0.0%	1,507,404 (a)	1,674,069 (a)	(166,665)	-10.0%	0.00054	0.00000	0.00054	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**34,901,030**	**40,080,800**	**(5,179,770)**	**-12.9%**	**1,507,404**	**1,674,069**	**(166,665)**	**-10.0%**	**2.31531**	**2.39421**	**(0.07891)**	**-3.3%**
6. *Fuel Cost of Purchased Power - Firm (A7)*	12,986,993	14,582,600	(1,595,607)	-10.9%	348,174	233,135	115,039	49.3%	3.73003	6.25500	(2.52497)	-40.4%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,098,386	1,025,700	72,686	7.1%	41,202	41,027	175	0.4%	2.66586	2.50006	0.16580	6.6%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**14,085,379**	**15,608,300**	**(1,522,921)**	**-9.8%**	**389,376**	**274,162**	**115,214**	**42.0%**	**3.61742**	**5.69309**	**(2.07567)**	**-36.5%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,896,780**	**1,948,231**	**(51,451)**	**-2.6%**				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	165,085	88,700	76,385	86.1%	5,719	6,055	(336)	-5.5%	2.88661	1.46491	1.42170	97.1%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	8,317	0	8,317	0.0%	229	0	229	0.0%	3.63188	0.00000	3.63188	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	1,277,587	998,700	278,887	27.9%	53,025	37,758	15,267	40.4%	2.40940	2.64500	(0.23560)	-8.9%
21. Fuel Cost of Market Base Sales (A6)	7,987	733,700	(725,713)	-98.9%	375	28,347	(27,972)	-98.7%	2.12987	2.58828	(0.45841)	-17.7%
21a. Gains on Market Based Sales	543	542,100	(541,557)	-99.9%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	**1,459,519**	**2,363,200**	**(903,681)**	**-38.2%**	**59,348**	**72,160**	**(12,812)**	**-17.8%**	**2.45926**	**3.27494**	**(0.81569)**	**-24.9%**
23. Net Inadvertant Interchange					(759)	0	(759)	0.0%				
24. Wheeling Rec'd. less Wheeling Delv'd.					(1,195)	0	(1,195)	0.0%				
25. Interchange and Wheeling Losses					220	1,000	(780)	-78.0%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	**47,526,890**	**53,325,900**	**(5,799,010)**	**-10.9%**	**1,835,258**	**1,875,071**	**(39,813)**	**-2.1%**	**2.58966**	**2.84394**	**(0.25428)**	**-8.9%**
27. Net Unbilled	1,911,814 (a)	2,485,319 (a)	(573,505)	-23.1%	73,825	87,390	(13,565)	-15.5%	2.58966	2.84394	(0.25428)	-8.9%
28. Company Use	113,945 (a)	116,602 (a)	(2,657)	-2.3%	4,400	4,100	300	7.3%	2.58966	2.84395	(0.25429)	-8.9%
29. T & D Losses	1,597,016 (a)	(1,045,233) (a)	2,642,249	-252.8%	61,669	(36,753)	98,422	-267.8%	2.58966	2.84394	(0.25428)	-8.9%
30. System KWH Sales	47,526,890	53,325,900	(5,799,010)	-10.9%	1,695,364	1,820,334	(124,970)	-6.9%	2.80334	2.92946	(0.12611)	-4.3%
31. Wholesale KWH Sales	(1,464,213)	(3,596,581)	2,132,368	-59.3%	(52,231)	(122,773)	70,542	-57.5%	2.80334	2.92946	(0.12612)	-4.3%
32. Jurisdictional KWH Sales	46,062,677	49,729,319	(3,666,642)	-7.4%	1,643,133	1,697,561	(54,428)	-3.2%	2.80334	2.92946	(0.12611)	-4.3%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	46,093,078	49,762,140	(3,669,062)	-7.4%	1,643,133	1,697,561	(54,428)	-3.2%	2.80519	2.93139	(0.12620)	-4.3%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	288,340	277,441	10,899	3.9%	1,643,133	1,697,561	(54,428)	-3.2%	0.01755	0.01634	0.00120	7.4%
35a. Adjustment	0	0	0	0.0%	1,643,133	1,697,561	(54,428)	-3.2%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	1,643,133	1,697,561	(54,428)	-3.2%	0.00000	0.00000	0.00000	0.0%
36. True-up *	7,389,395	7,389,395	0	0.0%	1,643,133	1,697,561	(54,428)	-3.2%	0.44971	0.43529	0.01442	3.3%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	53,770,813	57,428,976	(3,658,163)	-6.4%	1,643,133	1,697,561	(54,428)	-3.2%	3.27246	3.38303	(0.11057)	-3.3%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.27481	3.38546	(0.11065)	-3.3%
40. GPIF * (Already Adjusted for Taxes)	91,246	91,246	0	0.0%	1,643,133	1,697,561	(54,428)	-3.2%	0.00555	0.00538	0.00018	3.3%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**53,862,059**	**57,520,222**	**(3,658,163)**	**-6.4%**	**1,643,133**	**1,697,561**	**(54,428)**	**-3.2%**	**3.28036**	**3.39084**	**(0.11047)**	**-3.3%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.280**	**3.391**	**(0.111)**	**-3.3%**

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY

PERIOD TO DATE THROUGH: AUGUST 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	245,544,284	266,082,610	(20,538,326)	-7.7%	10,810,865	11,614,608	(803,743)	-6.9%	2.27127	2.29093	(0.01966)	-0.9%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. *Coal Car Investment*	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(48,446)	(32,000)	(16,446)	51.4%	10,810,865 (a)	11,614,608 (a)	(803,743)	-6.9%	(0.00045)	(0.00028)	(0.00017)	62.6%
4b. Adjustments to Fuel Cost (1)	(13,254)	0	(13,254)	0.0%	10,810,865 (a)	11,614,608 (a)	(803,743)	-6.9%	(0.00012)	0.00000	(0.00012)	0.0%
4c. Adjustments to Fuel Cost (2)	8,125	0	8,125	0.0%	10,810,865 (a)	11,614,608 (a)	(803,743)	-6.9%	0.00008	0.00000	0.00008	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**245,490,709**	**266,050,610**	**(20,559,901)**	**-7.7%**	**10,810,865**	**11,614,608**	**(803,743)**	**-6.9%**	**2.27078**	**2.29066**	**(0.01988)**	**-0.9%**
6. Fuel Cost of Purchased Power - Firm (A7)	90,827,228	91,108,800	(281,572)	-0.3%	2,106,714	1,604,666	502,048	31.3%	4.31132	5.67774	(1.36642)	-24.1%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	7,593,492	7,179,800	413,692	5.8%	323,570	315,495	8,075	2.6%	2.34678	2.27573	0.07106	3.1%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**98,420,720**	**98,288,600**	**132,120**	**0.1%**	**2,430,284**	**1,920,161**	**510,123**	**26.6%**	**4.04976**	**5.11877**	**(1.06901)**	**-20.9%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**13,241,149**	**13,534,769**	**(293,620)**	**-2.2%**				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	946,653	720,000	226,653	31.8%	36,744	48,753	(12,009)	-24.6%	2.58179	1.47683	1.10496	74.8%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	2,143	0	2,143	0.0%	(486)	0	(486)	0.0%	(0.44095)	0.00000	(0.44095)	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. *Fuel Cost of HPP Sch. D Separ. Sales (A6)*	8,229,050	9,690,800	(1,461,750)	-15.1%	319,714	379,842	(60,128)	-15.8%	2.57388	2.55127	0.02261	0.9%
21. Fuel Cost of Market Base Sales (A6)	555,599	4,085,300	(3,529,701)	-86.4%	27,613	167,285	(139,672)	-83.5%	2.01209	2.44212	(0.43003)	-17.6%
21a. Gains on Market Based Sales	70,874	2,697,800	(2,626,926)	-97.4%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	**9,806,319**	**17,193,900**	**(7,387,581)**	**-43.0%**	**383,585**	**595,880**	**(212,295)**	**-35.6%**	**2.55649**	**2.88546**	**(0.32897)**	**-11.4%**
23. Net Inadvertant Interchange					984	0	984	0.0%				
24. Wheeling Rec'd. less Wheeling Delv'd.					(31)	0	(31)	0.0%				
25. Interchange and Wheeling Losses					1,924	8,700	(6,776)	-77.9%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	**334,105,110**	**347,145,310**	**(13,040,200)**	**-3.8%**	**12,856,593**	**12,930,189**	**(73,596)**	**-0.6%**	**2.59871**	**2.68477**	**(0.08606)**	**-3.2%**
27. Net Unbilled	6,513,267 (a)	6,620,755 (a)	(107,488)	-1.6%	216,541	248,742	(32,201)	-12.9%	3.00787	2.66170	0.34617	13.0%
28. Company Use	831,224 (a)	876,693 (a)	(45,469)	-5.2%	32,100	32,800	(700)	-2.1%	2.58948	2.67284	(0.08336)	-3.1%
29. T & D Losses	15,421,080 (a)	(672,204) (a)	16,093,284	-2394.1%	587,178	(30,234)	617,412	-2042.1%	2.62630	2.22334	0.40297	18.1%
30. System KWH Sales	334,105,110	347,145,310	(13,040,200)	-3.8%	12,020,774	12,678,881	(658,107)	-5.2%	2.77940	2.73798	0.04142	1.5%
31. Wholesale KWH Sales	(8,993,132)	(23,910,365)	14,917,233	-62.4%	(313,560)	(871,118)	557,558	-64.0%	2.86807	2.74479	0.12328	4.5%
32. Jurisdictional KWH Sales	325,111,978	323,234,945	1,877,033	0.6%	11,707,214	11,807,763	(100,549)	-0.9%	2.77702	2.73748	0.03954	1.4%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	325,326,552	323,448,280	1,878,272	0.6%	11,707,214	11,807,763	(100,549)	-0.9%	2.77886	2.73928	0.03957	1.4%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	2,388,606	2,281,940	106,666	4.7%	11,707,214	11,807,763	(100,549)	-0.9%	0.02040	0.01933	0.00108	5.6%
35a. Adjustment	0	0	0	0.0%	11,707,214	11,807,763	(100,549)	-0.9%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	11,707,214	11,807,763	(100,549)	-0.9%	0.00000	0.00000	0.00000	0.0%
36. True-up *	59,115,160	59,115,160	0	0.0%	11,707,214	11,807,763	(100,549)	-0.9%	0.50495	0.50065	0.00430	0.9%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	386,830,318	384,845,380	1,984,938	0.5%	11,707,214	11,807,763	(100,549)	-0.9%	3.30420	3.25926	0.04495	1.4%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.30658	3.26160	0.04498	1.4%
40. GPIF * *(Already Adjusted for Taxes)*	729,968	729,968	0	0.0%	11,707,214	11,807,763	(100,549)	-0.9%	0.00624	0.00618	0.00005	0.9%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**387,560,286**	**385,575,348**	**1,984,938**	**0.5%**	**11,707,214**	**11,807,763**	**(100,549)**	**-0.9%**	**3.31282**	**3.26778**	**0.04503**	**1.4%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.313**	**3.268**	**0.045**	**1.4%**

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: AUGUST 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	34,902,296	40,084,800	(5,182,504)	-12.9%	245,544,284	266,082,610	(20,538,326)	-7.7%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	1,458,976	1,821,100	(362,124)	-19.9%	9,735,445	14,496,100	(4,760,655)	-32.8%
2a. GAINS FROM MARKET BASED SALES	543	542,100	(541,557)	-99.9%	70,874	2,697,800	(2,626,926)	-97.4%
3. FUEL COST OF PURCHASED POWER	12,986,993	14,582,600	(1,595,607)	-10.9%	90,827,228	91,108,800	(281,572)	-0.3%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,098,386	1,025,700	72,686	7.1%	7,593,492	7,179,800	413,692	5.8%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	47,528,156	53,329,900	(5,801,744)	-10.9%	334,158,685	347,177,310	(13,018,625)	-3.7%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(6,261)	(4,000)	(2,261)	56.5%	(48,446)	(32,000)	(16,446)	51.4%
6b. ADJ.TO FUEL COST	(3,130)	0	(3,130)	0.0%	(13,254)	0	(13,254)	0.0%
6c. ADJ.TO FUEL COST	8,125	0	8,125	0.0%	8,125	0	8,125	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	47,526,890	53,325,900	(5,799,010)	-10.9%	334,105,110	347,145,310	(13,040,200)	-3.8%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,643,133	1,697,561	(54,428)	-3.2%	11,707,214	11,807,763	(100,549)	-0.9%
2. NONJURISDICTIONAL SALES	52,231	122,773	(70,542)	-57.5%	313,560	871,118	(557,558)	-64.0%
3. TOTAL SALES	1,695,364	1,820,334	(124,970)	-6.9%	12,020,774	12,678,881	(658,107)	-5.2%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9691919	0.9325547	0.0366372	3.9%	0.9739152	0.9312938	0.0426214	4.6%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: AUGUST 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	54,022,305	55,995,683	(1,973,378)	-3.5%	383,407,208	389,275,721	(5,868,513)	-1.5%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(7,389,395)	(7,389,395)	0	0.0%	(59,115,160)	(59,115,160)	0	0.0%
2b. INCENTIVE PROVISION	(91,246)	(91,246)	0	0.0%	(729,968)	(729,968)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	46,541,664	48,515,042	(1,973,378)	-4.1%	323,562,080	329,430,593	(5,868,513)	-1.8%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	47,526,890	53,325,900	(5,799,010)	-10.9%	334,105,110	347,145,310	(13,040,200)	-3.8%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9691919	0.9325547	0.0366372	3.9%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	46,062,677	49,729,319	(3,666,642)	-7.4%	325,111,978	323,234,945	1,877,033	0.6%
6a. JURISDIC. LOSS MULTIPLIER	1.00066	1.00066	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	46,093,078	49,762,140	(3,669,062)	-7.4%	325,326,552	323,448,280	1,878,272	0.6%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	297,506	297,506	0	0.0%	2,450,916	2,450,916	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	288,340	277,441	10,899	3.9%	2,388,606	2,281,940	106,666	4.7%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	46,381,418	50,039,581	(3,658,163)	-7.3%	327,715,158	325,730,220	1,984,938	0.6%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	160,246	(1,524,539)	1,684,785	-110.5%	(4,153,078)	3,700,373	(7,853,451)	-212.2%
8. INTEREST PROVISION FOR THE MONTH	(67,484)	(100,311)	32,827	-32.7%	(789,273)	(1,434,017)	644,744	-45.0%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(50,966,243)	(33,055,764)	(17,910,479)	54.2%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	7,389,395	7,389,395	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(43,484,086)	(27,291,219)	(16,192,867)	59.3%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(50,966,243)	(33,055,764)	(17,910,479)	54.2%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(43,416,602)	(27,190,908)	(16,225,694)	59.7%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(94,382,845)	(60,246,672)	(34,136,173)	56.7%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(47,191,423)	(30,123,336)	(17,068,087)	56.7%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.730	4.000	(2)	-56.8%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.710	4.000	(2)	-57.3%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	3.440	8.000	(5)	-57.0%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.720	4.000	(2)	-57.0%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.143	0.333	(0)	-57.1%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(67,484)	(100,311)	32,827	-32.7%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	530,892	552,745	(21,853)	-4.0%	2,620,824	3,112,188	(491,364)	-15.8%
2	LIGHT OIL	399,137	1,948,408	(1,549,271)	-79.5%	8,189,339	11,569,937	(3,380,598)	-29.2%
3	COAL	30,718,933	32,468,563	(1,749,630)	-5.4%	216,165,162	228,200,387	(12,035,225)	-5.3%
4	NATURAL GAS	3,253,334	5,115,084	(1,861,750)	-36.4%	18,568,959	23,200,098	(4,631,139)	-20.0%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	34,902,296	40,084,800	(5,182,504)	-12.9%	245,544,284	266,082,610	(20,538,326)	-7.7%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	11,157	14,978	(3,821)	-25.5%	52,367	73,927	(21,560)	-29.2%
9	LIGHT OIL	6,446	27,437	(20,991)	-76.5%	160,519	167,557	(7,038)	-4.2%
10	COAL	1,436,129	1,540,456	(104,327)	-6.8%	10,292,428	10,943,774	(651,346)	-6.0%
11	NATURAL GAS	53,672	91,198	(37,526)	-41.1%	305,551	429,350	(123,799)	-28.8%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,507,404	1,674,069	(166,665)	-10.0%	10,810,865	11,614,608	(803,743)	-6.9%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	17,360	22,293	(4,933)	-22.1%	83,509	110,067	(26,558)	-24.1%
16	LIGHT OIL (BBL)	13,004	63,660	(50,656)	-79.6%	272,444	355,089	(82,645)	-23.3%
17	COAL (TON)	709,377	690,810	18,567	2.7%	4,909,266	4,875,687	33,579	0.7%
18	NATURAL GAS (MCF)	590,411	933,059	(342,648)	-36.7%	3,295,024	4,379,436	(1,084,412)	-24.8%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	108,914	139,982	(31,068)	-22.2%	523,907	691,103	(167,196)	-24.2%
22	LIGHT OIL	72,070	363,896	(291,826)	-80.2%	1,570,152	2,019,343	(449,191)	-22.2%
23	COAL	16,268,760	16,237,239	31,521	0.2%	114,146,263	114,367,846	(221,583)	-0.2%
24	NATURAL GAS	624,655	959,241	(334,587)	-34.9%	3,469,660	4,502,273	(1,032,613)	-22.9%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	17,074,399	17,700,358	(625,959)	-3.5%	119,709,982	121,580,565	(1,870,583)	-1.5%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.74%	0.89%	(0.00)	-	0.48%	0.64%	(0.00)	-
29	LIGHT OIL	0.43%	1.64%	(0.01)	-	1.48%	1.44%	0.00	-
30	COAL	95.27%	92.02%	0.03	-	95.20%	94.22%	0.01	-
31	NATURAL GAS	3.56%	5.45%	(0.02)	-	2.83%	3.70%	(0.01)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	30.58	24.79	5.79	23.3%	31.38	28.28	3.11	11.0%
36	LIGHT OIL ($/BBL)	30.69	30.61	0.09	0.3%	30.06	32.58	(2.52)	-7.7%
37	COAL ($/TON)	43.30	47.00	(3.70)	-7.9%	44.03	46.80	(2.77)	-5.9%
38	NATURAL GAS ($/MCF)	5.51	5.48	0.03	0.5%	5.64	5.30	0.34	6.4%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	4.87	3.95	0.93	23.4%	5.00	4.50	0.50	11.1%
42	LIGHT OIL	5.54	5.35	0.18	3.4%	5.22	5.73	(0.51)	-9.0%
43	COAL	1.89	2.00	(0.11)	-5.6%	1.89	2.00	(0.10)	-5.1%
44	NATURAL GAS	5.21	5.33	(0.12)	-2.3%	5.35	5.15	0.20	3.9%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.04	2.26	(0.22)	-9.7%	2.05	2.19	(0.14)	-6.3%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,762	9,346	416	4.5%	10,005	9,348	657	7.0%
49	LIGHT OIL	11,181	13,263	(2,082)	-15.7%	9,782	12,052	(2,270)	-18.8%
50	COAL	11,328	10,541	787	7.5%	11,090	10,450	640	6.1%
51	NATURAL GAS	11,638	10,518	1,120	10.6%	11,355	10,486	869	8.3%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	11,327	10,573	754	7.1%	11,073	10,468	605	5.8%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	4.76	3.69	1.07	29.0%	5.00	4.21	0.79	18.8%
56	LIGHT OIL	6.19	7.10	(0.91)	-12.8%	5.10	6.91	(1.81)	-26.2%
57	COAL	2.14	2.11	0.03	1.4%	2.10	2.09	0.01	0.5%
58	NATURAL GAS	6.06	5.61	0.45	8.0%	6.08	5.40	0.68	12.6%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.32	2.39	(0.07)	-2.9%	2.27	2.29	(0.02)	-0.9%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: AUGUST 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF *FUEL* ($/UNIT)
H.P.#1	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	0	-171	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-171**	—	—	—	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	44,015	51.9	79.2	61.1	12,810	COAL	24,297	23,206,320	563,844.0	935,610	2.13	38.51
GAN.#2	98	44,741	61.4	75.3	78.4	13,021	COAL	25,372	22,960,360	582,550.3	977,005	2.18	38.51
GAN.#3	145	64,750	60.0	78.0	69.2	12,728	COAL	45,797	17,995,780	824,152.7	1,763,515	2.72	38.51
GAN.#4	159	67,872	57.4	71.6	71.8	12,893	COAL	47,448	18,443,360	875,100.5	1,827,091	2.69	38.51
GAN.#5	217	122,031	75.6	95.4	75.6	11,312	COAL	59,355	23,256,380	1,380,382.4	2,285,596	1.87	38.51
GAN.#6	372	179,658	64.9	79.0	77.1	10,994	COAL	84,060	23,497,260	1,975,179.7	3,236,917	1.80	38.51
GANNON STATION	**1,105**	**523,067**	**63.6**	**80.7**	**73.5**	**11,855**	**COAL**	**286,329**	**21,657,637**	**6,201,209.6**	**11,025,734**	**2.11**	**38.51**
B.B.#1	416	156,729	50.6	58.4	73.5	11,291	COAL	72,873	24,282,820	1,769,552.0	3,413,102	2.18	46.84
B.B.#2	416	210,930	68.2	73.2	75.6	11,201	COAL	97,276	24,286,880	2,362,532.0	4,556,049	2.16	46.84
B.B.#3	433	147,523	45.8	55.5	74.8	10,841	COAL	65,412	24,449,000	1,599,266.5	3,063,657	2.08	46.84
B.B. 1 - 3	1,265	515,182	54.7	62.3	74.6	11,125	COAL	235,561	24,330,643	5,731,350.5	11,032,808	2.14	46.84
B.B.#4	442	248,022	75.4	87.2	75.4	10,948	COAL	125,413	21,651,984	2,715,442.7	6,265,540	2.53	49.96
B.B. STATION	**1,707**	**763,204**	**60.1**	**68.7**	**74.8**	**11,068**	**COAL**	**360,974**	**23,399,997**	**8,446,793.2**	**17,298,348**	**2.27**	**47.92**
SEB-PHIL. #1(HVY OIL)	17	5,647	44.6	100.0	91.2	9,615	HVY.OIL	8,654	6,273,540	54,293.6	264,651	4.69	30.58
SEB-PHIL. #2(HVY OIL)	17	5,681	44.9	99.9	91.2	9,615	HVY.OIL	8,706	6,273,540	54,620.5	266,241	4.69	30.58
SEB-PHILLIPS TOTAL	**34**	**11,328**	**44.8**	**100.0**	**91.2**	**9,615**	**HVY.OIL**	**17,360**	**6,273,540**	**108,914.1**	**530,892**	**4.69**	**30.58**
POLK #1 GASIFIER	250	149,858	80.6	85.6	90.8	10,815	COAL	62,074	26,110,000	1,620,757.4	2,394,851	1.60	38.58
POLK #1 CT (OIL)	225	4,726	2.8	98.5	58.0	9,185	LGT.OIL	8,107	5,823,622	43,409.8	252,886	5.35	31.19
POLK #1 TOTAL	**250**	**154,584**	**83.1**	**94.4**	**89.2**	**10,765**	-	-	-	**1,664,167.2**	**2,647,737**	**1.71**	-
POLK #2 CT (GAS)	150	14,533	13.0	100.0	77.0	11,118	GAS	152,717	972,290	161,574.0	683,602	4.70	4.48
POLK #2 CT (OIL)	160	-5	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**155**	**14,528**	**12.6**	**100.0**	**76.6**	**11,122**	-	-	-	**161,574.0**	**683,602**	**4.71**	-
POLK #3 CT (GAS)	150	37,062	33.2	99.7	76.6	11,914	GAS	417,341	972,290	441,547.0	2,540,661	6.86	6.09
POLK #3 CT (OIL)	160	28	0.0	99.7	22.8	51,557	LGT.OIL	248	5,823,786	1,443.6	7,733	27.62	31.18
POLK #3 TOTAL	**155**	**37,090**	**32.2**	**99.7**	**76.4**	**11,944**	-	-	-	**442,990.6**	**2,548,394**	**6.87**	-
POLK STATION TOTAL	**560**	**206,202**	**49.5**	**97.4**	**60.3**	**11,002**	-	-	-	**2,268,731.8**	**5,879,733**	**2.85**	-
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#2	66	1,697	3.5	100.0	71.4	16,038	LGT.OIL	4,649	5,853,890	27,216.9	138,518	8.16	29.80
B.B.C.T.#3	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**144**	**1,697**	**1.6**	**54.2**	**32.7**	**16,038**	**LGT.OIL**	**4,649**	**5,853,890**	**27,216.9**	**138,518**	**8.16**	**29.80**
CITY OF TAMPA	**6**	**2,077**	**0.0**	**0.0**	**0.0**	**10,368**	**GAS**	**20,353**	**972,290**	**21,533.5**	**29,071**	**1.40**	**1.43**
TOT. COAL (GN,BB,POLK)	**3,062**	**1,436,129**	**63.0**	**74.4**	**75.6**	**11,328**	**COAL**	**709,377**	**22,933,860**	**16,268,760.2**	**30,718,933**	**2.14**	**43.30**
SYSTEM	**3,556**	**1,507,404**	**57.1**	**76.7**	**70.6**	**11,326**	-	-	-	**17,074,399.1**	**34,902,296**	**2.32**	-

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT B.B. = BIG BEND

GAN. = GANNON C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	19,563	22,293	(2,730)	-12.2%	84,876	110,067	(25,191)	-22.9%
3 UNIT COST ($/BBL)	30.59	23.57	7.03	29.8%	28.46	27.21	1.26	4.6%
4 AMOUNT ($)	598,515	525,359	73,156	13.9%	2,415,912	2,994,632	(578,720)	-19.3%
5 BURNED:								
6 UNITS (BBL)	17,360	22,293	(4,933)	-22.1%	83,509	110,067	(26,558)	-24.1%
7 UNIT COST ($/BBL)	30.58	24.79	5.79	23.3%	31.38	28.28	3.11	11.0%
8 AMOUNT ($)	530,892	552,745	(21,853)	-4.0%	2,620,824	3,112,188	(491,364)	-15.8%
9 ENDING INVENTORY:								
10 UNITS (BBL)	19,016	59,129	(40,113)	-67.8%	19,016	59,129	(40,113)	-67.8%
11 UNIT COST ($/BBL)	31.30	25.53	5.77	22.6%	31.30	25.53	5.77	22.6%
12 AMOUNT ($)	595,193	1,509,715	(914,522)	-60.6%	595,193	1,509,715	(914,522)	-60.6%
13								
14 DAYS SUPPLY:	31	78	(47)	-60.5%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	24,659	74,826	(50,167)	-67.0%	340,775	434,803	(94,028)	-21.6%
17 UNIT COST ($/BBL)	29.93	29.74	0.18	0.6%	29.96	31.72	(1.76)	-5.6%
18 AMOUNT ($)	737,971	2,225,614	(1,487,643)	-66.8%	10,209,259	13,792,999	(3,583,740)	-26.0%
19 BURNED:								
20 UNITS (BBL)	13,004	63,660	(50,656)	-79.6%	272,444	355,089	(82,645)	-23.3%
21 UNIT COST ($/BBL)	30.69	30.61	0.09	0.3%	30.06	32.58	(2.52)	-7.7%
22 AMOUNT ($)	399,137	1,948,408	(1,549,271)	-79.5%	8,189,339	11,569,937	(3,380,598)	-29.2%
23 ENDING INVENTORY:								
24 UNITS (BBL)	107,766	113,465	(5,699)	-5.0%	107,766	113,465	(5,699)	-5.0%
25 UNIT COST ($/BBL)	30.39	30.86	(0.47)	-1.5%	30.39	30.86	(0.47)	-1.5%
26 AMOUNT ($)	3,275,124	3,501,356	(226,232)	-6.5%	3,275,124	3,501,356	(226,232)	-6.5%
27								
28 DAYS SUPPLY: NORMAL	70	70	(0)	-0.7%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	15	16	(1)	-3.8%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	542,623	673,000	(130,377)	-19.4%	5,035,450	5,247,000	(211,550)	-4.0%
32 UNIT COST ($/TON)	43.76	46.02	(2.26)	-4.9%	44.07	46.57	(2.50)	-5.4%
33 AMOUNT ($)	23,747,652	30,974,557	(7,226,905)	-23.3%	221,904,108	244,346,533	(22,442,425)	-9.2%
34 BURNED:								
35 UNITS (TONS)	709,377	690,810	18,567	2.7%	4,909,266	4,875,687	33,579	0.7%
36 UNIT COST ($/TON)	43.30	47.00	(3.70)	-7.9%	44.03	46.80	(2.77)	-5.9%
37 AMOUNT ($)	30,718,933	32,468,563	(1,749,630)	-5.4%	216,165,162	228,200,387	(12,035,225)	-5.3%
38 ENDING INVENTORY:								
39 UNITS (TONS)	751,664	1,348,133	(596,469)	-44.2%	751,664	1,348,133	(596,469)	-44.2%
40 UNIT COST ($/TON)	43.20	47.05	(3.85)	-8.2%	43.20	47.05	(3.85)	-8.2%
41 AMOUNT ($)	32,470,782	63,431,592	(30,960,810)	-48.8%	32,470,782	63,431,592	(30,960,810)	-48.8%
42								
43 DAYS SUPPLY:	40	76	(36)	-46.9%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	590,411	933,059	(342,648)	-36.7%	3,295,024	4,379,436	(1,084,412)	-24.8%
46 UNIT COST ($/MCF)	5.51	5.48	0.03	0.5%	5.64	5.30	0.34	6.4%
47 AMOUNT ($)	3,253,334	5,115,084	(1,861,750)	-36.4%	18,567,986	23,200,096	(4,632,110)	-20.0%
48 BURNED:								
49 UNITS (MCF)	590,411	933,059	(342,648)	-36.7%	3,295,024	4,379,436	(1,084,412)	-24.8%
50 UNIT COST ($/MCF)	5.51	5.48	0.03	0.5%	5.64	5.30	0.34	6.4%
51 AMOUNT ($)	3,253,334	5,115,084	(1,861,750)	-36.4%	18,568,959	23,200,098	(4,631,139)	-20.0%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	18,529
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	18,529

(2) RECONCILIATION - *LIGHT OIL*

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(9,561)	(286,107)
OTHER USAGE	(791)	(23,651)
TOTAL	(10,352)	(309,758)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	39,616
IGNITION #2 OIL	267,578
IGNITION PROPANE	3,610
AERIAL SURVEY ADJ.	(398,338)
ADDITIVES	78,258
GREEN FUEL	0
TOTAL	(9,276)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2002

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. -D	6,055.0	0.0	6,055.0	1.465	1.465	88,700.00	88,700.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	37,758.0	0.0	37,758.0	2.645	3.693	998,700.00	1,394,400.00	
VARIOUS	JURISDIC.	SCH. -MB	28,347.0	0.0	28,347.0	2.588	2.588	733,700.00	733,700.00	542,100.00
TOTAL			72,160.0	0.0	72,160.0	2.524	3.072	1,821,100.00	2,216,800.00	542,100.00
ACTUAL:										
FLA. PWR. & LIGHT	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR PARTNERS	SEP. CONTR.	SCH. -D	53,025.0	0.0	53,025.0	2.564	3.263	1,359,561.00	1,730,205.75	
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. -D	5,156.9	197.4	4,959.5	3.010	3.010	149,300.55	149,300.55	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. -D	760.8	0.0	760.8	2.105	2.105	16,013.60	16,013.60	
FLA. PWR. CORP.		SCH. -MA		0.0	0.0	0.000	0.000			
FLA. PWR. & LIGHT		SCH. -MA	375.0	0.0	375.0	2.130	2.589	7,988.03	9,708.42	542.89
CITY OF LAKELAND		SCH. -MA		0.0	0.0	0.000	0.000			
ORLANDO UTIL. COMM.		SCH. -MA		0.0	0.0	0.000	0.000			
THE ENTERGY-KOCH TRADING		SCH. -MA		0.0	0.0	0.000	0.000			
CITY OF LAKE WORTH		SCH. -MA		0.0	0.0	0.000	0.000			
AUBURNDALE POWER PARTNERS		SCH. -MA		0.0	0.0	0.000	0.000			
AUBURNDALE POWER PARTNERS		SCH. -OATT	116.0	0.0	116.0	2.578	2.578	2,990.31	2,990.31	
CARGILL ALLIANT		SCH. -OATT	3.0	0.0	3.0	5.767	5.767	173.00	173.00	
ADJUSTMENTS TO PREV. MONTHS										
HARDEE PWR PARTNERS	July 2002	CONTRACT	(48,220.0)	0.0	(48,220.0)	2.734	3.442	(1,318,334.80)	(1,659,732.40)	
HARDEE PWR PARTNERS	July 2002	CONTRACT	48,220.0	0.0	48,220.0	2.564	3.263	1,236,360.80	1,573,418.60	
SEMINOLE ELEC. PRECO-1	July 2002	SCH. -D	(5,240.6)	(374.5)	(4,866.1)	2.856	2.856	(138,995.55)	(138,995.55)	
SEMINOLE ELEC. PRECO-1	July 2002	SCH. -D	5,240.6	374.5	4,866.1	2.852	2.852	138,766.17	138,766.17	
SEMINOLE ELEC. PRECO-1	June 2002	SCH. -D	(5,511.7)	(464.2)	(5,047.5)	2.720	2.720	(137,298.41)	(137,298.41)	
SEMINOLE ELEC. PRECO-1	June 2002	SCH. -D	5,510.7	464.2	5,046.5	2.721	2.721	137,298.41	137,298.41	
CARGILL ALLIANT	July 2002	SCH. -OATT	110.0	0.0	110.0	4.685	4.685	5,153.35	5,153.35	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISDICTIONAL			5,916.7	197.4	5,719.3	2.886	2.886	165,084.77	165,084.77	
SUB-TOTAL SCHEDULE D POWER SALES-SEPARATED			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEP.			53,025.0	0.0	53,025.0	2.409	3.100	1,277,587.00	1,643,891.95	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISDICTIONAL			375.0	0.0	375.0	2.130	2.589	7,988.03	9,708.42	542.89
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISDICTIONAL			229.0	0.0	229.0	3.632	3.632	8,316.66	8,316.66	
TOTAL			59,545.7	197.4	59,348.3	2.458	3.078	1,458,976.46	1,827,001.80	542.89
CURRENT MONTH:										
DIFFERENCE			(12,614.3)	197.4	(12,811.7)	(0.066)	0.006	(362,123.54)	(389,798.20)	(541,557.11)
DIFFERENCE %			-17.5%	0.0%	-17.8%	-2.6%	0.2%	-19.9%	-17.6%	-99.9%
PERIOD TO DATE:										
ACTUAL			386,545.3	2,959.5	383,585.8	2.538	3.196	9,735,445.69	12,256,283.68	70,874.52
ESTIMATED			595,880.0	0.0	595,880.0	2.433	3.101	14,496,100.00	18,477,000.00	2,697,800.00
DIFFERENCE			(209,334.7)	2,959.5	(212,294.2)	0.105	0.095	(4,760,654.31)	(6,218,716.32)	(2,626,925.48)
DIFFERENCE %			-35.1%	0.0%	-35.6%	4.3%	3.1%	-32.8%	-33.7%	-97.4%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS FOR THE MONTH OF AUGUST 2002.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH.-J	34,885.0	0.0	17,673.0	17,212.0	9.685	9.685	1,667,000.00
HARDEE POWER PARTNERS		IPP	119,441.0	0.0	0.0	119,441.0	4.464	4.464	5,331,800.00
VARIOUS		OTHER	33,722.0	0.0	0.0	33,722.0	8.264	8.264	2,786,700.00
VARIOUS		MKT. BASE	62,760.0	0.0	0.0	62,760.0	7.644	7.644	4,797,100.00
TOTAL			**250,808.0**	**0.0**	**17,673.0**	**233,135.0**	**6.255**	**6.255**	**14,582,600.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	109,214.0	0.0	0.0	109,214.0	2.065	2.065	2,255,754.98
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH.-J	37,509.0	0.0	689.2	36,819.8	3.448	3.448	1,269,697.81
FLA. POWER & LIGHT		SCH.-J	31,090.0	0.0	1,309.0	29,781.0	4.753	4.753	1,415,598.26
CITY OF LAKELAND		SCH.-J	27,058.0	0.0	477.0	26,581.0	4.119	4.119	1,094,883.00
ORLANDO UTIL. COMM.		SCH.-J	6,200.0	0.0	530.0	5,670.0	5.928	5.928	336,112.00
THE ENERGY AUTHORITY		SCH.-J	22,424.0	0.0	2,266.9	20,157.1	4.871	4.871	981,902.49
REEDY CREEK		SCH.-J	145.0	0.0	0.0	145.0	4.707	4.707	6,825.00
OKEELANTA		SCH.-J	11,221.0	0.0	0.0	11,221.0	3.606	3.606	404,599.85
TALLAHASSEE		SCH.-J	2,877.0	0.0	30.0	2,847.0	4.521	4.521	128,724.90
AQUILA		SCH.-J	24,700.0	0.0	0.0	24,700.0	8.950	8.950	2,210,650.00
CARGILL ALLIANT		SCH.-J	10,631.0	0.0	601.0	10,030.0	3.839	3.839	385,033.50
KOCH ENERGY		SCH.-J	2,079.0	0.0	97.0	1,982.0	4.577	4.577	90,713.00
RELIANT		SCH.-J	6,823.0	0.0	0.0	6,823.0	4.450	4.450	303,611.00
SEMINOLE ELECTRIC CO-OP		SCH.-J	6,903.0	0.0	186.0	6,717.0	2.768	2.768	185,897.00
CALPINE		SCH.-J	1,640.0	0.0	0.0	1,640.0	4.891	4.891	80,214.00
DUKE ENERGY		SCH.-J	4,692.0	0.0	249.0	4,443.0	4.306	4.306	191,326.50
RINGHAVER		SCH.-J	4,163.0	0.0	0.0	4,163.0	6.815	6.815	283,693.79
FLA. POWER CORP.		SCH.-D	61,700.0	0.0	0.0	61,700.0	3.907	3.907	2,410,639.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	July 2002	IPP	(96,160.0)	0.0	0.0	(96,160.0)	2.907	2.907	(2,795,228.06)
HARDEE PWR. PART.-NATIVE	July 2002	IPP	96,160.0	0.0	0.0	96,160.0	2.842	2.842	2,732,745.19
CARGILL ALLIANT	July 2002	SCH.-J	(11,477.0)	0.0	(1,152.4)	(10,324.6)	4.473	4.473	(461,830.89)
CARGILL ALLIANT	July 2002	SCH.-J	11,471.0	0.0	1,151.4	10,319.6	4.481	4.481	462,382.39
DUKE ENERGY	July 2002	SCH.-J	(7,556.0)	0.0	(736.0)	(6,820.0)	4.995	4.995	(340,650.80)
DUKE ENERGY	July 2002	SCH.-J	7,556.0	0.0	736.0	6,820.0	4.995	4.995	340,665.80
RELIANT	July 2002	SCH.-J	(8,705.0)	0.0	(2,570.3)	(6,134.7)	4.639	4.639	(284,586.53)
RELIANT	July 2002	SCH.-J	8,701.0	0.0	2,570.3	6,130.7	4.636	4.636	284,199.53
OKEELANTA	July 2002	SCH.-D	(16,451.0)	0.0	0.0	(16,451.0)	4.396	4.396	(723,154.94)
FLA. POWER CORP.	July 2002	SCH.-D	(64,300.0)	0.0	0.0	(64,300.0)	4.100	4.100	(2,636,496.00)
FLA. POWER CORP.	July 2002	SCH.-D	64,300.0	0.0	0.0	64,300.0	3.895	3.895	2,504,681.00
FLA. POWER CORP.	June 2002	SCH.-D	(64,200.0)	0.0	0.0	(64,200.0)	4.101	4.101	(2,632,674.00)
FLA. POWER CORP.	June 2002	SCH.-D	64,200.0	0.0	0.0	64,200.0	3.896	3.896	2,501,064.00
TOTAL			**354,608.0**	**0.0**	**6,434.1**	**348,173.9**	**3.730**	**3.730**	**12,986,992.77**
CURRENT MONTH:									
DIFFERENCE			103,800.0	0.0	(11,238.9)	115,038.9	(2.525)	(2.525)	(1,595,607.23)
DIFFERENCE %			41.4%	0.0%	-63.6%	49.3%	-40.4%	-40.4%	-10.9%
PERIOD TO DATE:									
ACTUAL			2,231,562.0	0.0	124,849.7	2,106,712.4	4.311	4.311	90,827,228.26
ESTIMATED			1,682,237.0	0.0	77,571.0	1,604,666.0	5.678	5.678	91,108,800.00
DIFFERENCE			549,325.0	0.0	47,278.7	502,046.4	(1.367)	(1.367)	(281,571.74)
DIFFERENCE %			32.7%	0.0%	60.9%	31.3%	-24.1%	-24.1%	-0.3%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	41,027.0	0.0	0.0	41,027.0	2.500	2.500	1,025,700.00
TOTAL			**41,027.0**	**0.0**	**0.0**	**41,027.0**	**2.500**	**2.500**	**1,025,700.00**
ACTUAL:									
IMC-AGRICO-NICHOLS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE		COGEN.	13,193.0	0.0	0.0	13,193.0	2.380	2.380	314,005.12
MULBERRY PHOSPHATES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	206.0	0.0	0.0	206.0	3.424	3.424	7,053.20
HILLSBOROUGH COUNTY		COGEN.	15,932.0	0.0	0.0	15,932.0	2.364	2.364	376,700.69
CARGILL MILLPOINT		COGEN.	36.0	0.0	0.0	36.0	5.493	5.493	1,977.64
CF INDUSTRIES INC.		COGEN.	641.0	0.0	0.0	641.0	3.687	3.687	23,634.74
FARMLAND HYDRO LP		COGEN.	902.0	0.0	0.0	902.0	3.427	3.427	30,910.39
IMC-AGRICO-S. PIERCE		COGEN.	768.0	0.0	0.0	768.0	3.991	3.991	30,650.61
AUBURNDALE POWER PARTNERS		COGEN.	1,681.0	0.0	0.0	1,681.0	5.070	5.070	85,234.30
ORANGE COGENERATION L.P.		COGEN.	7,843.0	0.0	0.0	7,843.0	2.319	2.319	181,856.44
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
AS AVAILABLE ASSIGNMENT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR AUGUST 2002			41,202.0	0.0	0.0	41,202.0	2.553	2.553	1,052,023.13
ADJUSTMENTS FOR THE MONTH OF:	**JUNE 2002**								
IMC-AGRICO-NICHOLS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE		COGEN.	(12,661.0)	0.0	0.0	(12,661.0)	2.263	2.263	(286,480.45)
			12,661.0	0.0	0.0	12,661.0	2.367	2.367	299,661.48
MULBERRY PHOSPHATES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
HILLSBOROUGH COUNTY		COGEN.	(16,605.0)	0.0	0.0	(16,605.0)	2.261	2.261	(375,388.20)
			16,605.0	0.0	0.0	16,605.0	2.365	2.365	392,687.96
CARGILL MILLPOINT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
FARMLAND HYDRO LP		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	* April 2002 adj	COGEN. *	(1,390.0)	0.0	0.0	(1,390.0)	3.988	3.988	(55,427.36)
			1,390.0	0.0	0.0	1,390.0	4.291	4.291	59,639.01
AUBURNDALE POWER PARTNERS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
ORANGE COGENERATION L.P.		COGEN.	(7,199.0)	0.0	0.0	(7,199.0)	2.265	2.265	(163,037.56)
			7,199.0	0.0	0.0	7,199.0	2.427	2.427	174,707.97
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
AS AVAILABLE ASSIGNMENT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**JUNE 2002**		0.0	0.0	0.0	0.0	0.000	0.000	46,362.85
GRAND TOTAL			**41,202.0**	**0.0**	**0.0**	**41,202.0**	**2.666**	**2.666**	**1,098,385.98**
CURRENT MONTH:									
DIFFERENCE			175.0	0.0	0.0	175.0	0.166	0.166	72,685.98
DIFFERENCE %			0.4%	0.0%	0.0%	0.4%	6.6%	6.6%	7.1%
PERIOD TO DATE:									
ACTUAL			323,570.0	0.0	0.0	323,570.0	2.347	2.347	7,593,491.56
ESTIMATED			315,495.0	0.0	0.0	315,495.0	2.276	2.276	7,179,800.00
DIFFERENCE			8,075.0	0.0	0.0	8,075.0	0.071	0.071	413,691.56
DIFFERENCE %			2.6%	0.0%	0.0%	2.6%	0.031	0.031	5.8%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: AUGUST 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (5B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

SEPTEMBER 2002

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY

MONTH OF: SEPTEMBER 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	31,950,037	38,934,550	(6,984,513)	-17.9%	1,338,050	1,615,197	(277,147)	-17.2%	2.38781	2.41051	(0.02271)	-0.9%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(6,124)	(4,000)	(2,124)	53.1%	1,338,050 (a)	1,615,197 (a)	(277,147)	-17.2%	(0.00046)	(0.00025)	(0.00021)	84.8%
4b. Adjustments to Fuel Cost (1)	(2,793)	0	(2,793)	0.0%	1,338,050 (a)	1,615,197 (a)	(277,147)	-17.2%	(0.00021)	0.00000	(0.00021)	0.0%
4c. Adjustments to Fuel Cost (2)	(8,125)	0	(8,125)	0.0%	1,338,050 (a)	1,615,197 (a)	(277,147)	-17.2%	(0.00061)	0.00000	(0.00061)	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**31,932,995**	**38,930,550**	**(6,997,555)**	**-18.0%**	**1,338,050**	**1,615,197**	**(277,147)**	**-17.2%**	**2.38653**	**2.41027**	**(0.02373)**	**-1.0%**
6. Fuel Cost of Purchased Power - Firm (A7)	16,613,937	15,459,900	1,154,037	7.5%	418,518	288,315	130,203	45.2%	3.96971	5.36216	(1.39245)	-26.0%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	872,631	986,000	(113,369)	-11.5%	32,759	39,704	(6,945)	-17.5%	2.66379	2.48338	0.18041	7.3%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**17,486,568**	**16,445,900**	**1,040,668**	**6.3%**	**451,277**	**328,019**	**123,258**	**37.6%**	**3.87491**	**5.01370**	**(1.13880)**	**-22.7%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,789,327**	**1,943,216**	**(153,889)**	**-7.9%**				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	184,716	87,900	96,816	110.1%	5,186	6,030	(844)	-14.0%	3.56182	1.45771	2.10411	144.3%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	4,428	0	4,428	0.0%	62	0	62	0.0%	7.14194	0.00000	7.14194	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	380,471	686,800	(306,329)	-44.6%	14,945	26,100	(11,155)	-42.7%	2.54581	2.63142	(0.08561)	-3.3%
21. Fuel Cost of Market Base Sales (A6)	4,833	274,000	(269,167)	-98.2%	0	13,234	(13,234)	-100.0%	0.00000	2.07042	(2.07042)	-100.0%
21a. Gains on Market Based Sales	0	135,100	(135,100)	-100.0%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	**574,448**	**1,183,800**	**(609,352)**	**-51.5%**	**20,193**	**45,364**	**(25,171)**	**-55.5%**	**2.84479**	**2.60956**	**0.23523**	**9.0%**
23. Net Inadvertant Interchange					1,289	0	1,289	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					1,338	0	1,338	0.0%				
25. Interchange and Wheeling Losses					278	700	(422)	-60.3%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	**48,845,115**	**54,192,650**	**(5,347,535)**	**-9.9%**	**1,771,483**	**1,897,152**	**(125,669)**	**-6.6%**	**2.75730**	**2.85653**	**(0.09923)**	**-3.5%**
27. Net Unbilled	(1,343,991) (a)	(2,250,629) (a)	906,638	-40.3%	(48,743)	(78,789)	30,046	-38.1%	2.75730	2.85653	(0.09923)	-3.5%
28. Company Use	127,470 (a)	117,118 (a)	10,352	8.8%	4,623	4,100	523	12.8%	2.75730	2.85654	(0.09924)	-3.5%
29. T & D Losses	3,026,331 (a)	4,029,302 (a)	(1,002,971)	-24.9%	109,757	141,056	(31,299)	-22.2%	2.75730	2.85653	(0.09923)	-3.5%
30. System KWH Sales	48,845,115	54,192,650	(5,347,535)	-9.9%	1,705,846	1,830,785	(124,939)	-6.8%	2.86340	2.96008	(0.09668)	-3.3%
31. Wholesale KWH Sales	(1,594,742)	(3,135,104)	1,540,362	-49.1%	(55,694)	(105,913)	50,219	-47.4%	2.86340	2.96007	(0.09667)	-3.3%
32. Jurisdictional KWH Sales	47,250,373	51,057,546	(3,807,173)	-7.5%	1,650,152	1,724,872	(74,720)	-4.3%	2.86340	2.96008	(0.09668)	-3.3%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	47,281,558	51,091,244	(3,809,686)	-7.5%	1,650,152	1,724,872	(74,720)	-4.3%	2.86529	2.96203	(0.09675)	-3.3%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	285,344	277,910	7,434	2.7%	1,650,152	1,724,872	(74,720)	-4.3%	0.01729	0.01611	0.00118	7.3%
35a. Adjustment	0	0	0	0.0%	1,650,152	1,724,872	(74,720)	-4.3%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	1,650,152	1,724,872	(74,720)	-4.3%	0.00000	0.00000	0.00000	0.0%
36. True-up *	7,389,395	7,389,395	0	0.0%	1,650,152	1,724,872	(74,720)	-4.3%	0.44780	0.42840	0.01940	4.5%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	54,956,297	58,758,549	(3,802,252)	-6.5%	1,650,152	1,724,872	(74,720)	-4.3%	3.33038	3.40655	(0.07617)	-2.2%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.33278	3.40900	(0.07622)	-2.2%
40. GPIF * (Already Adjusted for Taxes)	91,246	91,246	0	0.0%	1,650,152	1,724,872	(74,720)	-4.3%	0.00553	0.00529	0.00024	4.5%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**55,047,543**	**58,849,795**	**(3,802,252)**	**-6.5%**	**1,650,152**	**1,724,872**	**(74,720)**	**-4.3%**	**3.33831**	**3.41429**	**(0.07598)**	**-2.2%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.338**	**3.414**	**(0.076)**	**-2.2%**

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY

PERIOD TO DATE THROUGH: SEPTEMBER 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	277,494,321	305,017,160	(27,522,839)	-9.0%	12,148,915	13,229,805	(1,080,890)	-8.2%	2.28411	2.30553	(0.02142)	-0.9%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(54,570)	(36,000)	(18,570)	51.6%	12,148,915 (a)	13,229,805 (a)	(1,080,890)	-8.2%	(0.00045)	(0.00027)	(0.00018)	65.1%
4b. Adjustments to Fuel Cost (1)	(16,047)	0	(16,047)	0.0%	12,148,915 (a)	13,229,805 (a)	(1,080,890)	-8.2%	(0.00013)	0.00000	(0.00013)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	12,148,915 (a)	13,229,805 (a)	(1,080,890)	-8.2%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**277,423,704**	**304,981,160**	**(27,557,456)**	**-9.0%**	**12,148,915**	**13,229,805**	**(1,080,890)**	**-8.2%**	**2.28353**	**2.30526**	**(0.02173)**	**-0.9%**
6. Fuel Cost of Purchased Power - Firm (A7)	107,441,165	106,568,700	872,465	0.8%	2,525,232	1,892,981	632,251	33.4%	4.25470	5.62968	(1.37497)	-24.4%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	8,466,123	8,165,800	300,323	3.7%	356,329	355,199	1,130	0.3%	2.37593	2.29894	0.07699	3.3%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**115,907,288**	**114,734,500**	**1,172,788**	**1.0%**	**2,881,561**	**2,248,180**	**633,381**	**28.2%**	**4.02238**	**5.10344**	**(1.08106)**	**-21.2%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**15,030,476**	**15,477,985**	**(447,509)**	**-2.9%**				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	1,133,369	807,900	325,469	40.3%	41,930	54,783	(12,853)	-23.5%	2.70300	1.47473	1.22828	83.3%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	6,571	0	6,571	0.0%	(424)	0	(424)	0.0%	(1.54976)	0.00000	(1.54976)	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	8,609,521	10,377,600	(1,768,079)	-17.0%	334,659	405,942	(71,283)	-17.6%	2.57262	2.55642	0.01620	0.6%
21. Fuel Cost of Market Base Sales (A6)	560,432	4,359,300	(3,798,868)	-87.1%	27,613	180,519	(152,906)	-84.7%	2.02959	2.41487	(0.38528)	-16.0%
21a. Gains on Market Based Sales	70,874	2,832,900	(2,762,026)	-97.5%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	**10,380,767**	**18,377,700**	**(7,996,933)**	**-43.5%**	**403,778**	**641,244**	**(237,466)**	**-37.0%**	**2.57091**	**2.86594**	**(0.29504)**	**-10.3%**
23. Net Inadvertant Interchange					2,273	0	2,273	0.0%				
24. Wheeling Rec'd. less Wheeling Delv'd.					1,307	0	1,307	0.0%				
25. Interchange and Wheeling Losses					2,202	9,400	(7,198)	-76.6%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	**382,950,225**	**401,337,960**	**(18,387,735)**	**-4.6%**	**14,628,076**	**14,827,341**	**(199,265)**	**-1.3%**	**2.61791**	**2.70674**	**(0.08883)**	**-3.3%**
27. Net Unbilled	5,169,276 (a)	4,370,126 (a)	799,150	18.3%	167,798	169,953	(2,155)	-1.3%	3.08065	2.57137	0.50928	19.8%
28. Company Use	958,694 (a)	993,811 (a)	(35,117)	-3.5%	36,723	36,900	(177)	-0.5%	2.61061	2.69325	(0.08265)	-3.1%
29. T & D Losses	18,447,411 (a)	3,357,098 (a)	15,090,313	449.5%	696,935	110,822	586,113	528.9%	2.64693	3.02927	(0.38234)	-12.6%
30. System KWH Sales	382,950,225	401,337,960	(18,387,735)	-4.6%	13,726,620	14,509,666	(783,046)	-5.4%	2.78984	2.76600	0.02383	0.9%
31. Wholesale KWH Sales	(10,587,874)	(27,045,469)	16,457,595	-60.9%	(369,254)	(977,031)	607,777	-62.2%	2.86737	2.76813	0.09924	3.6%
32. Jurisdictional KWH Sales	372,362,351	374,292,491	(1,930,140)	-0.5%	13,357,366	13,532,635	(175,269)	-1.3%	2.78769	2.76585	0.02184	0.8%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	372,608,110	374,539,524	(1,931,414)	-0.5%	13,357,366	13,532,635	(175,269)	-1.3%	2.78953	2.76768	0.02186	0.8%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	2,673,950	2,559,850	114,100	4.5%	13,357,366	13,532,635	(175,269)	-1.3%	0.02002	0.01892	0.00110	5.8%
35a. Adjustment	0	0	0	0.0%	13,357,366	13,532,635	(175,269)	-1.3%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	13,357,366	13,532,635	(175,269)	-1.3%	0.00000	0.00000	0.00000	0.0%
36. True-up *	66,504,555	66,504,555	0	0.0%	13,357,366	13,532,635	(175,269)	-1.3%	0.49789	0.49144	0.00645	1.3%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	441,786,615	443,603,929	(1,817,314)	-0.4%	13,357,366	13,532,635	(175,269)	-1.3%	3.30744	3.27803	0.02941	0.9%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.30982	3.28039	0.02943	0.9%
40. GPIF * (Already Adjusted for Taxes)	821,214	821,214	0	0.0%	13,357,366	13,532,635	(175,269)	-1.3%	0.00615	0.00607	0.00008	1.3%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**442,607,829**	**444,425,143**	**(1,817,314)**	**-0.4%**	**13,357,366**	**13,532,635**	**(175,269)**	**-1.3%**	**3.31597**	**3.28646**	**0.02951**	**0.9%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.316**	**3.286**	**0.030**	**0.9%**

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: SEPTEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	31,950,037	38,934,550	(6,984,513)	-17.9%	277,494,321	305,017,160	(27,522,839)	-9.0%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	574,448	1,048,700	(474,252)	-45.2%	10,309,893	15,544,800	(5,234,907)	-33.7%
2a. GAINS FROM MARKET BASED SALES	0	135,100	(135,100)	-100.0%	70,874	2,832,900	(2,762,026)	-97.5%
3. FUEL COST OF PURCHASED POWER	16,613,937	15,459,900	1,154,037	7.5%	107,441,165	106,568,700	872,465	0.8%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	872,631	986,000	(113,369)	-11.5%	8,466,123	8,165,800	300,323	3.7%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	48,862,157	54,196,650	(5,334,493)	-9.8%	383,020,842	401,373,960	(18,353,118)	-4.6%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(6,124)	(4,000)	(2,124)	53.1%	(54,570)	(36,000)	(18,570)	51.6%
6b. ADJ.TO FUEL COST	(2,793)	0	(2,793)	0.0%	(16,047)	0	(16,047)	0.0%
6c. ADJ.TO FUEL COST	(8,125)	0	(8,125)	0.0%	0	0	0	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	48,845,115	54,192,650	(5,347,535)	-9.9%	382,950,225	401,337,960	(18,387,735)	-4.6%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,650,152	1,724,872	(74,720)	-4.3%	13,357,366	13,532,635	(175,269)	-1.3%
2. NONJURISDICTIONAL SALES	55,694	105,913	(50,219)	-47.4%	369,254	977,031	(607,777)	-62.2%
3. TOTAL SALES	1,705,846	1,830,785	(124,939)	-6.8%	13,726,620	14,509,666	(783,046)	-5.4%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9673511	0.9421489	0.0252022	2.7%	0.9730994	0.9326634	0.0404360	4.3%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: SEPTEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	54,009,960	56,907,027	(2,897,067)	-5.1%	437,417,168	446,182,748	(8,765,580)	-2.0%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(7,389,395)	(7,389,395)	0	0.0%	(66,504,555)	(66,504,555)	0	0.0%
2b. INCENTIVE PROVISION	(91,246)	(91,246)	0	0.0%	(821,214)	(821,214)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	46,529,319	49,426,386	(2,897,067)	-5.9%	370,091,399	378,856,979	(8,765,580)	-2.3%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	48,845,115	54,192,650	(5,347,535)	-9.9%	382,950,225	401,337,960	(18,387,735)	-4.6%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9673511	0.9421489	0.0252022	2.7%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	47,250,373	51,057,546	(3,807,173)	-7.5%	372,362,351	374,292,491	(1,930,140)	-0.5%
6a. JURISDIC. LOSS MULTIPLIER	1.00066	1.00066	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	47,281,558	51,091,244	(3,809,686)	-7.5%	372,608,110	374,539,524	(1,931,414)	-0.5%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	294,975	294,975	0	0.0%	2,745,891	2,745,891	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	285,344	277,910	7,434	2.7%	2,673,950	2,559,850	114,100	4.5%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	47,566,902	51,369,154	(3,802,252)	-7.4%	375,282,060	377,099,374	(1,817,314)	-0.5%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(1,037,583)	(1,942,768)	905,185	-46.6%	(5,190,661)	1,757,605	(6,948,266)	-395.3%
8. INTEREST PROVISION FOR THE MONTH	(58,447)	(81,811)	23,364	-28.6%	(847,720)	(1,515,828)	668,108	-44.1%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(43,484,086)	(27,291,219)	(16,192,867)	59.3%	NOT APPLICABLE			
10. TRUE-UP COLLECTED (REFUNDED)	7,389,395	7,389,395	0	0.0%	NOT APPLICABLE			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(37,190,721)	(21,926,403)	(15,264,318)	69.6%	NOT APPLICABLE			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: SEPTEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(43,484,086)	(27,291,219)	(16,192,867)	59.3%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(37,132,274)	(21,844,592)	(15,287,682)	70.0%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(80,616,360)	(49,135,811)	(31,480,549)	64.1%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(40,308,180)	(24,567,906)	(15,740,274)	64.1%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.710	4.000	(2)	-57.3%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.760	4.000	(2)	-56.0%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	3.470	8.000	(5)	-56.6%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.735	4.000	(2)	-56.6%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.145	0.333	(0)	-56.5%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(58,447)	(81,811)	23,364	-28.6%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	537,728	646,831	(109,103)	-16.9%	3,158,552	3,759,019	(600,467)	-16.0%
2	LIGHT OIL	680,869	1,271,047	(590,178)	-46.4%	8,870,208	12,840,984	(3,970,776)	-30.9%
3	COAL	25,882,830	30,451,240	(4,568,410)	-15.0%	242,047,992	258,651,627	(16,603,635)	-6.4%
4	NATURAL GAS	4,848,610	6,565,432	(1,716,822)	-26.1%	23,417,569	29,765,530	(6,347,961)	-21.3%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	31,950,037	38,934,550	(6,984,513)	-17.9%	277,494,321	305,017,160	(27,522,839)	-9.0%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	11,145	17,799	(6,654)	-37.4%	63,512	91,726	(28,214)	-30.8%
9	LIGHT OIL	12,988	19,454	(6,466)	-33.2%	173,507	187,011	(13,504)	-7.2%
10	COAL	1,238,832	1,460,904	(222,072)	-15.2%	11,531,260	12,404,678	(873,418)	-7.0%
11	NATURAL GAS	75,085	117,040	(41,955)	-35.8%	380,636	546,390	(165,754)	-30.3%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,338,050	1,615,197	(277,147)	-17.2%	12,148,915	13,229,805	(1,080,890)	-8.2%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	17,418	26,509	(9,091)	-34.3%	100,927	136,576	(35,649)	-26.1%
16	LIGHT OIL (BBL)	21,232	41,680	(20,448)	-49.1%	293,676	396,769	(103,093)	-26.0%
17	COAL (TON)	601,977	653,677	(51,700)	-7.9%	5,511,243	5,529,364	(18,121)	-0.3%
18	NATURAL GAS (MCF)	821,932	1,197,386	(375,454)	-31.4%	4,116,956	5,576,822	(1,459,866)	-26.2%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	109,274	166,450	(57,176)	-34.4%	633,181	857,553	(224,372)	-26.2%
22	LIGHT OIL	120,383	236,496	(116,113)	-49.1%	1,690,535	2,255,839	(565,304)	-25.1%
23	COAL	14,190,816	15,342,312	(1,151,497)	-7.5%	128,337,079	129,710,158	(1,373,079)	-1.1%
24	NATURAL GAS	864,673	1,230,929	(366,256)	-29.8%	4,334,333	5,733,202	(1,398,869)	-24.4%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	15,285,145	16,976,187	(1,691,042)	-10.0%	134,995,127	138,556,752	(3,561,625)	-2.6%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.83%	1.10%	(0.00)	-	0.52%	0.69%	(0.00)	-
29	LIGHT OIL	0.97%	1.20%	(0.00)	-	1.43%	1.41%	0.00	-
30	COAL	92.58%	90.45%	0.02	-	94.92%	93.76%	0.01	-
31	NATURAL GAS	5.61%	7.25%	(0.02)	-	3.13%	4.13%	(0.01)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	30.87	24.40	6.47	26.5%	31.30	27.52	3.77	13.7%
36	LIGHT OIL ($/BBL)	32.07	30.50	1.57	5.2%	30.20	32.36	(2.16)	-6.7%
37	COAL ($/TON)	43.00	46.58	(3.59)	-7.7%	43.92	46.78	(2.86)	-6.1%
38	NATURAL GAS ($/MCF)	5.90	5.48	0.42	7.6%	5.69	5.34	0.35	6.6%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	4.92	3.89	1.03	26.6%	4.99	4.38	0.60	13.8%
42	LIGHT OIL	5.66	5.37	0.28	5.2%	5.25	5.69	(0.45)	-7.8%
43	COAL	1.82	1.98	(0.16)	-8.1%	1.89	1.99	(0.11)	-5.4%
44	NATURAL GAS	5.61	5.33	0.27	5.1%	5.40	5.19	0.21	4.1%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.09	2.29	(0.20)	-8.9%	2.06	2.20	(0.15)	-6.8%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,805	9,352	453	4.8%	9,969	9,349	620	6.6%
49	LIGHT OIL	9,269	12,157	(2,888)	-23.8%	9,743	12,063	(2,320)	-19.2%
50	COAL	11,455	10,502	953	9.1%	11,129	10,457	672	6.4%
51	NATURAL GAS	11,516	10,517	999	9.5%	11,387	10,493	894	8.5%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	11,423	10,510	913	8.7%	11,112	10,473	639	6.1%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	4.82	3.63	1.19	32.8%	4.97	4.10	0.87	21.2%
56	LIGHT OIL	5.24	6.53	(1.29)	-19.8%	5.11	6.87	(1.76)	-25.6%
57	COAL	2.09	2.08	0.01	0.5%	2.10	2.09	0.01	0.5%
58	NATURAL GAS	6.46	5.61	0.85	15.2%	6.15	5.45	0.70	12.8%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.39	2.41	(0.02)	-0.8%	2.28	2.31	(0.03)	-1.3%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: SEPTEMBER 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	0	-165	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-165**	**---**	**---**	**---**	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	40,940	49.9	64.3	74.2	12,129	COAL	22,289	22,278,000	496,554.3	873,246	2.13	39.18
GAN.#2	98	39,108	55.4	62.5	79.4	12,402	COAL	21,371	22,696,000	485,036.2	837,280	2.14	39.18
GAN.#3	145	65,992	63.2	72.2	78.7	12,417	COAL	41,483	19,754,000	819,455.2	1,625,235	2.46	39.18
GAN.#4	159	61,896	54.1	65.7	75.6	13,660	COAL	41,400	20,422,000	845,470.8	1,621,983	2.62	39.18
GAN.#5	217	89,300	57.2	71.6	74.1	11,961	COAL	45,420	23,516,000	1,068,096.7	1,779,480	1.99	39.18
GAN.#6	372	176,356	66.6	79.5	75.3	10,910	COAL	82,742	23,518,000	1,945,926.4	3,241,695	1.82	39.18
GANNON STATION	**1,105**	**475,592**	**59.8**	**71.9**	**75.8**	**11,902**	**COAL**	**254,705**	**22,223,905**	**5,660,539.6**	**9,978,919**	**2.10**	**39.18**
B.B.#1	416	225,793	75.4	84.3	75.4	11,295	COAL	103,307	24,687,000	2,550,346.8	4,722,152	2.09	45.71
B.B.#2	416	166,375	55.5	59.9	67.9	11,278	COAL	76,415	24,555,720	1,876,418.5	3,492,922	2.10	45.71
B.B.#3	433	194,783	62.5	71.4	71.9	10,722	COAL	86,478	24,150,420	2,088,489.9	3,952,900	2.03	45.71
B.B. 1 - 3	1,265	586,951	64.4	71.8	71.7	11,100	COAL	266,200	24,475,001	6,515,255.2	12,167,974	2.07	45.71
B.B.#4	442	55,348	17.4	22.6	68.7	12,043	COAL	29,315	22,737,953	666,552.4	1,594,959	2.88	54.41
B.B. STATION	**1,707**	**642,299**	**52.3**	**59.1**	**70.9**	**11,181**	**COAL**	**295,515**	**24,302,689**	**7,181,807.6**	**13,762,933**	**2.14**	**46.57**
SEB-PHIL. #1(HVY OIL)	17	5,581	45.6	94.6	91.3	9,662	HVY.OIL	8,595	6,273,540	53,922.1	265,345	4.75	30.87
SEB-PHIL. #2(HVY OIL)	17	5,729	46.8	100.0	90.0	9,662	HVY.OIL	8,823	6,273,540	55,352.0	272,383	4.75	30.87
SEB-PHILLIPS TOTAL	**34**	**11,310**	**46.2**	**97.3**	**90.6**	**9,662**	**HVY.OIL**	**17,418**	**6,273,540**	**109,274.1**	**537,728**	**4.75**	**30.87**
POLK #1 GASIFIER	250	120,941	67.2	73.3	84.8	11,150	COAL	51,757	26,054,000	1,348,468.3	2,140,978	1.77	41.37
POLK #1 CT (OIL)	225	11,202	6.9	97.5	74.7	8,312	LGT.OIL	16,562	5,810,967	93,107.9	536,443	4.79	32.39
POLK #1 TOTAL	**250**	**132,143**	**73.4**	**89.7**	**83.8**	**10,909**	**-**	**-**	**-**	**1,441,576.2**	**2,677,421**	**2.03**	**-**
POLK #2 CT (GAS)	150	23,776	22.0	99.7	98.3	11,164	GAS	252,314	972,290	265,434.0	1,865,614	7.85	7.39
POLK #2 CT (OIL)	160	617	0.5	98.9	48.2	15,412	LGT.OIL	1,636	5,810,942	9,509.2	53,009	8.59	32.40
POLK #2 TOTAL	**155**	**24,393**	**21.9**	**100.0**	**95.8**	**11,271**	**-**	**-**	**-**	**274,943.2**	**1,918,623**	**7.87**	**-**
POLK #3 CT (GAS)	150	49,434	45.8	100.0	78.4	11,728	GAS	551,107	972,290	579,765.0	2,867,793	5.80	5.20
POLK #3 CT (OIL)	160	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**155**	**49,434**	**44.3**	**100.0**	**78.4**	**11,728**	**-**	**-**	**-**	**579,765.0**	**2,867,793**	**5.80**	**-**
POLK STATION TOTAL	**560**	**205,970**	**51.1**	**95.4**	**83.1**	**11,149**	**-**	**-**	**-**	**2,296,284.4**	**7,463,837**	**3.62**	**-**
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	48	0.6	100.0	100.0	18,704	LGT.OIL	153	5,855,345	897.8	4,610	9.60	30.13
B.B.C.T.#2	66	1,121	2.4	32.9	70.8	15,047	LGT.OIL	2,881	5,853,913	16,867.7	86,807	7.74	30.13
B.B.C.T.#3	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**144**	**1,169**	**1.1**	**23.4**	**40.8**	**15,197**	**LGT.OIL**	**3,034**	**5,853,986**	**17,765.5**	**91,417**	**7.82**	**30.13**
CITY OF TAMPA	**6**	**1,875**	**0.0**	**0.0**	**0.0**	**10,386**	**GAS**	**18,511**	**972,290**	**19,473.6**	**115,203**	**6.14**	**6.22**
TOT. COAL (GN,BB,POLK)	**3,062**	**1,238,832**	**56.2**	**64.9**	**73.8**	**11,455**	**COAL**	**601,977**	**23,573,699**	**14,190,815.5**	**25,882,830**	**2.09**	**43.00**
SYSTEM	**3,556**	**1,338,050**	**52.4**	**67.7**	**70.2**	**11,422**	**-**	**-**	**-**	**15,285,144.8**	**31,950,037**	**2.39**	**-**

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT B.B. = BIG BEND

GAN. = GANNON C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	11,871	26,509	(14,638)	-55.2%	96,747	136,576	(39,829)	-29.2%
3 UNIT COST ($/BBL)	28.78	23.94	4.84	20.2%	28.50	26.57	1.93	7.3%
4 AMOUNT ($)	341,596	634,610	(293,014)	-46.2%	2,757,508	3,629,242	(871,734)	-24.0%
5 BURNED:								
6 UNITS (BBL)	17,418	26,509	(9,091)	-34.3%	100,927	136,576	(35,649)	-26.1%
7 UNIT COST ($/BBL)	30.87	24.40	6.47	26.5%	31.30	27.52	3.77	13.7%
8 AMOUNT ($)	537,728	646,831	(109,103)	-16.9%	3,158,552	3,759,019	(600,467)	-16.0%
9 ENDING INVENTORY:								
10 UNITS (BBL)	13,469	59,129	(45,660)	-77.2%	13,469	59,129	(45,660)	-77.2%
11 UNIT COST ($/BBL)	30.97	25.48	5.49	21.5%	30.97	25.48	5.49	21.5%
12 AMOUNT ($)	417,086	1,506,533	(1,089,447)	-72.3%	417,086	1,506,533	(1,089,447)	-72.3%
13								
14 DAYS SUPPLY:	26	90	(64)	-71.1%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	22,300	50,040	(27,740)	-55.4%	363,075	484,843	(121,768)	-25.1%
17 UNIT COST ($/BBL)	35.20	29.76	5.44	18.3%	30.28	31.52	(1.24)	-3.9%
18 AMOUNT ($)	785,070	1,489,266	(704,196)	-47.3%	10,994,329	15,282,265	(4,287,936)	-28.1%
19 BURNED:								
20 UNITS (BBL)	21,232	41,680	(20,448)	-49.1%	293,676	396,769	(103,093)	-26.0%
21 UNIT COST ($/BBL)	32.07	30.50	1.57	5.2%	30.20	32.36	(2.16)	-6.7%
22 AMOUNT ($)	680,869	1,271,047	(590,178)	-46.4%	8,870,208	12,840,984	(3,970,776)	-30.9%
23 ENDING INVENTORY:								
24 UNITS (BBL)	99,018	113,465	(14,447)	-12.7%	99,018	113,465	(14,447)	-12.7%
25 UNIT COST ($/BBL)	31.13	30.57	0.56	1.8%	31.13	30.57	0.56	1.8%
26 AMOUNT ($)	3,082,721	3,468,454	(385,733)	-11.1%	3,082,721	3,468,454	(385,733)	-11.1%
27								
28 DAYS SUPPLY: NORMAL	76	76	(0)	-0.3%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	14	16	(2)	-11.6%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	544,246	595,000	(50,754)	-8.5%	5,579,696	5,842,000	(262,304)	-4.5%
32 UNIT COST ($/TON)	43.51	45.81	(2.31)	-5.0%	44.01	46.49	(2.48)	-5.3%
33 AMOUNT ($)	23,678,090	27,258,458	(3,580,368)	-13.1%	245,582,198	271,604,991	(26,022,793)	-9.6%
34 BURNED:								
35 UNITS (TONS)	601,977	653,677	(51,700)	-7.9%	5,511,243	5,529,364	(18,121)	-0.3%
36 UNIT COST ($/TON)	43.00	46.58	(3.59)	-7.7%	43.92	46.78	(2.86)	-6.1%
37 AMOUNT ($)	25,882,830	30,451,240	(4,568,410)	-15.0%	242,047,992	258,651,627	(16,603,635)	-6.4%
38 ENDING INVENTORY:								
39 UNITS (TONS)	693,933	1,289,456	(595,523)	-46.2%	693,933	1,289,456	(595,523)	-46.2%
40 UNIT COST ($/TON)	43.58	47.01	(3.43)	-7.3%	43.58	47.01	(3.43)	-7.3%
41 AMOUNT ($)	30,240,747	60,620,653	(30,379,906)	-50.1%	30,240,747	60,620,653	(30,379,906)	-50.1%
42								
43 DAYS SUPPLY:	38	77	(39)	-51.0%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	821,932	1,197,386	(375,454)	-31.4%	4,116,956	5,576,822	(1,459,866)	-26.2%
46 UNIT COST ($/MCF)	5.90	5.48	0.42	7.6%	5.69	5.34	0.35	6.6%
47 AMOUNT ($)	4,848,610	6,565,431	(1,716,821)	-26.1%	23,416,596	29,765,527	(6,348,931)	-21.3%
48 BURNED:								
49 UNITS (MCF)	821,932	1,197,386	(375,454)	-31.4%	4,116,956	5,576,822	(1,459,866)	-26.2%
50 UNIT COST ($/MCF)	5.90	5.48	0.42	7.6%	5.69	5.34	0.35	6.6%
51 AMOUNT ($)	4,848,610	6,565,432	(1,716,822)	-26.1%	23,417,569	29,765,530	(6,347,961)	-21.3%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 *UNITS (MMBTU)*	*0*	*0*	*0*	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 *UNIT COST ($/MMBTU)*	*0.00*	*0.00*	*0.00*	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	18,025
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	18,025

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(8,935)	(269,443)
OTHER USAGE	(881)	(27,161)
TOTAL	(9,816)	(296,604)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	39,712
IGNITION #2 OIL	251,418
IGNITION PROPANE	4,587
AERIAL SURVEY ADJ.	(349,845)
ADDITIVES	28,833
GREEN FUEL	0
TOTAL	(25,295)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2002

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. -D	6,030.0	0.0	6,030.0	1.458	1.458	87,900.00	87,900.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	26,100.0	0.0	26,100.0	2.631	3.679	686,800.00	960,300.00	
VARIOUS	JURISDIC.	SCH. -MB	13,234.0	0.0	13,234.0	2.070	2.070	274,000.00	274,000.00	135,100.00
TOTAL			45,364.0	0.0	45,364.0	2.312	2.915	1,048,700.00	1,322,200.00	135,100.00
ACTUAL:										
FLA. PWR. & LIGHT	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR PARTNERS	SEP. CONTR.	SCH. -D	14,945.0	0.0	14,945.0	2.560	3.267	382,592.00	488,253.15	
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. -D	5,796.7	1,201.4	4,595.3	3.892	3.892	178,834.94	178,834.94	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. -D	590.7	0.0	590.7	0.458	0.458	2,708.34	2,708.34	
FLA. PWR. CORP.		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF LAKELAND		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
DUKE ENERGY		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
THE ENERGY AUTHORITY		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
AUBURNDALE POWER PARTNERS		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
AUBURNDALE POWER PARTNERS		SCH. -OATT	39.0	0.0	39.0	7.991	7.991	3,116.45	3,116.45	
CARGILL ALLIANT		SCH. -OATT	47.0	0.0	47.0	2.791	2.791	1,312.00	1,312.00	
ADJUSTMENTS TO PREV. MONTHS										
HARDEE PWR PART	Aug. 2002	CONTRACT	(53,025.0)	0.0	(53,025.0)	2.564	3.263	(1,359,561.00)	(1,730,205.75)	
HARDEE PWR PART	Aug. 2002	CONTRACT	53,025.0	0.0	53,025.0	2.560	3.267	1,357,440.00	1,732,326.75	
AUBURNDALE PWR PARTNERS	Aug. 2002	SCH. -OATT	(116.0)	0.0	(116.0)	2.578	2.578	(2,990.31)	(2,990.31)	
AUBURNDALE PWR PARTNERS	Aug. 2002	SCH. -OATT	92.0	0.0	92.0	3.250	3.250	2,990.31	2,990.31	
SEMINOLE ELEC. PRECO-1	July 2002	SCH. -D	(5,240.6)	(374.5)	(4,866.1)	2.852	2.852	(138,766.17)	(138,766.17)	
SEMINOLE ELEC. PRECO-1	July 2002	SCH. -D	5,240.6	374.5	4,866.1	2.855	2.855	138,951.31	138,951.31	
SEMINOLE ELEC. PRECO-1	June 2002	SCH. -D	(5,510.7)	(464.2)	(5,046.5)	2.721	2.721	(137,298.41)	(137,298.41)	
SEMINOLE ELEC. PRECO-1	June 2002	SCH. -D	5,510.7	464.2	5,046.5	2.726	2.726	137,572.03	137,572.03	
SEMINOLE ELEC. HARDEE	May 2002	SCH. -D	(946.9)	0.0	(946.9)	1.956	1.956	(18,526.01)	(18,526.01)	
SEMINOLE ELEC. HARDEE	May 2002	SCH. -D	946.9	0.0	946.9	2.243	2.243	21,239.98	21,239.98	
AQUILA	Feb. 2002	SCH. -MA	(800.0)	0.0	(800.0)	2.433	2.476	(19,462.21)	(19,810.66)	2,163.55
AQUILA	Feb. 2002	SCH. -MA	800.0	0.0	800.0	3.037	3.080	24,294.99	24,643.44	(2,163.55)
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISDICTIONAL			6,387.4	1,201.4	5,186.0	3.562	3.562	184,716.01	184,716.01	
SUB-TOTAL SCHEDULE D POWER SALES-SEPARATED			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEP.			14,945.0	0.0	14,945.0	2.546	3.281	380,471.00	490,374.15	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISDICTIONAL			0.0	0.0	0.0	0.000	0.000	4,832.78	4,832.78	0.00
SUB-TOTAL SCHEDULE OATT SALES-JURISDICTIONAL			62.0	0.0	62.0	7.143	7.143	4,428.45	4,428.45	
TOTAL			21,394.4	1,201.4	20,193.0	2.845	3.389	574,448.24	684,351.39	0.00
CURRENT MONTH:										
DIFFERENCE			(23,969.6)	1,201.4	(25,171.0)	0.533	0.474	(474,251.76)	(637,848.61)	(135,100.00)
DIFFERENCE %			-52.8%	0.0%	-55.5%	23.1%	16.3%	-45.2%	-48.2%	-100.0%
PERIOD TO DATE:										
ACTUAL			407,939.7	4,160.9	403,778.8	2.553	3.205	10,309,893.93	12,942,635.07	70,874.52
ESTIMATED			641,244.0	0.0	641,244.0	2.424	3.088	15,544,800.00	19,799,200.00	2,832,900.00
DIFFERENCE			(233,304.3)	4,160.9	(237,465.2)	0.129	0.117	(5,234,906.07)	(6,856,564.93)	(2,762,025.48)
DIFFERENCE %			-36.4%	0.0%	-37.0%	5.3%	3.8%	-33.7%	-34.6%	-97.5%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF SEPTEMBER 2002.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH.-J	55,087.0	0.0	29,190.0	25,897.0	5.809	5.809	1,504,300.00
HARDEE POWER PARTNERS		IPP	131,535.0	0.0	0.0	131,535.0	4.477	4.477	5,888,300.00
VARIOUS		OTHER	12,227.0	0.0	0.0	12,227.0	6.356	6.356	777,200.00
VARIOUS		MKT. BASE	118,656.0	0.0	0.0	118,656.0	6.144	6.144	7,290,100.00
TOTAL			**317,505.0**	**0.0**	**29,190.0**	**288,315.0**	**5.362**	**5.362**	**15,459,900.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	91,254.0	0.0	0.0	91,254.0	2.811	2.811	2,565,605.45
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH.-J	45,328.0	0.0	2,563.8	42,764.2	3.790	3.790	1,620,960.60
FLA. POWER & LIGHT		SCH.-J	46,610.0	0.0	4,697.4	41,912.6	5.113	5.113	2,142,914.68
CITY OF LAKELAND		SCH.-J	37,868.0	0.0	5,220.7	32,647.3	4.030	4.030	1,315,702.41
ORLANDO UTIL. COMM.		SCH.-J	32,650.0	0.0	6,211.8	26,438.2	5.466	5.466	1,445,116.24
THE ENERGY AUTHORITY		SCH.-J	40,248.0	0.0	6,098.5	34,149.5	4.400	4.400	1,502,412.65
REEDY CREEK		SCH.-J	181.0	0.0	10.0	171.0	4.508	4.508	7,709.00
OKEELANTA		SCH.-J	16,154.0	0.0	0.0	16,154.0	4.203	4.203	678,885.58
TALLAHASSEE		SCH.-J	479.0	0.0	0.0	479.0	3.772	3.772	18,065.60
CALPINE		SCH.-J	1,597.0	0.0	150.0	1,447.0	4.904	4.904	70,959.00
CARGILL ALLIANT		SCH.-J	25,739.0	0.0	2,774.0	22,965.0	4.076	4.076	936,085.50
KOCH ENERGY		SCH.-J	3,200.0	0.0	36.0	3,164.0	5.167	5.167	163,472.00
RELIANT		SCH.-J	17,486.0	0.0	5,881.9	11,604.1	6.291	6.291	729,988.62
SEMINOLE ELECTRIC CO-OP		SCH.-J	10,528.0	0.0	1,219.5	9,308.5	3.638	3.638	338,612.94
DUKE ENERGY		SCH.-J	12,853.0	0.0	2,275.7	10,577.3	4.773	4.773	504,858.92
DYNEGY POWER MARKETING		SCH.-J	2,383.0	0.0	0.0	2,383.0	3.035	3.035	72,328.00
RINGHAVER		SCH.-J	9,500.0	0.0	0.0	9,500.0	1.536	1.536	145,924.88
FLA. POWER CORP.		SCH.-D	61,700.0	0.0	0.0	61,700.0	3.907	3.907	2,410,639.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Aug. 2002	IPP	(109,214.0)	0.0	0.0	(109,214.0)	2.065	2.065	(2,255,754.98)
HARDEE PWR. PART.-NATIVE	Aug. 2002	IPP	109,214.0	0.0	0.0	109,214.0	1.853	1.853	2,023,382.86
FLA. POWER CORP.	Aug. 2002	SCH.-J	(37,509.0)	0.0	(689.2)	(36,819.8)	3.448	3.448	(1,269,697.81)
FLA. POWER CORP.	Aug. 2002	SCH.-J	37,509.0	0.0	689.2	36,819.8	3.449	3.449	1,269,753.81
THE ENERGY AUTHORITY	Aug. 2002	SCH.-J	(22,424.0)	0.0	(2,266.9)	(20,157.1)	4.871	4.871	(981,902.49)
THE ENERGY AUTHORITY	Aug. 2002	SCH.-J	22,425.0	0.0	2,266.9	20,158.1	4.871	4.871	981,977.49
OKEELANTA	Aug. 2002	SCH.-J	(11,221.0)	0.0	0.0	(11,221.0)	3.606	3.606	(404,599.85)
OKEELANTA	Aug. 2002	SCH.-J	11,244.0	0.0	0.0	11,244.0	3.603	3.603	405,136.63
CALPINE	Aug. 2002	SCH.-J	(1,640.0)	0.0	0.0	(1,640.0)	4.891	4.891	(80,214.00)
CALPINE	Aug. 2002	SCH.-J	1,520.0	0.0	0.0	1,520.0	4.859	4.859	73,854.00
CARGILL ALLIANT	Aug. 2002	SCH.-J	(10,631.0)	0.0	(601.0)	(10,030.0)	3.839	3.839	(385,033.50)
CARGILL ALLIANT	Aug. 2002	SCH.-J	10,626.0	0.0	601.0	10,025.0	3.844	3.844	385,353.50
FLA. POWER CORP.	Aug. 2002	SCH.-D	(61,700.0)	0.0	0.0	(61,700.0)	3.907	3.907	(2,410,639.00)
FLA. POWER CORP.	Aug. 2002	SCH.-D	61,700.0	0.0	0.0	61,700.0	4.051	4.051	2,499,487.00
FLA. POWER CORP.	July 2002	SCH.-D	(64,300.0)	0.0	0.0	(64,300.0)	3.895	3.895	(2,504,681.00)
FLA. POWER CORP.	July 2002	SCH.-D	64,300.0	0.0	0.0	64,300.0	4.039	4.039	2,597,273.00
TOTAL			**455,657.0**	**0.0**	**37,139.3**	**418,517.7**	**3.970**	**3.970**	**16,613,936.73**
CURRENT MONTH:									
DIFFERENCE			138,152.0	0.0	7,949.3	130,202.7	(1.392)	(1.392)	1,154,036.73
DIFFERENCE %			43.5%	0.0%	27.2%	45.2%	-26.0%	-26.0%	7.5%
PERIOD TO DATE:									
ACTUAL			2,687,219.0	0.0	161,989.0	2,525,230.1	4.255	4.255	107,441,164.99
ESTIMATED			1,999,742.0	0.0	106,761.0	1,892,981.0	5.630	5.630	106,568,700.00
DIFFERENCE			687,477.0	0.0	55,228.0	632,249.1	(1.375)	(1.375)	872,464.99
DIFFERENCE %			34.4%	0.0%	51.7%	33.4%	-24.4%	-24.4%	0.8%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE		(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS	COGEN.		39,704.0	0.0	0.0	39,704.0	2.483	2.483	986,000.00
TOTAL			**39,704.0**	**0.0**	**0.0**	**39,704.0**	**2.483**	**2.483**	**986,000.00**
ACTUAL:									
IMC-AGRICO-NICHOLS	COGEN.		0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.		12,594.0	0.0	0.0	12,594.0	2.451	2.451	308,644.76
MULBERRY PHOSPHATES INC.	COGEN.		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.		581.0	0.0	0.0	581.0	4.264	4.264	24,772.49
HILLSBOROUGH COUNTY	COGEN.		12,117.0	0.0	0.0	12,117.0	2.451	2.451	297,039.88
CARGILL MILLPOINT	COGEN.		94.0	0.0	0.0	94.0	6.501	6.501	6,110.87
CF INDUSTRIES INC.	COGEN.		626.0	0.0	0.0	626.0	4.511	4.511	28,240.47
FARMLAND HYDRO LP	COGEN.		670.0	0.0	0.0	670.0	4.398	4.398	29,467.34
IMC-AGRICO-S. PIERCE	COGEN.		506.0	0.0	0.0	506.0	4.663	4.663	23,595.93
AUBURNDALE POWER PARTNERS	COGEN.		2.0	0.0	0.0	2.0	4.998	4.998	99.96
ORANGE COGENERATION L.P.	COGEN.		5,566.0	0.0	0.0	5,566.0	2.289	2.289	127,427.10
CUTRALE CITRUS	COGEN.		3.0	0.0	0.0	3.0	7.083	7.083	212.50
AS AVAILABLE ASSIGNMENT	COGEN.		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR SEPTEMBER 2002			32,759.0	0.0	0.0	32,759.0	2.581	2.581	845,611.30
ADJUSTMENTS FOR THE MONTH OF: JULY 2002									
IMC-AGRICO-NICHOLS	COGEN.		0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	*	(51,696.0)	0.0	0.0	(51,696.0)	2.113	2.113	(1,092,563.22)
		*	51,696.0	0.0	0.0	51,696.0	2.136	2.136	1,104,004.82
MULBERRY PHOSPHATES INC.	COGEN.		0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.		0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	*	(837.0)	0.0	0.0	(837.0)	2.551	2.551	(21,349.06)
		*	837.0	0.0	0.0	837.0	2.603	2.603	21,785.17
HILLSBOROUGH COUNTY	COGEN.	*	(64,957.0)	0.0	0.0	(64,957.0)	2.131	2.131	(1,383,924.84)
		*	64,957.0	0.0	0.0	64,957.0	2.148	2.148	1,395,277.64
CARGILL MILLPOINT	COGEN.	*	(232.0)	0.0	0.0	(232.0)	3.108	3.108	(7,209.46)
		*	232.0	0.0	0.0	232.0	3.175	3.175	7,365.56
CF INDUSTRIES INC.	COGEN.	*	(1,562.0)	0.0	0.0	(1,562.0)	2.993	2.993	(46,750.99)
		*	1,562.0	0.0	0.0	1,562.0	3.049	3.049	47,622.94
FARMLAND HYDRO LP	COGEN.	*	(5,315.0)	0.0	0.0	(5,315.0)	3.068	3.068	(163,073.36)
		*	5,315.0	0.0	0.0	5,315.0	3.105	3.105	165,034.04
IMC-AGRICO-S. PIERCE	COGEN.	*	(1,808.0)	0.0	0.0	(1,808.0)	2.534	2.534	(45,823.06)
		*	1,808.0	0.0	0.0	1,808.0	2.621	2.621	47,389.04
AUBURNDALE POWER PARTNERS	COGEN.	*	(285.0)	0.0	0.0	(285.0)	4.096	4.096	(11,672.81)
		*	285.0	0.0	0.0	285.0	4.119	4.119	11,739.36
ORANGE COGENERATION L.P.	COGEN.	*	(24,012.0)	0.0	0.0	(24,012.0)	2.122	2.122	(509,455.81)
		*	24,012.0	0.0	0.0	24,012.0	2.118	2.118	508,620.56
CUTRALE CITRUS	COGEN.	*	(3.0)	0.0	0.0	(3.0)	2.016	2.016	(60.47)
		*	3.0	0.0	0.0	3.0	2.111	2.111	63.33
AS AVAILABLE ASSIGNMENT	COGEN.		0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF: JULY 2002			0.0	0.0	0.0	0.0	0.000	0.000	27,019.38
GRAND TOTAL			**32,759.0**	**0.0**	**0.0**	**32,759.0**	**2.664**	**2.664**	**872,630.68**
CURRENT MONTH:									
DIFFERENCE			(6,945.0)	0.0	0.0	(6,945.0)	0.180	0.180	(113,369.32)
DIFFERENCE %			-17.5%	0.0%	0.0%	-17.5%	7.3%	7.3%	-11.5%
PERIOD TO DATE:									
ACTUAL			356,329.0	0.0	0.0	356,329.0	2.376	2.376	8,466,122.24
ESTIMATED			355,199.0	0.0	0.0	355,199.0	2.299	2.299	8,165,800.00
DIFFERENCE			1,130.0	0.0	0.0	1,130.0	0.077	0.077	300,322.24
DIFFERENCE %			0.3%	0.0%	0.0%	0.3%	0.033	0.033	3.7%

* Includes adjustments to January, February, March, and July 2002.

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: SEPTEMBER 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

OCTOBER 2002

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	30,302,588	31,860,939	(1,558,351)	-4.9%	1,276,772	1,311,249	(34,477)	-2.6%	2.37338	2.42982	(0.05644)	-2.3%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(5,823)	(4,000)	(1,823)	45.6%	1,276,772 (a)	1,311,249 (a)	(34,477)	-2.6%	(0.00046)	(0.00031)	(0.00015)	49.5%
4b. Adjustments to Fuel Cost (1)	(3,394)	0	(3,394)	0.0%	1,276,772 (a)	1,311,249 (a)	(34,477)	-2.6%	(0.00027)	0.00000	(0.00027)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	1,276,772 (a)	1,311,249 (a)	(34,477)	-2.6%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**30,293,371**	**31,856,939**	**(1,563,568)**	**-4.9%**	**1,276,772**	**1,311,249**	**(34,477)**	**-2.6%**	**2.37265**	**2.42951**	**(0.05686)**	**-2.3%**
6. Fuel Cost of Purchased Power - Firm (A7)	28,657,519	17,790,700	10,866,819	61.1%	454,286	384,609	69,677	18.1%	6.30825	4.62566	1.68260	36.4%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	1,107,543	1,001,500	106,043	10.6%	41,833	41,027	806	2.0%	2.64753	2.44108	0.20646	8.5%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**29,765,062**	**18,792,200**	**10,972,862**	**58.4%**	**496,119**	**425,636**	**70,483**	**16.6%**	**5.99958**	**4.41509**	**1.58449**	**35.9%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**1,772,891**	**1,736,885**	**36,006**	**2.1%**				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	194,737	88,700	106,037	119.5%	4,997	6,054	(1,057)	-17.5%	3.89708	1.46515	2.43193	166.0%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	2,747	0	2,747	0.0%	66	0	66	0.0%	4.16212	0.00000	4.16212	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	0	1,398,200	(1,398,200)	-100.0%	56,973	53,940	3,033	5.6%	0.00000	2.59214	(2.59214)	-100.0%
21. Fuel Cost of Market Base Sales (A6)	1,760,704	151,200	1,609,504	1064.5%	1,655	7,184	(5,529)	-77.0%	106.38695	2.10468	104.28227	4954.8%
21a. Gains on Market Based Sales	22,105	61,300	(39,195)	-63.9%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	**1,980,293**	**1,699,400**	**280,893**	**16.5%**	**83,691**	**67,178**	**(3,487)**	**-5.2%**	**3.10922**	**2.52970**	**0.57952**	**22.9%**
23. Net Inadvertant Interchange					(1,580)	0	(1,580)	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					1,937	0	1,937	0.0%				
25. Interchange and Wheeling Losses					543	1,000	(457)	-45.7%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	**58,078,140**	**48,949,739**	**9,128,401**	**18.6%**	**1,709,014**	**1,668,707**	**40,307**	**2.4%**	**3.39834**	**2.93339**	**0.46495**	**15.9%**
27. Net Unbilled	(2,380,980) (a)	(3,376,277) (a)	995,297	-29.5%	(70,063)	(115,098)	45,035	-39.1%	3.39834	2.93339	0.46495	15.9%
28. Company Use	154,896 (a)	120,269 (a)	34,627	28.8%	4,558	4,100	458	11.2%	3.39833	2.93339	0.46494	15.9%
29. T & D Losses	2,476,610 (a)	4,096,718 (a)	(1,620,108)	-39.5%	72,877	139,658	(66,781)	-47.8%	3.39834	2.93339	0.46495	15.9%
30. System KWH Sales	58,078,140	48,949,739	9,128,401	18.6%	1,701,642	1,640,047	61,595	3.8%	3.41306	2.98465	0.42841	14.4%
31. Wholesale KWH Sales	(2,060,398)	(3,068,316)	1,007,918	-32.8%	(60,368)	(102,803)	42,435	-41.3%	3.41306	2.98466	0.42841	14.4%
32. Jurisdictional KWH Sales	56,017,742	45,881,423	10,136,319	22.1%	1,641,274	1,537,244	104,030	6.8%	3.41306	2.98465	0.42841	14.4%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	56,054,714	45,911,705	10,143,009	22.1%	1,641,274	1,537,244	104,030	6.8%	3.41532	2.98662	0.42869	14.4%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	282,069	274,113	7,956	2.9%	1,641,274	1,537,244	104,030	6.8%	0.01719	0.01783	(0.00065)	-3.6%
35a. Adjustment	0	0	0	0.0%	1,641,274	1,537,244	104,030	6.8%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	1,641,274	1,537,244	104,030	6.8%	0.00000	0.00000	0.00000	0.0%
36. True-up *	7,389,395	7,389,395	0	0.0%	1,641,274	1,537,244	104,030	6.8%	0.45022	0.48069	(0.03047)	-6.3%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	63,726,178	53,575,213	10,150,965	18.9%	1,641,274	1,537,244	104,030	6.8%	3.88273	3.48515	0.39758	11.4%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.88552	3.48766	0.39786	11.4%
40. GPIF * (Already Adjusted for Taxes)	91,246	91,246	0	0.0%	1,641,274	1,537,244	104,030	6.8%	0.00556	0.00594	(0.00038)	-6.3%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**63,817,424**	**53,666,459**	**10,150,965**	**18.9%**	**1,641,274**	**1,537,244**	**104,030**	**6.8%**	**3.89108**	**3.49360**	**0.39748**	**11.4%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.891**	**3.494**	**0.397**	**11.4%**

* Based on Jurisdictional Sales (a) included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY

PERIOD TO DATE THROUGH: OCTOBER 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	307,796,909	336,878,099	(29,081,190)	-8.6%	13,425,687	14,541,054	(1,115,367)	-7.7%	2.29260	2.31674	(0.02414)	-1.0%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(60,393)	(40,000)	(20,393)	51.0%	13,425,687 (a)	14,541,054 (a)	(1,115,367)	-7.7%	(0.00045)	(0.00028)	(0.00017)	63.5%
4b. Adjustments to Fuel Cost (1)	(19,441)	0	(19,441)	0.0%	13,425,687 (a)	14,541,054 (a)	(1,115,367)	-7.7%	(0.00014)	0.00000	(0.00014)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	13,425,687 (a)	14,541,054 (a)	(1,115,367)	-7.7%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**307,717,075**	**336,838,099**	**(29,121,024)**	**-8.6%**	**13,425,687**	**14,541,054**	**(1,115,367)**	**-7.7%**	**2.29200**	**2.31646**	**(0.02446)**	**-1.1%**
6. Fuel Cost of Purchased Power - Firm (A7)	136,098,684	124,359,400	11,739,284	9.4%	2,979,518	2,277,590	701,928	30.8%	4.56781	5.46013	(0.89232)	-16.3%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	9,573,666	9,167,300	406,366	4.4%	398,162	396,226	1,936	0.5%	2.40447	2.31365	0.09081	3.9%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**145,672,350**	**133,526,700**	**12,145,650**	**9.1%**	**3,377,680**	**2,673,816**	**703,864**	**26.3%**	**4.31279**	**4.99386**	**(0.68107)**	**-13.6%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					**16,803,367**	**17,214,870**	**(411,503)**	**-2.4%**				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	1,328,106	896,600	431,506	48.1%	46,927	60,837	(13,910)	-22.9%	2.83015	1.47377	1.35638	92.0%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	9,318	0	9,318	0.0%	(358)	0	(358)	0.0%	(2.60279)	0.00000	(2.60279)	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	8,609,521	11,775,800	(3,166,279)	-26.9%	391,632	459,882	(68,250)	-14.8%	2.19837	2.56061	(0.36224)	-14.1%
21. Fuel Cost of Market Base Sales (A6)	2,321,136	4,510,500	(2,189,364)	-48.5%	29,268	187,703	(158,435)	-84.4%	7.93063	2.40300	5.52763	230.0%
21a. Gains on Market Based Sales	92,979	2,894,200	(2,801,221)	-96.8%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	**12,361,060**	**20,077,100**	**(7,716,040)**	**-38.4%**	**467,469**	**708,422**	**(240,953)**	**-34.0%**	**2.64425**	**2.83406**	**(0.18981)**	**-6.7%**
23. Net Inadvertant Interchange					693	0	693	0.0%				
24. Wheeling Rec'd. less Wheeling Delv'd.					3,244	0	3,244	0.0%				
25. Interchange and Wheeling Losses					2,745	10,400	(7,655)	-73.6%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	**441,028,365**	**450,287,699**	**(9,259,334)**	**-2.1%**	**16,337,090**	**16,496,048**	**(158,958)**	**-1.0%**	**2.69955**	**2.72967**	**(0.03012)**	**-1.1%**
27. Net Unbilled	2,788,296 (a)	993,849 (a)	1,794,447	180.6%	97,735	54,855	42,880	78.2%	2.85291	1.81177	1.04114	57.5%
28. Company Use	1,113,590 (a)	1,114,080 (a)	(490)	0.0%	41,281	41,000	281	0.7%	2.69758	2.71727	(0.01968)	-0.7%
29. T & D Losses	20,924,021 (a)	7,453,816 (a)	13,470,205	180.7%	769,812	250,480	519,332	207.3%	2.71807	2.97581	(0.25774)	-8.7%
30. System KWH Sales	441,028,365	450,287,699	(9,259,334)	-2.1%	15,428,262	16,149,713	(721,451)	-4.5%	2.85857	2.78821	0.07037	2.5%
31. Wholesale KWH Sales	(12,648,272)	(30,113,785)	17,465,513	-58.0%	(429,622)	(1,079,834)	650,212	-60.2%	2.94405	2.78874	0.15530	5.6%
32. Jurisdictional KWH Sales	428,380,093	420,173,914	8,206,179	2.0%	14,998,640	15,069,879	(71,239)	-0.5%	2.85613	2.78817	0.06796	2.4%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	428,662,824	420,451,229	8,211,595	2.0%	14,998,640	15,069,879	(71,239)	-0.5%	2.85801	2.79001	0.06800	2.4%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	2,956,019	2,833,963	122,056	4.3%	14,998,640	15,069,879	(71,239)	-0.5%	0.01971	0.01881	0.00090	4.8%
35a. Adjustment	0	0	0	0.0%	14,998,640	15,069,879	(71,239)	-0.5%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	14,998,640	15,069,879	(71,239)	-0.5%	0.00000	0.00000	0.00000	0.0%
36. True-up *	73,893,950	73,893,950	0	0.0%	14,998,640	15,069,879	(71,239)	-0.5%	0.49267	0.49034	0.00233	0.5%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	505,512,793	497,179,142	8,333,651	1.7%	14,998,640	15,069,879	(71,239)	-0.5%	3.37039	3.29916	0.07123	2.2%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.37262	3.30153	0.07129	2.2%
40. GPIF * (Already Adjusted for Taxes)	912,460	912,460	0	0.0%	14,998,640	15,069,879	(71,239)	-0.5%	0.00608	0.00605	0.00003	0.5%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**506,425,253**	**498,091,602**	**8,333,651**	**1.7%**	**14,998,640**	**15,069,879**	**(71,239)**	**-0.5%**	**3.37890**	**3.30758**	**0.07132**	**2.2%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.379**	**3.308**	**0.071**	**2.1%**

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CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	30,302,588	31,860,939	(1,558,351)	-4.9%	307,796,909	336,878,099	(29,081,190)	-8.6%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	1,958,188	1,638,100	320,088	19.5%	12,268,081	17,182,900	(4,914,819)	-28.6%
2a. GAINS FROM MARKET BASED SALES	22,105	61,300	(39,195)	-63.9%	92,979	2,894,200	(2,801,221)	-96.8%
3. FUEL COST OF PURCHASED POWER	28,657,519	17,790,700	10,866,819	61.1%	136,098,684	124,359,400	11,739,284	9.4%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	1,107,543	1,001,500	106,043	10.6%	9,573,666	9,167,300	406,366	4.4%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	58,087,357	48,953,739	9,133,618	18.7%	441,108,199	450,327,699	(9,219,500)	-2.0%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(5,823)	(4,000)	(1,823)	45.6%	(60,393)	(40,000)	(20,393)	51.0%
6b. ADJ.TO FUEL COST	(3,394)	0	(3,394)	0.0%	(19,441)	0	(19,441)	0.0%
6c. ADJ.TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	58,078,140	48,949,739	9,128,401	18.6%	441,028,365	450,287,699	(9,259,334)	-2.1%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,641,274	1,537,244	104,030	6.8%	14,998,640	15,069,879	(71,239)	-0.5%
2. NONJURISDICTIONAL SALES	60,368	102,803	(42,435)	-41.3%	429,622	1,079,834	(650,212)	-60.2%
3. TOTAL SALES	1,701,642	1,640,047	61,595	3.8%	15,428,262	16,149,713	(721,451)	-4.5%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9645237	0.9373170	0.0272067	2.9%	0.9721536	0.9331360	0.0390176	4.2%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: OCTOBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	53,817,375	50,701,495	3,115,880	6.1%	491,234,543	496,884,243	(5,649,700)	-1.1%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(7,389,395)	(7,389,395)	0	0.0%	(73,893,950)	(73,893,950)	0	0.0%
2b. INCENTIVE PROVISION	(91,246)	(91,246)	0	0.0%	(912,460)	(912,460)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	46,336,734	43,220,854	3,115,880	7.2%	416,428,133	422,077,833	(5,649,700)	-1.3%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	58,078,140	48,949,739	9,128,401	18.6%	441,028,365	450,287,699	(9,259,334)	-2.1%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9645237	0.9373170	0.0272067	2.9%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	56,017,742	45,881,423	10,136,319	22.1%	428,380,093	420,173,914	8,206,179	2.0%
6a. JURISDIC. LOSS MULTIPLIER	1.00066	1.00066	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	56,054,714	45,911,705	10,143,009	22.1%	428,662,824	420,451,229	8,211,595	2.0%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	292,444	292,444	0	0.0%	3,038,335	3,038,335	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	282,069	274,113	7,956	2.9%	2,956,019	2,833,963	122,056	4.3%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	56,336,783	46,185,818	10,150,965	22.0%	431,618,843	423,285,192	8,333,651	2.0%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(10,000,049)	(2,964,964)	(7,035,085)	237.3%	(15,190,710)	(1,207,359)	(13,983,351)	1158.2%
8. INTEREST PROVISION FOR THE MONTH	(54,664)	(65,648)	10,984	-16.7%	(902,384)	(1,581,476)	679,092	-42.9%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(37,190,721)	(21,926,403)	(15,264,318)	69.6%	----------NOT APPLICABLE----------			
10. TRUE-UP COLLECTED (REFUNDED)	7,389,395	7,389,395	0	0.0%	----------NOT APPLICABLE----------			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(39,856,039)	(17,567,620)	(22,288,419)	126.9%	----------NOT APPLICABLE----------			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(37,190,721)	(21,926,403)	(15,264,318)	69.6%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(39,801,375)	(17,501,972)	(22,299,403)	127.4%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(76,992,096)	(39,428,375)	(37,563,721)	95.3%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(38,496,048)	(19,714,188)	(18,781,860)	95.3%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.760	4.000	(2)	-56.0%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.650	4.000	(2)	-58.8%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	3.410	8.000	(5)	-57.4%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.705	4.000	(2)	-57.4%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.142	0.333	(0)	-57.4%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(54,664)	(65,648)	10,984	-16.7%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	602,314	555,932	46,382	8.3%	3,760,866	4,314,951	(554,085)	-12.8%
2	LIGHT OIL	182,790	1,198,203	(1,015,413)	-84.7%	9,052,998	14,039,187	(4,986,189)	-35.5%
3	COAL	24,741,303	24,868,198	(126,895)	-0.5%	266,789,295	283,519,825	(16,730,530)	-5.9%
4	NATURAL GAS	4,776,181	5,238,606	(462,425)	-8.8%	28,193,750	35,004,136	(6,810,386)	-19.5%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	30,302,588	31,860,939	(1,558,351)	-4.9%	307,796,909	336,878,099	(29,081,190)	-8.6%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	11,903	15,060	(3,157)	-21.0%	75,415	106,786	(31,371)	-29.4%
9	LIGHT OIL	2,914	19,095	(16,181)	-84.7%	176,421	206,106	(29,685)	-14.4%
10	COAL	1,186,277	1,180,633	5,644	0.5%	12,717,537	13,585,311	(867,774)	-6.4%
11	NATURAL GAS	75,678	96,461	(20,783)	-21.5%	456,314	642,851	(186,537)	-29.0%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,276,772	1,311,249	(34,477)	-2.6%	13,425,687	14,541,054	(1,115,367)	-7.7%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	18,408	22,427	(4,019)	-17.9%	119,335	159,003	(39,668)	-24.9%
16	LIGHT OIL (BBL)	5,430	39,487	(34,057)	-86.2%	299,106	436,256	(137,150)	-31.4%
17	COAL (TON)	575,971	524,300	51,671	9.9%	6,087,214	6,053,664	33,550	0.6%
18	NATURAL GAS (MCF)	840,431	979,057	(138,626)	-14.2%	4,957,387	6,555,879	(1,598,492)	-24.4%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	115,486	140,821	(25,335)	-18.0%	748,667	998,374	(249,708)	-25.0%
22	LIGHT OIL	31,624	224,093	(192,469)	-85.9%	1,722,159	2,479,932	(757,773)	-30.6%
23	COAL	13,493,486	12,260,238	1,233,248	10.1%	141,830,565	141,970,396	(139,831)	-0.1%
24	NATURAL GAS	882,452	1,006,512	(124,060)	-12.3%	5,216,785	6,739,714	(1,522,929)	-22.6%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	14,523,048	13,631,664	891,384	6.5%	149,518,175	152,188,416	(2,670,241)	-1.8%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.93%	1.15%	(0.00)	-	0.56%	0.73%	(0.00)	-
29	LIGHT OIL	0.23%	1.46%	(0.01)	-	1.31%	1.42%	(0.00)	-
30	COAL	92.91%	90.04%	0.03	-	94.73%	93.43%	0.01	-
31	NATURAL GAS	5.93%	7.36%	(0.01)	-	3.40%	4.42%	(0.01)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	32.72	24.79	7.93	32.0%	31.52	27.14	4.38	16.1%
36	LIGHT OIL ($/BBL)	33.66	30.34	3.32	10.9%	30.27	32.18	(1.91)	-5.9%
37	COAL ($/TON)	42.96	47.43	(4.48)	-9.4%	43.83	46.83	(3.01)	-6.4%
38	NATURAL GAS ($/MCF)	5.68	5.35	0.33	6.2%	5.69	5.34	0.35	6.5%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	5.22	3.95	1.27	32.1%	5.02	4.32	0.70	16.2%
42	LIGHT OIL	5.78	5.35	0.43	8.1%	5.26	5.66	(0.40)	-7.1%
43	COAL	1.83	2.03	(0.19)	-9.6%	1.88	2.00	(0.12)	-5.8%
44	NATURAL GAS	5.41	5.20	0.21	4.0%	5.40	5.19	0.21	4.1%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.09	2.34	(0.25)	-10.7%	2.06	2.21	(0.15)	-7.0%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,702	9,351	351	3.8%	9,927	9,349	578	6.2%
49	LIGHT OIL	10,853	11,736	(883)	-7.5%	9,762	12,032	(2,270)	-18.9%
50	COAL	11,375	10,384	991	9.5%	11,152	10,450	702	6.7%
51	NATURAL GAS	11,661	10,434	1,227	11.8%	11,432	10,484	948	9.0%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	11,375	10,396	979	9.4%	11,137	10,466	671	6.4%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	5.06	3.69	1.37	37.1%	4.99	4.04	0.95	23.5%
56	LIGHT OIL	6.27	6.27	0.00	0.0%	5.13	6.81	(1.68)	-24.7%
57	COAL	2.09	2.11	(0.02)	-0.9%	2.10	2.09	0.01	0.5%
58	NATURAL GAS	6.31	5.43	0.88	16.2%	6.18	5.45	0.73	13.4%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.37	2.43	(0.06)	-2.5%	2.29	2.32	(0.03)	-1.3%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: OCTOBER 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	0	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	0	-158	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-158**	---	---	---	**0**	**HVY.OIL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	51,079	60.1	76.9	73.6	11,437	COAL	26,562	21,994,000	584,204.6	1,029,632	2.02	38.76
GAN.#2	98	52,415	71.8	83.7	80.2	12,566	COAL	29,231	22,532,000	658,632.9	1,133,092	2.16	38.76
GAN.#3	145	57,911	53.6	74.5	64.0	13,308	COAL	39,499	19,512,000	770,704.5	1,531,114	2.64	38.76
GAN.#4	159	60,861	51.4	69.1	66.1	14,136	COAL	42,460	20,262,000	860,324.5	1,645,892	2.70	38.76
GAN.#5	217	83,099	51.4	67.0	73.8	11,430	COAL	40,900	23,224,000	949,861.6	1,585,422	1.91	38.76
GAN.#6	372	39,227	14.2	17.8	73.6	10,861	COAL	18,115	23,518,000	426,028.6	702,198	1.79	38.76
GANNON STATION	**1,105**	**344,592**	**41.9**	**54.2**	**71.9**	**12,333**	**COAL**	**196,767**	**21,597,914**	**4,249,756.7**	**7,627,350**	**2.21**	**38.76**
B.B.#1	416	189,295	61.1	69.2	72.4	11,445	COAL	87,465	24,769,480	2,166,458.9	3,855,150	2.04	44.08
B.B.#2	416	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
B.B.#3	433	251,708	78.0	89.8	78.4	10,877	COAL	111,012	24,661,860	2,737,765.6	4,893,020	1.94	44.08
B.B. 1 - 3	1,265	441,003	46.8	53.5	50.7	**11,121**	COAL	198,477	24,709,286	4,904,224.5	8,748,170	1.98	44.08
B.B.#4	442	227,995	69.2	77.3	73.0	11,088	COAL	111,893	22,593,607	2,528,077.3	5,658,353	2.48	50.57
B.B. STATION	**1,707**	**668,998**	**52.6**	**59.6**	**56.4**	**11,110**	**COAL**	**310,370**	**23,946,550**	**7,432,301.8**	**14,406,523**	**2.15**	**46.42**
SEB-PHIL. #1(HVY OIL)	17	6,020	47.5	99.9	92.7	9,575	HVY.OIL	9,188	6,273,540	57,642.3	300,633	4.99	32.72
SEB-PHIL. #2(HVY OIL)	17	6,041	47.7	100.0	93.4	9,575	HVY.OIL	9,220	6,273,540	57,843.4	301,681	4.99	32.72
SEB-PHILLIPS TOTAL	**34**	**12,061**	**47.6**	**99.9**	**93.0**	**9,575**	**HVY.OIL**	**18,408**	**6,273,540**	**115,485.7**	**602,314**	**4.99**	**32.72**
POLK #1 GASIFIER	250	172,687	92.7	95.7	93.4	10,490	COAL	68,834	26,316,000	1,811,427.6	2,707,430	1.57	39.33
POLK #1 CT (OIL)	225	1,355	0.8	100.0	86.9	7,459	LGT.OIL	1,738	5,816,715	10,106.6	59,746	4.41	34.39
POLK #1 TOTAL	**250**	**174,042**	**93.4**	**96.4**	**93.4**	**10,466**	-	-	-	**1,821,534.2**	**2,767,176**	**1.59**	-
POLK #2 CT (GAS)	150	32,915	29.5	91.6	79.6	10,136	GAS	317,741	972,290	333,628.0	1,540,681	4.68	4.85
POLK #2 CT (OIL)	160	1,214	1.0	92.7	65.4	12,552	LGT.OIL	2,620	5,816,710	15,238.5	90,085	7.42	34.38
POLK #2 TOTAL	**155**	**34,129**	**29.6**	**93.1**	**79.0**	**10,222**	-	-	-	**348,866.5**	**1,630,766**	**4.78**	-
POLK #3 CT (GAS)	150	42,567	38.1	95.0	82.1	12,847	GAS	520,809	972,290	546,849.0	3,222,625	7.57	6.19
POLK #3 CT (OIL)	160	0	0.0	94.7	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**155**	**42,567**	**36.9**	**95.0**	**82.1**	**12,847**	-	-	-	**546,849.0**	**3,222,625**	**7.57**	-
POLK STATION TOTAL	**560**	**250,738**	**60.1**	**95.1**	**62.9**	**10,837**	-	-	-	**2,717,249.7**	**7,620,567**	**3.04**	-
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	345	3.9	100.0	102.7	18,201	LGT.OIL	1,072	5,855,496	6,279.2	32,959	9.55	30.75
B.B.C.T.#2	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**144**	**345**	**0.3**	**8.3**	**8.6**	**18,201**	**LGT.OIL**	**1,072**	**5,855,496**	**6,279.2**	**32,959**	**9.55**	**30.75**
CITY OF TAMPA	**6**	**196**	**0.0**	**0.0**	**0.0**	**10,077**	**GAS**	**1,881**	**972,290**	**1,975.1**	**12,875**	**6.57**	**6.84**
TOT. COAL (GN,BB,POLK)	**3,062**	**1,186,277**	**52.0**	**60.6**	**65.0**	**11,375**	**COAL**	**575,971**	**23,427,364**	**13,493,486.1**	**24,741,303**	**2.09**	**42.96**
SYSTEM	**3,556**	**1,276,772**	**48.3**	**61.9**	**60.7**	**11,373**	-	-	-	**14,523,048.2**	**30,302,588**	**2.37**	-

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT
GAN. = GANNON
B.B. = BIG BEND
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	10,263	22,427	(12,164)	-54.2%	107,010	159,003	(51,993)	-32.7%
3 UNIT COST ($/BBL)	34.72	24.51	10.21	41.6%	29.10	26.28	2.82	10.7%
4 AMOUNT ($)	356,321	549,699	(193,378)	-35.2%	3,113,829	4,178,941	(1,065,112)	-25.5%
5 BURNED:								
6 UNITS (BBL)	18,408	22,427	(4,019)	-17.9%	119,335	159,003	(39,668)	-24.9%
7 UNIT COST ($/BBL)	32.72	24.79	7.93	32.0%	31.52	27.14	4.38	16.1%
8 AMOUNT ($)	602,314	555,932	46,382	8.3%	3,760,866	4,314,951	(554,085)	-12.8%
9 ENDING INVENTORY:								
10 UNITS (BBL)	5,324	59,129	(53,805)	-91.0%	5,324	59,129	(53,805)	-91.0%
11 UNIT COST ($/BBL)	36.57	25.54	11.03	43.2%	36.57	25.54	11.03	43.2%
12 AMOUNT ($)	194,695	1,509,965	(1,315,270)	-87.1%	194,695	1,509,965	(1,315,270)	-87.1%
13								
14 DAYS SUPPLY:	16	114	(98)	-86.1%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	10,093	47,073	(36,980)	-78.6%	373,168	531,916	(158,748)	-29.8%
17 UNIT COST ($/BBL)	44.80	29.81	14.99	50.3%	30.67	31.37	(0.69)	-2.2%
18 AMOUNT ($)	452,131	1,403,045	(950,914)	-67.8%	11,446,460	16,685,310	(5,238,850)	-31.4%
19 BURNED:								
20 UNITS (BBL)	5,430	39,487	(34,057)	-86.2%	299,106	436,256	(137,150)	-31.4%
21 UNIT COST ($/BBL)	33.66	30.34	3.32	10.9%	30.27	32.18	(1.91)	-5.9%
22 AMOUNT ($)	182,790	1,198,203	(1,015,413)	-84.7%	9,052,998	14,039,187	(4,986,189)	-35.5%
23 ENDING INVENTORY:								
24 UNITS (BBL)	94,631	113,465	(18,834)	-16.6%	94,631	113,465	(18,834)	-16.6%
25 UNIT COST ($/BBL)	32.43	30.37	2.06	6.8%	32.43	30.37	2.06	6.8%
26 AMOUNT ($)	3,069,210	3,446,370	(377,160)	-10.9%	3,069,210	3,446,370	(377,160)	-10.9%
27								
28 DAYS SUPPLY: NORMAL	84	86	(2)	-2.9%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	14	16	(2)	-15.5%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	491,965	556,000	(64,035)	-11.5%	6,071,661	6,398,000	(326,339)	-5.1%
32 UNIT COST ($/TON)	44.25	46.25	(1.99)	-4.3%	44.03	46.47	(2.44)	-5.2%
33 AMOUNT ($)	21,771,677	25,713,635	(3,941,958)	-15.3%	267,353,875	297,318,626	(29,964,751)	-10.1%
34 BURNED:								
35 UNITS (TONS)	575,971	524,300	51,671	9.9%	6,087,214	6,053,664	33,550	0.6%
36 UNIT COST ($/TON)	42.96	47.43	(4.48)	-9.4%	43.83	46.83	(3.01)	-6.4%
37 AMOUNT ($)	24,741,303	24,868,198	(126,895)	-0.5%	266,789,295	283,519,825	(16,730,530)	-5.9%
38 ENDING INVENTORY:								
39 UNITS (TONS)	609,927	1,321,156	(711,229)	-53.8%	609,927	1,321,156	(711,229)	-53.8%
40 UNIT COST ($/TON)	43.74	46.79	(3.06)	-6.5%	43.74	46.79	(3.06)	-6.5%
41 AMOUNT ($)	26,677,537	61,823,236	(35,145,699)	-56.8%	26,677,537	61,823,236	(35,145,699)	-56.8%
42								
43 DAYS SUPPLY:	33	75	(42)	-56.3%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	840,431	979,057	(138,626)	-14.2%	4,957,387	6,555,879	(1,598,492)	-24.4%
46 UNIT COST ($/MCF)	5.68	5.35	0.33	6.2%	5.69	5.34	0.35	6.5%
47 AMOUNT ($)	4,776,181	5,238,606	(462,425)	-8.8%	28,192,777	35,004,133	(6,811,356)	-19.5%
48 BURNED:								
49 UNITS (MCF)	840,431	979,057	(138,626)	-14.2%	4,957,387	6,555,879	(1,598,492)	-24.4%
50 UNIT COST ($/MCF)	5.68	5.35	0.33	6.2%	5.69	5.34	0.35	6.5%
51 AMOUNT ($)	4,776,181	5,238,606	(462,425)	-8.8%	28,193,750	35,004,136	(6,810,386)	-19.5%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	23,602
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	23,602

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(8,348)	(260,958)
OTHER USAGE	(702)	(21,894)
TOTAL	(9,050)	(282,852)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	36,054
IGNITION #2 OIL	237,356
IGNITION PROPANE	203
AERIAL SURVEY ADJ.	(944,984)
ADDITIVES	77,787
GREEN FUEL	0
TOTAL	(593,584)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2002

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KW (A) FUEL COST	(6) CENTS/KW (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. -D	6,054.0	0.0	6,054.0	1.465	1.465	88,700.00	88,700.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	53,940.0	0.0	53,940.0	2.592	3.640	1,398,200.00	1,963,500.00	
VARIOUS	JURISDIC.	SCH. -MB	7,184.0	0.0	7,184.0	2.105	2.105	151,200.00	151,200.00	61,300.00
TOTAL			67,178.0	0.0	67,178.0	2.438	3.280	1,638,100.00	2,203,400.00	61,300.00
ACTUAL:										
FLA. PWR. & LIGHT	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR PARTNERS	SEP. CONTR.	SCH. -D	56,973.0	0.0	56,973.0	2.914	3.576	1,660,193.22	2,037,354.48	
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. -D	5,796.7	1,349.2	4,447.5	3.875	3.875	172,326.56	172,326.56	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. -D	549.2	0.0	549.2	2.210	2.210	12,135.46	12,135.46	
FLA. PWR. CORP.		SCH. -MA	180.0	0.0	180.0	3.096	4.962	5,572.12	8,932.17	2,794.85
FLA. PWR. & LIGHT		SCH. -MA	600.0	0.0	600.0	2.239	4.244	13,435.23	25,462.05	10,142.82
ORLANDO UTIL. COMM.		SCH. -MA	565.0	0.0	565.0	3.132	4.746	17,696.73	26,816.50	7,345.67
SEMINOLE ELECTRIC CO-OP		SCH. -MA	170.0	0.0	170.0	3.062	4.448	5,205.17	7,560.99	1,822.02
HARDEE PWR. PART. TO FLA. PWR. CORP.		SCH. -MA	70.0	0.0	70.0	4.069	4.702	2,848.30	3,291.06	
HARDEE PWR. PART. TO FLA. PWR. & LIGHT		SCH. -MA	70.0	0.0	70.0	4.069	4.982	2,848.30	3,487.06	
AUBURNDALE POWER PARTNERS		SCH. -OATT	1.0	0.0	1.0	2.030	2.030	20.30	20.30	
CARGILL ALLIANT		SCH. -OATT	65.0	0.0	65.0	4.195	4.195	2,726.72	2,726.72	
ADJUSTMENTS TO PREV. MONTHS										
HARDEE PWR PART	Sept. 2002	CONTRACT	(14,945.0)	0.0	(14,945.0)	2.560	3.267	(382,592.00)	(488,253.15)	
HARDEE PWR PART	Sept. 2002	CONTRACT	14,945.0	0.0	14,945.0	2.914	3.576	435,497.30	534,433.20	
SEMINOLE ELEC. PRECO-1	Sept. 2002	SCH. -D	(5,796.7)	(1,201.4)	(4,595.3)	3.892	3.892	(178,834.94)	(178,834.94)	
SEMINOLE ELEC. PRECO-1	Sept. 2002	SCH. -D	5,796.7	1,201.4	4,595.3	3.887	3.887	178,605.56	178,605.56	
SEMINOLE ELEC. HARDEE	Sept. 2002	SCH. -D	(590.7)	0.0	(590.7)	0.458	0.458	(2,708.34)	(2,708.34)	
SEMINOLE ELEC. HARDEE	Sept. 2002	SCH. -D	590.7	0.0	590.7	2.237	2.237	13,212.28	13,212.28	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISDICTIONAL			6,345.9	1,349.2	4,996.7	3.897	3.897	194,736.58	194,736.58	
SUB-TOTAL SCHEDULE D POWER SALES-SEPARATED			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEP.			56,973.0	0.0	56,973.0	3.007	3.657	1,713,098.52	2,083,534.53	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISDICTIONAL			1,655.0	0.0	1,655.0	2.876	4.565	47,605.85	75,549.83	22,105.36
SUB-TOTAL SCHEDULE OATT SALES-JURISDICTIONAL			66.0	0.0	66.0	4.162	4.162	2,747.02	2,747.02	
TOTAL			65,039.9	1,349.2	63,690.7	3.075	3.700	1,958,187.97	2,356,567.96	22,105.36
CURRENT MONTH:										
DIFFERENCE			(2,138.1)	1,349.2	(3,487.3)	0.637	0.420	320,087.97	153,167.96	(39,194.64)
DIFFERENCE %			-3.2%	0.0%	-5.2%	26.1%	12.8%	19.5%	7.0%	-63.9%
PERIOD TO DATE:										
ACTUAL			472,979.6	5,510.1	467,469.5	2.624	3.273	12,268,081.90	15,299,203.03	92,979.88
ESTIMATED			708,422.0	0.0	708,422.0	2.426	3.106	17,182,900.00	22,002,600.00	2,894,200.00
DIFFERENCE			(235,442.4)	5,510.1	(240,952.5)	0.198	0.167	(4,914,818.10)	(6,703,396.97)	(2,801,220.12)
DIFFERENCE %			-33.2%	0.0%	-34.0%	8.2%	5.4%	-28.6%	-30.5%	-96.8%

* SALES TO HARDEE POWER PARTNERS FOR OTHERS INCLUDES TEC 40% PROFIT. SEC 60% PROFIT OR $1,622.29 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH.-J	58,850.0	0.0	32,210.0	26,640.0	5.809	5.809	1,547,500.00
HARDEE POWER PARTNERS		IPP	104,536.0	0.0	0.0	104,536.0	4.463	4.463	4,665,600.00
VARIOUS		OTHER	39,602.0	0.0	0.0	39,602.0	4.037	4.037	1,598,900.00
VARIOUS		MKT. BASE	213,831.0	0.0	0.0	213,831.0	4.667	4.667	9,978,700.00
TOTAL			416,819.0	0.0	32,210.0	384,609.0	4.626	4.626	17,790,700.00
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	114,660.0	0.0	0.0	114,660.0	4.155	4.155	4,764,522.87
HARDEE PWR. PART.-OTHERS		IPP	140.0	0.0	0.0	140.0	4.069	4.069	5,696.60
FLA. POWER CORP.		SCH.-J	35,914.0	0.0	3,141.4	32,772.6	4.470	4.470	1,465,070.95
FLA. POWER & LIGHT		SCH.-J	34,014.0	0.0	4,752.6	29,261.4	4.568	4.568	1,336,570.42
CITY OF LAKELAND		SCH.-J	29,247.0	0.0	4,553.0	24,694.0	4.796	4.796	1,184,439.20
ORLANDO UTIL. COMM.		SCH.-J	17,700.0	0.0	3,470.3	14,229.7	7.711	7.711	1,097,223.59
CAROLINA POWER & LIGHT		SCH.-J	1,326.0	0.0	0.0	1,326.0	2.996	2.996	39,732.00
THE ENERGY AUTHORITY		SCH.-J	23,852.0	0.0	8,423.0	15,429.0	5.600	5.600	864,091.53
REEDY CREEK		SCH.-J	635.0	0.0	15.0	620.0	4.817	4.817	29,865.00
OKEELANTA		SCH.-J	15,230.0	0.0	0.0	15,230.0	4.163	4.163	634,026.68
TALLAHASSEE		SCH.-J	3,005.0	0.0	10.0	2,995.0	6.718	6.718	201,204.80
CALPINE		SCH.-J	389.0	0.0	19.0	370.0	5.408	5.408	20,008.00
CARGILL ALLIANT		SCH.-J	79,059.0	0.0	6,678.4	72,380.6	5.419	5.419	3,922,241.02
RELIANT		SCH.-J	23,760.0	0.0	9,240.0	14,520.0	7.598	7.598	1,103,221.18
SEMINOLE ELECTRIC CO-OP		SCH.-J	27,640.0	0.0	1,579.4	26,060.6	3.344	3.344	871,522.21
DUKE ENERGY		SCH.-J	2,350.0	0.0	0.0	2,350.0	3.776	3.776	88,732.00
DYNEGY POWER MARKETING		SCH.-J	1,360.0	0.0	0.0	1,360.0	3.435	3.435	46,714.00
RINGHAVER		SCH.-J	6,422.0	0.0	0.0	6,422.0	13.380	13.380	859,247.03
FLA. POWER CORP.		SCH.-D	79,475.0	0.0	0.0	79,475.0	3.909	3.909	3,106,809.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Sept. 2002	IPP	(60,294.0)	0.0	0.0	(60,294.0)	5.826	5.826	(3,512,458.10)
HARDEE PWR. PART.-NATIVE	Sept. 2002	IPP	60,294.0	0.0	0.0	60,294.0	6.456	6.456	3,892,442.48
HARDEE PWR. PART.-NATIVE	Aug. 2002	IPP	(72,928.0)	0.0	0.0	(72,928.0)	3.853	3.853	(2,809,616.93)
HARDEE PWR. PART.-NATIVE	Aug. 2002	IPP	72,928.0	0.0	0.0	72,928.0	4.854	4.854	3,540,153.70
HARDEE PWR. PART.-NATIVE	July 2002	IPP	(95,337.0)	0.0	0.0	(95,337.0)	2.348	2.348	(2,238,280.74)
HARDEE PWR. PART.-NATIVE	July 2002	IPP	95,337.0	0.0	0.0	95,337.0	3.931	3.931	3,747,535.17
HARDEE PWR. PART.-NATIVE	June 2002	IPP	(96,160.0)	0.0	0.0	(96,160.0)	2.842	2.842	(2,732,745.19)
HARDEE PWR. PART.-NATIVE	June 2002	IPP	96,160.0	0.0	0.0	96,160.0	3.955	3.955	3,803,573.49
HARDEE PWR. PART.-NATIVE	May 2002	IPP	(109,214.0)	0.0	0.0	(109,214.0)	1.853	1.853	(2,023,382.86)
HARDEE PWR. PART.-NATIVE	May 2002	IPP	109,214.0	0.0	0.0	109,214.0	3.198	3.198	3,492,517.34
HARDEE PWR. PART.-NATIVE	Apr. 2002	IPP	(91,254.0)	0.0	0.0	(91,254.0)	2.811	2.811	(2,565,605.45)
HARDEE PWR. PART.-NATIVE	Apr. 2002	IPP	91,254.0	0.0	0.0	91,254.0	4.434	4.434	4,046,125.17
CALPINE	Sept. 2002	SCH.-J	(1,597.0)	0.0	(150.0)	(1,447.0)	4.904	4.904	(70,959.00)
CALPINE	Sept. 2002	SCH.-J	1,592.0	0.0	150.0	1,442.0	4.904	4.904	70,722.00
CARGILL ALLIANT	Sept. 2002	SCH.-J	(25,739.0)	0.0	(2,774.0)	(22,965.0)	4.076	4.076	(936,085.50)
CARGILL ALLIANT	Sept. 2002	SCH.-J	25,739.0	0.0	2,774.0	22,965.0	4.074	4.074	935,644.50
DYNEGY POWER MARKETING	Sept. 2002	SCH.-J	(2,383.0)	0.0	0.0	(2,383.0)	3.035	3.035	(72,328.00)
DYNEGY POWER MARKETING	Sept. 2002	SCH.-J	2,383.0	0.0	0.0	2,383.0	3.034	3.034	72,297.00
FLA. POWER CORP.	Sept. 2002	SCH.-J	(45,328.0)	0.0	(2,563.8)	(42,764.2)	3.790	3.790	(1,620,960.60)
FLA. POWER CORP.	Sept. 2002	SCH.-J	45,328.0	0.0	2,563.8	42,764.2	3.790	3.790	1,620,965.60
RELIANT	Sept. 2002	SCH.-J	(17,486.0)	0.0	(5,881.9)	(11,604.1)	6.291	6.291	(729,988.62)
RELIANT	Sept. 2002	SCH.-J	17,481.0	0.0	5,881.9	11,599.1	6.294	6.294	730,049.62
FLA. POWER CORP.	Sept. 2002	SCH.-D	(61,700.0)	0.0	0.0	(61,700.0)	3.907	3.907	(2,410,639.00)
FLA. POWER CORP.	Sept. 2002	SCH.-D	61,700.0	0.0	0.0	61,700.0	4.595	4.595	2,835,114.00
FLA. POWER CORP.	Aug. 2002	SCH.-D	(61,700.0)	0.0	0.0	(61,700.0)	4.051	4.051	(2,499,487.00)
FLA. POWER CORP.	Aug. 2002	SCH.-D	61,700.0	0.0	0.0	61,700.0	3.974	3.974	2,451,978.00
TOTAL			496,168.0	0.0	41,882.0	454,286.0	6.308	6.308	28,657,519.16
CURRENT MONTH:									
DIFFERENCE			79,349.0	0.0	9,672.0	69,677.0	1.682	1.682	10,866,819.16
DIFFERENCE %			19.0%	0.0%	30.0%	18.1%	36.4%	36.4%	61.1%
PERIOD TO DATE:									
ACTUAL			3,183,387.0	0.0	203,871.0	2,979,516.0	4.568	4.568	136,098,684.15
ESTIMATED			2,416,561.0	0.0	138,971.0	2,277,590.0	5.460	5.460	124,359,400.00
DIFFERENCE			766,826.0	0.0	64,900.0	701,926.0	(0.892)	(0.892)	11,739,284.15
DIFFERENCE %			31.7%	0.0%	46.7%	30.8%	-16.3%	-16.3%	9.4%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		COGEN.	41,027.0	0.0	0.0	41,027.0	2.441	2.441	1,001,500.00
TOTAL			41,027.0	0.0	0.0	41,027.0	2.441	2.441	1,001,500.00
ACTUAL:									
IMC-AGRICO-NICHOLS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE		COGEN.	12,682.0	0.0	0.0	12,682.0	2.488	2.488	315,508.46
MULBERRY PHOSPHATES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	233.0	0.0	0.0	233.0	4.201	4.201	9,787.88
HILLSBOROUGH COUNTY		COGEN.	19,409.0	0.0	0.0	19,409.0	2.490	2.490	483,236.87
CARGILL MILLPOINT		COGEN.	782.0	0.0	0.0	782.0	4.784	4.784	37,409.23
CF INDUSTRIES INC.		COGEN.	778.0	0.0	0.0	778.0	5.123	5.123	39,857.58
FARMLAND HYDRO LP		COGEN.	887.0	0.0	0.0	887.0	4.507	4.507	39,975.83
IMC-AGRICO-S. PIERCE		COGEN.	452.0	0.0	0.0	452.0	4.646	4.646	20,997.67
AUBURNDALE POWER PARTNERS		COGEN.	605.0	0.0	0.0	605.0	2.776	2.776	16,797.51
ORANGE COGENERATION L.P.		COGEN.	6,256.0	0.0	0.0	6,256.0	2.333	2.333	145,950.70
CUTRALE CITRUS		COGEN.	58.0	0.0	0.0	58.0	3.880	3.880	2,250.43
AS AVAILABLE ASSIGNMENT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR OCTOBER 2002			42,142.0	0.0	0.0	42,142.0	2.638	2.638	1,111,772.16
ADJUSTMENTS FOR THE MONTH OF:	**AUGUST 2002**								
IMC-AGRICO-NICHOLS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE		COGEN.	(13,193.0)	0.0	0.0	(13,193.0)	2.380	2.380	(314,005.12)
			12,883.0	0.0	0.0	12,883.0	2.491	2.491	320,893.02
MULBERRY PHOSPHATES INC.		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
HILLSBOROUGH COUNTY		COGEN.	(15,932.0)	0.0	0.0	(15,932.0)	2.364	2.364	(376,700.69)
			15,932.0	0.0	0.0	15,932.0	2.323	2.323	370,177.36
CARGILL MILLPOINT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.		COGEN.	(641.0)	0.0	0.0	(641.0)	3.687	3.687	(23,634.74)
			642.0	0.0	0.0	642.0	3.680	3.680	23,626.82
FARMLAND HYDRO LP		COGEN.	(902.0)	0.0	0.0	(902.0)	3.427	3.427	(30,910.39)
			903.0	0.0	0.0	903.0	3.424	3.424	30,919.35
IMC-AGRICO-S. PIERCE		COGEN.	(768.0)	0.0	0.0	(768.0)	3.991	3.991	(30,650.61)
			767.0	0.0	0.0	767.0	3.998	3.998	30,667.44
AUBURNDALE POWER PARTNERS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
ORANGE COGENERATION L.P.		COGEN.	(7,843.0)	0.0	0.0	(7,843.0)	2.319	2.319	(181,856.44)
			7,843.0	0.0	0.0	7,843.0	2.260	2.260	177,244.85
CUTRALE CITRUS		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
AS AVAILABLE ASSIGNMENT		COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
			0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**AUGUST 2002**		(309.0)	0.0	0.0	(309.0)	1.369	1.369	(4,229.15)
GRAND TOTAL			41,833.0	0.0	0.0	41,833.0	2.648	2.648	1,107,543.01
CURRENT MONTH:									
DIFFERENCE			806.0	0.0	0.0	806.0	0.206	0.206	106,043.01
DIFFERENCE %			2.0%	0.0%	0.0%	2.0%	8.5%	8.5%	10.6%
PERIOD TO DATE:									
ACTUAL			398,162.0	0.0	0.0	398,162.0	2.404	2.404	9,573,665.25
ESTIMATED			396,226.0	0.0	0.0	396,226.0	2.314	2.314	9,167,300.00
DIFFERENCE			1,936.0	0.0	0.0	1,936.0	0.091	0.091	406,365.25
DIFFERENCE %			0.5%	0.0%	0.0%	0.5%	0.039	0.039	4.4%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: OCTOBER 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

NOVEMBER 2002

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	22,355,657	27,054,266	(4,698,609)	-17.4%	1,023,496	1,112,856	(89,360)	-8.0%	2.18424	2.43107	(0.24682)	-10.2%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (FLMeade/Wauch. Wheeling Losses)	(4,484)	(4,000)	(484)	12.1%	1,023,496 (a)	1,112,856 (a)	(89,360)	-8.0%	(0.00044)	(0.00036)	(0.00008)	21.9%
4b. Adjustments to Fuel Cost (1)	(2,589)	0	(2,589)	0.0%	1,023,496 (a)	1,112,856 (a)	(89,360)	-8.0%	(0.00025)	0.00000	(0.00025)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	1,023,496 (a)	1,112,856 (a)	(89,360)	-8.0%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c	22,348,584	27,050,266	(4,701,682)	-17.4%	1,023,496	1,112,856	(89,360)	-8.0%	2.18355	2.43071	(0.24715)	-10.2%
6. Fuel Cost of Purchased Power - Firm (A7)	18,535,695	14,296,000	2,239,695	15.7%	339,858	344,024	(4,166)	-1.2%	4.86547	4.15552	0.70995	17.1%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	986,623	812,100	174,523	21.5%	38,967	37,809	1,158	3.1%	2.53194	2.14790	0.38404	17.9%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11	17,522,318	15,108,100	2,414,218	16.0%	378,825	381,833	(3,008)	-0.8%	4.62544	3.95673	0.66871	16.9%
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,402,321	1,494,689	(92,368)	-6.2%				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	77,500	85,900	(8,400)	-9.8%	3,686	5,972	(2,286)	-38.3%	2.10255	1.43838	0.66417	46.2%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	1,026,043	621,900	404,143	65.0%	50,091	24,012	26,079	108.6%	2.04836	2.58996	(0.54160)	-20.9%
21. Fuel Cost of Market Base Sales (A6)	192,900	278,100	(85,200)	-30.6%	8,015	13,427	(5,412)	-40.3%	2.40674	2.07120	0.33554	16.2%
21a. Gains on Market Based Sales	35,821	115,500	(79,679)	-69.0%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	1,332,264	1,101,400	230,864	21.0%	61,792	43,411	18,381	42.3%	2.15605	2.53714	(0.38110)	-15.0%
23. Net Inadvertant Interchange					326	0	326	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					(977)	0	(977)	0.0%				
25. Interchange and Wheeling Losses					79	600	(521)	-86.8%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	38,538,638	41,056,966	(2,518,328)	-6.1%	1,339,799	1,450,678	(110,879)	-7.6%	2.87645	2.83019	0.04626	1.6%
27. Net Unbilled	(3,945,050) (a)	(2,029,191) (a)	(1,915,859)	94.4%	(137,150)	(71,698)	(65,452)	91.3%	2.87645	2.83019	0.04626	1.6%
28. Company Use	112,671 (a)	116,038 (a)	(3,367)	-2.9%	3,917	4,100	(183)	-4.5%	2.87646	2.83020	0.04627	1.6%
29. T & D Losses	1,337,261 (a)	3,230,749 (a)	(1,893,488)	-58.6%	46,490	114,153	(67,663)	-59.3%	2.87645	2.83019	0.04626	1.6%
30. System KWH Sales	38,538,638	41,056,968	(2,518,328)	-6.1%	1,426,542	1,404,123	22,419	1.6%	2.70154	2.92403	(0.22249)	-7.6%
31. Wholesale KWH Sales	(994,084)	(1,847,198)	853,114	-46.2%	(36,797)	(63,173)	26,376	-41.8%	2.70154	2.92403	(0.22250)	-7.6%
32. Jurisdictional KWH Sales	37,544,554	39,209,768	(1,665,214)	-4.2%	1,389,745	1,340,950	48,795	3.6%	2.70154	2.92403	(0.22249)	-7.6%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	37,569,333	39,235,648	(1,666,313)	-4.2%	1,389,745	1,340,950	48,795	3.6%	2.70333	2.92596	(0.22263)	-7.6%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	282,435	276,889	5,566	2.0%	1,389,745	1,340,950	48,795	3.6%	0.02032	0.02065	(0.00032)	-1.6%
35a. Adjustment	0	0	0	0.0%	1,389,745	1,340,950	48,795	3.6%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	1,389,745	1,340,950	48,795	3.6%	0.00000	0.00000	0.00000	0.0%
36. True-up *	7,389,395	7,389,395	0	0.0%	1,389,745	1,340,950	48,795	3.6%	0.53171	0.55106	(0.01935)	-3.5%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	45,241,183	46,901,910	(1,660,747)	-3.5%	1,389,745	1,340,950	48,795	3.6%	3.25536	3.49766	(0.24231)	-6.9%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.25770	3.50018	(0.24248)	-6.9%
40. GPIF * (Already Adjusted for Taxes)	91,246	91,246	0	0.0%	1,389,745	1,340,950	48,795	3.6%	0.00657	0.00680	(0.00024)	-3.5%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	45,332,409	46,993,156	(1,660,747)	-3.5%	1,389,745	1,340,950	48,795	3.6%	3.26427	3.50698	(0.24272)	-6.9%
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.264	3.507	(0.243)	-6.9%

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: NOVEMBER 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	330,152,566	363,932,365	(33,779,799)	-9.3%	14,449,183	15,653,910	(1,204,727)	-7.7%	2.28492	2.32487	(0.03994)	-1.7%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(64,877)	(44,000)	(20,877)	47.4%	14,449,183 (a)	15,653,910 (a)	(1,204,727)	-7.7%	(0.00045)	(0.00028)	(0.00017)	59.7%
4b. Adjustments to Fuel Cost (1)	(22,030)	0	(22,030)	0.0%	14,449,183 (a)	15,653,910 (a)	(1,204,727)	-7.7%	(0.00015)	0.00000	(0.00015)	0.0%
4c. Adjustments to Fuel Cost (2)	0	0	0	0.0%	14,449,183 (a)	15,653,910 (a)	(1,204,727)	-7.7%	0.00000	0.00000	0.00000	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c	330,065,659	363,888,365	(33,822,706)	-9.3%	14,449,183	15,653,910	(1,204,727)	-7.7%	2.28432	2.32458	(0.04026)	-1.7%
6. Fuel Cost of Purchased Power - Firm (A7)	152,634,379	138,655,400	13,978,979	10.1%	3,319,376	2,621,614	697,762	26.6%	4.59829	5.28893	(0.69065)	-13.1%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	10,560,289	9,979,400	580,889	5.8%	437,129	434,035	3,094	0.7%	2.41583	2.29922	0.11661	5.1%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11	163,194,668	148,634,800	14,559,868	9.8%	3,756,505	3,055,649	700,856	22.9%	4.34432	4.86426	(0.51994)	-10.7%
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					18,205,688	18,709,559	(503,871)	-2.7%				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	1,405,606	982,500	423,106	43.1%	50,613	66,809	(16,196)	-24.2%	2.77716	1.47061	1.30655	88.8%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	9,318	0	9,318	0.0%	(358)	0	(358)	0.0%	(2.60279)	0.00000	(2.60279)	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	9,635,564	12,397,700	(2,762,136)	-22.3%	441,723	483,894	(42,171)	-8.7%	2.18136	2.56207	(0.38071)	-14.9%
21. Fuel Cost of Market Base Sales (A6)	2,514,036	4,788,800	(2,274,564)	-47.5%	37,283	201,130	(163,847)	-81.5%	6.74312	2.38085	4.36227	183.2%
21a. Gains on Market Based Sales	128,800	3,009,700	(2,880,900)	-95.7%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	13,693,324	21,178,500	(7,485,176)	-35.3%	529,261	751,833	(222,572)	-29.6%	2.58725	2.81692	(0.22966)	-8.2%
23. Net Inadvertant Interchange					1,019	0	1,019	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					2,267	0	2,267	0.0%				
25. Interchange and Wheeling Losses					2,824	11,000	(8,176)	-74.3%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	479,567,003	491,344,665	(11,777,662)	-2.4%	17,676,889	17,946,726	(269,837)	-1.5%	2.71296	2.73780	(0.02484)	-0.9%
27. Net Unbilled	(1,156,754) (a)	(1,035,342) (a)	(121,412)	11.7%	(39,415)	(16,843)	(22,572)	134.0%	2.93481	6.14702	(3.21221)	-52.3%
28. Company Use	1,226,261 (a)	1,230,118 (a)	(3,857)	-0.3%	45,198	45,100	98	0.2%	2.71309	2.72753	(0.01445)	-0.5%
29. T & D Losses	22,261,282 (a)	10,684,585 (a)	11,576,717	108.3%	816,302	364,633	451,669	123.9%	2.72709	2.93022	(0.20314)	-6.9%
30. System KWH Sales	479,567,003	491,344,665	(11,777,662)	-2.4%	16,854,804	17,553,836	(699,032)	-4.0%	2.84528	2.79907	0.04621	1.7%
31. Wholesale KWH Sales	(13,642,356)	(31,960,983)	18,318,627	-57.3%	(466,419)	(1,143,007)	676,588	-59.2%	2.92491	2.79622	0.12869	4.6%
32. Jurisdictional KWH Sales	465,924,647	459,383,682	6,540,965	1.4%	16,388,385	16,410,829	(22,444)	-0.1%	2.84302	2.79927	0.04375	1.6%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	466,232,157	459,686,875	6,545,282	1.4%	16,388,385	16,410,829	(22,444)	-0.1%	2.84489	2.80112	0.04377	1.6%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	3,238,454	3,110,832	127,622	4.1%	16,388,385	16,410,829	(22,444)	-0.1%	0.01976	0.01896	0.00080	4.2%
35a. Adjustment	0	0	0	0.0%	16,388,385	16,410,829	(22,444)	-0.1%	0.00000	0.00000	0.00000	0.0%
35b. Adjustment	0	0	0	0.0%	16,388,385	16,410,829	(22,444)	-0.1%	0.00000	0.00000	0.00000	0.0%
36. True-up *	81,283,345	81,283,345	0	0.0%	16,388,385	16,410,829	(22,444)	-0.1%	0.49598	0.49530	0.00068	0.1%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	550,753,956	544,081,052	6,672,904	1.2%	16,388,385	16,410,829	(22,444)	-0.1%	3.36064	3.31538	0.04526	1.4%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.36306	3.31777	0.04529	1.4%
40. GPIF * (Already Adjusted for Taxes)	1,003,706	1,003,706	0	0.0%	16,388,385	16,410,829	(22,444)	-0.1%	0.00612	0.00612	0.00001	0.1%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	551,757,662	545,084,758	6,672,904	1.2%	16,388,385	16,410,829	(22,444)	-0.1%	3.36918	3.32389	0.04530	1.4%
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.369	3.324	0.045	1.4%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	22,355,657	27,054,266	(4,698,609)	-17.4%	330,152,566	363,932,365	(33,779,799)	-9.3%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	1,296,443	985,900	310,543	31.5%	13,564,524	18,168,800	(4,604,276)	-25.3%
2a. GAINS FROM MARKET BASED SALES	35,821	115,500	(79,679)	-69.0%	128,800	3,009,700	(2,880,900)	-95.7%
3. FUEL COST OF PURCHASED POWER	16,535,695	14,296,000	2,239,695	15.7%	152,634,379	138,655,400	13,978,979	10.1%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	986,623	812,100	174,523	21.5%	10,560,289	9,979,400	580,889	5.8%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	38,545,711	41,060,966	(2,515,255)	-6.1%	479,653,910	491,388,665	(11,734,755)	-2.4%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(4,484)	(4,000)	(484)	12.1%	(64,877)	(44,000)	(20,877)	47.4%
6b. ADJ.TO FUEL COST	(2,589)	0	(2,589)	0.0%	(22,030)	0	(22,030)	0.0%
6c. ADJ.TO FUEL COST	0	0	0	0.0%	0	0	0	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	38,538,638	41,056,966	(2,518,328)	-6.1%	479,567,003	491,344,665	(11,777,662)	-2.4%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,389,745	1,340,950	48,795	3.6%	16,388,385	16,410,829	(22,444)	-0.1%
2. NONJURISDICTIONAL SALES	36,797	63,173	(26,376)	-41.8%	466,419	1,143,007	(676,588)	-59.2%
3. TOTAL SALES	1,426,542	1,404,123	22,419	1.6%	16,854,804	17,553,836	(699,032)	-4.0%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9742055	0.9550089	0.0191966	2.0%	0.9723272	0.9348856	0.0374416	4.0%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	45,528,539	44,190,183	1,338,356	3.0%	536,763,082	541,074,426	(4,311,344)	-0.8%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(7,389,395)	(7,389,395)	0	0.0%	(81,283,345)	(81,283,345)	0	0.0%
2b. INCENTIVE PROVISION	(91,246)	(91,246)	0	0.0%	(1,003,706)	(1,003,706)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	38,047,898	36,709,542	1,338,356	3.6%	454,476,031	458,787,375	(4,311,344)	-0.9%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	38,538,638	41,056,966	(2,518,328)	-6.1%	479,567,003	491,344,665	(11,777,662)	-2.4%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9742055	0.9550089	0.0191966	2.0%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	37,544,554	39,209,768	(1,665,214)	-4.2%	465,924,647	459,383,682	6,540,965	1.4%
6a. JURISDIC. LOSS MULTIPLIER	1.00066	1.00066	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	37,569,333	39,235,646	(1,666,313)	-4.2%	466,232,157	459,686,875	6,545,282	1.4%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	289,913	289,913	0	0.0%	3,328,248	3,328,248	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	282,435	276,869	5,566	2.0%	3,238,454	3,110,832	127,622	4.1%
6e. OTHER	0	0	0	0.0%	0	0	0	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	37,851,768	39,512,515	(1,660,747)	-4.2%	469,470,611	462,797,707	6,672,904	1.4%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	196,130	(2,802,973)	2,999,103	-107.0%	(14,994,580)	(4,010,332)	(10,984,248)	273.9%
8. *INTEREST PROVISION FOR THE MONTH*	(44,358)	(50,864)	6,506	-12.8%	(946,742)	(1,632,340)	685,598	-42.0%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(39,856,039)	(17,567,620)	(22,288,419)	126.9%	----------NOT APPLICABLE----------			
10. TRUE-UP COLLECTED *(REFUNDED)*	7,389,395	7,389,395	0	0.0%	----------NOT APPLICABLE----------			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(32,314,872)	(13,032,062)	(19,282,810)	148.0%	----------NOT APPLICABLE----------			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(39,856,039)	(17,567,620)	(22,288,419)	126.9%	NOT APPLICABLE			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(32,270,514)	(12,981,198)	(19,289,316)	148.6%	NOT APPLICABLE			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(72,126,553)	(30,548,818)	(41,577,735)	136.1%	NOT APPLICABLE			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(36,063,277)	(15,274,409)	(20,788,868)	136.1%	NOT APPLICABLE			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.650	4.000	(2)	-58.8%	NOT APPLICABLE			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.300	4.000	(3)	-67.5%	NOT APPLICABLE			
7. TOTAL (LINE D5 + LINE D6)	2.950	8.000	(5)	-63.1%	NOT APPLICABLE			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.475	4.000	(3)	-63.1%	NOT APPLICABLE			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.123	0.333	(0)	-63.1%	NOT APPLICABLE			
10. INT. PROVISION (LINE D4 x LINE D9)	(44,358)	(50,864)	6,506	-12.8%	NOT APPLICABLE			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	376,039	526,204	(150,165)	-28.5%	4,136,905	4,841,155	(704,250)	-14.5%
2	LIGHT OIL	278,197	1,268,822	(990,625)	-78.1%	9,331,195	15,308,009	(5,976,814)	-39.0%
3	COAL	19,635,928	21,163,653	(1,527,725)	-7.2%	286,425,223	304,683,478	(18,258,255)	-6.0%
4	NATURAL GAS	2,065,493	4,095,587	(2,030,094)	-49.6%	30,259,243	39,099,723	(8,840,480)	-22.6%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	22,355,657	27,054,266	(4,698,609)	-17.4%	330,152,566	363,932,365	(33,779,799)	-9.3%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	6,760	13,853	(7,093)	-51.2%	82,175	120,639	(38,464)	-31.9%
9	LIGHT OIL	5,299	20,152	(14,853)	-73.7%	181,720	226,258	(44,538)	-19.7%
10	COAL	1,000,373	1,004,780	(4,407)	-0.4%	13,717,910	14,590,091	(872,181)	-6.0%
11	NATURAL GAS	11,064	74,071	(63,007)	-85.1%	467,378	716,922	(249,544)	-34.8%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,023,496	1,112,856	(89,360)	-8.0%	14,449,183	15,653,910	(1,204,727)	-7.7%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	10,761	20,632	(9,871)	-47.8%	130,096	179,635	(49,539)	-27.6%
16	LIGHT OIL (BBL)	8,126	42,836	(34,710)	-81.0%	307,232	479,092	(171,860)	-35.9%
17	COAL (TON)	462,431	443,555	18,876	4.3%	6,549,645	6,497,219	52,426	0.8%
18	NATURAL GAS (MCF)	125,027	747,035	(622,008)	-83.3%	5,082,414	7,302,914	(2,220,500)	-30.4%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	67,505	129,550	(62,045)	-47.9%	816,172	1,127,924	(311,752)	-27.6%
22	LIGHT OIL	47,255	243,128	(195,873)	-80.6%	1,769,414	2,723,060	(953,646)	-35.0%
23	COAL	11,007,139	10,386,128	621,011	6.0%	152,837,704	152,356,524	481,180	0.3%
24	NATURAL GAS	131,278	767,971	(636,693)	-82.9%	5,348,063	7,507,685	(2,159,622)	-28.8%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	11,253,177	11,526,777	(273,600)	-2.4%	160,771,352	163,715,193	(2,943,841)	-1.8%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.66%	1.24%	(0.01)	-	0.57%	0.77%	(0.00)	-
29	LIGHT OIL	0.52%	1.81%	(0.01)	-	1.26%	1.45%	(0.00)	-
30	COAL	97.74%	90.29%	0.07	-	94.94%	93.20%	0.02	-
31	NATURAL GAS	1.08%	6.66%	(0.06)	-	3.23%	4.58%	(0.01)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	34.94	25.50	9.44	37.0%	31.80	26.95	4.85	18.0%
36	LIGHT OIL ($/BBL)	34.24	29.62	4.61	15.6%	30.37	31.95	(1.58)	-4.9%
37	COAL ($/TON)	42.46	47.71	(5.25)	-11.0%	43.73	46.89	(3.16)	-6.7%
38	NATURAL GAS ($/MCF)	16.52	5.48	11.04	201.3%	5.95	5.35	0.60	11.2%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	5.57	4.06	1.51	37.1%	5.07	4.29	0.78	18.1%
42	LIGHT OIL	5.89	5.22	0.67	12.8%	5.27	5.62	(0.35)	-6.2%
43	COAL	1.78	2.04	(0.25)	-12.5%	1.87	2.00	(0.13)	-6.3%
44	NATURAL GAS	15.73	5.33	10.40	195.0%	5.66	5.21	0.45	8.6%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	1.99	2.35	(0.36)	-15.4%	2.05	2.22	(0.17)	-7.6%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,986	9,352	634	6.8%	9,932	9,350	582	6.2%
49	LIGHT OIL	8,918	12,065	(3,147)	-26.1%	9,737	12,035	(2,298)	-19.1%
50	COAL	11,003	10,337	666	6.4%	11,141	10,442	699	6.7%
51	NATURAL GAS	11,865	10,368	1,497	14.4%	11,443	10,472	971	9.3%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	10,995	10,358	637	6.1%	11,127	10,458	669	6.4%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	5.56	3.80	1.76	46.3%	5.03	4.01	1.02	25.4%
56	LIGHT OIL	5.25	6.30	(1.05)	-16.7%	5.13	6.77	(1.64)	-24.2%
57	COAL	1.96	2.11	(0.15)	-7.1%	2.09	2.09	0.00	0.0%
58	NATURAL GAS	18.67	5.53	13.14	237.6%	6.47	5.45	1.02	18.7%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.18	2.43	(0.25)	-10.3%	2.28	2.32	(0.04)	-1.7%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: NOVEMBER 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	0	0	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	0	-138	—	—	—	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	**90**	**-138**	—	—	—	**0**	HVY.OIL	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
GAN.#1	114	36,494	44.5	40.7	62.6	12,471	COAL	19,033	23,912,000	455,117.1	677,183	1.86	35.58
GAN.#2	98	37,407	53.0	65.6	73.8	12,261	COAL	19,226	23,856,000	458,655.5	684,050	1.83	35.58
GAN.#3	145	23,448	22.5	30.0	67.6	11,619	COAL	11,655	23,376,000	272,447.3	414,678	1.77	35.58
GAN.#4	159	55,035	48.1	64.8	69.5	12,743	COAL	33,224	21,108,000	701,292.2	1,182,090	2.15	35.58
GAN.#5	217	102,738	65.8	85.7	68.5	11,248	COAL	48,751	23,704,000	1,155,593.7	1,734,532	1.69	35.58
GAN.#6	372	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
GANNON STATION	**1,105**	**255,122**	**32.1**	**40.1**	**45.3**	**11,928**	COAL	**131,889**	**23,073,234**	**3,043,105.8**	**4,692,533**	**1.84**	**35.58**
B.B.#1	416	172,711	57.7	64.7	75.1	10,717	COAL	77,521	23,876,360	1,850,923.8	3,447,151	2.00	44.47
B.B.#2	416	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
B.B.#3	433	190,457	61.1	71.5	75.1	10,860	COAL	85,201	24,276,760	2,068,395.5	3,788,661	1.99	44.47
B.B. 1 - 3	1,265	363,168	39.9	45.7	50.4	10,792	COAL	162,722	24,086,008	3,919,319.3	7,235,812	1.99	44.47
B.B.#4	442	226,376	71.1	82.1	81.6	10,499	COAL	104,984	22,638,310	2,376,664.6	5,174,965	2.29	49.29
B.B. STATION	**1,707**	**589,544**	**48.0**	**55.1**	**58.5**	**10,679**	**COAL**	**267,706**	**23,518,275**	**6,295,983.9**	**12,410,777**	**2.11**	**46.36**
SEB-PHIL. #1(HVY OIL)	17	3,466	28.3	100.0	90.1	9,786	HVY.OIL	5,407	6,273,540	33,918.9	188,946	5.45	34.94
SEB-PHIL. #2(HVY OIL)	17	3,432	28.0	100.0	89.8	9,786	HVY.OIL	5,354	6,273,540	33,586.2	187,093	5.45	34.94
SEB-PHILLIPS TOTAL	**34**	**6,898**	**28.2**	**100.0**	**90.0**	**9,786**	HVY.OIL	**10,761**	**6,273,540**	**67,505.1**	**376,039**	**5.45**	**34.94**
POLK #1 GASIFIER	250	155,707	86.5	92.5	92.0	10,713	COAL	62,836	26,546,000	1,668,049.0	2,532,618	1.63	40.31
POLK #1 CT (OIL)	225	5,285	3.3	99.6	77.8	8,892	LGT.OIL	8,081	5,815,034	46,992.8	276,821	5.24	34.25
POLK #1 TOTAL	*250*	*160,992*	*89.4*	*97.5*	*91.4*	*10,653*	-	-	-	**1,715,041.8**	**2,809,439**	**1.75**	-
POLK #2 CT (GAS)	150	5,566	5.2	100.0	77.2	9,685	GAS	51,342	972,290	53,909.0	1,153,438	20.72	22.47
POLK #2 CT (OIL)	160	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	**155**	**5,566**	**5.0**	**100.0**	**77.2**	**9,685**	-	-	-	**53,909.0**	**1,153,438**	**20.72**	-
POLK #3 CT (GAS)	150	5,498	5.1	100.0	75.0	14,072	GAS	73,685	972,290	77,369.0	913,775	16.62	12.40
POLK #3 CT (OIL)	160	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	**155**	**5,498**	**4.9**	**100.0**	**75.0**	**14,072**	-	-	-	**77,369.0**	**913,775**	**16.62**	-
POLK STATION TOTAL	**560**	**172,056**	**42.7**	**98.9**	**61.5**	**10,731**	-	-	-	**1,846,319.8**	**4,876,652**	**2.83**	-
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	12	14	0.2	100.0	116.7	18,721	LGT.OIL	45	5,855,675	262.1	1,376	9.83	30.58
B.B.C.T.#2	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	66	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
C.T. TOTAL	**144**	**14**	**0.0**	**8.3**	**9.7**	**18,721**	LGT.OIL	**45**	**5,855,675**	**262.1**	**1,376**	**9.83**	**30.58**
CITY OF TAMPA	**6**	**0**	**0.0**	**0.0**	**0.0**	**0**	GAS	**0**	**0**	**0.0**	**-1,720**	**0.00**	**0.00**
TOT. COAL (GN,BB,POLK)	**3,062**	**1,000,373**	**45.4**	**52.8**	**56.5**	**11,003**	COAL	**462,431**	**23,802,760**	**11,007,138.7**	**19,635,928**	**1.96**	**42.46**
SYSTEM	**3,556**	**1,023,496**	**40.0**	**55.9**	**53.2**	**10,993**	-	-	-	**11,253,176.7**	**22,355,657**	**2.18**	-

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT B.B. = BIG BEND

GAN. = GANNON C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	12,281	20,632	(8,351)	-40.5%	119,291	179,635	(60,344)	-33.6%
3 UNIT COST ($/BBL)	35.39	25.49	9.90	38.8%	29.75	26.19	3.56	13.6%
4 AMOUNT ($)	434,677	525,934	(91,257)	-17.4%	3,548,506	4,704,875	(1,156,369)	-24.6%
5 BURNED:								
6 UNITS (BBL)	10,761	20,632	(9,871)	-47.8%	130,096	179,635	(49,539)	-27.6%
7 UNIT COST ($/BBL)	34.94	25.50	9.44	37.0%	31.80	26.95	4.85	18.0%
8 AMOUNT ($)	376,039	526,204	(150,165)	-28.5%	4,136,905	4,841,155	(704,250)	-14.5%
9 ENDING INVENTORY:								
10 UNITS (BBL)	6,844	59,129	(52,285)	-88.4%	6,844	59,129	(52,285)	-88.4%
11 UNIT COST ($/BBL)	39.11	25.68	13.43	52.3%	39.11	25.68	13.43	52.3%
12 AMOUNT ($)	267,687	1,518,342	(1,250,655)	-82.4%	267,687	1,518,342	(1,250,655)	-82.4%
13								
14 DAYS SUPPLY:	27	153	(126)	-82.4%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	12,581	50,908	(38,327)	-75.3%	385,749	582,824	(197,075)	-33.8%
17 UNIT COST ($/BBL)	33.00	27.86	5.14	18.4%	30.75	31.06	(0.31)	-1.0%
18 AMOUNT ($)	415,162	1,418,451	(1,003,289)	-70.7%	11,861,622	18,103,761	(6,242,139)	-34.5%
19 BURNED:								
20 UNITS (BBL)	8,126	42,836	(34,710)	-81.0%	307,232	479,092	(171,860)	-35.9%
21 UNIT COST ($/BBL)	34.24	29.62	4.61	15.6%	30.37	31.95	(1.58)	-4.9%
22 AMOUNT ($)	278,197	1,268,822	(990,625)	-78.1%	9,331,195	15,308,009	(5,976,814)	-39.0%
23 ENDING INVENTORY:								
24 UNITS (BBL)	91,553	113,465	(21,912)	-19.3%	91,553	113,465	(21,912)	-19.3%
25 UNIT COST ($/BBL)	32.47	29.57	2.90	9.8%	32.47	29.57	2.90	9.8%
26 AMOUNT ($)	2,972,978	3,355,123	(382,145)	-11.4%	2,972,978	3,355,123	(382,145)	-11.4%
27								
28 DAYS SUPPLY: NORMAL	84	100	(16)	-16.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	13	16	(3)	-18.3%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	405,874	374,000	31,874	8.5%	6,477,535	6,772,000	(294,465)	-4.3%
32 UNIT COST ($/TON)	43.91	46.64	(2.73)	-5.8%	44.03	46.48	(2.45)	-5.3%
33 AMOUNT ($)	17,823,596	17,443,569	380,027	2.2%	285,177,471	314,762,195	(29,584,724)	-9.4%
34 BURNED:								
35 UNITS (TONS)	462,431	443,555	18,876	4.3%	6,549,645	6,497,219	52,426	0.8%
36 UNIT COST ($/TON)	42.46	47.71	(5.25)	-11.0%	43.73	46.89	(3.16)	-6.7%
37 AMOUNT ($)	19,635,928	21,163,653	(1,527,725)	-7.2%	286,425,223	304,683,478	(18,258,255)	-6.0%
38 ENDING INVENTORY:								
39 UNITS (TONS)	553,370	1,251,601	(698,231)	-55.8%	553,370	1,251,601	(698,231)	-55.8%
40 UNIT COST ($/TON)	43.67	46.72	(3.05)	-6.5%	43.67	46.72	(3.05)	-6.5%
41 AMOUNT ($)	24,164,084	58,476,329	(34,312,245)	-58.7%	24,164,084	58,476,329	(34,312,245)	-58.7%
42								
43 DAYS SUPPLY:	30	66	(36)	-54.5%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	125,027	747,035	(622,008)	-83.3%	5,082,414	7,302,914	(2,220,500)	-30.4%
46 UNIT COST ($/MCF)	16.52	5.48	11.04	201.3%	5.95	5.35	0.60	11.2%
47 AMOUNT ($)	2,065,493	4,095,587	(2,030,094)	-49.6%	30,258,270	39,099,720	(8,841,450)	-22.6%
48 BURNED:								
49 UNITS (MCF)	125,027	747,035	(622,008)	-83.3%	5,082,414	7,302,914	(2,220,500)	-30.4%
50 UNIT COST ($/MCF)	16.52	5.48	11.04	201.3%	5.95	5.35	0.60	11.2%
51 AMOUNT ($)	2,065,493	4,095,587	(2,030,094)	-49.6%	30,259,243	39,099,723	(8,840,480)	-22.6%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	14,354
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	14,354

(2) RECONCILIATION - LIGHT OIL

DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(7,003)	(216,771)
OTHER USAGE	(530)	(16,426)
TOTAL	(7,533)	(233,197)

(3) RECONCILIATION - COAL

DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	0
IGNITION #2 OIL	202,417
IGNITION PROPANE	3,559
AERIAL SURVEY ADJ.	(944,984)
ADDITIVES	37,887
GREEN FUEL	0
TOTAL	(701,121)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2002

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. -D	5,972.0	0.0	5,972.0	1.438	1.438	85,900.00	85,900.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	24,012.0	0.0	24,012.0	2.590	3.638	621,900.00	873,500.00	
VARIOUS	JURISDIC.	SCH. -MB	13,427.0	0.0	13,427.0	2.071	2.071	278,100.00	278,100.00	115,500.00
TOTAL			**43,411.0**	**0.0**	**43,411.0**	**2.271**	**2.851**	**985,900.00**	**1,237,500.00**	**115,500.00**
ACTUAL:										
FLA. PWR. & LIGHT	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPARATED	SCH. -D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR PARTNERS	SEP. CONTR.	SCH. -D	50,091.0	0.0	50,091.0	2.509	3.247	1,256,783.19	1,626,454.77	
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. -D	2,935.3	262.1	2,673.2	2.015	2.015	53,852.27	53,852.27	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. -D	1,013.0	0.0	1,013.0	2.334	2.334	23,647.34	23,647.34	
FLA. PWR. CORP.		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT		SCH. -MA	1,140.0	0.0	1,140.0	2.141	3.181	24,403.97	36,263.74	8,280.17
CITY OF LAKELAND		SCH. -MA	75.0	0.0	75.0	2.123	3.325	1,592.11	2,493.84	666.23
ORLANDO UTIL. COMM.		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ENTERGY-KOCH TRADING		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
THE ENERGY AUTHORITY		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK		SCH. -MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SEMINOLE ELEC. CO-OP		SCH. -MA	6,750.0	0.0	6,750.0	2.450	3.163	165,401.08	213,471.08	26,875.00
HARDEE PWR. PART. TO CITY OF LAKELAND		SCH. -MA	50.0	0.0	50.0	3.007	3.344	1,503.50	1,672.16	
AUBURNDALE POWER PARTNERS		SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ADJUSTMENTS TO PREV. MONTHS										
HARDEE PWR PARTNERS	Oct. 2002	CONTRACT	(56,973.0)	0.0	(56,973.0)	2.914	3.576	(1,660,193.22)	(2,037,354.48)	
HARDEE PWR PARTNERS	Oct. 2002	CONTRACT	56,973.0	0.0	56,973.0	2.509	3.247	1,429,452.57	1,849,913.31	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			3,948.3	262.1	3,686.2	2.102	2.102	77,499.61	77,499.61	
SUB-TOTAL SCHEDULE D POWER SALES-SEP.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEP.			50,091.0	0.0	50,091.0	2.048	2.873	1,026,042.54	1,439,013.60	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			8,015.0	0.0	8,015.0	2.407	3.168	192,900.66	253,900.82	35,821.40
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL			**62,054.3**	**262.1**	**61,792.2**	**2.098**	**2.865**	**1,296,442.81**	**1,770,414.03**	**35,821.40**
CURRENT MONTH:										
DIFFERENCE			18,643.3	262.1	18,381.2	(0.173)	0.014	310,542.81	532,914.03	(79,678.60)
DIFFERENCE %			42.9%	0.0%	42.3%	-7.6%	0.5%	31.5%	43.1%	-69.0%
PERIOD TO DATE:										
ACTUAL			535,033.9	5,772.2	529,261.7	2.563	3.225	13,564,524.71	17,069,617.06	128,801.28
ESTIMATED			751,833.0	0.0	751,833.0	2.417	3.091	18,168,800.00	23,240,100.00	3,009,700.00
DIFFERENCE			(216,799.1)	5,772.2	(222,571.3)	0.146	0.134	(4,604,275.29)	(6,170,482.94)	(2,880,898.72)
DIFFERENCE %			-28.8%	0.0%	-29.6%	6.0%	4.3%	-25.3%	-26.6%	-95.7%

* SALES TO HARDEE POWER PARTNERS FOR OTHERS INCLUDES TEC 40% PROFIT. SEC 60% PROFIT OR $252.99 HAS BEEN EXCLUDED.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH.-J	20,955.0	0.0	10,508.0	10,447.0	5.809	5.809	606,900.00
HARDEE POWER PARTNERS		IPP	62,004.0	0.0	0.0	62,004.0	4.727	4.727	2,931,200.00
VARIOUS		OTHER	75,131.0	0.0	0.0	75,131.0	4.037	4.037	3,033,400.00
VARIOUS		MKT. BASE	196,442.0	0.0	0.0	196,442.0	3.932	3.932	7,724,500.00
TOTAL			**354,532.0**	**0.0**	**10,508.0**	**344,024.0**	**4.156**	**4.156**	**14,296,000.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	48,948.0	0.0	0.0	48,948.0	5.158	5.158	2,524,528.91
HARDEE PWR. PART.-OTHERS		IPP	50.0	0.0	0.0	50.0	3.007	3.007	1,503.50
FLA. POWER CORP.		SCH.-J	47,129.0	0.0	686.8	46,442.2	4.143	4.143	1,924,126.42
FLA. POWER & LIGHT		SCH.-J	92,898.0	0.0	1,553.3	91,344.7	4.216	4.216	3,851,209.36
CITY OF LAKELAND		SCH.-J	16,322.0	0.0	2,353.7	13,968.3	4.393	4.393	613,606.98
ORLANDO UTIL. COMM.		SCH.-J	7,000.0	0.0	1,496.6	5,503.4	5.755	5.755	316,697.70
CAROLINA POWER & LIGHT		SCH.-J	6,079.0	0.0	0.0	6,079.0	3.111	3.111	189,098.38
THE ENERGY AUTHORITY		SCH.-J	15,662.0	0.0	1,576.0	14,086.0	4.365	4.365	614,797.53
REEDY CREEK		SCH.-J	215.0	0.0	0.0	215.0	3.884	3.884	8,350.00
OKEELANTA		SCH.-J	2,674.0	0.0	0.0	2,674.0	4.558	4.558	121,872.74
TALLAHASSEE		SCH.-J	1,341.0	0.0	0.0	1,341.0	4.601	4.601	61,705.40
CALPINE		SCH.-J	2,756.0	0.0	147.0	2,609.0	3.741	3.741	97,596.00
CARGILL ALLIANT		SCH.-J	43,095.0	0.0	1,603.3	41,491.7	4.441	4.441	1,842,529.50
KOCH ENERGY		SCH.-J	231.0	0.0	0.0	231.0	5.768	5.768	13,325.00
RELIANT		SCH.-J	2,320.0	0.0	2,143.6	176.4	7.101	7.101	12,526.76
SEMINOLE ELECTRIC CO-OP		SCH.-J	8,535.0	0.0	1,039.5	7,495.5	3.838	3.838	287,691.15
DUKE ENERGY		SCH.-J	2,884.0	0.0	643.4	2,240.6	5.137	5.137	115,093.17
DYNEGY POWER MARKETING		SCH.-J	6,669.0	0.0	76.0	6,593.0	3.718	3.718	245,146.00
RINGHAVER		SCH.-J	1,889.0	0.0	0.0	1,889.0	18.286	18.286	345,415.20
FLA. POWER CORP.		SCH.-D	59,500.0	0.0	0.0	59,500.0	4.143	4.143	2,464,940.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Oct. 2002	IPP	(114,660.0)	0.0	0.0	(114,660.0)	4.155	4.155	(4,764,522.87)
HARDEE PWR. PART.-NATIVE	Oct. 2002	IPP	91,254.0	0.0	0.0	91,254.0	5.928	5.928	5,409,642.10
OKEELANTA	Oct. 2002	SCH.-J	(15,230.0)	0.0	0.0	(15,230.0)	4.163	4.163	(634,026.68)
OKEELANTA	Oct. 2002	SCH.-J	15,216.0	0.0	0.0	15,216.0	4.162	4.162	633,354.68
FLA. POWER CORP.	Oct. 2002	SCH.-D	(79,475.0)	0.0	0.0	(79,475.0)	3.909	3.909	(3,106,809.00)
FLA. POWER CORP.	Oct. 2002	SCH.-D	79,475.0	0.0	0.0	79,475.0	4.067	4.067	3,232,379.50
FLA. POWER CORP.	Sept. 2002	SCH.-D	(61,700.0)	0.0	0.0	(61,700.0)	4.595	4.595	(2,835,114.00)
FLA. POWER CORP.	Sept. 2002	SCH.-D	72,100.0	0.0	0.0	72,100.0	4.090	4.090	2,949,032.00
TOTAL			**353,177.0**	**0.0**	**13,319.2**	**339,857.8**	**4.865**	**4.865**	**16,535,695.43**
CURRENT MONTH:									
DIFFERENCE			(1,355.0)	0.0	2,811.2	(4,166.2)	0.709	0.709	2,239,695.43
DIFFERENCE %			-0.4%	0.0%	26.8%	-1.2%	17.1%	17.1%	15.7%
PERIOD TO DATE:									
ACTUAL			3,536,564.0	0.0	217,190.2	3,319,373.8	4.598	4.598	152,634,379.58
ESTIMATED			2,771,093.0	0.0	149,479.0	2,621,614.0	5.289	5.289	138,655,400.00
DIFFERENCE			765,471.0	0.0	67,711.2	697,759.8	(0.691)	(0.691)	13,978,979.58
DIFFERENCE %			27.6%	0.0%	45.3%	26.6%	-13.1%	-13.1%	10.1%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	37,809.0	0.0	0.0	37,809.0	2.148	2.148	812,100.00
TOTAL		**37,809.0**	**0.0**	**0.0**	**37,809.0**	**2.148**	**2.148**	**812,100.00**
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	12,937.0	0.0	0.0	12,937.0	2.321	2.321	300,262.85
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	308.0	0.0	0.0	308.0	3.720	3.720	11,457.91
HILLSBOROUGH COUNTY	COGEN.	18,482.0	0.0	0.0	18,482.0	2.320	2.320	428,768.10
CARGILL MILLPOINT	COGEN.	13.0	0.0	0.0	13.0	6.579	6.579	855.21
CF INDUSTRIES INC.	COGEN.	688.0	0.0	0.0	688.0	3.772	3.772	25,949.06
FARMLAND HYDRO LP	COGEN.	614.0	0.0	0.0	614.0	3.805	3.805	23,365.46
IMC-AGRICO-S. PIERCE	COGEN.	8.0	0.0	0.0	8.0	3.737	3.737	298.92
AUBURNDALE POWER PARTNERS	COGEN.	487.0	0.0	0.0	487.0	3.179	3.179	15,479.63
ORANGE COGENERATION L.P.	COGEN.	5,400.0	0.0	0.0	5,400.0	2.179	2.179	117,691.72
CUTRALE CITRUS	COGEN.	30.0	0.0	0.0	30.0	2.824	2.824	847.18
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR NOVEMBER 2002		38,967.0	0.0	0.0	38,967.0	2.374	2.374	924,976.04
ADJUSTMENTS FOR THE MONTH OF:	**SEPTEMBER 2002**							
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	(12,594.0)	0.0	0.0	(12,594.0)	2.451	2.451	(308,644.76)
		12,594.0	0.0	0.0	12,594.0	2.470	2.470	311,060.85
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	(581.0)	0.0	0.0	(581.0)	4.264	4.264	(24,772.49)
		581.0	0.0	0.0	581.0	4.477	4.477	26,008.75
HILLSBOROUGH COUNTY	COGEN.	(12,117.0)	0.0	0.0	(12,117.0)	2.451	2.451	(297,039.88)
		12,117.0	0.0	0.0	12,117.0	2.534	2.534	307,015.37
CARGILL MILLPOINT	COGEN.	(94.0)	0.0	0.0	(94.0)	6.501	6.501	(6,110.87)
		94.0	0.0	0.0	94.0	7.762	7.762	7,296.61
CF INDUSTRIES INC.	COGEN.	(626.0)	0.0	0.0	(626.0)	4.511	4.511	(28,240.47)
		626.0	0.0	0.0	626.0	5.008	5.008	31,352.04
FARMLAND HYDRO LP	COGEN.	(670.0)	0.0	0.0	(670.0)	4.398	4.398	(29,467.34)
		670.0	0.0	0.0	670.0	4.697	4.697	31,469.85
IMC-AGRICO-S. PIERCE	COGEN.	(506.0)	0.0	0.0	(506.0)	4.663	4.663	(23,595.93)
		506.0	0.0	0.0	506.0	6.401	6.401	32,387.23
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ORANGE COGENERATION L.P.	COGEN.	(5,566.0)	0.0	0.0	(5,566.0)	2.289	2.289	(127,427.10)
		5,566.0	0.0	0.0	5,566.0	2.361	2.361	131,414.50
CUTRALE CITRUS	COGEN.	(3.0)	0.0	0.0	(3.0)	7.083	7.083	(212.50)
		3.0	0.0	0.0	3.0	9.997	9.997	299.92
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**SEPTEMBER 2002**	0.0	0.0	0.0	0.0	0.000	0.000	32,793.58

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ADJUSTMENTS FOR THE MONTH OF:	**AUGUST 2002**							
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	(12,883.0)	0.0	0.0	(12,883.0)	2.491	2.491	(320,893.02)
		12,883.0	0.0	0.0	12,883.0	2.542	2.542	327,441.04
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
HILLSBOROUGH COUNTY	COGEN.	(15,932.0)	0.0	0.0	(15,932.0)	2.323	2.323	(370,177.36)
		15,932.0	0.0	0.0	15,932.0	2.405	2.405	383,224.02
CARGILL MILLPOINT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	(642.0)	0.0	0.0	(642.0)	3.680	3.680	(23,626.82)
		642.0	0.0	0.0	642.0	3.678	3.678	23,610.98
FARMLAND HYDRO LP	COGEN.	(903.0)	0.0	0.0	(903.0)	3.424	3.424	(30,919.35)
		903.0	0.0	0.0	903.0	3.426	3.426	30,937.27
IMC-AGRICO-S. PIERCE	COGEN.	(767.0)	0.0	0.0	(767.0)	3.998	3.998	(30,667.44)
		767.0	0.0	0.0	767.0	4.003	4.003	30,701.10
AUBURNDALE POWER PARTNERS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
ORANGE COGENERATION L.P.	COGEN.	(7,843.0)	0.0	0.0	(7,843.0)	2.260	2.260	(177,244.85)
		7,843.0	0.0	0.0	7,843.0	2.378	2.378	186,468.03
CUTRALE CITRUS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	**AUGUST 2002**	0.0	0.0	0.0	0.0	0.000	0.000	28,853.60
ADJUSTMENT SUB-TOTAL FOR AUGUST AND SEPTEMBER 2002		0.0	0.0	0.0	0.0	0.000	0.000	61,647.18
GRAND TOTAL		**38,967.0**	**0.0**	**0.0**	**38,967.0**	**2.532**	**2.532**	**986,623.22**
CURRENT MONTH:								
DIFFERENCE		1,158.0	0.0	0.0	1,158.0	0.384	0.384	174,523.22
DIFFERENCE %		3.1%	0.0%	0.0%	3.1%	17.9%	17.9%	21.5%
PERIOD TO DATE:								
ACTUAL		437,129.0	0.0	0.0	437,129.0	2.416	2.416	10,560,288.47
ESTIMATED		434,035.0	0.0	0.0	434,035.0	2.299	2.299	9,979,400.00
DIFFERENCE		3,094.0	0.0	0.0	3,094.0	0.117	0.117	580,888.47
DIFFERENCE %		0.7%	0.0%	0.0%	0.7%	0.051	0.051	5.8%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: NOVEMBER 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULES A1 THROUGH A9

DECEMBER 2002

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	26,439,760	28,756,090	(2,316,330)	-8.1%	1,177,391	1,325,391	(148,000)	-11.2%	2.24562	2.16963	0.07599	3.5%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(4,949)	(4,000)	(949)	23.7%	1,177,391 (a)	1,325,391 (a)	(148,000)	-11.2%	(0.00042)	(0.00030)	(0.00012)	39.3%
4b. Adjustments to Fuel Cost (1)	(2,829)	0	(2,829)	0.0%	1,177,391 (a)	1,325,391 (a)	(148,000)	-11.2%	(0.00024)	0.00000	(0.00024)	0.0%
4c. Risk Management O&M	83,786	0	83,786	0.0%	1,177,391 (a)	1,325,391 (a)	(148,000)	-11.2%	0.00712	0.00000	0.00712	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	**26,515,768**	**28,752,090**	**(2,236,322)**	**-7.8%**	**1,177,391**	**1,325,391**	**(148,000)**	**-11.2%**	**2.25208**	**2.16933**	**0.08275**	**3.8%**
6. Fuel Cost of Purchased Power - Firm (A7)	17,295,511	4,713,200	12,582,311	267.0%	327,948	102,612	225,336	219.6%	5.27386	4.59322	0.68063	14.8%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	856,174	783,300	72,874	9.3%	39,802	39,069	733	1.9%	2.15108	2.00491	0.14617	7.3%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	**18,151,685**	**5,496,500**	**12,655,185**	**230.2%**	**367,750**	**141,681**	**226,069**	**159.6%**	**4.93588**	**3.87949**	**1.05639**	**27.2%**
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					1,545,141	1,467,072	78,069	5.3%				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	51,880	86,700	(34,820)	-40.2%	2,074	5,995	(3,921)	-65.4%	2.50145	1.44621	1.05524	73.0%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	920,676	56,000	864,676	1544.1%	43,765	2,157	41,608	1929.0%	2.10368	2.59620	(0.49252)	-19.0%
21. Fuel Cost of Market Base Sales (A6)	174	322,600	(322,426)	-99.9%	675	15,768	(15,093)	-95.7%	0.02578	2.04592	(2.02014)	-98.7%
21a. Gains on Market Based Sales	2,509	140,800	(138,291)	-98.2%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	**975,239**	**606,100**	**369,139**	**60.9%**	**46,514**	**23,920**	**22,594**	**94.5%**	**2.09666**	**2.53386**	**(0.43721)**	**-17.3%**
23. Net Inadvertant Interchange					(157)	0	(157)	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					1,455	0	1,455	0.0%				
25. Interchange and Wheeling Losses					98	400	(302)	-75.5%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	**43,692,214**	**33,642,490**	**10,049,724**	**29.9%**	**1,499,827**	**1,442,752**	**57,075**	**4.0%**	**2.91315**	**2.33183**	**0.58132**	**24.9%**
27. Net Unbilled	(314,882) (a)	(935,788) (a)	620,904	-66.4%	(10,809)	(40,131)	29,322	-73.1%	2.91315	2.33183	0.58132	24.9%
28. Company Use	113,205 (a)	95,605 (a)	17,600	18.4%	3,886	4,100	(214)	-5.2%	2.91315	2.33183	0.58132	24.9%
29. T & D Losses	4,306,597 (a)	2,375,629 (a)	1,930,768	81.3%	147,833	101,887	45,946	45.1%	2.91315	2.33183	0.58132	24.9%
30. System KWH Sales	43,692,214	33,642,490	10,049,724	29.9%	1,358,917	1,376,896	(17,979)	-1.3%	3.21522	2.44336	0.77187	31.6%
31. Wholesale KWH Sales	(1,148,770)	(884,518)	(264,252)	29.9%	(35,729)	(36,201)	472	-1.3%	3.21523	2.44335	0.77188	31.6%
32. Jurisdictional KWH Sales	42,543,444	32,757,972	9,785,472	29.9%	1,323,188	1,340,695	(17,507)	-1.3%	3.21522	2.44336	0.77187	31.6%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	42,571,523	32,779,592	9,791,931	29.9%	1,323,188	1,340,695	(17,507)	-1.3%	3.21735	2.44497	0.77237	31.6%
35. Peabody Coal Contract Buy-Out Amort. Jurisd.	279,827	279,827	0	0.0%	1,323,188	1,340,695	(17,507)	-1.3%	0.02115	0.02087	0.00028	1.3%
35a. Adjustment	(254,359)	0	(254,359)	0.0%	1,323,188	1,340,695	(17,507)	-1.3%	(0.01922)	0.00000	(0.01922)	0.0%
35b. Adjustment	0	0	0	0.0%	1,323,188	1,340,695	(17,507)	-1.3%	0.00000	0.00000	0.00000	0.0%
36. True-up *	7,389,390	7,389,390	(0)	0.0%	1,323,188	1,340,695	(17,507)	-1.3%	0.55845	0.55116	0.00729	1.3%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	49,986,381	40,448,809	9,537,572	23.6%	1,323,188	1,340,695	(17,507)	-1.3%	3.77772	3.01700	0.76072	25.2%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.78044	3.01918	0.76126	25.2%
40. GPIF * (Already Adjusted for Taxes)	91,250	91,250	0	0.0%	1,323,188	1,340,695	(17,507)	-1.3%	0.00690	0.00681	0.00009	1.3%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	**50,077,631**	**40,540,059**	**9,537,572**	**23.5%**	**1,323,188**	**1,340,695**	**(17,507)**	**-1.3%**	**3.78734**	**3.02599**	**0.76135**	**25.2%**
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									**3.787**	**3.026**	**0.761**	**25.1%**

* Based on Jurisdictional Sales (a) Included for informational purposes only

COMPARISON OF ESTIMATED AND ACTUAL
FUEL AND PURCHASED POWER COST RECOVERY FACTOR
TAMPA ELECTRIC COMPANY
PERIOD TO DATE THROUGH: DECEMBER 2002

	$		DIFFERENCE		MWH		DIFFERENCE		CENTS/KWH		DIFFERENCE	
	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
1. Fuel Cost of System Net Generation (A3)	356,592,326	392,688,455	(36,096,129)	-9.2%	15,626,574	16,979,301	(1,352,727)	-8.0%	2.28196	2.31275	(0.03079)	-1.3%
2. Spent Nuclear Fuel Disposal Cost	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
3. Coal Car Investment	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
4a. Adj. to Fuel Cost (Ft.Meade/Wauch. Wheeling Losses)	(69,826)	(48,000)	(21,826)	45.5%	15,626,574 (a)	16,979,301 (a)	(1,352,727)	-8.0%	(0.00045)	(0.00028)	(0.00016)	58.1%
4b. Adjustments to Fuel Cost (1)	(24,859)	0	(24,859)	0.0%	15,626,574 (a)	16,979,301 (a)	(1,352,727)	-8.0%	(0.00016)	0.00000	(0.00016)	0.0%
4c. Risk Management O&M	83,786	0	83,786	0.0%	15,626,574 (a)	16,979,301 (a)	(1,352,727)	-8.0%	0.00054	0.00000	0.00054	0.0%
5. TOTAL COST OF GENERATED POWER (Lines 1 through 4c)	356,581,427	392,640,455	(36,059,028)	-9.2%	15,626,574	16,979,301	(1,352,727)	-8.0%	2.28189	2.31247	(0.03057)	-1.3%
6. Fuel Cost of Purchased Power - Firm (A7)	169,929,890	143,368,600	26,561,290	18.5%	3,647,324	2,724,226	923,098	33.9%	4.65903	5.26273	(0.60370)	-11.5%
7. Energy Cost of Sch C,X Econ. Purch. (Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
8. Energy Cost of Other Econ. Purch. (Non-Broker) (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
9. Energy Cost of Sch. E Economy Purchases (A9)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
10. Capacity Cost of Sch. E Economy Purchases	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
11. Payments to Qualifying Facilities (A8)	11,416,463	10,762,700	653,763	6.1%	476,931	473,104	3,827	0.8%	2.39373	2.27491	0.11882	5.2%
12. TOTAL COST OF PURCHASED POWER (Lines 6 through 11)	181,346,353	154,131,300	27,215,053	17.7%	4,124,255	3,197,330	926,925	29.0%	4.39707	4.82063	(0.42356)	-8.8%
13. TOTAL AVAILABLE KWH (LINE 5 + LINE 12)					19,750,829	20,176,631	(425,802)	-2.1%				
14. Fuel Cost of Economy Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
15. Gain on Economy Sales - 80% (A6)	0	0	0	0.0%	0 (a)	0 (a)	0	0.0%	0.00000	0.00000	0.00000	0.0%
16. Fuel Cost of Sch. D Separ. Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
17. Fuel Cost of Sch. D Jurisd. Sales (A6)	1,457,486	1,069,200	388,286	36.3%	52,687	72,804	(20,117)	-27.6%	2.76631	1.46860	1.29771	88.4%
18. Fuel Cost of Sch. OATT Jurisd. Sales (A6)	9,318	0	9,318	0.0%	(358)	0	(358)	0.0%	(2.60279)	0.00000	(2.60279)	0.0%
19. Fuel Cost of Other Sales (A6)	0	0	0	0.0%	0	0	0	0.0%	0.00000	0.00000	0.00000	0.0%
20. Fuel Cost of HPP Sch. D Separ. Sales (A6)	10,556,240	12,453,700	(1,897,460)	-15.2%	485,488	486,051	(563)	-0.1%	2.17436	2.56222	(0.38786)	-15.1%
21. Fuel Cost of Market Base Sales (A6)	2,514,210	5,111,200	(2,596,990)	-50.8%	37,958	216,898	(178,940)	-82.5%	6.62366	2.35650	4.26716	181.1%
21a. Gains on Market Based Sales	131,309	3,150,500	(3,019,191)	-95.8%								
22. TOTAL FUEL COST AND GAINS OF POWER SALES (LINE 14 + 15 + 16 + 17 + 18 + 19 + 20 + 21 + 21a)	14,668,563	21,784,600	(7,116,037)	-32.7%	575,775	775,753	(199,978)	-25.8%	2.54762	2.80819	(0.26057)	-9.3%
23. Net Inadvertant Interchange					862	0	862	0.0%				
24. Wheeling Rec'd. less Wheeling Del'd.					3,722	0	3,722	0.0%				
25. Interchange and Wheeling Losses					2,922	11,400	(8,478)	-74.4%				
26. TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5 + 12 - 22 + 23 + 24 - 25)	523,259,217	524,987,155	(1,727,938)	-0.3%	19,176,716	19,389,478	(212,762)	-1.1%	2.72862	2.70759	0.02103	0.8%
27. Net Unbilled	(1,471,636) (a)	(1,971,128) (a)	499,492	-25.3%	(50,224)	(56,974)	6,750	-11.8%	2.93014	3.45970	(0.52955)	-15.3%
28. Company Use	1,339,466 (a)	1,325,723 (a)	13,743	1.0%	49,084	49,200	(116)	-0.2%	2.72893	2.69456	0.03437	1.3%
29. T & D Losses	26,567,879 (a)	13,060,394 (a)	13,507,485	103.4%	964,135	466,520	497,615	106.7%	2.75562	2.79954	(0.04392)	-1.6%
30. System KWH Sales	523,259,217	524,987,155	(1,727,938)	-0.3%	18,213,721	18,930,732	(717,011)	-3.8%	2.87288	2.77320	0.09968	3.6%
31. Wholesale KWH Sales	(14,791,126)	(32,845,501)	18,054,375	-55.0%	(502,148)	(1,179,208)	677,060	-57.4%	2.94557	2.78539	0.16018	5.8%
32. Jurisdictional KWH Sales	508,468,091	492,141,654	16,326,437	3.3%	17,711,573	17,751,524	(39,951)	-0.2%	2.87082	2.77239	0.09843	3.6%
33. Jurisdictional Loss Multiplier - 1.00066									1.00066	1.00066	0.00000	0.0%
34. Jurisdictional KWH Sales Adjusted for Line Losses	508,803,680	492,466,467	16,337,213	3.3%	17,711,573	17,751,524	(39,951)	-0.2%	2.87272	2.77422	0.09850	3.6%
35. Peabody Cost Contract Buy-Out Amort. Jurisd.	3,518,281	3,390,659	127,622	3.8%	17,711,573	17,751,524	(39,951)	-0.2%	0.01986	0.01910	0.00076	4.0%
35a. Adjustment	(254,359)	0	(254,359)	0.0%	17,711,573	17,751,524	(39,951)	-0.2%	(0.00144)	0.00000	(0.00144)	0.0%
35b. Adjustment	0	0	0	0.0%	17,711,573	17,751,524	(39,951)	-0.2%	0.00000	0.00000	0.00000	0.0%
36. True-up *	88,672,735	88,672,735	0	0.0%	17,711,573	17,751,524	(39,951)	-0.2%	0.50065	0.49952	0.00113	0.2%
37. Total Jurisdictional Fuel Cost (Excl. GPIF)	600,740,337	584,529,861	16,210,476	2.8%	17,711,573	17,751,524	(39,951)	-0.2%	3.39180	3.29284	0.09895	3.0%
38. Revenue Tax Factor									1.00072	1.00072	0.00000	0.0%
39. Fuel Cost Adjusted for Taxes (Excl. GPIF)									3.39424	3.29521	0.09903	3.0%
40. GPIF * (Already Adjusted for Taxes)	1,094,956	1,094,956	0	0.0%	17,711,573	17,751,524	(39,951)	-0.2%	0.00618	0.00617	0.00001	0.2%
41. Fuel Cost Adjusted for Taxes (Incl. GPIF)	601,835,293	585,624,817	16,210,476	2.8%	17,711,573	17,751,524	(39,951)	-0.2%	3.40042	3.30138	0.09904	3.0%
42. Fuel FAC Rounded to the Nearest .001 cents per KWH									3.400	3.301	0.099	3.0%

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CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
A. FUEL COST & NET POWER TRANSACTION								
1. FUEL COST OF SYSTEM NET GENERATION	26,439,760	28,756,090	(2,316,330)	-8.1%	356,592,326	392,688,455	(36,096,129)	-9.2%
1a. FUEL REL. R & D AND DEMO. COST	0	0	0	0.0%	0	0	0	0.0%
2. FUEL COST OF POWER SOLD	972,730	465,300	507,430	109.1%	14,537,254	18,634,100	(4,096,846)	-22.0%
2a. GAINS FROM MARKET BASED SALES	2,509	140,800	(138,291)	-98.2%	131,309	3,150,500	(3,019,191)	-95.8%
3. FUEL COST OF PURCHASED POWER	17,295,511	4,713,200	12,582,311	267.0%	169,929,890	143,368,600	26,561,290	18.5%
3a. DEMAND & NONFUEL COST OF PUR. PWR.	0	0	0	0.0%	0	0	0	0.0%
3b. PAYMENT TO QUALIFIED FACILITIES	856,174	783,300	72,874	9.3%	11,416,463	10,762,700	653,763	6.1%
4. ENERGY COST OF ECONOMY PURCHASES	0	0	0	0.0%	0	0	0	0.0%
5. TOTAL FUEL & NET POWER TRANSACTION	43,616,206	33,646,490	9,969,716	29.6%	523,270,116	525,035,155	(1,765,039)	-0.3%
6a. ADJUSTMENTS TO FUEL COST (FT. MEADE/WAUCHULA WHEELING LOSSES)	(4,949)	(4,000)	(949)	23.7%	(69,826)	(48,000)	(21,826)	45.5%
6b. ADJ.TO FUEL COST	(2,829)	0	(2,829)	0.0%	(24,859)	0	(24,859)	0.0%
6c. RISK MANAGEMENT O&M	83,786	0	83,786	0.0%	83,786	0	83,786	0.0%
7. ADJUSTED TOTAL FUEL & NET PWR.TRANS.	43,692,214	33,642,490	10,049,724	29.9%	523,259,217	524,987,155	(1,727,938)	-0.3%
B. MWH SALES								
1. JURISDICTIONAL SALES	1,323,188	1,340,695	(17,507)	-1.3%	17,711,573	17,751,524	(39,951)	-0.2%
2. NONJURISDICTIONAL SALES	35,729	36,201	(472)	-1.3%	502,148	1,179,208	(677,060)	-57.4%
3. TOTAL SALES	1,358,917	1,376,896	(17,979)	-1.3%	18,213,721	18,930,732	(717,011)	-3.8%
4. JURISDIC. SALES-% TOTAL MWH SALES	0.9737077	0.9737083	(0.0000006)	0.0%	0.9724302	0.9377093	0.0347209	3.7%

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY

MONTH OF: DECEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
C. TRUE-UP CALCULATION								
1. 1. JURISDICTIONAL FUEL REVENUE	43,209,813	44,176,193	(966,380)	-2.2%	579,972,895	585,250,619	(5,277,724)	-0.9%
2. 2. FUEL ADJUSTMENT NOT APPLICABLE	0	0	0	0.0%	0	0	0	0.0%
2a. TRUE-UP PROVISION	(7,389,390)	(7,389,390)	0	0.0%	(88,672,735)	(88,672,735)	0	0.0%
2b. INCENTIVE PROVISION	(91,250)	(91,250)	0	0.0%	(1,094,956)	(1,094,956)	0	0.0%
2c. TRANSITION ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
2d. OTHER ADJUSTMENT	0	0	0	0.0%	0	0	0	0.0%
3. JURIS. FUEL REVENUE APPL. TO PERIOD	35,729,173	36,695,553	(966,380)	-2.6%	490,205,204	495,482,928	(5,277,724)	-1.1%
4. ADJ. TOTAL FUEL & NET PWR. TRANS. (LINE A7)	43,692,214	33,642,490	10,049,724	29.9%	523,259,217	524,987,155	(1,727,938)	-0.3%
5. JURISDIC. SALES- % TOTAL MWH SALES (LINE B4)	0.9737077	0.9737083	(0.0000006)	0.0%	NA	NA	-	0.0%
6. JURISDIC. TOTAL FUEL & NET PWR.TRANS.	42,543,444	32,757,972	9,785,472	29.9%	508,468,091	492,141,654	16,326,437	3.3%
6a. JURISDIC. LOSS MULTIPLIER	1.00066	1.00066	0.00000	0.0%	NA	NA	-	0.0%
6b. (LINE C6 x LINE C6a)	42,571,523	32,779,592	9,791,931	29.9%	508,803,680	492,466,467	16,337,213	3.3%
6c. PEABODY COAL CONTR. BUY-OUT AMORT.	287,383	287,383	0	0.0%	3,615,631	3,615,631	0	0.0%
6d. (LINE C6c x LINE C5) PB. JURISD.	279,827	279,827	0	0.0%	3,518,281	3,390,659	127,622	3.8%
6e. 1999 REVENUE REFUND ADJ	(254,359)	0	(254,359)	0.0%	(254,359)	0	(254,359)	0.0%
6f. OTHER	0	0	0	0.0%	0	0	0	0.0%
6g. OTHER	0	0	0	0.0%	0	0	0	0.0%
6h. JURISDIC. TOTAL FUEL & NET PWR INCL. ALL ADJ.(LNS. C6b+C6d+C6e+C6f+C6g)	42,596,991	33,059,419	9,537,572	28.8%	512,067,602	495,857,126	16,210,476	3.3%
7. TRUE-UP PROV. FOR MO. +/- COLLECTED (LINE C3 - LINE C6h)	(6,867,818)	3,636,134	(10,503,952)	-288.9%	(21,862,398)	(374,198)	(21,488,200)	5742.5%
8. INTEREST PROVISION FOR THE MONTH	(34,618)	(25,039)	(9,579)	38.3%	(981,360)	(1,657,379)	676,019	-40.8%
9. TRUE-UP & INT. PROV. BEG. OF MONTH	(32,314,872)	(13,032,062)	(19,282,810)	148.0%	----------NOT APPLICABLE----------			
10. TRUE-UP COLLECTED (REFUNDED)	7,389,390	7,389,390	(0)	0.0%	----------NOT APPLICABLE----------			
11. END OF PERIOD TOTAL NET TRUE-UP (LINE C7 through C10)	(31,827,918)	(2,031,577)	(29,796,341)	1466.7%	----------NOT APPLICABLE----------			

CALCULATION OF TRUE-UP AND INTEREST PROVISION
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
D. INTEREST PROVISION								
1. BEGINNING TRUE-UP AMOUNT (LINE C9)	(32,314,872)	(13,032,062)	(19,282,810)	148.0%	----------NOT APPLICABLE----------			
2. ENDING TRUE-UP AMOUNT BEFORE INT. (LINES C7 + C9 + C10)	(31,793,300)	(2,006,538)	(29,786,762)	1484.5%	----------NOT APPLICABLE----------			
3. TOTAL BEG. & END. TRUE-UP AMOUNT	(64,108,172)	(15,038,600)	(49,069,572)	326.3%	----------NOT APPLICABLE----------			
4. AVG. TRUE-UP AMOUNT - (50% OF LINE D3)	(32,054,086)	(7,519,300)	(24,534,786)	326.3%	----------NOT APPLICABLE----------			
5. INT. RATE-FIRST DAY REP. BUS. MONTH	1.300	4.000	(3)	-67.5%	----------NOT APPLICABLE----------			
6. INT. RATE-FIRST DAY SUBSEQUENT MONTH	1.290	4.000	(3)	-67.8%	----------NOT APPLICABLE----------			
7. TOTAL (LINE D5 + LINE D6)	2.590	8.000	(5)	-67.6%	----------NOT APPLICABLE----------			
8. AVERAGE INT. RATE (50% OF LINE D7)	1.295	4.000	(3)	-67.6%	----------NOT APPLICABLE----------			
9. MONTHLY AVG. INT. RATE (LINE D8/12)	0.108	0.333	(0)	-67.6%	----------NOT APPLICABLE----------			
10. INT. PROVISION (LINE D4 x LINE D9)	(34,618)	(25,039)	(9,579)	38.3%	----------NOT APPLICABLE----------			

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL	235,302	427,635	(192,333)	-45.0%	4,372,207	5,268,790	(896,583)	-17.0%
2	LIGHT OIL	520,279	840,485	(320,206)	-38.1%	9,851,474	16,148,494	(6,297,020)	-39.0%
3	COAL	24,267,038	25,108,360	(841,322)	-3.4%	310,692,261	329,791,838	(19,099,577)	-5.8%
4	NATURAL GAS	1,417,141	2,379,610	(962,469)	-40.4%	31,676,384	41,479,333	(9,802,949)	-23.6%
5	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
6	OTHER	0	0	0	0.0%	0	0	0	0.0%
7	TOTAL ($)	26,439,760	28,756,090	(2,316,330)	-8.1%	356,592,326	392,688,455	(36,096,129)	-9.2%
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	4,473	11,199	(6,726)	-60.1%	86,648	131,838	(45,190)	-34.3%
9	LIGHT OIL	9,476	14,882	(5,406)	-36.3%	191,196	241,140	(49,944)	-20.7%
10	COAL	1,157,370	1,257,922	(100,552)	-8.0%	14,875,280	15,848,013	(972,733)	-6.1%
11	NATURAL GAS	6,072	41,388	(35,316)	-85.3%	473,450	758,310	(284,860)	-37.6%
12	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
13	OTHER	0	0	0	0.0%	0	0	0	0.0%
14	TOTAL (MWH)	1,177,391	1,325,391	(148,000)	-11.2%	15,626,574	16,979,301	(1,352,727)	-8.0%
	UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL)	7,087	16,635	(9,548)	-57.4%	137,183	196,270	(59,087)	-30.1%
16	LIGHT OIL (BBL)	15,139	28,385	(13,246)	-46.7%	322,371	507,477	(185,106)	-36.5%
17	COAL (TON)	550,494	553,670	(3,176)	-0.6%	7,100,139	7,050,889	49,250	0.7%
18	NATURAL GAS (MCF)	69,009	424,524	(355,515)	-83.7%	5,151,423	7,727,438	(2,576,015)	-33.3%
19	NUCLEAR (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
20	OTHER (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
	BTUS BURNED (MMBTU)								
21	HEAVY OIL	44,462	104,454	(59,992)	-57.4%	860,634	1,232,378	(371,744)	-30.2%
22	LIGHT OIL	86,120	159,231	(73,111)	-45.9%	1,855,534	2,882,291	(1,026,757)	-35.6%
23	COAL	12,588,244	13,085,564	(497,320)	-3.8%	165,425,948	165,442,088	(16,141)	0.0%
24	NATURAL GAS	72,666	436,388	(363,722)	-83.3%	5,420,729	7,944,073	(2,523,344)	-31.8%
25	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
26	OTHER	0	0	0	0.0%	0	0	0	0.0%
27	TOTAL (MMBTU)	12,791,493	13,785,637	(994,144)	-7.2%	173,562,845	177,500,830	(3,937,985)	-2.2%
	GENERATION MIX (% MWH)								
28	HEAVY OIL	0.38%	0.84%	(0.00)	-	0.55%	0.78%	(0.00)	-
29	LIGHT OIL	0.80%	1.12%	(0.00)	-	1.22%	1.42%	(0.00)	-
30	COAL	98.30%	94.91%	0.03	-	95.19%	93.34%	0.02	-
31	NATURAL GAS	0.52%	3.12%	(0.03)	-	3.03%	4.47%	(0.01)	-
32	NUCLEAR	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
33	OTHER	0.00%	0.00%	0.00	-	0.00%	0.00%	0.00	-
34	TOTAL (%)	100.00%	100.00%	0.00	-	100.00%	100.00%	0.00	-
	FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL)	33.20	25.71	7.49	29.2%	31.87	26.84	5.03	18.7%
36	LIGHT OIL ($/BBL)	34.37	29.61	4.76	16.1%	30.56	31.82	(1.26)	-4.0%
37	COAL ($/TON)	44.08	45.35	(1.27)	-2.8%	43.76	46.77	(3.01)	-6.4%
38	NATURAL GAS ($/MCF)	20.54	5.61	14.93	266.4%	6.15	5.37	0.78	14.6%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
40	OTHER ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
	FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL	5.29	4.09	1.20	29.3%	5.08	4.28	0.80	18.8%
42	LIGHT OIL	6.04	5.28	0.76	14.5%	5.31	5.60	(0.29)	-5.2%
43	COAL	1.93	1.92	0.01	0.5%	1.88	1.99	(0.12)	-5.8%
44	NATURAL GAS	19.50	5.45	14.05	257.6%	5.84	5.22	0.62	11.9%
45	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
46	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
47	TOTAL ($/MMBTU)	2.07	2.09	(0.02)	-0.9%	2.05	2.21	(0.16)	-7.1%

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2002

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	9,940	9,327	613	6.6%	9,933	9,348	585	6.3%
49	LIGHT OIL	9,088	10,700	(1,612)	-15.1%	9,705	11,953	(2,248)	-18.8%
50	COAL	10,877	10,403	474	4.6%	11,121	10,439	682	6.5%
51	NATURAL GAS	11,967	10,544	1,423	13.5%	11,449	10,476	973	9.3%
52	NUCLEAR	0	0	0	0.0%	0	0	0	0.0%
53	OTHER	0	0	0	0.0%	0	0	0	0.0%
54	TOTAL (BTU/KWH)	10,864	10,401	463	4.5%	11,107	10,454	653	6.2%
	GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL	5.26	3.82	1.44	37.7%	5.05	4.00	1.05	26.3%
56	LIGHT OIL	5.49	5.65	(0.16)	-2.8%	5.15	6.70	(1.55)	-23.1%
57	COAL	2.10	2.00	0.10	5.0%	2.09	2.08	0.01	0.5%
58	NATURAL GAS	23.34	5.75	17.59	305.9%	6.69	5.47	1.22	22.3%
59	NUCLEAR	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
60	OTHER	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61	TOTAL (cents/KWH)	2.25	2.17	0.08	3.7%	2.28	2.31	(0.03)	-1.3%

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE A4
PAGE 1 OF 1

ACTUAL FOR MONTH OF: DECEMBER 2002

(A) PLANT/UNIT	(B) NET CAP-ABILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) NET AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE BTU/KWH	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
H.P.#1	32	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#2	32	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#3	32	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#4	41	0	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P.#5	52	-135	---	---	---	0	HVY.OIL	-	0	0.0	0	0.00	0.00
H.P. STATION *	90	-135	---	---	---	0	HVY.OIL	0	0	0.0	0	0.00	0.00
GAN.#1	114	27,043	31.9	43.1	50.2	12,302	COAL	14,180	23,462,000	332,691.2	564,926	2.09	39.84
GAN.#2	98	24,678	33.8	37.4	63.8	12,641	COAL	13,237	23,566,000	311,943.1	527,357	2.14	39.84
GAN.#3	155	39,051	33.9	51.9	62.1	13,446	COAL	22,956	22,874,000	525,095.5	914,559	2.34	39.84
GAN.#4	159	51,249	43.3	61.9	65.6	11,880	COAL	26,766	22,746,000	608,819.4	1,066,347	2.08	39.84
GAN.#5	217	99,138	61.4	86.2	65.0	11,484	COAL	48,136	23,652,000	1,138,512.7	1,917,720	1.93	39.84
GAN.#6	392	57,508	19.7	33.1	46.2	13,567	COAL	33,130	23,550,000	780,211.5	1,319,887	2.30	39.84
GANNON STATION	1,135	298,667	35.4	51.2	56.6	12,379	COAL	158,405	23,340,636	3,697,273.4	6,310,796	2.11	39.84
B.B.#1	426	223,156	70.4	82.1	70.4	10,369	COAL	102,004	22,685,220	2,313,981.6	4,409,582	1.98	43.23
B.B.#2	426	48,051	15.2	16.4	58.3	10,765	COAL	21,657	23,886,000	517,292.7	936,221	1.95	43.23
B.B.#3	433	217,841	67.6	82.9	67.6	10,042	COAL	97,929	22,338,660	2,187,612.2	4,233,421	1.94	43.23
B.B. 1 - 3	1,285	489,048	51.2	60.6	65.4	10,263	COAL	221,590	22,649,418	5,018,886.5	9,579,224	1.96	43.23
B.B.#4	447	249,537	75.0	87.4	79.2	10,213	COAL	120,473	21,154,775	2,548,587.9	6,319,493	2.53	52.46
B.B. STATION	1,732	738,585	57.3	67.5	69.0	10,246	COAL	342,063	22,123,010	7,567,474.4	15,898,717	2.15	46.48
SEB-PHIL. #1(HVY OIL)	17	2,302	18.2	100.0	89.2	9,649	HVY.OIL	3,540	6,273,540	22,211.9	117,535	5.11	33.20
SEB-PHIL. #2(HVY OIL)	17	2,306	18.2	98.9	88.6	9,649	HVY.OIL	3,547	6,273,540	22,250.5	117,767	5.11	33.20
SEB-PHILLIPS TOTAL	34	4,608	18.2	99.5	88.9	9,649	HVY.OIL	7,087	6,273,540	44,462.4	235,302	5.11	33.20
POLK #1 GASIFIER	250	120,118	64.6	72.1	88.3	11,018	COAL	50,026	26,456,000	1,323,496.1	2,057,525	1.71	41.13
POLK #1 CT (OIL)	245	9,331	5.1	92.6	65.0	9,079	LGT.OIL	14,898	5,813,937	84,712.2	512,763	5.50	34.42
POLK #1 TOTAL	250	129,449	69.6	91.1	86.0	10,878	-	-	-	1,408,208.3	2,570,288	1.99	-
POLK #2 CT (GAS)	160	2,265	1.9	100.0	75.9	11,876	GAS	25,546	972,290	26,900.0	510,385	22.53	19.98
POLK #2 CT (OIL)	180	0	0.0	100.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #2 TOTAL	170	2,265	1.8	100.0	75.9	11,876	-	-	-	26,900.0	510,385	22.53	-
POLK #3 CT (GAS)	160	3,807	3.2	99.1	72.8	12,022	GAS	43,463	972,290	45,766.0	906,879	23.82	20.87
POLK #3 CT (OIL)	180	0	0.0	99.1	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
POLK #3 TOTAL	170	3,807	3.0	99.1	72.8	12,022	-	-	-	45,766.0	906,879	23.82	-
POLK STATION TOTAL	590	135,521	30.9	96.0	57.0	10,927	-	-	-	1,480,874.3	3,987,552	2.94	-
GAN.C.T.#1	0	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#1	17	29	0.2	100.0	85.3	11,707	LGT.OIL	58	5,844,379	339.5	1,809	6.24	31.19
B.B.C.T.#2	80	0	0.0	0.0	0.0	0	LGT.OIL	0	0	0.0	0	0.00	0.00
B.B.C.T.#3	80	116	0.2	0.0	29.0	9,212	LGT.OIL	183	5,854,701	1,068.6	5,707	4.92	31.19
C.T. TOTAL	177	145	0.1	9.6	21.3	9,711	LGT.OIL	241	5,852,209	1,408.1	7,516	5.18	31.19
CITY OF TAMPA	6	0	0.0	0.0	0.0	0	GAS	0	972,290	0.0	-123	0.00	0.00
TOT. COAL (GN,BB,POLK)	3,117	1,157,370	49.9	61.9	66.0	10,877	COAL	550,494	22,867,144	12,588,243.9	24,267,038	2.10	44.08
SYSTEM	3,674	1,177,391	43.1	64.6	61.1	10,863	-	-	-	12,791,492.6	26,439,760	2.25	-

* Hookers Point limited to 90 MW

LEGEND:

H.P. = HOOKERS POINT
B.B. = BIG BEND
GAN. = GANNON
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
HEAVY OIL[1]								
1 PURCHASES:								
2 UNITS (BBL)	10,985	16,635	(5,650)	-34.0%	130,276	196,270	(65,994)	-33.6%
3 UNIT COST ($/BBL)	30.91	25.25	5.66	22.4%	29.84	26.11	3.73	14.3%
4 AMOUNT ($)	339,534	420,015	(80,481)	-19.2%	3,886,040	5,124,890	(1,236,850)	-24.1%
5 BURNED:								
6 UNITS (BBL)	7,087	16,635	(9,548)	-57.4%	137,183	196,270	(59,087)	-30.1%
7 UNIT COST ($/BBL)	33.20	25.71	7.49	29.2%	31.87	26.84	5.03	18.7%
8 AMOUNT ($)	235,302	427,635	(192,333)	-45.0%	4,372,207	5,268,790	(896,583)	-17.0%
9 ENDING INVENTORY:								
10 UNITS (BBL)	10,742	59,129	(48,387)	-81.8%	10,742	59,129	(48,387)	-81.8%
11 UNIT COST ($/BBL)	35.83	25.70	10.14	39.4%	35.83	25.70	10.14	39.4%
12 AMOUNT ($)	384,932	1,519,455	(1,134,523)	-74.7%	384,932	1,519,455	(1,134,523)	-74.7%
13								
14 DAYS SUPPLY:	36	185	(149)	-80.3%	-	-	-	-
LIGHT OIL[2]								
15 PURCHASES:								
16 UNITS (BBL)	23,538	37,907	(14,369)	-37.9%	409,287	620,731	(211,444)	-34.1%
17 UNIT COST ($/BBL)	34.90	29.92	4.98	16.6%	30.99	30.99	(0.00)	0.0%
18 AMOUNT ($)	821,406	1,134,124	(312,718)	-27.6%	12,683,028	19,237,885	(6,554,857)	-34.1%
19 BURNED:								
20 UNITS (BBL)	15,139	28,385	(13,246)	-46.7%	322,371	507,477	(185,106)	-36.5%
21 UNIT COST ($/BBL)	34.37	29.61	4.76	16.1%	30.56	31.82	(1.26)	-4.0%
22 AMOUNT ($)	520,279	840,485	(320,206)	-38.1%	9,851,474	16,148,494	(6,297,020)	-39.0%
23 ENDING INVENTORY:								
24 UNITS (BBL)	89,540	113,465	(23,925)	-21.1%	89,540	113,465	(23,925)	-21.1%
25 UNIT COST ($/BBL)	32.91	29.66	3.25	11.0%	32.91	29.66	3.25	11.0%
26 AMOUNT ($)	2,946,602	3,364,854	(418,252)	-12.4%	2,946,602	3,364,854	(418,252)	-12.4%
27								
28 DAYS SUPPLY: NORMAL	85	103	(18)	-17.0%	-	-	-	-
29 DAYS SUPPLY: EMERGENCY	13	16	(3)	-20.1%	-	-	-	-
COAL[3]								
30 PURCHASES:								
31 UNITS (TONS)	435,481	556,000	(120,519)	-21.7%	6,913,016	7,328,000	(414,984)	-5.7%
32 UNIT COST ($/TON)	44.82	44.50	0.32	0.7%	44.08	46.33	(2.25)	-4.9%
33 AMOUNT ($)	19,519,186	24,740,420	(5,221,234)	-21.1%	304,696,657	339,502,615	(34,805,958)	-10.3%
34 BURNED:								
35 UNITS (TONS)	550,494	553,670	(3,176)	-0.6%	7,100,139	7,050,889	49,250	0.7%
36 UNIT COST ($/TON)	44.08	45.35	(1.27)	-2.8%	43.76	46.77	(3.01)	-6.4%
37 AMOUNT ($)	24,267,038	25,108,360	(841,322)	-3.4%	310,692,261	329,791,838	(19,099,577)	-5.8%
38 ENDING INVENTORY:								
39 UNITS (TONS)	438,357	1,253,931	(815,574)	-65.0%	438,357	1,253,931	(815,574)	-65.0%
40 UNIT COST ($/TON)	42.96	46.67	(3.72)	-8.0%	42.96	46.67	(3.72)	-8.0%
41 AMOUNT ($)	18,831,125	58,525,510	(39,694,385)	-67.8%	18,831,125	58,525,510	(39,694,385)	-67.8%
42								
43 DAYS SUPPLY:	24	65	(41)	-63.2%	-	-	-	-
NATURAL GAS[4]								
44 PURCHASES:								
45 UNITS (MCF)	69,009	424,524	(355,515)	-83.7%	5,151,423	7,727,438	(2,576,015)	-33.3%
46 UNIT COST ($/MCF)	20.54	5.61	14.93	266.4%	6.15	5.37	0.78	14.6%
47 AMOUNT ($)	1,417,141	2,379,610	(962,469)	-40.4%	31,675,411	41,479,330	(9,803,919)	-23.6%
48 BURNED:								
49 UNITS (MCF)	69,009	424,524	(355,515)	-83.7%	5,151,423	7,727,438	(2,576,015)	-33.3%
50 UNIT COST ($/MCF)	20.54	5.61	14.93	266.4%	6.15	5.37	0.78	14.6%
51 AMOUNT ($)	1,417,141	2,379,610	(962,469)	-40.4%	31,676,384	41,479,333	(9,802,949)	-23.6%
52 ENDING INVENTORY:								
53 UNITS (MCF)	0	0	0	0.0%	0	0	0	0.0%
54 UNIT COST ($/MCF)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
55 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
56								
57 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-
NUCLEAR								
58 BURNED:								
59 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
60 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
61 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%

SYSTEM GENERATED FUEL COST
INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2002

	CURRENT MONTH				PERIOD TO DATE			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	DIFFERENCE %
OTHER								
62 PURCHASES:								
63 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
64 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
65 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
66 BURNED:								
67 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
68 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
69 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
70 ENDING INVENTORY:								
71 UNITS (MMBTU)	0	0	0	0.0%	0	0	0	0.0%
72 UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.0%	0.00	0.00	0.00	0.0%
73 AMOUNT ($)	0	0	0	0.0%	0	0	0	0.0%
74 DAYS SUPPLY:	0	0	0	0.0%	-	-	-	-

(1) RECONCILIATION - HEAVY OIL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
IGNITION	13,013
LUBE OIL	0
FUEL ANALYSIS	0
TOTAL	13,013

(2) RECONCILIATION - LIGHT OIL
DIFFERENCE IN ENDING INVENTORY UNITS AND DOLLARS DUE TO:

	UNITS	DOLLARS
START-UP FUEL	0	0
IGNITION	(9,573)	(300,073)
OTHER USAGE	(839)	(27,430)
TOTAL	(10,412)	(327,503)

(3) RECONCILIATION - COAL
DIFFERENCE IN ENDING INVENTORY DOLLARS DUE TO:

	DOLLARS
FUEL ANALYSIS	55,414
IGNITION #2 OIL	287,060
IGNITION PROPANE	7,812
AERIAL SURVEY ADJ.	(944,984)
ADDITIVES	9,591
GREEN FUEL	0
TOTAL	(585,107)

POWER SOLD
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2002

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. - D	5,995.0	0.0	5,995.0	1.446	1.446	86,700.00	86,700.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	2,157.0	0.0	2,157.0	2.596	3.644	56,000.00	78,600.00	
VARIOUS	JURISDIC.	SCH. - MB	15,768.0	0.0	15,768.0	2.046	2.046	322,600.00	322,600.00	140,800.00
TOTAL			23,920.0	0.0	23,920.0	1.945	2.040	465,300.00	487,900.00	140,800.00
ACTUAL:										
FLA. PWR. & LIGHT	SEPARATED	SCH. - D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FMPA	SEPARATED	SCH. - D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
KISSIMMEE ELEC. UTIL.	SEPARATED	SCH. - D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF NEW SMYRNA BCH.	SEPARATED	SCH. - D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK	SEPARATED	SCH. - D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
WAUCHULA	SEPARATED	SCH. - D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FT. MEADE	SEPARATED	SCH. - D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
CITY OF ST. CLOUD	SEPARATED	SCH. - D	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR PARTNERS	SEP. CONTR.	SCH. - D	43,765.0	0.0	43,765.0	2.320	3.077	1,015,348.00	1,346,649.05	
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	1,079.5	16.3	1,063.2	2.504	2.504	26,618.81	26,618.81	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	1,011.2	0.0	1,011.2	2.121	2.121	21,446.83	21,446.83	
FLA. PWR. CORP.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
FLA. PWR. & LIGHT		SCH. - MA	475.0	0.0	475.0	1.919	2.361	9,112.91	11,216.82	612.41
CITY OF LAKELAND		SCH. - MA	200.0	0.0	200.0	2.208	2.801	4,415.78	5,601.04	557.26
ORLANDO UTIL. COMM.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
REEDY CREEK		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
THE ENERGY AUTHORITY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
DUKE ENERGY		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
HARDEE PWR. PART. TO THE ENGY. AUTH.		SCH. - MA	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
ADJUSTMENTS										
HARDEE PWR PART. EST.	Nov. 2002	CONTRACT	(50,091.0)	0.0	(50,091.0)	2.509	3.247	(1,256,783.19)	(1,626,454.77)	
HARDEE PWR PART. ACT.	Nov. 2002	CONTRACT	50,091.0	0.0	50,091.0	2.320	3.077	1,162,111.20	1,541,300.07	
CITY OF LAKELAND	Nov. 2002	SCH. - MA	(75.0)	0.0	(75.0)	2.123	3.325	(1,592.11)	(2,493.84)	(666.23)
ORLANDO UTIL. COMM.	Nov. 2002	SCH. - MA	75.0	0.0	75.0	2.123	3.325	1,592.11	2,493.84	666.23
HARDEE PWR TO LAKELAND	Nov. 2002	SCH. - MA	(50.0)	0.0	(50.0)	3.007	3.344	(1,503.50)	(1,672.16)	
HARDEE PWR TO ORLANDO	Nov. 2002	SCH. - MA	50.0	0.0	50.0	3.007	3.344	1,503.50	1,672.16	
SEMINOLE ELEC. CO-OP	Nov. 2002	SCH. - MA	(6,750.0)	0.0	(6,750.0)	2.450	3.163	(165,401.08)	(213,471.08)	(26,875.00)
SEMINOLE ELEC. CO-OP	Nov. 2002	SCH. - MA	6,750.0	0.0	6,750.0	2.253	2.985	152,046.08	201,456.08	28,215.00
SEMINOLE ELEC. PRECO-1	Nov. 2002	SCH. - D	(2,935.3)	(262.1)	(2,673.2)	2.015	2.015	(53,852.27)	(53,852.27)	
SEMINOLE ELEC. PRECO-1	Nov. 2002	SCH. - D	2,935.3	262.1	2,673.2	2.157	2.157	57,666.50	57,666.50	
SUB-TOTAL ECONOMY POWER SALES			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			2,090.7	16.3	2,074.4	2.501	2.501	51,879.87	51,879.87	
SUB-TOTAL SCHEDULE D POWER SALES-SEP.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEP.			43,765.0	0.0	43,765.0	2.104	2.882	920,676.01	1,261,494.35	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			675.0	0.0	675.0	0.026	0.712	173.69	4,802.86	2,509.67
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			0.0	0.0	0.0	0.000	0.000	0.00	0.00	
TOTAL			46,530.7	16.3	46,514.4	2.091	2.834	972,729.57	1,318,177.08	2,509.67
CURRENT MONTH:										
DIFFERENCE			22,610.7	16.3	22,594.4	0.146	0.794	507,429.57	830,277.08	(138,290.33)
DIFFERENCE %			94.5%	0.0%	94.5%	7.5%	38.9%	109.1%	170.2%	-98.2%
PERIOD TO DATE:										
ACTUAL			581,564.6	5,788.5	575,776.1	2.525	3.194	14,537,254.28	18,387,794.14	131,310.95
ESTIMATED			775,753.0	0.0	775,753.0	2.402	3.059	18,634,100.00	23,728,000.00	3,150,500.00
DIFFERENCE			(194,188.4)	5,788.5	(199,976.9)	0.123	0.135	(4,096,845.72)	(5,340,205.86)	(3,019,189.05)
DIFFERENCE %			-25.0%	0.0%	-25.8%	5.1%	4.4%	-22.0%	-22.5%	-95.8%

* NO SALES TO HARDEE POWER PARTNERS FOR OTHERS IN THE MONTH OF DECEMBER 2002.

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2002

(1) PURCHASED FROM		(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:									
VARIOUS		SCH. - J	3,308.0	0.0	2,039.0	1,269.0	5.808	5.808	73,700.00
HARDEE POWER PARTNERS		IPP	78,776.0	0.0	0.0	78,776.0	4.522	4.522	3,561,900.00
VARIOUS		OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
VARIOUS		MKT. BASE	22,567.0	0.0	0.0	22,567.0	4.775	4.775	1,077,600.00
TOTAL			**104,651.0**	**0.0**	**2,039.0**	**102,612.0**	**4.593**	**4.593**	**4,713,200.00**
ACTUAL:									
HARDEE PWR. PART.-NATIVE		IPP	43,674.0	0.0	0.0	43,674.0	5.576	5.576	2,435,159.87
HARDEE PWR. PART.-OTHERS		IPP	0.0	0.0	0.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.		SCH. - J	64,987.0	0.0	432.7	64,554.3	4.067	4.067	2,625,304.96
FLA. POWER & LIGHT		SCH. - J	65,325.0	0.0	827.3	64,497.7	4.385	4.385	2,828,156.19
CITY OF LAKELAND		SCH. - J	12,210.0	0.0	204.2	12,005.8	4.627	4.627	555,501.23
ORLANDO UTIL. COMM.		SCH. - J	9,400.0	0.0	0.0	9,400.0	2.914	2.914	273,900.00
CAROLINA POWER & LIGHT		SCH. - J	1,472.0	0.0	0.0	1,472.0	5.147	5.147	75,766.00
THE ENERGY AUTHORITY		SCH. - J	11,091.0	0.0	0.0	11,091.0	4.416	4.416	489,742.50
REEDY CREEK		SCH. - J	210.0	0.0	0.0	210.0	4.138	4.138	8,690.00
OKEELANTA		SCH. - J	90.0	0.0	0.0	90.0	3.718	3.718	3,346.20
TALLAHASSEE		SCH. - J	1,149.0	0.0	0.0	1,149.0	5.322	5.322	61,147.50
CARGILL ALLIANT		SCH. - J	17,667.0	0.0	0.0	17,667.0	3.998	3.998	706,360.00
CONOCO		SCH. - J	2,061.0	0.0	172.7	1,888.3	4.092	4.092	77,263.75
CORAL POWER		SCH. - J	352.0	0.0	537.3	(185.3)	8.197	8.197	(15,189.66)
SEMINOLE ELEC. CO-OP		SCH. - J	1,412.0	0.0	0.0	1,412.0	4.354	4.354	61,477.50
DUKE ENERGY		SCH. - J	3,563.0	0.0	0.0	3,563.0	3.983	3.983	141,899.00
DYNEGY POWER MARKETING		SCH. - J	6,758.0	0.0	0.0	6,758.0	3.807	3.807	257,280.40
RINGHAVER		SCH. - J	1,302.0	0.0	0.0	1,302.0	7.233	7.233	94,175.41
FLA. POWER CORP.		SCH. - D	45,000.0	0.0	0.0	45,000.0	4.445	4.445	2,000,100.00
ADJUSTMENTS TO PRIOR MONTHS:									
HARDEE PWR. PART.-NATIVE	Nov. 2002	IPP	(48,948.0)	0.0	0.0	(48,948.0)	5.158	5.158	(2,524,528.91)
HARDEE PWR. PART.-NATIVE	Nov. 2002	IPP	91,254.0	0.0	0.0	91,254.0	7.504	7.504	6,847,718.74
HARDEE PWR. PART.-OTHER	Nov. 2002	IPP	(50.0)	0.0	0.0	(50.0)	3.007	3.007	(1,503.50)
HARDEE PWR. PART.-OTHER	Nov. 2002	IPP	140.0	0.0	0.0	140.0	1.074	1.074	1,503.50
FLA. POWER CORP.	Oct. 2002	SCH. - D	(79,475.0)	0.0	0.0	(79,475.0)	4.067	4.067	(3,232,379.50)
FLA. POWER CORP.	Oct. 2002	SCH. - D	79,475.0	0.0	0.0	79,475.0	4.272	4.272	3,395,303.25
FLA. POWER CORP.	Nov. 2002	SCH. - D	(59,500.0)	0.0	0.0	(59,500.0)	4.143	4.143	(2,464,940.00)
FLA. POWER CORP.	Nov. 2002	SCH. - D	59,500.0	0.0	0.0	59,500.0	4.348	4.348	2,586,915.00
THE ENERGY AUTHORITY	Nov. 2002	SCH. - J	(15,662.0)	0.0	(1,576.0)	(14,086.0)	4.365	4.365	(614,797.53)
THE ENERGY AUTHORITY	Nov. 2002	SCH. - J	15,662.0	0.0	1,576.0	14,086.0	4.368	4.368	615,297.53
CARGILL ALLIANT	Nov. 2002	SCH. - J	(43,095.0)	0.0	(1,603.3)	(41,491.7)	4.441	4.441	(1,842,529.50)
CARGILL ALLIANT	Nov. 2002	SCH. - J	43,100.0	0.0	1,603.3	41,496.7	4.453	4.453	1,848,031.50
DYNEGY POWER MARKETING	Nov. 2002	SCH. - J	(6,669.0)	0.0	(76.0)	(6,593.0)	3.718	3.718	(245,146.00)
DYNEGY POWER MARKETING	Nov. 2002	SCH. - J	6,667.0	0.0	76.0	6,591.0	3.719	3.719	245,146.00
FLA. POWER CORP.	Nov. 2002	SCH. - J	(47,129.0)	0.0	(686.8)	(46,442.2)	4.143	4.143	(1,924,126.42)
FLA. POWER CORP.	Nov. 2002	SCH. - J	47,129.0	0.0	686.8	46,442.2	4.146	4.146	1,925,466.42
TOTAL			**330,122.0**	**0.0**	**2,174.2**	**327,947.8**	**5.274**	**5.274**	**17,295,511.43**
CURRENT MONTH:									
DIFFERENCE			225,471.0	0.0	135.2	225,335.8	0.681	0.681	12,582,311.43
DIFFERENCE %			215.5%	0.0%	6.6%	219.6%	14.8%	14.8%	267.0%
PERIOD TO DATE:									
ACTUAL			3,866,686.0	0.0	219,364.4	3,647,321.6	4.659	4.659	169,929,891.01
ESTIMATED			2,875,744.0	0.0	151,518.0	2,724,226.0	5.263	5.263	143,368,600.00
DIFFERENCE			990,942.0	0.0	67,846.4	923,095.6	(0.604)	(0.604)	26,561,291.01
DIFFERENCE %			34.5%	0.0%	44.8%	33.9%	-11.5%	-11.5%	18.5%

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	39,069.0	0.0	0.0	39,069.0	2.005	2.005	783,300.00
TOTAL		39,069.0	0.0	0.0	39,069.0	2.005	2.005	783,300.00
ACTUAL:								
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY *REFUSE*	COGEN.	12,999.0	0.0	0.0	12,999.0	2.224	2.224	289,048.82
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	122.0	0.0	0.0	122.0	3.064	3.064	3,738.36
HILLSBOROUGH COUNTY	COGEN.	19,286.0	0.0	0.0	19,286.0	2.225	2.225	429,182.58
CARGILL *MILLPOINT*	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	1,225.0	0.0	0.0	1,225.0	3.632	3.632	44,491.02
FARMLAND HYDRO LP	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	352.0	0.0	0.0	352.0	3.609	3.609	12,704.75
AUBURNDALE POWER PARTNERS	COGEN.	164.0	0.0	0.0	164.0	2.664	2.664	4,368.86
ORANGE COGENERATION L.P.	COGEN.	5,652.0	0.0	0.0	5,652.0	2.110	2.110	119,263.18
CUTRALE CITRUS	COGEN.	2.0	0.0	0.0	2.0	5.460	5.460	109.19
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR DECEMBER 2002		39,802.0	0.0	0.0	39,802.0	2.268	2.268	902,906.76
ADJUSTMENTS FOR THE MONTH OF:	**OCTOBER 2002**							
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
McKAY BAY REFUSE	COGEN.	(12,682.0)	0.0	0.0	(12,682.0)	2.488	2.488	(315,508.46)
		12,682.0	0.0	0.0	12,682.0	2.365	2.365	299,948.94
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-NEW WALES	COGEN.	(233.0)	0.0	0.0	(233.0)	4.201	4.201	(9,787.88)
		233.0	0.0	0.0	233.0	4.198	4.198	9,780.25
HILLSBOROUGH COUNTY	COGEN.	(19,409.0)	0.0	0.0	(19,409.0)	2.490	2.490	(483,236.87)
		19,409.0	0.0	0.0	19,409.0	2.367	2.367	459,379.37
CARGILL MILLPOINT	COGEN.	(782.0)	0.0	0.0	(782.0)	4.784	4.784	(37,409.23)
		782.0	0.0	0.0	782.0	4.801	4.801	37,546.32
CF INDUSTRIES INC.	COGEN.	(778.0)	0.0	0.0	(778.0)	5.123	5.123	(39,857.58)
		778.0	0.0	0.0	778.0	5.114	5.114	39,784.66
FARMLAND HYDRO LP	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	(452.0)	0.0	0.0	(452.0)	4.646	4.646	(20,997.67)
		452.0	0.0	0.0	452.0	4.641	4.641	20,976.63
AUBURNDALE POWER PARTNERS	COGEN.	(605.0)	0.0	0.0	(605.0)	2.776	2.776	(16,797.51)
		605.0	0.0	0.0	605.0	3.027	3.027	18,311.33
ORANGE COGENERATION L.P.	COGEN.	(6,256.0)	0.0	0.0	(6,256.0)	2.333	2.333	(145,950.70)
		6,256.0	0.0	0.0	6,256.0	2.191	2.191	137,099.61
CUTRALE CITRUS	COGEN.	(58.0)	0.0	0.0	(58.0)	3.880	3.880	(2,250.43)
		58.0	0.0	0.0	58.0	3.856	3.856	2,236.44
AS AVAILABLE ASSIGNMENT	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
		0.0	0.0	0.0	0.0	0.000	0.000	0.00
SUB-TOTAL FOR THE MONTH OF:	***OCTOBER 2002***	0.0	0.0	0.0	0.0	0.000	0.000	(46,732.78)
GRAND TOTAL		39,802.0	0.0	0.0	39,802.0	2.151	2.151	856,173.98
CURRENT MONTH:								
DIFFERENCE		733.0	0.0	0.0	733.0	0.146	0.146	72,873.98
DIFFERENCE %		1.9%	0.0%	0.0%	1.9%	7.3%	7.3%	9.3%
PERIOD TO DATE:								
ACTUAL		476,931.0	0.0	0.0	476,931.0	2.394	2.394	11,416,462.45
ESTIMATED		473,104.0	0.0	0.0	473,104.0	2.275	2.275	10,762,700.00
DIFFERENCE		3,827.0	0.0	0.0	3,827.0	0.119	0.119	653,762.45
DIFFERENCE %		0.8%	0.0%	0.0%	0.8%	0.052	0.052	6.1%

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
MONTH OF: DECEMBER 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) COST IF GENERATED (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
CURRENT MONTH:							
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
PERIOD TO DATE:							
ACTUAL		0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A6

JANUARY 2002 - DECEMBER 2002

POWER SOLD
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2002 THROUGH DECEMBER 2002

(1) SOLD TO	(2) TYPE & SCHEDULE		(3) TOTAL MWH SOLD	(4) MWH WHEELED OTHER SYSTEM	(5) MWH FROM OWN GENERATION	(6) CENTS/KWH (A) FUEL COST	(6) CENTS/KWH (B) TOTAL COST	(7) TOTAL $ FOR FUEL ADJUSTMENT (5)X(6A)	(8) TOTAL $ FOR TOTAL COST (5)X(6B)	(9) GAINS ON MARKET BASED SALES
ESTIMATED:										
VARIOUS		ECON.	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
VARIOUS	JURISDIC.	SCH. - D	72,804.0	0.0	72,804.0	1.469	1.469	1,069,200.00	1,069,200.00	
HARDEE PWR PARTNERS	SEPARATED	CONTRACT	486,051.0	0.0	486,051.0	2.562	3.610	12,453,700.00	17,547,600.00	
VARIOUS	JURISDIC.	SCH. - MB	216,898.0	0.0	216,898.0	2.356	2.356	5,111,200.00	5,111,200.00	3,150,500.00
TOTAL			775,753.0	0.0	775,753.0	2.402	3.059	18,634,100.00	23,728,000.00	3,150,500.00
ACTUAL:										
HARDEE PWR PARTNERS	SEP. CONTR	SCH. - D	485,488.0	0.0	485,488.0	2.527	3.270	12,269,338.12	15,877,339.45	
SEMINOLE ELEC. PRECO-1	JURISDIC.	SCH. - D	48,925.6	5,788.5	43,137.1	2.931	2.931	1,264,182.67	1,264,182.67	
SEMINOLE ELEC. HARDEE	JURISDIC.	SCH. - D	9,551.0	0.0	9,551.0	2.024	2.024	193,301.61	193,301.61	
AQUILA		SCH. -MA	1,989.0	0.0	1,989.0	2.456	3.167	48,848.92	62,988.60	8,477.73
CITY OF LAKELAND		SCH. -MA	4,321.0	0.0	4,321.0	1.930	2.394	83,378.65	103,453.27	8,682.60
DUKE ENERGY		SCH. -MA	1,604.0	0.0	1,604.0	2.035	3.034	32,641.29	48,670.71	11,024.72
FLA. PWR. & LIGHT		SCH. -MA	18,747.0	0.0	18,747.0	2.005	2.547	375,863.98	477,428.06	47,875.75
FLA. PWR. CORP.		SCH. -MA	2,042.0	0.0	2,042.0	2.094	2.948	42,764.80	60,196.05	11,554.50
ORLANDO UTIL. COMM.		SCH. -MA	1,315.0	0.0	1,315.0	2.479	3.581	32,604.06	47,094.62	10,523.71
REEDY CREEK		SCH. -MA	60.0	0.0	60.0	2.347	2.872	1,407.94	1,723.42	138.88
RELIANT		SCH. -MA	20.0	0.0	20.0	3.282	7.850	656.40	1,570.06	850.86
SEMINOLE ELEC. CO-OP		SCH. -MA	6,920.0	0.0	6,920.0	2.272	3.020	157,251.25	209,017.07	30,037.02
THE ENERGY AUTHORITY		SCH. -MA	610.0	0.0	610.0	2.421	3.060	14,769.92	18,664.71	2,145.18
HARDEE PWR. PART. TO ORLANDO		SCH. -MA	50.0	0.0	50.0	3.007	3.344	1,503.50	1,672.16	
HARDEE PWR. PART. TO FLA. PWR. & LIGHT		SCH. -MA	210.0	0.0	210.0	3.131	3.752	6,574.65	7,879.04	
HARDEE PWR. PART. TO FLA. PWR. CORP.		SCH. -MA	70.0	0.0	70.0	4.069	4.702	2,848.30	3,291.06	
AUBURNDALE POWER PARTNERS		SCH. -OATT	(890.0)	0.0	(890.0)	1.556	1.556	(13,847.09)	(13,846.95)	
CARGILL ALLIANT		SCH. -OATT	529.0	0.0	529.0	4.335	4.336	22,932.21	22,935.10	
DUKE ENERGY		SCH. -OATT	3.0	0.0	3.0	7.770	7.781	233.10	233.43	
SUB-TOTAL SCHEDULE D POWER SALES-JURISD.			58,476.6	5,788.5	52,688.1	2.766	2.766	1,457,484.28	1,457,484.28	
SUB-TOTAL HARDEE PWR. PART.CONTRACT SALES-SEP.			485,488.0	0.0	485,488.0	2.527	3.270	12,269,338.12	15,877,339.45	
SUB-TOTAL SCHEDULE MA POWER SALES-JURISD.			37,958.0	0.0	37,958.0	2.111	2.749	801,113.66	1,043,648.63	131,310.95
SUB-TOTAL SCHEDULE OATT POWER SALES-JURISD.			(358.0)	0.0	(358.0)	(2.603)	(2.604)	9,318.22	9,321.58	
TOTAL			581,564.6	5,788.5	575,776.1	2.525	3.194	14,537,254.28	18,387,794.14	131,310.95
DIFFERENCE			(194,188.4)	5,788.5	(199,976.9)	0.123	0.135	(4,096,845.72)	(5,340,205.86)	(3,019,189.05)
DIFFERENCE %			-25.0%	0.0%	-25.8%	5.1%	4.4%	-22.0%	-22.5%	-95.8%

* SALES TO HARDEE POWER PARTNERS FOR OTHERS INCLUDES TEC 40% PROFIT. SEC 60% PROFIT OR $2,873.72 HAS BEEN EXCLUDED.

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A7

JANUARY 2002 - DECEMBER 2002

PURCHASED POWER
(EXCLUSIVE OF ECONOMY & COGENERATION)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2002 THROUGH DECEMBER 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	SCH. - J	280,950.0	0.0	151,518.0	129,432.0	7.161	7.161	9,269,100.00
HARDEE POWER PARTNERS	IPP	1,050,349.0	0.0	0.0	1,050,349.0	4.619	4.619	48,513,600.00
VARIOUS	OTHER	427,344.0	0.0	0.0	427,344.0	5.907	5.907	25,244,200.00
VARIOUS	MKT. BASE	1,117,101.0	0.0	0.0	1,117,101.0	5.402	5.402	60,341,700.00
TOTAL		2,875,744.0	0.0	151,518.0	2,724,226.0	5.263	5.263	143,368,600.00
ACTUAL:								
HARDEE PWR. PART.-NATIVE	IPP	902,080.0	0.0	0.0	902,080.0	4.915	4.915	44,333,232.81
HARDEE PWR. PART.-OTHERS	IPP	420.0	0.0	0.0	420.0	2.602	2.602	10,926.45
FLA. POWER & LIGHT	SCH.-A	475.0	0.0	475.0	0.0	0.000	0.000	0.00
FLA. POWER CORP.	SCH.-D	682,077.0	0.0	0.0	682,077.0	3.960	3.960	27,008,011.23
OKEELANTA	SCH.-D	6,909.0	0.0	0.0	6,909.0	4.739	4.739	327,437.60
AQUILA	SCH.-J	139,249.0	0.0	2,332.8	136,916.2	6.196	6.196	8,483,514.55
AUBURNDALE POWER PARTNERS	SCH.-J	9,381.0	0.0	0.0	9,381.0	3.553	3.553	333,294.00
AXIA	SCH.-J	822.0	0.0	311.7	510.3	9.202	9.202	46,959.97
CALPINE	SCH.-J	10,839.0	0.0	376.0	10,463.0	3.046	3.046	318,678.00
CARGILL ALLIANT	SCH.-J	273,589.0	0.0	18,539.7	255,049.3	4.825	4.825	12,304,889.04
CAROLINA POWER & LIGHT	SCH.-J	8,877.0	0.0	0.0	8,877.0	3.431	3.431	304,596.38
CITY OF LAKELAND	SCH.-J	235,501.0	0.0	31,959.1	203,541.9	4.463	4.463	9,083,818.38
CONOCO	SCH.-J	2,061.0	0.0	172.7	1,888.3	4.092	4.092	77,263.75
CORAL POWER	SCH.-J	1,851.0	0.0	537.3	1,313.7	3.079	3.079	40,448.34
DUKE ENERGY	SCH.-J	109,597.0	0.0	12,716.6	96,880.5	4.730	4.730	4,582,157.70
DYNEGY POWER MARKETING	SCH.-J	29,534.0	0.0	1,380.6	28,153.4	3.648	3.648	1,027,013.33
FLA. POWER & LIGHT	SCH.-J	435,324.0	0.0	46,296.2	389,027.8	4.464	4.464	17,365,880.06
FLA. POWER CORP.	SCH.-J	408,889.0	0.0	20,131.3	388,757.7	3.776	3.776	14,681,253.50
HOMESTEAD	SCH.-J	419.0	0.0	35.0	384.0	7.597	7.597	29,171.59
KOCH ENERGY	SCH.-J	9,703.0	0.0	1,571.8	8,131.2	4.731	4.731	384,684.16
LAKE WORTH	SCH.-J	147.0	0.0	68.0	79.0	15.929	15.929	12,583.72
LOUISVILLE	SCH.-J	4,304.0	0.0	0.0	4,304.0	3.693	3.693	158,958.00
OKEELANTA	SCH.-J	72,377.0	0.0	86.0	72,291.0	3.993	3.993	2,886,251.40
ORLANDO UTIL. COMM.	SCH.-J	155,850.0	0.0	20,382.5	135,467.5	6.119	6.119	8,289,779.05
REEDY CREEK	SCH.-J	3,686.0	0.0	81.3	3,604.7	5.538	5.538	199,611.98
RELIANT	SCH.-J	79,353.0	0.0	24,385.1	54,967.9	5.896	5.896	3,240,673.78
RINGHAVER	SCH.-J	33,904.0	0.0	0.0	33,904.0	6.163	6.163	2,089,588.43
SEMINOLE ELECTRIC CO-OP	SCH.-J	58,032.0	0.0	4,424.4	53,607.6	3.416	3.416	1,831,497.80
TALLAHASSEE	SCH.-J	16,460.0	0.0	753.2	15,706.8	5.380	5.380	845,043.53
THE ENERGY AUTHORITY	SCH.-J	174,861.0	0.0	32,348.2	142,512.8	4.757	4.757	6,778,740.48
KOCH ENERGY	SCH.-Ja	34.0	0.0	0.0	34.0	7.422	7.422	2,523.50
THE ENERGY AUTHORITY	SCH.-Ja	0.0	0.0	0.0	0.0	0.000	0.000	50,000.00
CARGILL ALLIANT	SCH.-Jc	0.0	0.0	0.0	0.0	0.000	0.000	2,000,000.00
ENRON	SCH.-Jc	9.0	0.0	0.0	9.0	8.022	8.022	722.00
KOCH ENERGY	SCH.-Jc	72.0	0.0	0.0	72.0	0.953	0.953	686.50
THE ENERGY AUTHORITY	SCH.-Jc	0.0	0.0	0.0	0.0	0.000	0.000	800,000.00
TOTAL		3,866,686.0	0.0	219,364.4	3,647,321.6	4.659	4.659	169,929,891.01
DIFFERENCE		990,942.0	0.0	67,846.4	923,095.6	(0.604)	(0.604)	26,561,291.01
DIFFERENCE %		34.5%	0.0%	44.8%	33.9%	-11.5%	-11.5%	18.5%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A8

JANUARY 2002 - DECEMBER 2002

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2002 THROUGH DECEMBER 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) MWH FROM OTHER UTILITIES	(5) MWH FOR INTER-RUPTIBLE	(6) MWH FOR FIRM	(7) CENTS/KWH (A) FUEL COST	(7) CENTS/KWH (B) TOTAL COST	(8) TOTAL $ FOR FUEL ADJUSTMENT (6)X(7A)
ESTIMATED:								
VARIOUS	COGEN.	473,104.0	0.0	0.0	473,104.0	2.275	2.275	10,762,700.00
TOTAL		**473,104.0**	**0.0**	**0.0**	**473,104.0**	**2.275**	**2.275**	**10,762,700.00**
ACTUAL:								
AUBURNDALE POWER PARTNERS	COGEN.	9,393.0	0.0 #	0.0	9,393.0	3.895	3.895	365,867.62
CARGILL MILLPOINT	COGEN.	1,503.0	0.0	0.0	1,503.0	4.686	4.686	70,430.36
CARGILL RIDGEWOOD	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
CF INDUSTRIES INC.	COGEN.	7,474.0	0.0	0.0	7,474.0	3.758	3.758	280,890.41
CUTRALE CITRUS	COGEN.	5,569.0	0.0	0.0	5,569.0	1.888	1.888	105,118.87
FARMLAND HYDRO LP	COGEN.	12,582.0	0.0	0.0	12,582.0	3.526	3.526	443,586.64
HILLSBOROUGH COUNTY	COGEN.	203,909.0	0.0	0.0	203,909.0	2.263	2.263	4,613,476.00
IMC-AGRICO-NEW WALES	COGEN.	2,623.0	0.0	0.0	2,623.0	3.524	3.524	92,446.53
IMC-AGRICO-NICHOLS	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
IMC-AGRICO-S. PIERCE	COGEN.	10,226.0	0.0	0.0	10,226.0	3.803	3.803	388,901.53
McKAY BAY REFUSE	COGEN.	151,807.0	0.0	0.0	151,807.0	2.271	2.271	3,447,138.74
MULBERRY PHOSPHATES INC.	COGEN.	0.0	0.0	0.0	0.0	0.000	0.000	0.00
ORANGE COGENERATION L.P.	COGEN.	71,845.0	0.0	0.0	71,845.0	2.239	2.239	1,608,605.75
TOTAL		**476,931.0**	**0.0**	**0.0**	**476,931.0**	**2.394**	**2.394**	**11,416,462.45**
DIFFERENCE		3,827.0	0.0	0.0	3,827.0	0.119	0.119	653,762.45
DIFFERENCE %		0.8%	0.0%	0.0%	0.8%	5.2%	5.2%	6.1%

FUEL AND PURCHASED POWER COST RECOVERY

SCHEDULE A9

JANUARY 2002 - DECEMBER 2002

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
FOR THE PERIOD JANUARY 2002 THROUGH DECEMBER 2002

(1) PURCHASED FROM	(2) TYPE & SCHEDULE	(3) TOTAL MWH PURCHASED	(4) TRANSACTION COSTS CENTS/KWH	(5) TOTAL $ FOR FUEL ADJUSTMENT (3) X (4)	(6) COST IF GENERATED (A) CENTS PER KWH	(6) (B) TOTAL COST	(7) FUEL SAVINGS (6B)-5
ESTIMATED:							
VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
ACTUAL:							
FLA. PWR. CORP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FLA. PWR. & LIGHT	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF LAKELAND	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FT. PIERCE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF GAINESVILLE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF HOMESTEAD	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
JACKSONVILLE ELEC. AUTH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
LAKE WORTH UTILITIES	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
ORLANDO UTIL. COMM.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
SEMINOLE ELECTRIC CO-OP.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TALLAHASSEE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF VERO BEACH	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KISSIMMEE ELEC.UTIL.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
CITY OF NEW SMYRNA BCH.	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
KEY WEST	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
FMPA	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
OGLETHORPE	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
REEDY CREEK	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
PECO	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
THE ENERGY AUTHORITY	ECON.-C	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL		**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**
DIFFERENCE		0.0	0.000	0.00	0.000	0.00	0.00
DIFFERENCE %		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

EXHIBIT NO._____
DOCKET NO. 030001-EI
TAMPA ELECTRIC COMPANY
(JDJ-2)
FILED 08/12/03
DOCUMENT NO. 1

TAMPA ELECTRIC COMPANY

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 29
COMPANY/ TECO
WITNESS: JDJ-2
DATE: 11-12-03

SCHEDULE E1-B

CALCULATION OF ESTIMATED TRUE-UP
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2003 THROUGH DECEMBER 2003

		ACTUAL						ESTIMATED						
		Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	TOTAL
A. 1.	Fuel Cost of System Net Generation	31,877,915	24,850,700	32,533,978	36,891,645	47,178,688	52,099,093	49,339,779	52,278,706	49,894,460	40,846,433	52,301,445	52,731,058	522,823,900
2.	Fuel Cost of Power Sold (1)	458,396	483,751	1,523,284	534,032	845,620	118,633	55,500	78,900	245,300	208,000	139,700	317,600	5,008,716
3.	Fuel Cost of Purchased Power	14,320,140	7,708,351	13,922,672	8,169,033	14,643,590	13,218,541	21,356,700	16,776,400	12,308,300	20,766,900	4,504,900	1,320,000	149,015,527
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	1,258,765	1,168,729	1,347,837	1,168,907	726,725	736,351	1,161,400	1,195,500	1,152,100	1,195,900	1,110,700	1,111,200	13,334,114
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)	(6,108)	(4,371)	(5,269)	(6,002)	(8,114)	(7,310)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(73,174)
5a.	Adjustment to Fuel Cost	(2,738)	(1,862)	(2,253)	(1,081)	(4,817)	(4,554)	0	0	0	0	0	0	(17,325)
5b.	Incremental O&M Hedging Costs	0	0	0	0	0	0	0	38,169	38,169	38,169	38,169	38,171	190,847
6.	**TOTAL FUEL & NET POWER TRANS.**	**46,989,578**	**33,237,776**	**46,273,681**	**45,688,470**	**61,690,452**	**65,923,488**	**71,796,379**	**70,203,875**	**63,141,729**	**62,633,402**	**57,809,514**	**54,876,829**	**680,265,173**
(1)	Includes Gains													
B. 1.	Jurisdictional MWH Sales	1,479,489	1,370,642	1,253,104	1,341,472	1,573,534	1,650,043	1,690,943	1,708,752	1,745,628	1,597,543	1,417,543	1,428,113	18,256,806
2.	Non-Jurisdictional MWH Sales	46,230	38,296	54,184	44,493	54,089	51,688	54,236	54,551	40,811	36,035	22,682	22,867	520,162
3.	**TOTAL SALES (LINE B1+B2)**	**1,525,719**	**1,408,938**	**1,307,288**	**1,385,965**	**1,627,623**	**1,701,731**	**1,745,179**	**1,763,303**	**1,786,439**	**1,633,578**	**1,440,225**	**1,450,980**	**18,776,968**
4.	**Jurisdictional % of Total Sales**	**0.9696995**	**0.9728192**	**0.9585524**	**0.9678975**	**0.9667681**	**0.9696262**	**0.9689224**	**0.9690632**	**0.9771551**	**0.9779411**	**0.9842511**	**0.9842403**	-
C. 1.	Jurisdictional Fuel Recovery Revenue (Net of Revenue Taxes)	43,921,774	40,722,045	37,106,542	45,646,859	53,592,145	56,277,645	58,060,197	58,656,767	59,924,854	54,813,534	48,606,004	48,966,744	606,295,110
1a.	Adjustment to Fuel Revenue	0	0	0	0	0	0	0	0	0	0	0	0	0
2.	True-up Provision	(263,799)	(263,799)	(263,799)	(3,152,688)	(3,152,688)	(3,152,688)	(3,152,688)	(3,152,688)	(3,152,688)	(3,152,688)	(3,152,688)	(3,152,690)	(29,165,591)
2a.	Incentive Provision	69,203	69,203	68,561	69,252	69,252	69,252	69,252	69,252	69,252	69,252	69,252	69,257	830,240
2b.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	**FUEL REVENUE APPLICABLE TO PERIOD**	**43,727,178**	**40,527,449**	**36,911,304**	**42,563,423**	**50,508,709**	**53,194,209**	**54,976,761**	**55,573,331**	**56,841,418**	**51,730,098**	**45,522,568**	**45,883,311**	**577,959,759**
4.	Total Fuel and Net Power Transactions (Line A6)	46,989,578	33,237,776	46,273,681	45,688,470	61,690,452	65,923,488	71,796,379	70,203,875	63,141,729	62,633,402	57,809,514	54,876,829	680,265,173
5.	Jurisd. Total Fuel and Net Power Transactions (Line A6*Line B4)	45,565,770	32,334,348	44,355,749	44,221,752	59,640,361	63,921,143	69,565,120	68,031,992	61,699,263	61,251,778	56,899,078	54,011,987	661,498,341
5a.	Jurisdictional Loss Multiplier	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	-
5b.	Jurisdictional Sales Adjusted for Line Losses	45,617,715	32,371,209	44,406,315	44,272,165	59,708,351	63,994,013	69,644,164	68,109,294	61,769,369	61,321,376	56,963,730	54,073,358	662,251,059
5c.	Peabody Coal Contract Buyout Amortization	284,852	282,321	279,790	277,259	274,728	272,197	269,666	267,135	264,604	262,073	259,542	257,011	3,251,178
5d.	Peabody Jurisdictionalized (Line 5c*Line B4)	276,221	274,647	268,193	268,358	265,598	263,929	261,285	258,871	258,559	256,292	255,454	252,961	3,160,368
6.	**JURISD. TOTAL FUEL AND NET POWER TRANSACTIONS INCLUDING PEABODY**	**45,893,936**	**32,645,856**	**44,674,508**	**44,540,523**	**59,973,949**	**64,257,942**	**69,905,449**	**68,368,165**	**62,027,928**	**61,577,668**	**57,219,184**	**54,326,319**	**665,411,427**
7.	Over/(Under) Recovery	(2,166,758)	7,881,593	(7,763,204)	(1,977,100)	(9,465,240)	(11,063,733)	(14,928,688)	(12,794,834)	(5,186,510)	(9,847,570)	(11,696,616)	(8,443,008)	(87,451,668)
8.	Interest Provision	(35,074)	(31,178)	(29,695)	(32,267)	(35,194)	(38,954)	(65,279)	(105,206)	(115,131)	(122,612)	(135,541)	(147,319)	(893,450)
9.	**TOTAL ESTIMATED TRUE-UP FOR THE PERIOD**													**(88,345,118)**

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2003 THROUGH DECEMBER 2003

SCHEDULE E2

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	TOTAL
		ACTUAL						ESTIMATED						
		Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	PERIOD
1.	Fuel Cost of System Net Generation	31,877,915	24,850,700	32,533,978	36,891,645	47,178,688	52,099,093	49,339,779	52,278,706	49,894,460	40,846,433	52,301,445	52,731,058	522,823,900
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold [1]	458,396	483,751	1,523,284	534,032	845,620	118,633	55,500	78,900	245,300	208,000	139,700	317,600	5,008,716
4.	Fuel Cost of Purchased Power	14,320,140	7,708,351	13,922,672	8,169,033	14,643,590	13,218,541	21,356,700	16,776,400	12,308,300	20,766,900	4,504,900	1,320,000	149,015,527
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	1,258,765	1,168,729	1,347,837	1,168,907	726,725	736,351	1,161,400	1,195,500	1,152,100	1,195,900	1,110,700	1,111,200	13,334,114
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)	(6,108)	(4,371)	(5,269)	(6,002)	(8,114)	(7,310)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(73,174)
8a.	Adjustment to Fuel Cost	(2,738)	(1,882)	(2,253)	(1,081)	(4,817)	(4,554)	0	0	0	0	0	0	(17,325)
8b.	Incremental O&M Hedging Costs	0	0	0	0	0	0	0	38,169	38,169	38,169	38,169	38,171	190,847
9.	**TOTAL FUEL & NET POWER TRANSACTIONS**	**46,989,578**	**33,237,776**	**46,273,681**	**45,688,470**	**61,690,452**	**65,923,488**	**71,796,379**	**70,203,875**	**63,141,729**	**62,633,402**	**57,809,514**	**54,876,829**	**680,265,173**
10.	Jurisdictional kWh Sold	1,479,489	1,370,642	1,253,104	1,341,472	1,573,534	1,650,043	1,690,943	1,708,752	1,745,628	1,597,543	1,417,543	1,428,113	18,256,806
11.	Jurisdictional % of Total Sales	0.9696995	0.9728192	0.9585524	0.9678975	0.9667681	0.9696262	0.9689224	0.9690632	0.9771551	0.9779411	0.9842511	0.9842403	-
12.	Jurisdictional Total Fuel & Net Power Transactions (Line 9 * Line 11)	45,565,770	32,334,348	44,355,749	44,221,752	59,640,361	63,921,143	69,565,120	68,031,992	61,699,263	61,251,778	56,899,078	54,011,987	661,498,341
13.	Jurisdictional Loss Multiplier	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	-
14.	Jurisdictional Sales Adjusted for Line Losses (Line 12 * Line 13)	45,617,715	32,371,209	44,406,315	44,272,165	59,708,351	63,994,013	69,644,164	68,109,294	61,769,369	61,321,376	56,963,730	54,073,358	662,251,059
15.	Peabody Coal Contract Buyout Amortization	284,852	282,321	279,790	277,259	274,728	272,197	269,666	267,135	264,604	262,073	259,542	257,011	3,251,178
16.	Peabody Jurisdictionalized (Line 15 * Line 11)	276,221	274,647	268,193	268,358	265,598	263,929	261,285	258,871	258,559	256,292	255,454	252,961	3,160,368
17.	**JURISD. TOTAL FUEL & NET PWR. TRANS. INCL. PEABODY (LINE 14+16)**	**45,893,936**	**32,645,856**	**44,674,508**	**44,540,523**	**59,973,949**	**64,257,942**	**69,905,449**	**68,368,165**	**62,027,928**	**61,577,668**	**57,219,184**	**54,326,319**	**665,411,427**
18.	Cost Per kWh Sold (Cents/kWh)	3.1020	2.3818	3.5651	3.3203	3.8114	3.8943	4.1341	4.0011	3.5533	3.8545	4.0365	3.8041	3.6447
19.	True-up (Cents/kWh) [2]	0.0178	0.0192	0.0211	0.2350	0.2004	0.1911	0.1864	0.1845	0.1806	0.1973	0.2224	0.2208	0.1564
20.	Total (Cents/kWh) (Line 18+19)	3.1198	2.4010	3.5862	3.5553	4.0118	4.0854	4.3205	4.1856	3.7339	4.0518	4.2589	4.0249	3.8011
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)	3.1220	2.4027	3.5888	3.5579	4.0147	4.0883	4.3236	4.1886	3.7366	4.0547	4.2620	4.0278	3.8038
23.	GPIF Adjusted for Taxes (Cents/kWh) [2]	(0.0047)	(0.0050)	(0.0055)	(0.0052)	(0.0044)	(0.0042)	(0.0041)	(0.0041)	(0.0040)	(0.0043)	(0.0049)	(0.0048)	(0.0046)
24.	**TOTAL RECOVERY FACTOR (LINE 22+23)**	**3.1173**	**2.3977**	**3.5833**	**3.5527**	**4.0103**	**4.0841**	**4.3195**	**4.1845**	**3.7326**	**4.0504**	**4.2571**	**4.0230**	**3.7992**
25.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**3.117**	**2.398**	**3.583**	**3.553**	**4.010**	**4.084**	**4.320**	**4.185**	**3.733**	**4.050**	**4.257**	**4.023**	**3.799**

[1] Includes Gains
[2] Based on Jurisdictional Sales Only

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2003 THROUGH JUNE 2003

	ACTUAL					
	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	471,614	385,066	627,987	64,717	521,104	528,186
2. LIGHT OIL	1,754,226	1,241,591	219,523	828,657	589,896	782,597
3. COAL	28,285,132	22,010,478	25,618,380	23,369,261	27,066,002	24,796,476
4. NATURAL GAS	1,366,943	1,213,565	6,068,088	12,629,010	19,001,686	25,991,834
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**31,877,915**	**24,850,700**	**32,533,978**	**36,891,645**	**47,178,688**	**52,099,093**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	8,717	6,485	10,384	681	8,284	9,638
9. LIGHT OIL	30,591	19,856	2,610	6,466	8,633	11,444
10. COAL	1,294,869	1,056,358	1,176,228	1,059,825	1,220,021	1,089,409
11. NATURAL GAS	10,216	2,211	57,422	235,799	397,706	417,735
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,344,393**	**1,084,910**	**1,246,644**	**1,302,771**	**1,634,644**	**1,528,226**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	13,252	9,874	15,877	1,619	12,850	14,967
16. LIGHT OIL (BBL)	47,648	30,813	6,904	18,932	15,547	20,486
17. COAL (TON)	615,626	478,410	548,335	491,369	561,996	505,207
18. NATURAL GAS (MCF)	117,763	25,363	665,874	1,743,750	2,957,416	3,018,929
19. NUCLEAR (MMBTU)	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	83,135	61,942	99,606	10,158	80,613	93,900
22. LIGHT OIL	276,951	178,915	39,921	88,319	90,225	115,957
23. COAL	14,465,442	11,464,264	13,028,693	11,811,605	13,511,738	12,101,895
24. NATURAL GAS	125,299	26,860	705,160	1,844,887	3,125,989	3,212,139
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**14,950,827**	**11,731,981**	**13,873,380**	**13,754,969**	**16,808,565**	**15,523,891**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.65	0.60	0.83	0.05	0.51	0.63
29. LIGHT OIL	2.28	1.83	0.21	0.50	0.53	0.75
30. COAL	96.31	97.37	94.35	81.35	74.63	71.29
31. NATURAL GAS	0.76	0.20	4.61	18.10	24.33	27.33
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	35.59	39.00	39.55	39.97	40.55	35.29
36. LIGHT OIL ($/BBL)	36.82	40.29	31.80	43.77	37.94	38.20
37. COAL ($/TON)	45.95	46.01	46.72	47.56	48.16	49.08
38. NATURAL GAS ($/MCF)	11.61	47.85	9.11	7.24	6.43	8.61
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	5.67	6.22	6.30	6.37	6.46	5.62
42. LIGHT OIL	6.33	6.94	5.50	9.38	6.54	6.75
43. COAL	1.96	1.92	1.97	1.98	2.00	2.05
44. NATURAL GAS	10.91	45.18	8.61	6.85	6.08	8.09
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**2.13**	**2.12**	**2.35**	**2.68**	**2.81**	**3.36**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	9,537	9,552	9,592	14,916	9,731	9,743
49. LIGHT OIL	9,053	9,011	15,295	13,659	10,451	10,133
50. COAL	11,171	10,853	11,077	11,145	11,075	11,109
51. NATURAL GAS	12,265	12,148	12,280	7,824	7,860	7,689
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**11,121**	**10,814**	**11,129**	**10,558**	**10,283**	**10,158**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	5.41	5.94	6.05	9.50	6.29	5.48
56. LIGHT OIL	5.73	6.25	8.41	12.82	6.83	6.84
57. COAL	2.18	2.08	2.18	2.21	2.22	2.28
58. NATURAL GAS	13.38	54.89	10.57	5.36	4.78	6.22
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**2.37**	**2.29**	**2.61**	**2.83**	**2.89**	**3.41**

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2003 THROUGH DECEMBER 2003

	ESTIMATED						
	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)							
1. HEAVY OIL	609,828	525,299	457,042	285,562	98,970	35,961	4,611,336
2. LIGHT OIL	609,162	644,064	613,431	703,056	733,893	756,324	9,476,420
3. COAL	23,838,752	26,651,053	25,317,602	17,272,989	16,203,823	18,013,772	278,443,720
4. NATURAL GAS	24,282,037	24,458,290	23,506,385	22,584,826	35,264,759	33,925,001	230,292,424
5. NUCLEAR	0	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0	0
7. TOTAL ($)	**49,339,779**	**52,278,706**	**49,894,460**	**40,846,433**	**52,301,445**	**52,731,058**	**522,823,900**
SYSTEM NET GENERATION (MWH)							
8. HEAVY OIL	11,578	10,001	8,733	5,460	1,864	681	82,506
9. LIGHT OIL	10,314	10,924	10,485	11,984	12,300	12,608	148,215
10. COAL	1,063,120	1,185,660	1,133,840	831,784	751,435	822,093	12,684,642
11. NATURAL GAS	429,148	436,684	413,853	422,633	561,113	657,839	4,042,359
12. NUCLEAR	0	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0	0
14. TOTAL (MWH)	**1,514,160**	**1,643,269**	**1,566,911**	**1,271,861**	**1,326,712**	**1,493,221**	**16,957,722**
UNITS OF FUEL BURNED							
15. HEAVY OIL (BBL)	18,002	15,541	13,569	8,484	2,879	1,054	127,968
16. LIGHT OIL (BBL)	16,224	17,056	16,157	18,431	19,108	19,611	246,917
17. COAL (TON)	487,875	546,296	519,730	371,523	332,273	365,748	5,824,388
18. NATURAL GAS (MCF)	3,697,795	3,723,184	3,555,094	3,401,172	5,188,360	4,829,137	32,923,837
19. NUCLEAR (MMBTU)	0	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)							
21. HEAVY OIL	113,030	97,578	85,203	53,269	18,078	6,613	803,125
22. LIGHT OIL	146,478	143,731	138,719	135,345	137,071	149,674	1,641,306
23. COAL	11,897,960	13,298,380	12,651,150	9,196,970	8,137,410	8,921,530	140,487,037
24. NATURAL GAS	3,801,245	3,827,394	3,654,617	3,496,431	5,333,678	4,964,425	34,118,124
25. NUCLEAR	0	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0	0
27. TOTAL (MMBTU)	**15,958,713**	**17,367,083**	**16,529,689**	**12,882,015**	**13,626,237**	**14,042,242**	**177,049,592**
GENERATION MIX (% MWH)							
28. HEAVY OIL	0.76	0.61	0.56	0.43	0.14	0.05	0.49
29. LIGHT OIL	0.68	0.66	0.67	0.94	0.93	0.84	0.87
30. COAL	70.22	72.16	72.36	65.40	56.64	55.05	74.80
31. NATURAL GAS	28.34	26.57	26.41	33.23	42.29	44.06	23.84
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT							
35. HEAVY OIL ($/BBL)	33.88	33.80	33.68	33.66	34.38	34.12	36.04
36. LIGHT OIL ($/BBL)	37.55	37.76	37.97	38.15	38.41	38.57	38.38
37. COAL ($/TON)	48.86	48.79	48.71	46.49	48.77	49.25	47.81
38. NATURAL GAS ($/MCF)	6.57	6.57	6.61	6.64	6.80	7.03	6.99
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)							
41. HEAVY OIL	5.40	5.38	5.36	5.36	5.47	5.44	5.74
42. LIGHT OIL	4.16	4.48	4.42	5.19	5.35	5.05	5.77
43. COAL	2.00	2.00	2.00	1.88	1.99	2.02	1.98
44. NATURAL GAS	6.39	6.39	6.43	6.46	6.61	6.83	6.75
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**3.09**	**3.01**	**3.02**	**3.17**	**3.84**	**3.76**	**2.95**
BTU BURNED PER KWH (BTU/KWH)							
48. HEAVY OIL	9,762	9,757	9,756	9,756	9,698	9,711	9,734
49. LIGHT OIL	14,202	13,157	13,230	11,294	11,144	11,871	11,074
50. COAL	11,192	11,216	11,158	11,057	10,829	10,852	11,075
51. NATURAL GAS	8,858	8,765	8,831	8,273	9,506	7,547	8,440
52. NUCLEAR	0	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**10,540**	**10,569**	**10,549**	**10,128**	**10,271**	**9,404**	**10,441**
GENERATED FUEL COST PER KWH (CENTS/KWH)							
55. HEAVY OIL	5.27	5.25	5.23	5.23	5.31	5.28	5.59
56. LIGHT OIL	5.91	5.90	5.85	5.87	5.97	6.00	6.39
57. COAL	2.24	2.25	2.23	2.08	2.16	2.19	2.20
58. NATURAL GAS	5.66	5.60	5.68	5.34	6.28	5.16	5.70
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**3.26**	**3.18**	**3.18**	**3.21**	**3.94**	**3.53**	**3.08**

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2003 THROUGH JUNE 2003

	ACTUAL					
	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	11,973	16,247	10,823	4,075	12,003	17,459
3. UNIT COST ($/BBL)	34.01	39.11	37.61	43.81	37.21	30.97
4. AMOUNT ($)	407,180	635,371	407,091	178,540	446,624	540,788
5. BURNED:						
6. UNITS (BBL)	13,252	9,874	15,877	1,619	12,850	14,967
7. UNIT COST ($/BBL)	35.59	39.00	39.55	39.97	40.55	35.29
8. AMOUNT ($)	471,614	385,066	627,987	64,717	521,104	528,186
9. ENDING INVENTORY:						
10. UNITS (BBL)	9,463	15,836	10,782	13,238	12,391	14,883
11. UNIT COST ($/BBL)	36.71	39.00	39.32	40.87	39.74	35.12
12. AMOUNT ($)	347,419	617,565	423,956	541,052	492,475	522,758
13. DAYS SUPPLY:	30	56	40	36	27	33
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	53,236	28,748	15,202	36,067	31,955	25,407
16. UNIT COST ($/BBL)	39.50	45.80	49.28	35.74	33.79	35.85
17. AMOUNT ($)	2,102,841	1,316,725	749,214	1,288,908	1,079,852	910,728
18. BURNED:						
19. UNITS (BBL)	47,648	30,813	6,904	18,932	15,547	20,486
20. UNIT COST ($/BBL)	36.82	40.29	31.80	43.77	37.94	38.20
21. AMOUNT ($)	1,754,226	1,241,591	219,523	828,657	589,896	782,597
22. ENDING INVENTORY:						
23. UNITS (BBL)	82,890	71,537	68,333	77,484	82,925	77,076
24. UNIT COST ($/BBL)	34.90	37.12	40.32	37.74	36.62	36.31
25. AMOUNT ($)	2,892,719	2,655,220	2,754,944	2,924,372	3,036,606	2,798,710
26. DAYS SUPPLY: NORMAL	85	84	91	110	119	111
27. DAYS SUPPLY: EMERGENCY	12	10	10	11	12	11
COAL						
28. PURCHASES:						
29. UNITS (TONS)	509,773	599,894	594,579	663,934	576,928	520,798
30. UNIT COST ($/TON)	47.25	47.14	47.28	48.19	48.22	48.89
31. AMOUNT ($)	24,084,451	28,277,069	28,109,310	31,995,557	27,820,080	25,463,316
32. BURNED:						
33. UNITS (TONS)	615,626	478,410	548,335	491,369	561,996	505,207
34. UNIT COST ($/TON)	45.95	46.01	46.72	47.56	48.16	49.08
35. AMOUNT ($)	28,285,132	22,010,478	25,618,380	23,369,261	27,066,002	24,796,476
36. ENDING INVENTORY:						
37. UNITS (TONS)	332,504	453,988	500,232	672,797	687,729	703,320
38. UNIT COST ($/TON)	45.25	46.67	47.05	47.47	48.10	48.60
39. AMOUNT ($)	15,047,120	21,187,290	23,533,546	31,940,620	33,076,382	34,181,444
40. DAYS SUPPLY:	19	25	27	33	33	34
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	117,763	25,363	665,874	1,743,750	2,957,416	3,018,929
43. UNIT COST ($/MCF)	11.61	47.85	9.11	7.24	6.43	8.61
44. AMOUNT ($)	1,366,943	1,213,565	6,068,088	12,629,010	19,001,686	25,991,834
45. BURNED:						
46. UNITS (MCF)	117,763	25,363	665,874	1,743,750	2,957,416	3,018,929
47. UNIT COST ($/MCF)	11.61	47.85	9.11	7.24	6.43	8.61
48. AMOUNT ($)	1,366,943	1,213,565	6,068,088	12,629,010	19,001,686	25,991,834
49. ENDING INVENTORY:						
50. UNITS (MCF)	0	0	0	0	0	0
51. UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00
52. AMOUNT ($)	0	0	0	0	0	0
53. DAYS SUPPLY:	0	0	0	0	0	0
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2003 THROUGH DECEMBER 2003

	ESTIMATED						
	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	TOTAL
HEAVY OIL							
1. PURCHASES:							
2. UNITS (BBL)	18,002	15,541	13,569	8,484	2,879	1,054	132,109
3. UNIT COST ($/BBL)	32.06	33.16	32.97	32.50	32.10	31.69	34.49
4. AMOUNT ($)	577,220	515,318	447,329	275,755	92,411	33,404	4,557,031
5. BURNED:							
6. UNITS (BBL)	18,002	15,541	13,569	8,484	2,879	1,054	127,968
7. UNIT COST ($/BBL)	33.88	33.80	33.68	33.66	34.38	34.12	36.04
8. AMOUNT ($)	609,828	525,299	457,042	285,562	98,970	35,961	4,611,336
9. ENDING INVENTORY:							
10. UNITS (BBL)	14,883	14,883	14,883	14,883	14,883	14,883	14,883
11. UNIT COST ($/BBL)	33.45	33.30	33.14	32.91	32.78	32.71	32.71
12. AMOUNT ($)	497,820	495,609	493,239	489,787	487,830	486,761	486,761
13. DAYS SUPPLY:	36	55	109	89	50	41	-
LIGHT OIL							
14. PURCHASES:							
15. UNITS (BBL)	25,255	24,824	23,889	23,392	23,625	25,784	337,384
16. UNIT COST ($/BBL)	36.02	37.93	38.15	38.46	38.65	38.76	38.60
17. AMOUNT ($)	909,584	941,499	911,382	899,734	913,129	999,323	13,022,919
18. BURNED:							
19. UNITS (BBL)	16,224	17,056	16,157	18,431	19,108	19,611	246,917
20. UNIT COST ($/BBL)	37.55	37.76	37.97	38.15	38.41	38.57	38.38
21. AMOUNT ($)	609,162	644,064	613,431	703,056	733,893	756,324	9,476,420
22. ENDING INVENTORY:							
23. UNITS (BBL)	77,076	77,076	77,076	77,076	77,076	77,076	77,076
24. UNIT COST ($/BBL)	36.22	36.57	36.89	37.14	37.36	37.60	37.60
25. AMOUNT ($)	2,791,361	2,818,708	2,843,414	2,862,896	2,879,557	2,898,417	2,898,417
26. DAYS SUPPLY: NORMAL	98	100	96	96	100	100	-
27. DAYS SUPPLY: EMERGENCY	11	11	11	11	11	11	
COAL							
28. PURCHASES:							
29. UNITS (TONS)	660,000	548,600	350,500	428,700	422,000	387,100	6,262,806
30. UNIT COST ($/TON)	47.38	47.46	46.30	47.93	48.48	48.29	47.74
31. AMOUNT ($)	31,271,488	26,034,533	16,229,497	20,547,145	20,460,311	18,694,666	298,987,423
32. BURNED:							
33. UNITS (TONS)	487,875	546,296	519,730	371,523	332,273	365,748	5,824,388
34. UNIT COST ($/TON)	48.86	48.79	48.71	46.49	48.77	49.25	47.81
35. AMOUNT ($)	23,838,752	26,651,053	25,317,602	17,272,989	16,203,823	18,013,772	278,443,720
36. ENDING INVENTORY:							
37. UNITS (TONS)	875,445	877,749	708,519	765,696	855,423	876,775	876,775
38. UNIT COST ($/TON)	48.02	47.58	46.60	47.73	47.98	47.93	47.93
39. AMOUNT ($)	42,036,503	41,762,372	33,020,346	36,545,631	41,040,462	42,024,435	42,024,435
40. DAYS SUPPLY:	56	66	60	61	65	65	-
NATURAL GAS							
41. PURCHASES:							
42. UNITS (MCF)	3,697,795	3,723,184	3,555,094	3,401,172	5,188,360	4,829,137	32,923,837
43. UNIT COST ($/MCF)	6.57	6.57	6.61	6.64	6.80	7.03	6.99
44. AMOUNT ($)	24,282,037	24,458,289	23,506,386	22,584,826	35,264,760	33,925,001	230,292,425
45. BURNED:							
46. UNITS (MCF)	3,697,795	3,723,184	3,555,094	3,401,172	5,188,360	4,829,137	32,923,837
47. UNIT COST ($/MCF)	6.57	6.57	6.61	6.64	6.80	7.03	6.99
48. AMOUNT ($)	24,282,037	24,458,290	23,506,385	22,584,826	35,264,759	33,925,001	230,292,424
49. ENDING INVENTORY:							
50. UNITS (MCF)	0	0	0	0	0	0	0
51. UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52. AMOUNT ($)	0	0	0	0	0	0	0
53. DAYS SUPPLY:	0	0	0	0	0	0	-
NUCLEAR							
54. BURNED:							
55. UNITS (MMBTU)	0	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0	0
OTHER							
58. PURCHASES:							
59. UNITS (MMBTU)	0	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0	0
62. BURNED:							
63. UNITS (MMBTU)	0	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0	0
66. ENDING INVENTORY:							
67. UNITS (MMBTU)	0	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0	

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

POWER SOLD
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2003 THROUGH JUNE 2003

(1)	(2)		(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
					MWH WHEELED		CENTS/KWH				
MONTH	SOLD TO		TYPE & SCHEDULE	TOTAL MWH SOLD	FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST	GAINS ON MARKET BASED SALES
ACTUAL Jan-03											
	VARIOUS	JURISD.	SCH. -D	2,064.9	5.3	2,059.6	2.321	2.321	47,806.51	47,806.51	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	108,974.85	140,485.65	
	VARIOUS	JURISD.	MKT. BASE	6,395.0	0.0	6,395.0	3.700	4.933	236,640.44	315,445.07	60,294.33
	VARIOUS	JURISD.	SCH. -OATT	46.0	0.0	46.0	10.174	10.174	4,679.89	4,679.89	
	TOTAL			8,505.9	5.3	8,500.6	4.683	5.981	398,101.69	508,417.12	60,294.33
ACTUAL Feb-03											
	VARIOUS	JURISD.	SCH. -D	2,033.9	0.0	2,033.9	2.402	2.402	48,848.52	48,848.52	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	12,833.86	(1,001.82)	
	VARIOUS	JURISD.	MKT. BASE	8,956.0	0.0	8,956.0	3.020	5.064	270,456.65	453,490.47	154,911.98
	VARIOUS	JURISD.	SCH. -OATT	6.0	0.0	6.0	(55.008)	(55.008)	(3,300.49)	(3,300.49)	
	TOTAL			10,995.9	0.0	10,995.9	2.991	4.529	328,838.56	498,036.68	154,911.98
ACTUAL Mar-03											
	VARIOUS	JURISD.	SCH. -D	2,343.3	54.7	2,288.6	2.359	2.359	53,991.65	53,991.65	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	MKT. BASE	41,328.0	0.0	41,328.0	2.862	3.936	1,182,886.42	1,626,513.41	285,857.77
	VARIOUS	JURISD.	SCH. -OATT	8.0	0.0	8.0	6.848	6.848	547.83	547.83	
	TOTAL			43,679.3	54.7	43,624.6	2.837	3.853	1,237,425.90	1,681,052.89	285,857.77
ACTUAL Apr-03											
	VARIOUS	JURISD.	SCH. -D	2,351.3	1.3	2,350.0	2.922	2.922	68,660.75	68,660.75	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	MKT. BASE	13,598.0	0.0	13,598.0	2.947	3.795	400,792.35	516,109.62	64,578.74
	VARIOUS	JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL			15,949.3	1.3	15,948.0	2.944	3.667	469,453.10	584,770.37	64,578.74
ACTUAL May-03											
	VARIOUS	JURISD.	SCH. -D	2,455.6	50.6	2,405.0	3.003	3.003	72,220.19	72,220.19	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	MKT. BASE	11,891.0	0.0	11,891.0	4.519	6.855	537,349.28	815,075.02	235,120.50
	VARIOUS	JURISD.	SCH. -OATT	8.0	0.0	8.0	11.626	11.626	930.08	930.08	
	TOTAL			14,354.6	50.6	14,304.0	4.268	6.210	610,499.55	888,225.29	235,120.50
ACTUAL Jun-03											
	VARIOUS	JURISD.	SCH. -D	2,754.6	57.8	2,696.8	2.521	2.521	67,994.05	67,994.05	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	MKT. BASE	1,128.0	0.0	1,128.0	4.081	4.868	46,032.48	54,909.51	4,545.51
	VARIOUS	JURISD.	SCH. -OATT	1.0	0.0	1.0	6.100	6.100	61.00	61.00	
	TOTAL			3,883.6	57.8	3,825.8	2.982	3.214	114,087.53	122,964.56	4,545.51

POWER SOLD
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2003 THROUGH DECEMBER 2003

(1)	(2)		(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
MONTH	SOLD TO		TYPE & SCHEDULE	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	CENTS/KWH (A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST	GAINS ON MARKET BASED SALES
ESTIMATED											
Jul-03											
	VARIOUS	JURISD.	SCH. -D	1,934.0	0.0	1,934.0	2.870	2.870	55,500.00	55,500.00	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL			1,934.0	0.0	1,934.0	2.870	2.870	55,500.00	55,500.00	0.00
ESTIMATED											
Aug-03											
	VARIOUS	JURISD.	SCH. -D	2,678.0	0.0	2,678.0	2.946	2.946	78,900.00	78,900.00	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	MKT. BASE	0.0	0.0	0.0	0.000	0.000	0.00	0.00	0.00
	VARIOUS	JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL			2,678.0	0.0	2,678.0	2.946	2.946	78,900.00	78,900.00	0.00
ESTIMATED											
Sep-03											
	VARIOUS	JURISD.	SCH. -D	2,555.0	0.0	2,555.0	3.115	3.115	79,600.00	79,600.00	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	MKT. BASE	2,490.0	0.0	2,490.0	5.088	6.976	126,700.00	173,700.00	39,000.00
	VARIOUS	JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL			5,045.0	0.0	5,045.0	4.089	5.021	206,300.00	253,300.00	39,000.00
ESTIMATED											
Oct-03											
	VARIOUS	JURISD.	SCH. -D	3,273.0	0.0	3,273.0	3.315	3.315	108,500.00	108,500.00	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	MKT. BASE	1,717.0	0.0	1,717.0	4.840	6.115	83,100.00	105,000.00	16,400.00
	VARIOUS	JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL			4,990.0	0.0	4,990.0	3.840	4.279	191,600.00	213,500.00	16,400.00
ESTIMATED											
Nov-03											
	VARIOUS	JURISD.	SCH. -D	2,642.0	0.0	2,642.0	2.665	2.665	70,400.00	70,400.00	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	MKT. BASE	1,180.0	0.0	1,180.0	4.669	6.195	55,100.00	73,100.00	14,200.00
	VARIOUS	JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL			3,822.0	0.0	3,822.0	3.284	3.755	125,500.00	143,500.00	14,200.00
ESTIMATED											
Dec-03											
	VARIOUS	JURISD.	SCH. -D	2,172.0	0.0	2,172.0	2.477	2.477	53,800.00	53,800.00	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	MKT. BASE	4,368.0	0.0	4,368.0	4.341	6.362	189,600.00	277,900.00	74,200.00
	VARIOUS	JURISD.	SCH. -OATT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	TOTAL			6,540.0	0.0	6,540.0	3.722	5.072	243,400.00	331,700.00	74,200.00
Jan-03											
THRU	VARIOUS	JURISD.	SCH. -D	29,257.6	169.7	29,087.9	2.772	2.772	806,221.67	806,221.67	
Dec-03	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	121,808.73	139,483.83	
	VARIOUS	JURISD.	MKT. BASE	93,051.0	0.0	93,051.0	3.362	4.741	3,128,657.62	4,411,243.10	949,108.83
	VARIOUS	JURISD.	SCH. -OATT	69.0	0.0	69.0	4.229	4.229	2,918.31	2,918.31	
	TOTAL			122,377.6	169.7	122,207.9	3.322	4.386	4,059,606.33	5,359,866.91	949,108.83

PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
TAMPA ELECTRIC COMPANY
ACTUAL FOR THE PERIOD: JANUARY 2003 THROUGH JUNE 2003

(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
ACTUAL Jan-03									
	VARIOUS	SCH. J	122,296.0	0.0	508.2	121,787.8	5.040	5.040	6,138,540.85
	HPP	IPP	34,524.0	0.0	0.0	34,524.0	16.446	16.446	5,677,984.74
	VARIOUS	OTHER	75,450.0	0.0	0.0	75,450.0	3.318	3.318	2,503,614.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**232,270.0**	**0.0**	**508.2**	**231,761.8**	**6.179**	**6.179**	**14,320,139.59**
ACTUAL Feb-03									
	VARIOUS	SCH. J	72,724.0	0.0	243.0	72,481.0	4.286	4.286	3,106,700.33
	HPP	IPP	34,643.0	0.0	0.0	34,643.0	7.909	7.909	2,739,958.50
	VARIOUS	OTHER	45,900.0	0.0	0.0	45,900.0	4.056	4.056	1,861,692.27
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**153,267.0**	**0.0**	**243.0**	**153,024.0**	**5.037**	**5.037**	**7,708,351.10**
ACTUAL Mar-03									
	VARIOUS	SCH. J	119,141.0	0.0	6,978.0	112,163.0	6.150	6.150	6,898,389.63
	HPP	IPP	47,865.0	0.0	0.0	47,865.0	7.285	7.285	3,486,881.48
	VARIOUS	OTHER	78,500.0	0.0	0.0	78,500.0	4.506	4.506	3,537,401.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**245,506.0**	**0.0**	**6,978.0**	**238,528.0**	**5.837**	**5.837**	**13,922,672.11**
ACTUAL Apr-03									
	VARIOUS	SCH. J	60,062.0	0.0	506.8	59,555.2	5.570	5.570	3,317,336.57
	HPP	IPP	42,989.0	0.0	0.0	42,989.0	5.673	5.673	2,438,953.07
	VARIOUS	OTHER	53,250.0	0.0	0.0	53,250.0	4.531	4.531	2,412,743.50
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**156,301.0**	**0.0**	**506.8**	**155,794.2**	**5.243**	**5.243**	**8,169,033.14**
ACTUAL May-03									
	VARIOUS	SCH. J	131,053.0	0.0	5,669.6	125,383.4	7.147	7.147	8,961,524.68
	HPP	IPP	82,351.0	0.0	0.0	82,351.0	6.305	6.305	5,191,954.96
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	490,110.00
	VARIOUS	MKT BASED	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	TOTAL		**213,404.0**	**0.0**	**5,669.6**	**207,734.4**	**7.049**	**7.049**	**14,643,589.64**
ACTUAL Jun-03									
	VARIOUS	SCH. J	152,420.0	0.0	4,673.8	147,746.2	5.730	5.730	8,465,641.89
	HPP	IPP	77,302.0	0.0	0.0	77,302.0	6.148	6.148	4,752,899.47
	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		**229,722.0**	**0.0**	**4,673.8**	**225,048.2**	**5.874**	**5.874**	**13,218,541.36**

PURCHASED POWER
(EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES)
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JULY 2003 THROUGH DECEMBER 2003

(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
ESTIMATED Jul-03									
	VARIOUS	SCH. J	97,580.0	0.0	39,657.0	57,923.0	8.780	8.780	5,085,700.00
	HPP	IPP	94,061.0	0.0	0.0	94,061.0	5.926	5.926	5,574,000.00
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	173,480.0	0.0	0.0	173,480.0	6.166	6.166	10,697,000.00
	TOTAL		**365,121.0**	**0.0**	**39,657.0**	**325,464.0**	**6.562**	**6.562**	**21,356,700.00**
ESTIMATED Aug-03									
	VARIOUS	SCH. J	56,240.0	0.0	23,248.0	32,992.0	9.446	9.446	3,116,400.00
	HPP	IPP	96,126.0	0.0	0.0	96,126.0	6.135	6.135	5,897,200.00
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	120,966.0	0.0	0.0	120,966.0	6.417	6.417	7,762,800.00
	TOTAL		**273,332.0**	**0.0**	**23,248.0**	**250,084.0**	**6.708**	**6.708**	**16,776,400.00**
ESTIMATED Sep-03									
	VARIOUS	SCH. J	32,337.0	0.0	17,057.0	15,280.0	8.859	8.859	1,353,600.00
	HPP	IPP	82,244.0	0.0	0.0	82,244.0	6.014	6.014	4,946,200.00
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	90,128.0	0.0	0.0	90,128.0	6.667	6.667	6,008,500.00
	TOTAL		**204,709.0**	**0.0**	**17,057.0**	**187,652.0**	**6.559**	**6.559**	**12,308,300.00**
ESTIMATED Oct-03									
	VARIOUS	SCH. J	21,799.0	0.0	11,425.0	10,374.0	8.475	8.475	879,200.00
	HPP	IPP	44,606.0	0.0	0.0	44,606.0	6.024	6.024	2,687,000.00
	VARIOUS	OTHER	138,408.0	0.0	0.0	138,408.0	7.017	7.017	9,711,600.00
	VARIOUS	MKT BASED	145,771.0	0.0	0.0	145,771.0	5.138	5.138	7,489,100.00
	TOTAL		**350,584.0**	**0.0**	**11,425.0**	**339,159.0**	**6.123**	**6.123**	**20,766,900.00**
ESTIMATED Nov-03									
	VARIOUS	SCH. J	359.0	0.0	274.0	85.0	7.529	7.529	6,400.00
	HPP	IPP	7,576.0	0.0	0.0	7,576.0	7.186	7.186	544,400.00
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	72,393.0	0.0	0.0	72,393.0	5.462	5.462	3,954,100.00
	TOTAL		**80,328.0**	**0.0**	**274.0**	**80,054.0**	**5.627**	**5.627**	**4,504,900.00**
ESTIMATED Dec-03									
	VARIOUS	SCH. J	37.0	0.0	27.0	10.0	8.000	8.000	800.00
	HPP	IPP	12,365.0	0.0	0.0	12,365.0	7.169	7.169	886,400.00
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	14,034.0	0.0	0.0	14,034.0	3.084	3.084	432,800.00
	TOTAL		**26,436.0**	**0.0**	**27.0**	**26,409.0**	**4.998**	**4.998**	**1,320,000.00**
Jan-03 THRU Dec-03	VARIOUS	SCH. J	866,048.0	0.0	110,267.4	755,780.6	6.262	6.262	47,330,233.95
	HPP	IPP	656,652.0	0.0	0.0	656,652.0	6.826	6.826	44,823,832.22
	VARIOUS	OTHER	391,508.0	0.0	0.0	391,508.0	5.241	5.241	20,517,160.77
	VARIOUS	MKT BASED	616,772.0	0.0	0.0	616,772.0	5.893	5.893	36,344,300.00
	TOTAL		**2,530,980.0**	**0.0**	**110,267.4**	**2,420,712.6**	**6.156**	**6.156**	**149,015,526.94**

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2003 THROUGH DECEMBER 2003

SCHEDULE E8

(1) MONTH		(2) PURCHASED FROM	(3) TYPE & SCHEDULE	(4) TOTAL MWH PURCHASED	(5) MWH FOR OTHER UTILITIES	(6) MWH FOR INTERRUPTIBLE	(7) MWH FOR FIRM	(8) CENTS/KWH (A) FUEL COST	(8) CENTS/KWH (B) TOTAL COST	(9) TOTAL $ FOR FUEL ADJUSTMENT
ACTUAL	Jan-03	VARIOUS	CO-GEN.	47,337.0	0.0	0.0	47,337.0	2.659	2.659	1,258,765.12
ACTUAL	Feb-03	VARIOUS	CO-GEN.	50,742.0	0.0	0.0	50,742.0	2.303	2.303	1,168,728.50
ACTUAL	Mar-03	VARIOUS	CO-GEN.	49,744.0	0.0	0.0	49,744.0	2.710	2.710	1,347,837.47
ACTUAL	Apr-03	VARIOUS	CO-GEN.	50,046.0	0.0	0.0	50,046.0	2.336	2.336	1,168,907.26
ACTUAL	May-03	VARIOUS	CO-GEN.	40,368.0	0.0	0.0	40,368.0	1.800	1.800	726,725.22
ACTUAL	Jun-03	VARIOUS	CO-GEN.	38,612.0	0.0	0.0	38,612.0	1.907	1.907	736,351.32
ESTIMATED	Jul-03	VARIOUS	CO-GEN.	41,424.0	0.0	0.0	41,424.0	2.804	2.804	1,161,400.00
ESTIMATED	Aug-03	VARIOUS	CO-GEN.	41,424.0	0.0	0.0	41,424.0	2.886	2.886	1,195,500.00
ESTIMATED	Sep-03	VARIOUS	CO-GEN.	40,080.0	0.0	0.0	40,080.0	2.875	2.875	1,152,100.00
ESTIMATED	Oct-03	VARIOUS	CO-GEN.	41,424.0	0.0	0.0	41,424.0	2.887	2.887	1,195,900.00
ESTIMATED	Nov-03	VARIOUS	CO-GEN.	38,172.0	0.0	0.0	38,172.0	2.910	2.910	1,110,700.00
ESTIMATED	Dec-03	VARIOUS	CO-GEN.	39,452.0	0.0	0.0	39,452.0	2.817	2.817	1,111,200.00
	TOTAL			**518,825.0**	**0.0**	**0.0**	**518,825.0**	**2.570**	**2.570**	**13,334,114.89**

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
ACTUAL/ESTIMATED FOR THE PERIOD: JANUARY 2003 THROUGH DECEMBER 2003

SCHEDULE E9

(1)		(2)	(3)	(4)	(5)	(6)	(7)		(8)
MONTH		PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST CENTS/KWH	TOTAL $ FOR FUEL ADJUSTMENT	COST IF GENERATED (A) CENTS PER KWH	(B) ($000)	FUEL SAVINGS (7B)-(6)
ACTUAL	Jan-03	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	Feb-03	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	Mar-03	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	Apr-03	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	May-03	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ACTUAL	Jun-03	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Jul-03	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Aug-03	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Sep-03	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Oct-03	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Nov-03	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
ESTIMATED	Dec-03	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
	TOTAL			**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**

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DOCKET NO. 030001-EI
TAMPA ELECTRIC COMPANY
(JDJ-2)
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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY
ACTUAL / ESTIMATED
JANUARY 2003 THROUGH DECEMBER 2003

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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY
CALCULATION OF THE CURRENT (ACTUAL/ESTIMATED) PERIOD TRUE-UP
JANUARY 2003 THROUGH DECEMBER 2003

1.	FINAL OVER/(UNDER) RECOVERY FOR JANUARY 2002 THROUGH DECEMBER 2002	($314,462)
2.	ACTUAL/ESTIMATED OVER/(UNDER) RECOVERY FOR THE CURRENT PERIOD JANUARY 2003 THROUGH DECEMBER 2003	($1,847,047)
3.	CURRENT PERIOD TRUE-UP AMOUNT TO BE REFUNDED/(RECOVERED) IN THE PROJECTION PERIOD JANUARY 2004 THROUGH DECEMBER 2004	($2,161,509)

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT

	Actual Jan-03	Actual Feb-03	Actual Mar-03	Actual Apr-03	Actual May-03	Actual Jun-03	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated Dec-03	Total
1 UNIT POWER CAPACITY CHARGES	2,477,225	2,823,682	2,914,809	2,584,335	1,907,151	1,703,227	1,635,400	1,635,400	1,635,400	2,035,400	1,635,400	1,635,400	24,622,829
2 CAPACITY PAYMENTS TO COGENERATORS	1,537,065	1,718,645	1,480,795	1,616,695	1,612,045	1,612,045	1,612,000	1,612,000	1,617,000	1,617,000	1,617,000	1,617,000	19,269,290
3 SECURITY COSTS	0	0	0	63,157	37,397	32,763	8,950	8,950	8,950	8,950	8,950	8,950	187,017
4 (UNIT POWER CAPACITY REVENUES)	(75,160)	(51,688)	(125,625)	(88,307)	(83,402)	(37,408)	(45,600)	(60,800)	(57,000)	(63,400)	(70,200)	(67,300)	(825,890)
5 TOTAL CAPACITY DOLLARS	3,939,130	4,490,639	4,269,979	4,175,880	3,473,191	3,310,627	3,210,750	3,195,550	3,204,350	3,597,950	3,191,150	3,194,050	43,253,246
6 SEPARATION FACTOR	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	
7 JURISDICTIONAL CAPACITY DOLLARS	3,759,352	4,285,691	4,075,102	3,985,297	3,314,679	3,159,535	3,064,215	3,049,709	3,058,107	3,433,744	3,045,509	3,048,277	41,279,217
8 CAPACITY COST RECOVERY REVENUES (Net of Revenue Taxes)	3,317,287	3,049,230	2,714,160	2,934,940	3,492,901	3,752,058	3,928,172	3,935,167	4,014,110	3,612,399	3,123,751	3,140,739	41,014,914
9 PRIOR PERIOD TRUE-UP PROVISION	(127,338)	(127,338)	(127,338)	(127,338)	(127,338)	(127,338)	(127,338)	(127,338)	(127,338)	(127,338)	(127,338)	(127,336)	(1,528,054)
10 CAPACITY COST RECOVERY REVENUES APPLICABLE TO CURRENT PERIOD (Net of Revenue Taxes)	3,189,949	2,921,892	2,586,822	2,807,602	3,365,563	3,624,720	3,800,834	3,807,829	3,886,772	3,485,061	2,996,413	3,013,403	39,486,860
11 TRUE-UP PROVISION FOR MONTH OVER/(UNDER) RECOVERY (Line 10 - Line 7)	(569,403)	(1,363,799)	(1,488,280)	(1,177,695)	50,884	465,185	736,619	758,120	828,665	51,317	(49,096)	(34,874)	(1,792,357)
12 INTEREST PROVISION FOR MONTH	(2,208)	(3,050)	(4,249)	(5,363)	(5,858)	(5,040)	(5,944)	(6,491)	(4,964)	(4,025)	(3,817)	(3,681)	(54,690)
13 TRUE-UP AND INT. PROVISION BEGINNING OF MONTH - OVER/(UNDER) RECOVERY	(1,842,516)	(2,286,789)	(3,526,300)	(4,891,491)	(5,947,211)	(5,774,847)	(5,187,364)	(4,329,351)	(3,450,384)	(2,499,345)	(2,324,715)	(2,250,290)	(1,842,516)
14 PRIOR PERIOD TRUE-UP PROVISION COLLECTED/(REFUNDED) THIS MONTH	127,338	127,338	127,338	127,338	127,338	127,338	127,338	127,338	127,338	127,338	127,338	127,336	1,528,054
15 END OF PERIOD TRUE-UP - OVER/(UNDER) RECOVERY (SUM OF LINES 11 - 14)	(2,286,789)	(3,526,300)	(4,891,491)	(5,947,211)	(5,774,847)	(5,187,364)	(4,329,351)	(3,450,384)	(2,499,345)	(2,324,715)	(2,250,290)	(2,161,509)	**(2,161,509)**

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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ACTUAL/ESTIMATED TRUE-UP AMOUNT

	Actual Jan-03	Actual Feb-03	Actual Mar-03	Actual Apr-03	Actual May-03	Actual Jun-03	Estimated Jul-03	Estimated Aug-03	Estimated Sep-03	Estimated Oct-03	Estimated Nov-03	Estimated Dec-03	Total
1 BEGINNING TRUE-UP AMOUNT	(1,842,516)	(2,286,789)	(3,526,300)	(4,891,491)	(5,947,211)	(5,774,847)	(5,187,364)	(4,329,351)	(3,450,384)	(2,499,345)	(2,324,715)	(2,250,290)	(1,842,516)
2 ENDING TRUE-UP AMOUNT BEFORE INTEREST	(2,284,581)	(3,523,250)	(4,887,242)	(5,941,848)	(5,768,989)	(5,182,324)	(4,323,407)	(3,443,893)	(2,494,381)	(2,320,690)	(2,246,473)	(2,157,828)	(2,106,819)
3 TOTAL BEGINNING & ENDING TRUE-UP AMT. (LINE 1 + LINE 2)	(4,127,097)	(5,810,039)	(8,413,542)	(10,833,339)	(11,716,200)	(10,957,171)	(9,510,771)	(7,773,244)	(5,944,765)	(4,820,035)	(4,571,188)	(4,408,118)	(3,949,335)
4 AVERAGE TRUE-UP AMOUNT (50% OF LINE 3)	(2,063,549)	(2,905,020)	(4,206,771)	(5,416,670)	(5,858,100)	(5,478,586)	(4,755,386)	(3,886,622)	(2,972,383)	(2,410,018)	(2,285,594)	(2,204,059)	(1,974,668)
5 INTEREST RATE % - 1ST DAY OF MONTH	1.290	1.270	1.250	1.180	1.190	1.210	1.000	2.000	2.000	2.000	2.000	2.000	NA
6 INTEREST RATE % - 1ST DAY OF NEXT MONTH	1.270	1.250	1.180	1.190	1.210	1.000	2.000	2.000	2.000	2.000	2.000	2.000	NA
7 TOTAL (LINE 5 + LINE 6)	2.560	2.520	2.430	2.370	2.400	2.210	3.000	4.000	4.000	4.000	4.000	4.000	NA
8 AVERAGE INTEREST RATE % (50% OF LINE 7)	1.280	1.260	1.215	1.185	1.200	1.105	1.500	2.000	2.000	2.000	2.000	2.000	NA
9 MONTHLY AVERAGE INTEREST RATE % (LINE 8/12)	0.107	0.105	0.101	0.099	0.100	0.092	0.125	0.167	0.167	0.167	0.167	0.167	NA
10 INTEREST PROVISION (LINE 4 X LINE 9)	(2,208)	(3,050)	(4,249)	(5,363)	(5,858)	(5,040)	(5,944)	(6,491)	(4,964)	(4,025)	(3,817)	(3,681)	(54,690)

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TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
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EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 1

PROJECTED CAPACITY COST RECOVERY

JANUARY 2004 - DECEMBER 2004

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO 30
COMPANY/ TECO
WITNESS. JDJ-3
DATE: 11-12-03

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2004 THROUGH DECEMBER 2004
PROJECTED

RATE CLASS	(1) AVG 12 CP LOAD FACTOR AT METER %	(2) PROJECTED SALES AT METER MWH	(3) PROJECTED AVG 12 CP AT METER MWH	(4) DEMAND LOSS EXPANSION FACTOR	(5) ENERGY LOSS EXPANSION FACTOR	(6) PROJECTED SALES AT GENERATION MWH	(7) PROJECTED AVG 12 CP AT GENERATION MWH	(8) PERCENTAGE OF SALES AT GENERATION %	(9) PERCENTAGE OF DEMAND AT GENERATION %
RS	57.72%	8,393,405	1,660	1.06028	1.04917	8,806,067	1,760	44.91%	56.06%
GS, TS	63.59%	1,070,071	192	1.06028	1.04917	1,122,681	204	5.72%	6.50%
GSD, EV-X	74.67%	5,221,207	798	1.05875	1.04848	5,474,352	845	27.92%	26.92%
GSLD, SBF	84.60%	2,233,911	301	1.04616	1.03740	2,317,466	315	11.82%	10.04%
IS-1&3, SBI-1&3	NA	1,647,561	NA	NA	1.01796	1,677,148	NA	8.55%	NA
SL/OL	163.91%	202,731	14	1.06028	1.04917	212,698	15	1.08%	0.48%
TOTAL		18,768,886	2,965			19,610,412	3,139	100.00%	100.00%

(1) AVG 12 CP load factor based on actual 2001 calendar data.
(2) Projected MWH sales for the period Jan. 2004 thru Dec. 2004.
(3) Calculated: Col (2) / (8760*Col (1)).
(4) Based on 2001 demand losses.
(5) Based on 2001 energy losses.
(6) Col (2) * Col (5).
(7) Col (3) * Col (4).
(8) Col (6) / total for Col (6).
(9) Col (7) / total for Col (7).

NOTE: Interruptible rates not included in demand allocation of capacity payments.

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TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2004 THROUGH DECEMBER 2004
PROJECTED

	Projected JANUARY	Projected FEBRUARY	Projected MARCH	Projected APRIL	Projected MAY	Projected JUNE	Projected JULY	Projected AUGUST	Projected SEPTEMBER	Projected OCTOBER	Projected NOVEMBER	Projected DECEMBER	Total
1 UNIT POWER CAPACITY CHARGES	1,710,000	1,710,000	1,710,000	1,710,000	1,710,000	1,710,000	1,910,000	1,910,000	1,710,000	1,710,000	1,710,000	1,710,000	20,920,000
2 CAPACITY PAYMENTS TO COGENERATORS	1,655,200	1,655,200	1,655,200	1,696,400	1,696,400	1,696,400	1,696,400	1,696,400	1,701,600	1,701,600	1,701,600	1,701,600	20,254,000
3 SECURITY COSTS	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	120,000
4 (UNIT POWER CAPACITY REVENUES)	(77,300)	(100,700)	(99,300)	(101,500)	(97,300)	(75,900)	(74,700)	(79,000)	(85,000)	(68,200)	(97,300)	(102,000)	(1,058,200)
5 TOTAL CAPACITY DOLLARS	$3,297,900	$3,274,500	$3,275,900	$3,314,900	$3,319,100	$3,340,500	$3,541,700	$3,537,400	$3,336,600	$3,353,400	$3,324,300	$3,319,600	$40,235,800
6 SEPARATION FACTOR	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	0.9543611	
7 JURISDICTIONAL CAPACITY DOLLARS	$3,147,387	$3,125,055	$3,126,392	$3,163,612	$3,167,620	$3,188,043	$3,380,061	$3,375,957	$3,184,321	$3,200,355	$3,172,583	$3,168,097	$38,399,483
8 ACTUAL/ESTIMATED TRUE-UP FOR THE PERIOD JAN. 2003 - DEC. 2003 OVER/(UNDER) RECOVERY													2,161,509
9 TOTAL													$40,560,992
10 REVENUE TAX FACTOR													1.00072
11 TOTAL RECOVERABLE CAPACITY DOLLARS													$40,590,196

EXHIBIT NO. ____
DOCKET NO. 030001-EI
TAMPA ELECTRIC COMPANY
(JDJ-3)
DOCUMENT NO. 1
PAGE 2 OF 3
FILED: 9/12/03

TAMPA ELECTRIC COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
JANUARY 2004 THROUGH DECEMBER 2004
PROJECTED

RATE CLASS	(1) PERCENTAGE OF SALES AT GENERATION %	(2) PERCENTAGE OF DEMAND AT GENERATION %	(3) ENERGY RELATED COSTS ($)	(4) DEMAND RELATED COSTS ($)	(5) TOTAL CAPACITY COSTS ($)	(6) PROJECTED SALES AT METER MWH	(7) CAPACITY RECOVERY FACTOR $/MWH
RS	44.91%	56.06%	1,401,814	21,005,014	22,406,828	8,393,405	2.67
GS, TS	5.72%	6.50%	178,543	2,435,473	2,614,016	1,070,071	2.44
GSD, EV-X	27.92%	26.92%	871,491	10,086,604	10,958,095	5,221,207	2.10
GSLD, SBF	11.82%	10.04%	368,948	3,761,869	4,130,817	2,233,911	1.85
IS-1&3, SBI-1&3	8.55%	NA	266,879	0	266,879	1,647,561	0.16
SL/OL	1.08%	0.48%	33,711	179,850	213,561	202,731	1.05
TOTAL	100.00%	100.00%	3,121,386	37,468,810	40,590,196	18,768,886	2.16
			7.69%	92.31%			

NOTE: Using the 12 CP and 1/13th allocation method requires 1/13th or 7.69% of capacity costs to be allocated on the basis of energy, and 12/13th or 92.31% to be allocated on the basis of demand.

EXHIBIT NO. _____
DOCKET NO. 030001-EI
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TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
FILED: 09/12/03

EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 2

PROJECTED FUEL AND PURCHASED POWER COST RECOVERY
JANUARY 2004 - DECEMBER 2004

SCHEDULES E1 THROUGH E10
SCHEDULE H-1

EXHIBIT NO._____
DOCKET NO. 030001-EI
TAMPA ELECTRIC COMPANY
(JDJ-3)
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DOCUMENT NO. 2

TAMPA ELECTRIC COMPANY

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25	Schedule E-1D Fuel Adjustment Factor for TOD	(")
26	Schedule E-1E Fuel Recovery Factor-with Line Losses	(")
27	Schedule E-2 Cost Recovery Clause Calculation (By Month)	(")
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SCHEDULE E1

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

		DOLLARS	MWH	CENTS/KWH
1.	Fuel Cost of System Net Generation (E3)	625,448,633	19,250,235	3.24904
2.	Nuclear Fuel Disposal Cost	0	0	0.00000
3.	Coal Car Investment	0	0	0.00000
4a.	Adjustments to Fuel Cost (Ft. Meade / Wauchula Wheeling)	(72,000)	19,250,235 (1)	(0.00037)
4b.	Adjustments to Fuel Cost	0	19,250,235 (1)	0.00000
4bc.	Adjustments to Fuel Cost (Incremental Hedging O&M)	280,847	19,250,235 (1)	0.00146
5.	**TOTAL COST OF GENERATED POWER (LINES 1 THROUGH 4c)**	**625,657,480**	**19,250,235**	**3.25013**
6.	Fuel Cost of Purchased Power - System (Exclusive of Economy)(E7)	46,121,600	862,113	5.34983
7.	Energy Cost of Economy Purchases (E9)	0	0	0.00000
8.	Demand and Non-Fuel Cost of Purchased Power	0	0	0.00000
9.	Energy Payments to Qualifying Facilities (E8)	13,165,200	455,607	2.88960
10.	**TOTAL COST OF PURCHASED POWER (LINES 6 THROUGH 9)**	**59,286,800**	**1,317,720**	**4.49920**
11.	**TOTAL AVAILABLE KWH (LINE 5 + LINE 10)**		20,567,955	
12.	Fuel Cost of Schedule D Sales - Jurisd. (E6)	618,700	23,718	2.60857
13.	Fuel Cost of Schedule D HPP Sales - Separated (E6)	0	0	0.00000
14.	Fuel Cost of Market Based Sales - Jurisd. (E6)	14,591,700	280,272	5.20626
15.	**TOTAL FUEL COST AND GAINS OF POWER SALES**	**15,210,400**	**303,990**	**5.00359**
16.	Net Inadvertant Interchange		0	
17.	Wheeling Received Less Wheeling Delivered		0	
18.	Interchange and Wheeling Losses		6,200	
19.	**TOTAL FUEL AND NET POWER TRANSACTIONS (LINE 5+10-15+16+17-18)**	**669,733,880**	**20,257,765**	**3.30606**
20.	Net Unbilled	NA (1)(a)	NA (a)	NA
21.	Company Use	1,666,254 (1)	50,400	0.00864
22.	T & D Losses	30,671,983 (1)	927,750	0.15909
23.	System MWH Sales	669,733,880	19,279,615	3.47379
24.	Wholesale MWH Sales	(17,839,129)	(510,729)	3.49288
25.	Jurisdictional MWH Sales	651,894,751	18,768,886	3.47327
26.	Jurisdictional Loss Multiplier			1.00114
27.	Jurisdictional MWH Sales Adjusted for Line Loss	652,635,470	18,768,886	3.47722
28.	True-up (2)	91,007,445	18,768,886	0.48488
29.	Peabody Coal Contract Buy-Out Amort. (Jurisdictionalized)	2,810,037	18,768,886	0.01497
30.	Total Jurisdictional Fuel Cost (Excl. GPIF)	746,452,952	18,768,886	3.97708
31.	Revenue Tax Factor			1.00072
32.	Fuel Factor (Excl. GPIF) Adjusted for Taxes	746,990,398	18,768,886	3.97994
33.	GPIF Adjusted for Taxes (2)	(2,496,021)	18,768,886	(0.01330)
34.	**Fuel Factor Adjusted for Taxes Including GPIF**	744,494,377	18,768,886	3.96664
35.	**Fuel Factor Rounded to Nearest .001 cents per KWH**			**3.967**

(a) Data not available at this time.
(1) Included For Informational Purposes Only
(2) Calculation Based on Jurisdictional KWH Sales

CALCULATION OF PROJECTED PERIOD TOTAL TRUE-UP
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2004 THRU DECEMBER 2004

SCHEDULE E1-A

1.	ESTIMATED OVER/(UNDER) RECOVERY (SCH. E1-B) January 2003 - December 2003 (6 months actual, 6 months estimated)	($88,345,118)
2.	FINAL TRUE-UP (January 2002 - December 2002) (Per True-Up filed April 1, 2003)	($28,662,327)
3.	2002 FINAL UNDER RECOVERY ALLOWED TO COLLECT IN THE MID COURSE PERIOD (APRIL 2003 THRU DECEMBER 2003)	($26,000,000)
4.	REMAINING 2002 FINAL UNDER RECOVERY TO BE COLLECTED IN THE PROJECTED PERIOD (JANUARY 2004 THRU DECEMBER 2004)	($2,662,327)
3.	TOTAL OVER/(UNDER) RECOVERY (Lines 1 + 4) To be included in the 12 month projected period January 2004 thru December 2004 (Schedule E1, line 28)	($91,007,445)
4.	JURISDICTIONAL MWH SALES (Projected January 2004 thru December 2004)	18,768,886
5.	TRUE-UP FACTOR - cents/kwh (Lines 3/4) * (100 cents/1000 KWH)	**0.4849**

SCHEDULE E1-C

INCENTIVE FACTOR AND TRUE-UP FACTOR
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2004 THRU DECEMBER 2004

1.	TOTAL AMOUNT OF ADJUSTMENTS		
	A. GENERATING PERFORMANCE INCENTIVE REWARD (PENALTY) (January 2004 Through December 2004)	($2,496,021)	
	B. TRUE-UP OVER / (UNDER) RECOVERED (January 2003 Through December 2003)	($91,007,445)	
2.	TOTAL SALES (January 2004 Through December 2004)	18,768,886	MWh
3.	ADJUSTMENT FACTORS		
	A. GENERATING PERFORMANCE INCENTIVE FACTOR	**(0.0133)**	Cents/kWh
	B. TRUE-UP FACTOR	**0.4849**	Cents/kWh

SCHEDULE E1-D

FUEL ADJUSTMENT FACTOR FOR
OPTIONAL TIME-OF-DAY RATES
TAMPA ELECTRIC COMPANY

ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

1. COST RATIO
   ON-PEAK COST / OFF-PEAK COST = $\frac{4.336}{3.001}$ = 1.4449

2. SALES/GENERATION

   34.02 % ON-PEAK

   65.98 % OFF-PEAK

3. FORMULA
   FUEL ADJUSTMENT FACTOR ADJUSTED FOR TAX AND GPIF = (% ON-PEAK GENERATION * COST RATIO * OFF-PEAK FACTOR) + (% OFF-PEAK GENERATION * OFF-PEAK FACTOR)

3.9666	=	0.3402	*	1.4449	Y +	0.6598	Y
3.9666	=	1.1514	*	Y			
3.4451	=	Y					

   where Y = OFF-PEAK FACTOR and

X	=	1.4449	Y	
X	=	1.4449	*	3.4451
X	=	4.9778		

   where X = ON-PEAK FACTOR

4.	**FUEL COST (CENTS/KWH)**	**ON-PEAK**	**OFF-PEAK**
		4.9778	**3.4451**
5.	**FUEL FACTOR (CENTS/KWH, NEAREST 0.001)**	**4.978**	**3.445**

SCHEDULE E1-E

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)
TAMPA ELECTRIC COMPANY
FOR THE PERIOD: JANUARY 2004 THRU DECEMBER 2004

GROUP	RATE SCHEDULE	AVERAGE FACTOR	FUEL RECOVERY LOSS MULTIPLIER	FUEL RECOVERY FACTOR
A	RS,GS,TS	3.967	1.0043	3.984
A1•	SL-2, OL-1&3	3.967	N/A	3.691
B	GSD,GSLD,SBF	3.967	1.0005	3.969
C	IS-1&3,SBI-1&3	3.967	0.9745	3.866
A	RST,GST			
	ON-PEAK	4.978	1.0043	4.999
	OFF-PEAK	3.445	1.0043	3.460
A1	SL-2, OL-1&3			
	ON-PEAK	N/A	N/A	N/A
	OFF-PEAK	N/A	N/A	N/A
B	GSDT, EV-X, GSLDT, SBFT			
	ON-PEAK	4.978	1.0005	4.980
	OFF-PEAK	3.445	1.0005	3.447
C	IST-1&3, SBIT-1&3			
	ON-PEAK	4.978	0.9745	4.851
	OFF-PEAK	3.445	0.9745	3.357

• GROUP A1 IS BASED ON GROUP A, 15% ON-PEAK AND 85% OFF-PEAK

FUEL AND PURCHASED POWER COST RECOVERY CLAUSE CALCULATION
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

SCHEDULE E2

		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
		ESTIMATED												TOTAL
		Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	PERIOD
1.	Fuel Cost of System Net Generation	47,616,080	45,478,612	49,421,897	46,767,249	54,696,386	55,695,139	59,203,170	60,409,861	56,318,499	54,114,135	46,626,485	49,101,120	625,448,633
2.	Nuclear Fuel Disposal	0	0	0	0	0	0	0	0	0	0	0	0	0
3.	Fuel Cost of Power Sold [1]	919,800	1,818,100	1,723,400	1,686,200	1,605,300	820,300	810,300	1,035,100	1,125,500	545,800	1,469,500	1,651,100	15,210,400
4.	Fuel Cost of Purchased Power	786,400	993,100	1,378,500	1,068,500	2,739,500	7,143,000	8,509,200	8,195,400	6,693,000	5,188,900	835,100	2,591,000	46,121,600
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	1,070,700	1,012,000	1,085,600	1,097,900	1,142,900	1,125,800	1,160,100	1,167,700	1,121,500	1,118,300	1,016,900	1,045,800	13,165,200
7.	Energy Cost of Economy Purchases	0	0	0	0	0	0	0	0	0	0	0	0	0
8a.	Adj. to Fuel Cost (Ft. Meade/Wauchula Wheeling)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(72,000)
8b.	Adj. To Fuel Cost	0	0	0	0	0	0	0	0	0	0	0	0	0
8c.	Adj. To Fuel Cost (Incremental Hedging O&M)	23,404	23,404	23,404	23,404	23,404	23,404	23,404	23,404	23,404	23,404	23,404	23,403	280,847
9.	**TOTAL FUEL & NET POWER TRANSACTIONS**	**48,570,784**	**45,683,016**	**50,180,001**	**47,264,853**	**56,990,890**	**63,161,043**	**68,079,574**	**68,755,265**	**63,024,903**	**59,892,939**	**47,026,389**	**51,104,223**	**669,733,880**
10.	Jurisdictional kWh Sold	1,500,372	1,365,986	1,313,359	1,384,243	1,477,760	1,710,530	1,781,813	1,761,414	1,825,521	1,702,788	1,455,952	1,489,147	18,768,886
11.	Jurisdictional % of Total Sales	0.9751097	0.9747080	0.9683874	0.9721224	0.9687187	0.9723578	0.9725809	0.9717867	0.9760125	0.9714108	0.9785847	0.9803444	
12.	Jurisdictional Total Fuel & Net Power Transactions (Line 9 * Line 11)	47,361,843	44,527,601	48,593,681	45,947,222	55,208,141	61,415,133	66,212,893	66,815,452	61,513,093	58,180,648	46,019,305	50,099,739	651,894,751
13.	Jurisdictional Loss Multiplier	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	1.00114	
14.	Jurisdictional Sales Adjusted for Line Losses (Line 12 * Line 13)	47,415,658	44,578,196	48,648,896	45,999,430	55,270,872	61,484,916	66,288,128	66,891,371	61,582,988	58,246,756	46,071,595	50,156,665	652,635,471
15.	Peabody Coal Contract Buyout Amortization	254,480	251,949	249,418	246,887	244,356	241,825	239,294	236,764	234,233	231,702	229,171	226,607	2,886,686
16.	Peabody Jurisdictionalized (Line 15 * Line 11)	248,146	245,577	241,533	240,004	236,712	235,140	232,733	230,084	228,614	225,078	224,263	222,153	2,810,037
17.	**JURISD. TOTAL FUEL & NET PWR. TRANS. INCL. PEABODY (LINE 14+16)**	**47,663,804**	**44,823,773**	**48,890,429**	**46,239,434**	**55,507,584**	**61,720,056**	**66,520,861**	**67,121,455**	**61,811,602**	**58,471,834**	**46,295,858**	**50,378,818**	**655,445,508**
18.	Cost Per kWh Sold (Cents/kWh)	3.1768	3.2814	3.7226	3.3404	3.7562	3.6082	3.7333	3.8107	3.3860	3.4339	3.1798	3.3831	3.4922
19.	True-up (Cents/kWh) [2]	0.4849	0.4849	0.4849	0.4849	0.4849	0.4849	0.4849	0.4849	0.4849	0.4849	0.4849	0.4849	0.4849
20.	Total (Cents/kWh) (Line 18+19)	3.6617	3.7663	4.2075	3.8253	4.2411	4.0931	4.2182	4.2956	3.8709	3.9188	3.6647	3.8680	3.9771
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)	3.6643	3.7690	4.2105	3.8281	4.2442	4.0960	4.2212	4.2987	3.8737	3.9216	3.6673	3.8708	3.9800
23.	GPIF Adjusted for Taxes (Cents/kWh) [2]	-0.0133	-0.0133	-0.0133	-0.0133	-0.0133	-0.0133	-0.0133	-0.0133	-0.0133	-0.0133	-0.0133	-0.0133	-0.0133
24.	**TOTAL RECOVERY FACTOR (LINE 22+23)**	**3.6510**	**3.7557**	**4.1972**	**3.8148**	**4.2309**	**4.0827**	**4.2079**	**4.2854**	**3.8604**	**3.9083**	**3.6540**	**3.8575**	**3.9667**
25.	**RECOVERY FACTOR ROUNDED TO NEAREST 0.001 CENTS/KWH**	**3.651**	**3.756**	**4.197**	**3.815**	**4.231**	**4.083**	**4.208**	**4.285**	**3.860**	**3.908**	**3.654**	**3.858**	**3.967**

[1] Includes Gains
[2] Based on Jurisdictional Sales Only

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

SCHEDULE E3
PAGE 1 OF 2

	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
FUEL COST OF SYSTEM NET GENERATION ($)						
1. HEAVY OIL	373,604	475,381	212,107	30,632	145,092	430,831
2. LIGHT OIL	735,063	640,237	755,874	431,545	825,727	592,525
3. COAL	22,592,246	18,743,931	19,389,972	20,349,959	21,819,220	21,249,456
4. NATURAL GAS	23,915,167	25,619,063	29,063,944	25,955,113	31,906,347	33,422,327
5. NUCLEAR	0	0	0	0	0	0
6. OTHER	0	0	0	0	0	0
7. TOTAL ($)	**47,616,080**	**45,478,612**	**49,421,897**	**46,767,249**	**54,696,386**	**55,695,139**
SYSTEM NET GENERATION (MWH)						
8. HEAVY OIL	7,411	9,619	4,261	606	2,929	8,960
9. LIGHT OIL	12,237	10,937	12,665	7,437	13,429	10,468
10. COAL	1,024,652	846,646	862,176	900,976	966,610	938,819
11. NATURAL GAS	460,303	500,125	580,606	573,149	711,133	749,721
12. NUCLEAR	0	0	0	0	0	0
13. OTHER	0	0	0	0	0	0
14. TOTAL (MWH)	**1,504,603**	**1,367,327**	**1,459,708**	**1,482,168**	**1,694,101**	**1,707,968**
UNITS OF FUEL BURNED						
15. HEAVY OIL (BBL)	11,422	14,829	6,615	938	4,550	13,928
16. LIGHT OIL (BBL)	19,045	16,616	19,911	11,507	22,906	16,514
17. COAL (TON)	459,695	379,708	387,964	406,134	436,080	425,303
18. NATURAL GAS (MCF)	3,392,280	3,667,252	4,268,447	4,214,514	5,309,093	5,557,919
19. NUCLEAR (MMBTU)	0	0	0	0	0	0
20. OTHER	0	0	0	0	0	0
BTUS BURNED (MMBTU)						
21. HEAVY OIL	71,722	93,114	41,538	5,891	28,567	87,454
22. LIGHT OIL	110,333	96,470	115,371	66,663	132,968	96,162
23. COAL	11,094,701	9,153,746	9,349,917	9,748,030	10,503,281	10,246,801
24. NATURAL GAS	3,487,297	3,769,994	4,387,968	4,332,440	5,457,782	5,713,558
25. NUCLEAR	0	0	0	0	0	0
26. OTHER	0	0	0	0	0	0
27. TOTAL (MMBTU)	**14,764,053**	**13,113,324**	**13,894,794**	**14,153,024**	**16,122,598**	**16,143,975**
GENERATION MIX (% MWH)						
28. HEAVY OIL	0.49	0.70	0.29	0.04	0.17	0.52
29. LIGHT OIL	0.81	0.80	0.87	0.50	0.79	0.61
30. COAL	68.11	61.92	59.06	60.79	57.06	54.97
31. NATURAL GAS	30.59	36.58	39.78	38.67	41.98	43.90
32. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
33. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
34. TOTAL (%)	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT						
35. HEAVY OIL ($/BBL)	32.71	32.06	32.06	32.66	31.89	30.93
36. LIGHT OIL ($/BBL)	38.60	38.53	37.96	37.50	36.05	35.88
37. COAL ($/TON)	49.15	49.36	49.98	50.11	50.03	49.96
38. NATURAL GAS ($/MCF)	7.05	6.99	6.81	6.16	6.01	6.01
39. NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
40. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)						
41. HEAVY OIL	5.21	5.11	5.11	5.20	5.08	4.93
42. LIGHT OIL	6.66	6.64	6.55	6.47	6.21	6.16
43. COAL	2.04	2.05	2.07	2.09	2.08	2.07
44. NATURAL GAS	6.86	6.80	6.62	5.99	5.85	5.85
45. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
46. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
47. TOTAL ($/MMBTU)	**3.23**	**3.47**	**3.56**	**3.30**	**3.39**	**3.45**
BTU BURNED PER KWH (BTU/KWH)						
48. HEAVY OIL	9,678	9,680	9,748	9,721	9,753	9,760
49. LIGHT OIL	9,016	8,821	9,109	8,964	9,902	9,186
50. COAL	10,828	10,812	10,845	10,819	10,866	10,915
51. NATURAL GAS	7,576	7,538	7,558	7,559	7,675	7,621
52. NUCLEAR	0	0	0	0	0	0
53. OTHER	0	0	0	0	0	0
54. TOTAL (BTU/KWH)	**9,813**	**9,590**	**9,519**	**9,549**	**9,517**	**9,452**
GENERATED FUEL COST PER KWH (CENTS/KWH)						
55. HEAVY OIL	5.04	4.94	4.98	5.05	4.95	4.81
56. LIGHT OIL	6.01	5.85	5.97	5.80	6.15	5.66
57. COAL	2.20	2.21	2.25	2.26	2.26	2.26
58. NATURAL GAS	5.20	5.12	5.01	4.53	4.49	4.46
59. NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00
60. OTHER	0.00	0.00	0.00	0.00	0.00	0.00
61. TOTAL (CENTS/KWH)	**3.16**	**3.33**	**3.39**	**3.16**	**3.23**	**3.26**

		Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	TOTAL
FUEL COST OF SYSTEM NET GENERATION ($)								
1.	HEAVY OIL	305,727	338,508	444,661	312,305	112,641	161,265	3,342,754
2.	LIGHT OIL	859,223	893,797	577,392	578,643	575,552	600,386	8,065,964
3.	COAL	21,900,424	22,164,060	21,518,484	16,902,115	19,109,295	21,702,738	247,441,900
4.	NATURAL GAS	36,137,796	37,013,496	33,777,962	36,321,072	26,828,997	26,636,731	366,598,015
5.	NUCLEAR	0	0	0	0	0	0	0
6.	OTHER	0	0	0	0	0	0	0
7.	**TOTAL ($)**	**59,203,170**	**60,409,861**	**56,318,499**	**54,114,135**	**46,626,485**	**49,101,120**	**625,448,633**
SYSTEM NET GENERATION (MWH)								
8.	HEAVY OIL	6,394	7,147	9,507	6,703	2,368	3,437	69,342
9.	LIGHT OIL	14,391	14,862	10,511	10,197	10,931	11,398	139,463
10.	COAL	974,890	980,429	956,400	802,076	862,697	989,831	11,106,202
11.	NATURAL GAS	806,100	823,266	757,257	816,829	589,801	566,938	7,935,228
12.	NUCLEAR	0	0	0	0	0	0	0
13.	OTHER	0	0	0	0	0	0	0
14.	**TOTAL (MWH)**	**1,801,775**	**1,825,704**	**1,733,675**	**1,635,805**	**1,465,797**	**1,571,604**	**19,250,235**
UNITS OF FUEL BURNED								
15.	HEAVY OIL (BBL)	9,939	11,117	14,790	10,398	3,682	5,344	107,552
16.	LIGHT OIL (BBL)	24,618	25,818	16,612	16,719	16,605	17,316	224,187
17.	COAL (TON)	437,651	440,076	426,762	352,749	381,008	437,430	4,970,560
18.	NATURAL GAS (MCF)	6,022,454	6,152,907	5,615,152	6,019,337	4,315,019	4,155,517	58,689,891
19.	NUCLEAR (MMBTU)	0	0	0	0	0	0	0
20.	OTHER	0	0	0	0	0	0	0
BTUS BURNED (MMBTU)								
21.	HEAVY OIL	62,407	69,804	92,864	65,292	23,122	33,555	675,330
22.	LIGHT OIL	143,389	149,561	96,585	96,959	96,033	100,306	1,300,800
23.	COAL	10,700,381	10,759,751	10,434,971	8,731,554	9,317,143	10,708,931	120,749,207
24.	NATURAL GAS	6,191,089	6,325,117	5,772,341	6,187,856	4,435,904	4,271,833	60,333,179
25.	NUCLEAR	0	0	0	0	0	0	0
26.	OTHER	0	0	0	0	0	0	0
27.	**TOTAL (MMBTU)**	**17,097,266**	**17,304,233**	**16,396,761**	**15,081,661**	**13,872,202**	**15,114,625**	**183,058,516**
GENERATION MIX (% MWH)								
28.	HEAVY OIL	0.35	0.39	0.55	0.41	0.16	0.22	0.36
29.	LIGHT OIL	0.80	0.81	0.61	0.62	0.75	0.73	0.72
30.	COAL	54.11	53.71	55.16	49.04	58.85	62.98	57.70
31.	NATURAL GAS	44.74	45.09	43.68	49.93	40.24	36.07	41.22
32.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34.	**TOTAL (%)**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**	**100.00**
FUEL COST PER UNIT								
35.	HEAVY OIL ($/BBL)	30.76	30.45	30.06	30.04	30.59	30.18	31.08
36.	LIGHT OIL ($/BBL)	34.90	34.62	34.76	34.61	34.66	34.67	35.98
37.	COAL ($/TON)	50.04	50.36	50.42	47.92	50.15	49.61	49.78
38.	NATURAL GAS ($/MCF)	6.00	6.02	6.02	6.03	6.22	6.41	6.25
39.	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FUEL COST PER MMBTU ($/MMBTU)								
41.	HEAVY OIL	4.90	4.85	4.79	4.78	4.87	4.81	4.95
42.	LIGHT OIL	5.99	5.98	5.98	5.97	5.99	5.99	6.20
43.	COAL	2.05	2.06	2.06	1.94	2.05	2.03	2.05
44.	NATURAL GAS	5.84	5.85	5.85	5.87	6.05	6.24	6.08
45.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
46.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
47.	**TOTAL ($/MMBTU)**	**3.46**	**3.49**	**3.43**	**3.59**	**3.36**	**3.25**	**3.42**
BTU BURNED PER KWH (BTU/KWH)								
48.	HEAVY OIL	9,760	9,767	9,768	9,741	9,764	9,763	9,739
49.	LIGHT OIL	9,964	10,063	9,189	9,509	8,785	8,800	9,327
50.	COAL	10,976	10,975	10,911	10,886	10,800	10,819	10,872
51.	NATURAL GAS	7,680	7,683	7,623	7,575	7,521	7,535	7,603
52.	NUCLEAR	0	0	0	0	0	0	0
53.	OTHER	0	0	0	0	0	0	0
54.	**TOTAL (BTU/KWH)**	**9,489**	**9,478**	**9,458**	**9,220**	**9,464**	**9,617**	**9,509**
GENERATED FUEL COST PER KWH (CENTS/KWH)								
55.	HEAVY OIL	4.78	4.74	4.68	4.66	4.76	4.69	4.82
56.	LIGHT OIL	5.97	6.01	5.49	5.67	5.27	5.27	5.78
57.	COAL	2.25	2.26	2.25	2.11	2.22	2.19	2.23
58.	NATURAL GAS	4.48	4.50	4.46	4.45	4.55	4.70	4.62
59.	NUCLEAR	0.00	0.00	0.00	0.00	0.00	0.00	0.00
60.	OTHER	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	**TOTAL (CENTS/KWH)**	**3.29**	**3.31**	**3.25**	**3.31**	**3.18**	**3.12**	**3.25**

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: JANUARY 2004

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. GAN.#1	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2. GAN.#2	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
3. GAN.#3	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
4. GAN.#4	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
5. GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
6. GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
7. GANNON STA.	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**COAL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
8. B.B.#1	428	195,710	61.5	71.2	77.5	11,069	COAL	89,140	24,302,333	2,166,310.0	4,193,657	2.14	47.05
9. B.B.#2	433	211,471	65.6	70.7	81.5	10,898	COAL	94,828	24,302,421	2,304,550.0	4,461,254	2.11	47.05
10. B.B.#3	438	211,498	64.9	71.7	80.6	10,743	COAL	93,490	24,302,278	2,272,020.0	4,398,306	2.08	47.05
11. B.B. 1 - 3	1,299	618,679	64.0	71.2	26.6	10,899	COAL	277,458	24,302,345	6,742,880.0	13,053,217	2.11	47.05
12. B.B.#4	460	252,428	73.8	82.9	83.1	10,515	COAL	118,237	22,448,895	2,654,290.0	6,916,747	2.74	58.50
13. B.B. STA.	**1,759**	**871,107**	**66.6**	**74.3**	**20.2**	**10,788**	**COAL**	**395,695**	**23,748,518**	**9,397,170.0**	**19,969,964**	**2.29**	**50.47**
14. PHILLIPS #1 (HVY OIL)	17	3,745	29.6	91.7	76.0	9,678	HVY OIL	5,772	6,279,158	36,243.3	188,797	5.04	32.71
15. PHILLIPS #2 (HVY OIL)	17	3,666	29.0	91.7	76.2	9,678	HVY OIL	5,650	6,279,416	35,478.7	184,807	5.04	32.71
16. SEB-PHILLIPS TOTAL	**34**	**7,411**	**29.3**	**91.7**	**38.0**	**9,678**	**HVY OIL**	**11,422**	**6,279,286**	**71,722.0**	**373,604**	**5.04**	**32.71**
17. POLK #1 GASIFIER	260	153,545	79.4	-	-	11,056	COAL	64,000	26,523,922	1,697,531.0	2,622,282	1.71	40.97
18. POLK #1 CT OIL	260	11,557	6.0	-	-	8,784	LGT OIL	17,500	5,801,029	101,518.0	675,517	5.85	38.60
19. POLK #1 TOTAL	**260**	**165,102**	**85.4**	**89.5**	**94.9**	**10,897**		**-**	**-**	**1,799,049.0**	**3,297,799**	**2.00**	**-**
20. POLK #2 CT GAS	180	1,102	0.8	-	-	12,403	GAS	13,300	1,027,669	13,668.0	93,761	8.51	7.05
21. POLK #2 CT OIL	180	367	0.3	-	-	12,414	LGT OIL	800	5,695,000	4,556.0	31,021	8.45	38.78
22. POLK #2 TOTAL	**180**	**1,469**	**1.1**	**92.3**	**74.2**	**12,406**		**-**	**-**	**18,224.0**	**124,782**	**8.49**	**-**
23. POLK #3 CT GAS	180	692	0.5	0.0	-	12,311	GAS	8,300	1,026,386	8,519.0	58,513	8.46	7.05
24. POLK #3 CT OIL	180	231	0.2	0.0	-	12,294	LGT OIL	500	5,680,000	2,840.0	19,388	8.39	38.78
25. POLK #3 TOTAL	**180**	**923**	**0.7**	**92.3**	**73.3**	**12,307**		**-**	**-**	**11,359.0**	**77,901**	**8.44**	**-**
26. CITY OF TAMPA GAS	**6**	**37**	**0.8**	**100.0**	**51.4**	**10,541**	**GAS**	**380**	**1,026,316**	**390.0**	**3,289**	**8.89**	**8.66**
27. BAYSIDE #1	779	234,359	40.4	95.5	61.8	7,549	GAS	1,720,900	1,027,997	1,769,080.0	12,131,829	5.18	7.05
28. BAYSIDE #2	1,022	224,113	29.5	95.9	62.2	7,566	GAS	1,649,400	1,028,034	1,695,640.0	11,627,775	5.19	7.05
29. BAYSIDE TOTAL	**1,801**	**458,472**	**34.2**	**95.7**	**30.3**	**7,557**	**GAS**	**3,370,300**	**1,028,015**	**3,464,720.0**	**23,759,604**	**5.18**	**7.05**
30. B.B.C.T.#1	15	36	0.3	72.2	120.0	17,972	LGT OIL	112	5,776,786	647.0	4,177	11.60	37.29
31. B.B.C.T.#2	80	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#3	70	46	0.1	72.3	65.7	16,783	LGT OIL	133	5,804,511	772.0	4,960	10.78	37.29
33. C.T. TOTAL (OIL)	**165**	**82**	**0.1**	**85.7**	**16.6**	**17,305**	**LGT OIL**	**245**	**5,791,837**	**1,419.0**	**9,137**	**11.14**	**37.29**
34. TOT COAL (GN,BB,POLK)	**2,019**	**1,024,652**	**68.2**	**64.7**	**20.7**	**10,828**	**COAL**	**459,695**	**24,134,918**	**11,094,701.0**	**22,592,246**	**2.20**	**49.15**
35. SYSTEM	**4,385**	**1,504,603**	**46.1**	**86.1**	**8.9**	**9,813**	**-**	**-**	**-**	**14,764,053.0**	**47,616,080**	**3.16**	**-**

LEGEND:
B.B. = BIG BEND
GAN. = GANNON
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: FEBRUARY 2004

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. GAN.#1	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2. GAN.#2	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
3. GAN.#3	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
4. GAN.#4	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
5. GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
6. GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
7. GANNON STA.	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**COAL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
8. B.B.#1	428	183,649	61.7	71.2	78.0	11,061	COAL	83,586	24,302,395	2,031,340.0	3,925,841	2.14	46.97
9. B.B.#2	433	88,502	29.4	31.7	81.8	10,890	COAL	39,658	24,302,184	963,776.0	1,862,644	2.10	46.97
10. B.B.#3	438	193,440	63.5	71.7	78.7	10,744	COAL	85,522	24,302,402	2,078,390.0	4,016,770	2.08	46.97
11. B.B. 1 - 3	1,299	465,591	51.5	58.2	26.3	10,897	COAL	208,766	24,302,358	5,073,506.0	9,805,255	2.11	46.97
12. B.B.#4	460	236,986	74.0	82.9	83.4	10,500	COAL	110,842	22,448,891	2,488,280.0	6,523,132	2.75	58.85
13. B.B. STA.	**1,759**	**702,577**	**57.4**	**64.7**	**20.2**	**10,763**	**COAL**	**319,608**	**23,659,564**	**7,561,786.0**	**16,328,387**	**2.32**	**51.09**
14. PHILLIPS #1 (HVY OIL)	17	4,859	41.1	75.9	77.9	9,680	HVY OIL	7,490	6,279,866	47,036.2	240,111	4.94	32.06
15. PHILLIPS #2 (HVY OIL)	17	4,760	40.2	91.7	78.0	9,680	HVY OIL	7,339	6,278,485	46,077.8	235,270	4.94	32.06
16. SEB-PHILLIPS TOTAL	**34**	**9,619**	**40.6**	**83.8**	**39.0**	**9,680**	**HVY OIL**	**14,829**	**6,279,183**	**93,114.0**	**475,381**	**4.94**	**32.06**
17. POLK #1 GASIFIER	260	144,069	79.6	-	-	11,050	COAL	60,100	26,488,519	1,591,960.0	2,415,544	1.68	40.19
18. POLK #1 CT OIL	260	10,844	6.0	-	-	8,782	LGT OIL	16,400	5,806,768	95,231.0	631,842	5.83	38.53
19. POLK #1 TOTAL	**260**	**154,913**	**85.6**	**89.5**	**95.2**	**10,891**		**-**	**-**	**1,687,191.0**	**3,047,386**	**1.97**	**-**
20. POLK #2 CT GAS	180	171	0.1	-	-	13,234	GAS	2,200	1,028,636	2,263.0	15,368	8.99	6.99
21. POLK #2 CT OIL	180	57	0.0	-	-	13,228	LGT OIL	100	7,540,000	754.0	3,830	6.72	38.30
22. POLK #2 TOTAL	**180**	**228**	**0.2**	**92.2**	**63.3**	**13,232**		**-**	**-**	**3,017.0**	**19,198**	**8.42**	**-**
23. POLK #3 CT GAS	180	92	0.1	0.0	-	12,728	GAS	1,100	1,064,545	1,171.0	7,684	8.35	6.99
24. POLK #3 CT OIL	180	31	0.0	0.0	-	12,581	LGT OIL	100	3,900,000	390.0	3,830	12.35	38.30
25. POLK #3 TOTAL	**180**	**123**	**0.1**	**92.6**	**68.3**	**12,691**		**-**	**-**	**1,561.0**	**11,514**	**9.36**	**-**
26. CITY OF TAMPA GAS	**6**	**113**	**2.7**	**100.0**	**67.3**	**10,478**	**GAS**	**1,152**	**1,027,778**	**1,184.0**	**9,888**	**8.76**	**8.58**
27. BAYSIDE #1	779	127,775	23.6	72.4	68.8	7,592	GAS	943,600	1,028,048	970,066.0	6,591,423	5.16	6.99
28. BAYSIDE #2	1,022	371,974	52.3	95.9	63.9	7,515	GAS	2,719,200	1,027,990	2,795,310.0	18,994,700	5.11	6.99
29. BAYSIDE TOTAL	**1,801**	**499,749**	**39.9**	**85.7**	**34.3**	**7,535**	**GAS**	**3,662,800**	**1,028,005**	**3,765,376.0**	**25,586,123**	**5.12**	**6.99**
30. B.B.C.T.#1	15	4	0.0	72.3	0.0	19,000	LGT OIL	13	5,846,154	76.0	597	14.93	45.92
31. B.B.C.T.#2	80	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#3	70	1	0.0	37.5	0.0	19,000	LGT OIL	3	6,333,333	19.0	138	13.80	46.00
33. C.T. TOTAL (OIL)	**165**	**5**	**0.0**	**71.0**	**0.0**	**19,000**	**LGT OIL**	**16**	**5,937,500**	**95.0**	**735**	**14.70**	**45.94**
34. TOT COAL (GN,BB,POLK)	**2,019**	**846,646**	**60.2**	**56.4**	**21.2**	**10,812**	**COAL**	**379,708**	**24,107,330**	**9,153,746.0**	**18,743,931**	**2.21**	**49.36**
35. SYSTEM	**4,385**	**1,367,327**	**44.8**	**77.5**	**8.8**	**9,590**	**-**	**-**	**-**	**13,113,324.0**	**45,478,612**	**3.33**	**-**

LEGEND:
B.B. = BIG BEND
GAN. = GANNON
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: MARCH 2004

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. GAN.#1	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2. GAN.#2	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
3. GAN.#3	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
4. GAN.#4	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
5. GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
6. GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
7. GANNON STA.	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**COAL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
8. B.B.#1	428	199,411	62.6	71.2	77.9	11,118	COAL	91,225	24,302,329	2,216,980.0	4,286,794	2.15	46.99
9. B.B.#2	433	177,342	55.0	59.3	81.6	10,864	COAL	79,277	24,302,383	1,926,620.0	3,725,341	2.10	46.99
10. B.B.#3	438	78,443	24.1	27.8	77.2	10,774	COAL	34,776	24,302,306	845,137.0	1,634,174	2.08	46.99
11. B.B. 1 - 3	1,299	455,196	47.1	52.6	26.3	10,960	COAL	205,278	24,302,346	4,988,737.0	9,646,309	2.12	46.99
12. B.B.#4	460	252,968	73.9	82.9	83.3	10,515	COAL	118,486	22,448,897	2,659,880.0	7,015,632	2.77	59.21
13. B.B. STA.	**1,759**	**708,164**	**54.1**	**60.5**	**20.2**	**10,801**	**COAL**	**323,764**	**23,624,050**	**7,648,617.0**	**16,661,941**	**2.35**	**51.46**
14. PHILLIPS #1 (HVY OIL)	17	1,965	15.5	65.1	92.5	9,748	HVY OIL	3,050	6,280,525	19,155.6	97,797	4.98	32.06
15. PHILLIPS #2 (HVY OIL)	17	2,296	18.2	91.7	92.5	9,748	HVY OIL	3,565	6,278,373	22,382.4	114,310	4.98	32.06
16. SEB-PHILLIPS TOTAL	**34**	**4,261**	**16.8**	**78.4**	**46.2**	**9,748**	**HVY OIL**	**6,615**	**6,279,365**	**41,538.0**	**212,107**	**4.98**	**32.06**
17. POLK #1 GASIFIER	260	154,012	79.6	-	-	11,047	COAL	64,200	26,500,000	1,701,300.0	2,728,031	1.77	42.49
18. POLK #1 CT OIL	260	11,592	6.0	-	-	8,782	LGT OIL	17,600	5,784,261	101,803.0	670,278	5.78	38.08
19. POLK #1 TOTAL	**260**	**165,604**	**85.6**	**89.5**	**95.2**	**10,888**		**-**	**-**	**1,803,103.0**	**3,398,309**	**2.05**	**-**
20. POLK #2 CT GAS	180	1,818	1.4	-	-	12,738	GAS	22,500	1,029,244	23,158.0	153,182	8.43	6.81
21. POLK #2 CT OIL	180	606	0.5	-	-	12,738	LGT OIL	1,300	5,937,692	7,719.0	48,069	7.93	36.98
22. POLK #2 TOTAL	**180**	**2,424**	**1.8**	**92.3**	**64.1**	**12,738**		**-**	**-**	**30,877.0**	**201,251**	**8.30**	**-**
23. POLK #3 CT GAS	180	1,391	1.0	0.0	-	12,484	GAS	16,900	1,027,515	17,365.0	115,057	8.27	6.81
24. POLK #3 CT OIL	180	464	0.3	0.0	-	12,474	LGT OIL	1,000	5,788,000	5,788.0	36,976	7.97	36.98
25. POLK #3 TOTAL	**180**	**1,855**	**1.4**	**92.3**	**68.7**	**12,481**		**-**	**-**	**23,153.0**	**152,033**	**8.20**	**-**
26. CITY OF TAMPA GAS	**6**	**241**	**5.4**	**100.0**	**49.0**	**10,436**	**GAS**	**2,447**	**1,027,789**	**2,515.0**	**20,590**	**8.54**	**8.41**
27. BAYSIDE #1	779	225,571	38.9	95.5	69.5	7,572	GAS	1,661,500	1,027,999	1,708,020.0	11,311,658	5.01	6.81
28. BAYSIDE #2	1,022	351,585	46.2	95.9	70.4	7,500	GAS	2,565,100	1,027,995	2,636,910.0	17,463,457	4.97	6.81
29. BAYSIDE TOTAL	**1,801**	**577,156**	**43.1**	**95.7**	**35.4**	**7,528**	**GAS**	**4,226,600**	**1,027,996**	**4,344,930.0**	**28,775,115**	**4.99**	**6.81**
30. B.B.C.T.#1	15	3	0.0	72.2	0.0	18,667	LGT OIL	10	5,600,000	56.0	501	16.70	50.10
31. B.B.C.T.#2	80	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#3	70	0	0.0	72.3	0.0	0	LGT OIL	1	5,000,000	5.0	50	0.00	50.00
33. C.T. TOTAL (OIL)	**165**	**3**	**0.0**	**85.7**	**0.0**	**20,333**	**LGT OIL**	**11**	**5,545,455**	**61.0**	**551**	**18.37**	**50.09**
34. TOT COAL (GN,BB,POLK)	**2,019**	**862,176**	**57.4**	**52.7**	**21.4**	**10,845**	**COAL**	**387,964**	**24,099,960**	**9,349,917.0**	**19,389,972**	**2.25**	**49.98**
35. SYSTEM	**4,385**	**1,459,708**	**44.7**	**80.5**	**10.2**	**9,519**	**-**	**-**	**-**	**13,894,794.0**	**49,421,897**	**3.39**	**-**

LEGEND:
B.B. = BIG BEND
GAN. = GANNON
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: APRIL 2004

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. GAN.#1	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2. GAN.#2	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
3. GAN.#3	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
4. GAN.#4	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
5. GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
6. GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
7. GANNON STA.	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**COAL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
8. B.B.#1	421	183,674	60.6	71.2	77.2	11,104	COAL	83,921	24,302,260	2,039,470.0	3,939,885	2.15	46.95
9. B.B.#2	411	197,723	66.8	70.7	82.9	10,859	COAL	88,351	24,302,498	2,147,150.0	4,147,862	2.10	46.95
10. B.B.#3	428	182,173	59.1	66.9	78.7	10,774	COAL	80,761	24,302,448	1,962,690.0	3,791,530	2.08	46.95
11. B.B. 1 - 3	1,260	563,570	62.1	69.6	26.5	10,911	COAL	253,033	24,302,403	6,149,310.0	11,879,277	2.11	46.95
12. B.B.#4	452	242,569	74.5	82.9	84.0	10,513	COAL	113,601	22,448,922	2,550,220.0	6,772,660	2.79	59.62
13. B.B. STA.	**1,712**	**806,139**	**65.4**	**73.1**	**20.3**	**10,792**	**COAL**	**366,634**	**23,728,105**	**8,699,530.0**	**18,651,937**	**2.31**	**50.87**
14. PHILLIPS #1 (HVY OIL)	17	425	3.5	91.7	86.2	9,721	HVY OIL	658	6,278,875	4,131.5	21,488	5.06	32.66
15. PHILLIPS #2 (HVY OIL)	17	181	1.5	27.5	88.7	9,721	HVY OIL	280	6,283,929	1,759.5	9,144	5.05	32.66
16. SEB-PHILLIPS TOTAL	**34**	**606**	**2.5**	**59.6**	**43.5**	**9,721**	**HVY OIL**	**938**	**6,280,384**	**5,891.0**	**30,632**	**5.05**	**32.66**
17. POLK #1 GASIFIER	255	94,837	51.7	-	-	11,056	COAL	39,500	26,544,304	1,048,500.0	1,698,022	1.79	42.99
18. POLK #1 CT OIL	255	7,138	3.9	-	-	8,786	LGT OIL	10,800	5,806,574	62,711.0	406,190	5.69	37.61
19. POLK #1 TOTAL	**255**	**101,975**	**55.5**	**65.6**	**92.6**	**10,897**		**-**	**-**	**1,111,211.0**	**2,104,212**	**2.06**	**-**
20. POLK #2 CT GAS	160	612	0.5	-	-	13,317	GAS	7,900	1,031,646	8,150.0	48,648	7.95	6.16
21. POLK #2 CT OIL	160	204	0.2	-	-	13,319	LGT OIL	500	5,434,000	2,717.0	17,823	8.74	35.65
22. POLK #2 TOTAL	**160**	**816**	**0.7**	**92.2**	**63.8**	**13,317**		**-**	**-**	**10,867.0**	**66,471**	**8.15**	**-**
23. POLK #3 CT GAS	165	282	0.2	0.0	-	12,720	GAS	3,500	1,024,857	3,587.0	21,553	7.64	6.16
24. POLK #3 CT OIL	165	94	0.1	0.0	-	12,723	LGT OIL	200	5,980,000	1,196.0	7,129	7.58	35.65
25. POLK #3 TOTAL	**165**	**376**	**0.3**	**67.8**	**76.0**	**12,721**		**-**	**-**	**4,783.0**	**28,682**	**7.63**	**-**
26. CITY OF TAMPA GAS	**6**	**100**	**2.3**	**100.0**	**41.7**	**10,430**	GAS	**1,014**	1,028,600	**1,043.0**	**8,380**	**8.38**	**8.26**
27. BAYSIDE #1	690	168,638	33.9	95.5	73.6	7,651	GAS	1,255,100	1,027,966	1,290,200.0	7,728,906	4.58	6.16
28. BAYSIDE #2	908	403,517	61.7	95.9	75.9	7,508	GAS	2,947,000	1,027,981	3,029,460.0	18,147,626	4.50	6.16
29. BAYSIDE TOTAL	**1,598**	**572,155**	**49.7**	**95.7**	**39.0**	**7,550**	**GAS**	**4,202,100**	**1,027,976**	**4,319,660.0**	**25,876,532**	**4.52**	**6.16**
30. B.B.C.T.#1	14	0	0.0	72.2	0.0	0	LGT OIL	2	5,500,000	11.0	115	0.00	57.50
31. B.B.C.T.#2	66	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#3	60	1	0.0	72.2	0.0	28,000	LGT OIL	5	5,600,000	28.0	288	28.80	57.60
33. C.T. TOTAL (OIL)	**140**	**1**	**0.0**	**85.3**	**0.0**	**39,000**	**LGT OIL**	**7**	**5,571,429**	**39.0**	**403**	**40.30**	**57.57**
34. TOT COAL (GN,BB,POLK)	**1,967**	**900,976**	**63.6**	**63.7**	**19.7**	**10,819**	**COAL**	**406,134**	**24,002,004**	**9,748,030.0**	**20,349,959**	**2.26**	**50.11**
35. SYSTEM	**4,070**	**1,482,168**	**50.6**	**82.4**	**11.0**	**9,549**	**-**	**-**	**-**	**14,153,024.0**	**46,767,249**	**3.16**	**-**

LEGEND:
B.B. = BIG BEND
GAN. = GANNON
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: MAY 2004

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. GAN.#1	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2. GAN.#2	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
3. GAN.#3	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
4. GAN.#4	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
5. GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
6. GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
7. GANNON STA.	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**COAL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
8. B.B.#1	421	182,742	58.3	71.2	75.1	11,168	COAL	83,978	24,302,198	2,040,850.0	3,931,517	2.15	46.82
9. B.B.#2	411	201,336	65.8	70.7	82.2	10,887	COAL	90,198	24,302,424	2,192,030.0	4,222,712	2.10	46.82
10. B.B.#3	428	199,007	62.5	71.7	77.6	10,768	COAL	88,173	24,302,451	2,142,820.0	4,127,910	2.07	46.82
11. B.B. 1 - 3	1,260	583,085	62.2	71.2	26.1	10,934	COAL	262,349	24,302,361	6,375,700.0	12,282,139	2.11	46.82
12. B.B.#4	452	250,558	74.5	82.9	84.0	10,539	COAL	117,631	22,449,014	2,640,700.0	7,046,627	2.81	59.90
13. B.B. STA.	**1,712**	**833,643**	**65.4**	**74.3**	**20.0**	**10,816**	**COAL**	**379,980**	**23,728,617**	**9,016,400.0**	**19,328,766**	**2.32**	**50.87**
14. PHILLIPS #1 (HVY OIL)	17	1,927	15.2	91.7	90.0	9,753	HVY OIL	2,994	6,277,321	18,794.3	95,474	4.95	31.89
15. PHILLIPS #2 (HVY OIL)	17	1,002	7.9	50.3	86.7	9,753	HVY OIL	1,556	6,280,656	9,772.7	49,618	4.95	31.89
16. SEB-PHILLIPS TOTAL	**34**	**2,929**	**11.6**	**71.0**	**44.4**	**9,753**	**HVY OIL**	**4,550**	**6,278,462**	**28,567.0**	**145,092**	**4.95**	**31.89**
17. POLK #1 GASIFIER	255	132,967	70.1	-	-	11,182	COAL	56,100	26,504,118	1,486,881.0	2,490,454	1.87	44.39
18. POLK #1 CT OIL	255	10,008	5.3	-	-	8,884	LGT OIL	15,300	5,811,307	88,913.0	563,348	5.63	36.82
19. POLK #1 TOTAL	**255**	**142,975**	**75.4**	**89.5**	**83.8**	**11,021**		**-**	**-**	**1,575,794.0**	**3,053,802**	**2.14**	**-**
20. POLK #2 CT GAS	160	5,902	5.0	-	-	13,036	GAS	74,800	1,028,583	76,938.0	449,406	7.61	6.01
21. POLK #2 CT OIL	160	1,967	1.7	-	-	13,038	LGT OIL	4,400	5,828,636	25,646.0	151,693	7.71	34.48
22. POLK #2 TOTAL	**160**	**7,869**	**6.6**	**92.3**	**68.3**	**13,036**		**-**	**-**	**102,584.0**	**601,099**	**7.64**	**-**
23. POLK #3 CT GAS	165	4,356	3.5	0.0	-	12,657	GAS	53,600	1,028,601	55,133.0	322,034	7.39	6.01
24. POLK #3 CT OIL	165	1,452	1.2	0.0	-	12,657	LGT OIL	3,200	5,743,125	18,378.0	110,322	7.60	34.48
25. POLK #3 TOTAL	**165**	**5,808**	**4.7**	**92.3**	**71.8**	**12,657**		**-**	**-**	**73,511.0**	**432,356**	**7.44**	**-**
26. CITY OF TAMPA GAS	**6**	**412**	**9.2**	**100.0**	**58.7**	**10,464**	**GAS**	**4,193**	**1,028,142**	**4,311.0**	**33,977**	**8.25**	**8.10**
27. BAYSIDE #1	690	238,502	46.5	95.5	77.0	7,663	GAS	1,778,000	1,027,958	1,827,710.0	10,682,402	4.48	6.01
28. BAYSIDE #2	908	461,961	68.4	95.9	88.4	7,563	GAS	3,398,500	1,028,009	3,493,690.0	20,418,528	4.42	6.01
29. BAYSIDE TOTAL	**1,598**	**700,463**	**58.9**	**95.7**	**42.8**	**7,597**	**GAS**	**5,176,500**	**1,027,992**	**5,321,400.0**	**31,100,930**	**4.44**	**6.01**
30. B.B.C.T.#1	14	1	0.0	72.2	0.0	16,000	LGT OIL	3	5,333,333	16.0	182	18.20	60.67
31. B.B.C.T.#2	66	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#3	60	1	0.0	72.3	0.0	15,000	LGT OIL	3	5,000,000	15.0	182	18.20	60.67
33. C.T. TOTAL (OIL)	**140**	**2**	**0.0**	**85.4**	**0.0**	**15,500**	**LGT OIL**	**6**	**5,166,667**	**31.0**	**364**	**18.20**	**60.67**
34. TOT COAL (GN,BB,POLK)	**1,967**	**966,610**	**66.1**	**64.7**	**20.2**	**10,866**	**COAL**	**436,080**	**24,085,675**	**10,503,281.0**	**21,819,220**	**2.26**	**50.03**
35. SYSTEM	**4,070**	**1,694,101**	**55.9**	**85.5**	**11.0**	**9,517**	**-**	**-**	**-**	**16,122,598.0**	**54,696,386**	**3.23**	**-**

LEGEND:
B.B. = BIG BEND
GAN. = GANNON
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: JUNE 2004

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. GAN.#1	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2. GAN.#2	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
3. GAN.#3	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
4. GAN.#4	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
5. GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
6. GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
7. GANNON STA.	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**COAL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
8. B.B.#1	421	182,012	60.0	71.2	77.8	11,195	COAL	83,842	24,302,376	2,037,560.0	3,918,804	2.15	46.74
9. B.B.#2	411	198,366	67.0	70.7	83.6	10,909	COAL	89,042	24,302,352	2,163,930.0	4,161,853	2.10	46.74
10. B.B.#3	428	192,550	62.5	71.7	78.0	10,815	COAL	85,688	24,302,236	2,082,410.0	4,005,086	2.08	46.74
11. B.B. 1 - 3	1,260	572,928	63.2	71.2	26.6	10,968	COAL	258,572	24,302,322	6,283,900.0	12,085,743	2.11	46.74
12. B.B.#4	452	237,213	72.9	82.9	83.2	10,640	COAL	112,431	22,449,880	2,523,950.0	6,759,017	2.85	60.12
13. B.B. STA.	**1,712**	**810,141**	**65.7**	**74.3**	**20.2**	**10,872**	**COAL**	**371,003**	**23,740,644**	**8,807,850.0**	**18,844,760**	**2.33**	**50.79**
14. PHILLIPS #1 (HVY OIL)	17	4,496	36.7	91.7	97.6	9,760	HVY OIL	6,989	6,278,895	43,883.2	216,189	4.81	30.93
15. PHILLIPS #2 (HVY OIL)	17	4,464	36.5	91.7	97.6	9,760	HVY OIL	6,939	6,279,118	43,570.8	214,642	4.81	30.93
16. SEB-PHILLIPS TOTAL	**34**	**8,960**	**36.6**	**91.7**	**48.8**	**9,760**	**HVY OIL**	**13,928**	**6,279,006**	**87,454.0**	**430,831**	**4.81**	**30.93**
17. POLK #1 GASIFIER	255	128,678	70.1	-	-	11,183	COAL	54,300	26,500,018	1,438,951.0	2,404,696	1.87	44.29
18. POLK #1 CT OIL	255	9,685	5.3	-	-	8,884	LGT OIL	14,800	5,813,851	86,045.0	534,207	5.52	36.10
19. POLK #1 TOTAL	**255**	**138,363**	**75.4**	**89.5**	**83.7**	**11,022**		**-**	**-**	**1,524,996.0**	**2,938,903**	**2.12**	**-**
20. POLK #2 CT GAS	160	1,339	1.2	-	-	13,014	GAS	17,000	1,025,059	17,426.0	102,158	7.63	6.01
21. POLK #2 CT OIL	160	446	0.4	-	-	13,025	LGT OIL	1,000	5,809,000	5,809.0	33,926	7.61	33.93
22. POLK #2 TOTAL	**160**	**1,785**	**1.5**	**92.2**	**69.7**	**13,017**		**-**	**-**	**23,235.0**	**136,084**	**7.62**	**-**
23. POLK #3 CT GAS	165	999	0.8	0.0	-	12,694	GAS	12,300	1,030,976	12,681.0	73,914	7.40	6.01
24. POLK #3 CT OIL	165	333	0.3	0.0	-	12,694	LGT OIL	700	6,038,571	4,227.0	23,748	7.13	33.93
25. POLK #3 TOTAL	**165**	**1,332**	**1.1**	**92.4**	**73.4**	**12,694**		**-**	**-**	**16,908.0**	**97,662**	**7.33**	**-**
26. CITY OF TAMPA GAS	**6**	**1,093**	**25.3**	**100.0**	**81.7**	**10,458**	**GAS**	**11,119**	**1,028,060**	**11,431.0**	**89,942**	**8.23**	**8.09**
27. BAYSIDE #1	690	279,104	56.2	95.5	82.1	7,657	GAS	2,079,000	1,027,999	2,137,210.0	12,493,335	4.48	6.01
28. BAYSIDE #2	908	467,186	71.5	95.9	89.6	7,566	GAS	3,438,500	1,028,009	3,534,810.0	20,662,978	4.42	6.01
29. BAYSIDE TOTAL	**1,598**	**746,290**	**64.9**	**95.7**	**43.8**	**7,600**	**GAS**	**5,517,500**	**1,028,005**	**5,672,020.0**	**33,156,313**	**4.44**	**6.01**
30. B.B.C.T.#1	14	2	0.0	72.2	0.0	20,500	LGT OIL	7	5,857,143	41.0	322	16.10	46.00
31. B.B.C.T.#2	66	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#3	60	2	0.0	72.2	0.0	20,000	LGT OIL	7	5,714,286	40.0	322	16.10	46.00
33. C.T. TOTAL (OIL)	**140**	**4**	**0.0**	**85.3**	**0.0**	**20,250**	**LGT OIL**	**14**	**5,785,714**	**81.0**	**644**	**16.10**	**46.00**
34. TOT COAL (GN,BB,POLK)	**1,967**	**938,819**	**66.3**	**84.7**	**20.4**	**10,915**	**COAL**	**425,303**	**24,092,943**	**10,246,801.0**	**21,249,456**	**2.26**	**49.96**
35. SYSTEM	**4,070**	**1,707,968**	**58.3**	**85.7**	**10.1**	**9,452**	**-**	**-**	**-**	**16,143,975.0**	**55,695,139**	**3.26**	**-**

LEGEND:
B.B. = BIG BEND
GAN. = GANNON
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: JULY 2004

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
PLANT/UNIT	NET CAPA-BILITY (MW)	NET GENERATION (MWH)	NET CAPACITY FACTOR (%)	EQUIV. AVAIL. FACTOR (%)	NET OUTPUT FACTOR (%)	AVG. NET HEAT RATE (BTU/KWH)	FUEL TYPE	FUEL BURNED (UNITS)	FUEL HEAT VALUE (BTU/UNIT)	FUEL BURNED (MM BTU)	AS BURNED FUEL COST ($)	FUEL COST PER KWH (cents/KWH)	COST OF FUEL ($/UNIT)
1. GAN.#1	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2. GAN.#2	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
3. GAN.#3	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
4. GAN.#4	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
5. GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
6. GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
7. GANNON STA.	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**COAL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
8. B.B.#1	421	190,141	60.7	71.2	77.6	11,294	COAL	86,889	24,714,176	2,147,390.0	4,077,755	2.14	46.93
9. B.B.#2	411	201,942	66.0	70.7	82.9	10,970	COAL	89,641	24,714,138	2,215,400.0	4,206,908	2.08	46.93
10. B.B.#3	428	199,416	62.6	71.7	78.2	10,902	COAL	87,964	24,714,201	2,173,960.0	4,128,205	2.07	46.93
11. B.B. 1 - 3	1,260	591,499	63.1	71.2	26.5	11,051	COAL	264,494	24,714,171	6,536,750.0	12,412,868	2.10	46.93
12. B.B.#4	452	250,424	74.5	82.9	84.5	10,689	COAL	117,057	22,867,065	2,676,750.0	7,058,345	2.82	60.30
13. B.B. STA.	**1,712**	**841,923**	**66.1**	**74.3**	**20.3**	**10,943**	**COAL**	**381,551**	**24,147,493**	**9,213,500.0**	**19,471,213**	**2.31**	**51.03**
14. PHILLIPS #1 (HVY OIL)	17	3,209	25.4	91.7	97.3	9,760	HVY OIL	4,988	6,279,190	31,320.6	153,433	4.78	30.76
15. PHILLIPS #2 (HVY OIL)	17	3,185	25.2	91.7	97.1	9,760	HVY OIL	4,951	6,278,812	31,086.4	152,294	4.78	30.76
16. SEB-PHILLIPS TOTAL	**34**	**6,394**	**25.3**	**91.7**	**48.6**	**9,760**	**HVY OIL**	**9,939**	**6,279,002**	**62,407.0**	**305,727**	**4.78**	**30.76**
17. POLK #1 GASIFIER	255	132,967	70.1	-	-	11,182	COAL	56,100	26,504,118	1,486,881.0	2,429,211	1.83	43.30
18. POLK #1 CT OIL	255	10,008	5.3	-	-	8,884	LGT OIL	15,300	5,811,307	88,913.0	543,487	5.43	35.52
19. POLK #1 TOTAL	**255**	**142,975**	**75.4**	**89.6**	**83.8**	**11,021**		**-**	**-**	**1,575,794.0**	**2,972,698**	**2.08**	**-**
20. POLK #2 CT GAS	160	6,879	5.8	-	-	12,475	GAS	83,500	1,027,737	85,816.0	500,825	7.28	6.00
21. POLK #2 CT OIL	160	2,293	1.9	-	-	12,475	LGT OIL	4,900	5,837,755	28,605.0	165,840	7.23	33.84
22. POLK #2 TOTAL	**160**	**9,172**	**7.7**	**92.3**	**83.1**	**12,475**		**-**	**-**	**114,421.0**	**666,665**	**7.27**	**-**
23. POLK #3 CT GAS	165	6,255	5.1	0.0	-	12,359	GAS	75,200	1,028,032	77,308.0	451,042	7.21	6.00
24. POLK #3 CT OIL	165	2,085	1.7	0.0	-	12,359	LGT OIL	4,400	5,856,591	25,769.0	148,918	7.14	33.85
25. POLK #3 TOTAL	**165**	**8,340**	**6.8**	**92.3**	**81.5**	**12,359**		**-**	**-**	**103,077.0**	**599,960**	**7.19**	**-**
26. CITY OF TAMPA GAS	**6**	**743**	**16.6**	**100.0**	**83.1**	**10,451**	**GAS**	**7,554**	**1,027,932**	**7,765.0**	**61,027**	**8.21**	**8.08**
27. BAYSIDE #1	690	298,982	58.2	95.5	83.3	7,655	GAS	2,226,400	1,028,000	2,288,740.0	13,353,725	4.47	6.00
28. BAYSIDE #2	908	493,241	73.0	95.9	89.9	7,565	GAS	3,629,800	1,028,007	3,731,460.0	21,771,177	4.41	6.00
29. BAYSIDE TOTAL	**1,598**	**792,223**	**66.6**	**95.7**	**44.1**	**7,599**	**GAS**	**5,856,200**	**1,028,005**	**6,020,200.0**	**35,124,902**	**4.43**	**6.00**
30. B.B.C.T.#1	14	2	0.0	72.2	0.0	25,500	LGT OIL	9	5,666,667	51.0	489	24.45	54.33
31. B.B.C.T.#2	66	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#3	60	3	0.0	72.3	0.0	17,000	LGT OIL	9	5,666,667	51.0	489	16.30	54.33
33. C.T. TOTAL (OIL)	**140**	**5**	**0.0**	**85.4**	**0.0**	**20,400**	**LGT OIL**	**18**	**5,666,667**	**102.0**	**978**	**19.56**	**54.33**
34. TOT COAL (GN,BB,POLK)	**1,967**	**974,890**	**66.6**	**64.7**	**20.4**	**10,976**	**COAL**	**437,651**	**24,449,575**	**10,700,381.0**	**21,900,424**	**2.25**	**50.04**
35. SYSTEM	**4,070**	**1,801,776**	**59.5**	**85.7**	**10.8**	**9,489**	**-**	**-**	**-**	**17,097,266.0**	**59,203,170**	**3.29**	**-**

LEGEND:
B.B. = BIG BEND
GAN. = GANNON
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: AUGUST 2004

	(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1.	GAN.#1	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2.	GAN.#2	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
3.	GAN.#3	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
4.	GAN.#4	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
5.	GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
6.	GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
7.	**GANNON STA.**	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
8.	B.B.#1	421	192,675	61.5	71.2	78.2	11,289	COAL	88,007	24,714,170	2,175,020.0	4,152,773	2.16	47.19
9.	B.B.#2	411	202,874	66.3	70.7	83.1	10,970	COAL	90,049	24,713,989	2,225,470.0	4,249,128	2.09	47.19
10.	B.B.#3	428	200,877	63.1	71.7	78.7	10,898	COAL	88,579	24,713,984	2,189,140.0	4,179,764	2.08	47.19
11.	B.B. 1 - 3	1,260	596,426	63.6	71.2	26.7	11,049	COAL	266,635	24,714,047	6,589,630.0	12,581,665	2.11	47.19
12.	B.B.#4	452	251,036	74.6	82.9	84.7	10,689	COAL	117,341	22,867,029	2,683,240.0	7,093,390	2.83	60.45
13.	**B.B. STA.**	1,712	847,462	66.6	74.3	20.4	10,942	COAL	383,976	24,149,608	9,272,870.0	19,675,055	2.32	51.24
14.	PHILLIPS #1 (HVY OIL)	17	3,586	28.4	91.7	98.6	9,767	HVY OIL	5,578	6,278,971	35,024.1	169,848	4.74	30.45
15.	PHILLIPS #2 (HVY OIL)	17	3,561	28.2	91.7	98.3	9,767	HVY OIL	5,539	6,279,094	34,779.9	168,660	4.74	30.45
16.	**SEB-PHILLIPS TOTAL**	34	7,147	28.3	91.7	49.2	9,767	HVY OIL	11,117	6,279,032	69,804.0	338,508	4.74	30.45
17.	POLK #1 GASIFIER	255	132,967	70.1	-	-	11,182	COAL	56,100	26,504,118	1,486,881.0	2,489,005	1.87	44.37
18.	POLK #1 CT OIL	255	10,008	5.3	-	-	8,884	LGT OIL	15,300	5,811,307	88,913.0	537,234	5.37	35.11
19.	**POLK #1 TOTAL**	256	142,975	75.4	89.5	83.8	11,021		-	-	1,575,794.0	3,026,239	2.12	-
20.	POLK #2 CT GAS	160	7,702	6.5	-	-	12,558	GAS	94,100	1,027,843	96,720.0	565,804	7.35	6.01
21.	POLK #2 CT OIL	160	2,567	2.2	-	-	12,559	LGT OIL	5,600	5,757,143	32,240.0	189,755	7.39	33.88
22.	**POLK #2 TOTAL**	160	10,269	8.6	92.3	80.2	12,558		-	-	128,960.0	755,559	7.36	-
23.	POLK #3 CT GAS	165	6,847	5.6	0.0	-	12,399	GAS	82,600	1,027,809	84,897.0	496,657	7.25	6.01
24.	POLK #3 CT OIL	165	2,282	1.9	0.0	-	12,401	LGT OIL	4,900	5,775,306	28,299.0	166,036	7.28	33.88
25.	**POLK #3 TOTAL**	165	9,129	7.4	92.3	80.2	12,400		-	-	113,196.0	662,693	7.26	-
26.	**CITY OF TAMPA GAS**	6	817	18.3	100.0	82.5	10,453	GAS	8,307	1,028,049	8,540.0	67,246	8.23	8.10
27.	BAYSIDE #1	690	300,313	58.5	95.5	82.8	7,654	GAS	2,235,900	1,027,998	2,298,500.0	13,444,020	4.48	6.01
28.	BAYSIDE #2	908	507,587	75.1	95.9	89.7	7,558	GAS	3,732,000	1,027,990	3,836,460.0	22,439,770	4.42	6.01
29.	**BAYSIDE TOTAL**	1,598	807,900	68.0	95.7	44.0	7,594	GAS	5,967,900	1,027,993	6,134,960.0	35,883,790	4.44	6.01
30.	B.B.C.T.#1	14	2	0.0	72.2	0.0	27,000	LGT OIL	9	6,000,000	54.0	386	19.30	42.89
31.	B.B.C.T.#2	66	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32.	B.B.C.T.#3	60	3	0.0	72.3	0.0	18,333	LGT OIL	9	6,111,111	55.0	386	12.87	42.89
33.	**C.T. TOTAL (OIL)**	140	6	0.0	85.4	0.0	21,800	LGT OIL	18	6,055,556	109.0	772	16.44	42.89
34.	**TOT COAL (GN,BB,POLK)**	1,967	980,429	67.0	64.7	20.5	10,976	COAL	440,076	24,449,756	10,759,751.0	22,164,060	2.26	50.36
35.	**SYSTEM**	4,070	1,825,704	60.3	85.7	10.8	9,478	-	-	-	17,304,233.0	60,409,862	3.31	-

LEGEND:
B.B. = BIG BEND
GAN. = GANNON
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: SEPTEMBER 2004

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. GAN.#1	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2. GAN.#2	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
3. GAN.#3	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
4. GAN.#4	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
5. GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
6. GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
7. GANNON STA.	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**COAL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
8. B.B.#1	421	189,663	62.6	71.2	78.3	11,193	COAL	85,895	24,714,011	2,122,810.0	4,064,294	2.14	47.32
9. B.B.#2	411	198,387	67.0	70.7	83.2	10,915	COAL	87,617	24,713,925	2,165,360.0	4,145,774	2.09	47.32
10. B.B.#3	428	196,128	63.6	71.7	79.0	10,810	COAL	85,787	24,714,001	2,120,140.0	4,059,184	2.07	47.32
11. B.B. 1 - 3	1,260	584,178	64.4	71.2	26.7	10,970	COAL	259,299	24,713,979	6,408,310.0	12,269,252	2.10	47.32
12. B.B.#4	452	243,544	74.8	82.9	84.3	10,625	COAL	113,163	22,867,103	2,587,710.0	6,852,424	2.81	60.55
13. B.B. STA.	**1,712**	**827,722**	**67.2**	**74.3**	**20.4**	**10,868**	**COAL**	**372,462**	**24,152,853**	**8,996,020.0**	**19,121,676**	**2.31**	**51.34**
14. PHILLIPS #1 (HVY OIL)	17	4,772	39.0	91.7	98.5	9,768	HVY OIL	7,423	6,279,496	46,612.7	223,172	4.68	30.06
15. PHILLIPS #2 (HVY OIL)	17	4,735	38.7	91.7	98.8	9,768	HVY OIL	7,367	6,278,173	46,251.3	221,489	4.68	30.07
16. SEB-PHILLIPS TOTAL	**34**	**9,507**	**38.8**	**91.7**	**49.3**	**9,768**	**HVY OIL**	**14,790**	**6,278,837**	**92,864.0**	**444,661**	**4.68**	**30.06**
17. POLK #1 GASIFIER	255	128,678	70.1	-	-	11,183	COAL	54,300	26,500,018	1,438,951.0	2,396,808	1.86	44.14
18. POLK #1 CT OIL	255	9,685	5.3	-	-	8,884	LGT OIL	14,800	5,813,851	86,045.0	515,585	5.32	34.84
19. POLK #1 TOTAL	**255**	**138,363**	**75.4**	**89.5**	**83.7**	**11,022**		**-**	**-**	**1,524,996.0**	**2,912,393**	**2.10**	**-**
20. POLK #2 CT GAS	160	1,362	1.2	-	-	12,850	GAS	17,000	1,029,529	17,502.0	102,192	7.50	6.01
21. POLK #2 CT OIL	160	454	0.4	-	-	12,850	LGT OIL	1,000	5,834,000	5,834.0	34,025	7.49	34.03
22. POLK #2 TOTAL	**160**	**1,816**	**1.6**	**92.2**	**70.9**	**12,850**		**-**	**-**	**23,336.0**	**136,217**	**7.50**	**-**
23. POLK #3 CT GAS	165	1,105	0.9	0.0	-	12,578	GAS	13,500	1,029,556	13,899.0	81,153	7.34	6.01
24. POLK #3 CT OIL	165	368	0.3	0.0	-	12,590	LGT OIL	800	5,791,250	4,633.0	27,220	7.40	34.03
25. POLK #3 TOTAL	**165**	**1,473**	**1.2**	**92.4**	**74.4**	**12,581**		**-**	**-**	**18,532.0**	**108,373**	**7.36**	**-**
26. CITY OF TAMPA GAS	**8**	**1,116**	**25.8**	**100.0**	**81.2**	**10,457**	**GAS**	**11,352**	**1,028,013**	**11,670.0**	**91,839**	**8.23**	**8.09**
27. BAYSIDE #1	690	284,376	57.2	95.5	82.0	7,658	GAS	2,118,400	1,027,974	2,177,660.0	12,734,338	4.48	6.01
28. BAYSIDE #2	908	469,298	71.8	95.9	89.7	7,568	GAS	3,454,900	1,027,992	3,551,610.0	20,768,440	4.43	6.01
29. BAYSIDE TOTAL	**1,598**	**753,674**	**65.5**	**95.7**	**43.7**	**7,602**	**GAS**	**5,573,300**	**1,027,985**	**5,729,270.0**	**33,502,778**	**4.45**	**6.01**
30. B.B.C.T.#1	14	2	0.0	72.2	0.0	21,000	LGT OIL	7	6,000,000	42.0	328	16.40	46.86
31. B.B.C.T.#2	66	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#3	60	2	0.0	72.2	0.0	15,500	LGT OIL	5	6,200,000	31.0	234	11.70	46.80
33. C.T. TOTAL (OIL)	**140**	**4**	**0.0**	**85.3**	**0.0**	**18,250**	**LGT OIL**	**12**	**6,083,333**	**73.0**	**562**	**14.05**	**46.83**
34. TOT COAL (GN,BB,POLK)	**1,967**	**956,400**	**67.5**	**84.7**	**20.5**	**10,911**	**COAL**	**426,762**	**24,451,500**	**10,434,971.0**	**21,518,484**	**2.25**	**50.42**
35. SYSTEM	**4,070**	**1,733,675**	**59.2**	**85.7**	**10.0**	**9,458**	**-**	**-**	**-**	**16,396,761.0**	**56,318,499**	**3.25**	**-**

LEGEND:
B.B. = BIG BEND
GAN. = GANNON
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: OCTOBER 2004

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. GAN.#1	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2. GAN.#2	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
3. GAN.#3	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
4. GAN.#4	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
5. GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
6. GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
7. GANNON STA.	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**COAL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
8. B.B.#1	428	201,524	63.3	71.2	78.2	11,096	COAL	90,480	24,713,970	2,236,120.0	4,266,074	2.12	47.15
9. B.B.#2	433	206,066	64.0	70.7	79.4	10,853	COAL	90,493	24,714,177	2,236,460.0	4,266,686	2.07	47.15
10. B.B.#3	438	203,740	62.5	71.7	77.7	10,770	COAL	88,786	24,714,031	2,194,260.0	4,186,203	2.05	47.15
11. B.B. 1 - 3	1,299	611,330	63.3	71.2	26.1	10,905	COAL	269,759	24,714,060	6,666,840.0	12,718,963	2.08	47.15
12. B.B.#4	460	81,779	23.9	26.8	83.5	10,511	COAL	37,590	22,867,066	859,573.0	2,226,580	2.72	59.23
13. B.B. STA.	**1,759**	**693,109**	**53.0**	**59.6**	**19.6**	**10,859**	**COAL**	**307,349**	**24,488,165**	**7,526,413.0**	**14,945,543**	**2.16**	**48.63**
14. PHILLIPS #1 (HVY OIL)	17	3,365	26.6	91.7	92.9	9,741	HVY OIL	5,220	6,279,215	32,777.5	156,783	4.66	30.04
15. PHILLIPS #2 (HVY OIL)	17	3,338	26.4	91.7	93.1	9,741	HVY OIL	5,178	6,279,355	32,514.5	155,522	4.66	30.04
16. SEB-PHILLIPS TOTAL	**34**	**6,703**	**26.5**	**91.7**	**46.5**	**9,741**	**HVY OIL**	**10,398**	**6,279,284**	**65,292.0**	**312,305**	**4.66**	**30.04**
17. POLK #1 GASIFIER	260	108,967	56.3	-	-	11,060	COAL	45,400	26,544,956	1,205,141.0	1,956,572	1.80	43.10
18. POLK #1 CT OIL	260	8,202	4.2	-	-	8,785	LGT OIL	12,400	5,810,806	72,054.0	430,464	5.25	34.71
19. POLK #1 TOTAL	**260**	**117,169**	**60.6**	**66.4**	**90.7**	**10,900**		**-**	**-**	**1,277,195.0**	**2,387,036**	**2.04**	**-**
20. POLK #2 CT GAS	180	3,143	2.3	-	-	12,540	GAS	38,300	1,029,086	39,414.0	230,995	7.35	6.03
21. POLK #2 CT OIL	180	1,048	0.8	-	-	12,536	LGT OIL	2,300	5,712,174	13,138.0	78,831	7.52	34.27
22. POLK #2 TOTAL	**180**	**4,191**	**3.1**	**92.3**	**72.8**	**12,539**		**-**	**-**	**52,552.0**	**309,826**	**7.39**	**-**
23. POLK #3 CT GAS	180	2,822	2.1	0.0	-	12,393	GAS	34,000	1,028,647	34,974.0	205,061	7.27	6.03
24. POLK #3 CT OIL	180	941	0.7	0.0	-	12,389	LGT OIL	2,000	5,829,000	11,658.0	68,549	7.28	34.27
25. POLK #3 TOTAL	**180**	**3,763**	**2.8**	**92.3**	**74.7**	**12,392**		**-**	**-**	**46,632.0**	**273,610**	**7.27**	**-**
26. CITY OF TAMPA GAS	**6**	**810**	**18.1**	**100.0**	**69.2**	**10,454**	**GAS**	**8,237**	**1,028,044**	**8,468.0**	**66,925**	**8.26**	**8.12**
27. BAYSIDE #1	779	309,933	53.5	73.9	75.4	7,578	GAS	2,284,600	1,027,992	2,348,550.0	13,778,880	4.45	6.03
28. BAYSIDE #2	1,022	500,121	65.8	95.9	75.6	7,511	GAS	3,654,200	1,027,982	3,756,450.0	22,039,211	4.41	6.03
29. BAYSIDE TOTAL	**1,801**	**810,054**	**60.5**	**86.4**	**38.3**	**7,537**	**GAS**	**5,938,800**	**1,027,985**	**6,105,000.0**	**35,818,091**	**4.42**	**6.03**
30. B.B.C.T.#1	15	1	0.0	39.5	0.0	17,000	LGT OIL	3	5,666,667	17.0	126	12.60	42.00
31. B.B.C.T.#2	80	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#3	70	5	0.0	72.3	0.0	18,400	LGT OIL	16	5,750,000	92.0	673	13.46	42.06
33. C.T. TOTAL (OIL)	**165**	**6**	**0.0**	**82.8**	**0.0**	**18,167**	**LGT OIL**	**19**	**5,736,842**	**109.0**	**799**	**13.32**	**42.05**
34. TOT COAL (GN,BB,POLK)	**2,019**	**802,076**	**53.4**	**51.9**	**19.7**	**10,886**	**COAL**	**352,749**	**24,752,881**	**8,731,554.0**	**16,902,115**	**2.11**	**47.92**
35. SYSTEM	**4,385**	**1,635,805**	**50.1**	**74.9**	**9.8**	**9,220**	**-**	**-**	**-**	**15,081,661.0**	**54,114,135**	**3.31**	**-**

LEGEND:
B.B. = BIG BEND
GAN. = GANNON
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: NOVEMBER 2004

(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED FUEL COST ($)	(M) FUEL COST PER KWH (cents/KWH)	(N) COST OF FUEL ($/UNIT)
1. GAN.#1	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2. GAN.#2	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
3. GAN.#3	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
4. GAN.#4	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
5. GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
6. GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
7. GANNON STA.	**0**	**0**	**0.0**	**0.0**	**0.0**	**0**	**COAL**	**0**	**0**	**0.0**	**0**	**0.00**	**0.00**
8. B.B.#1	428	75,731	24.6	28.5	79.3	11,091	COAL	33,986	24,714,353	839,942.0	1,605,792	2.12	47.25
9. B.B.#2	433	196,046	62.9	70.7	96.4	10,898	COAL	86,453	24,714,006	2,136,600.0	4,084,787	2.08	47.25
10. B.B.#3	438	200,503	63.6	71.7	78.9	10,734	COAL	87,087	24,714,022	2,152,270.0	4,114,742	2.05	47.25
11. B.B. 1 - 3	1,299	472,280	50.5	57.2	26.3	10,860	COAL	207,526	24,714,070	5,128,812.0	9,805,321	2.08	47.25
12. B.B.#4	460	245,233	74.0	82.9	83.4	10,535	COAL	112,982	22,866,917	2,583,550.0	6,641,134	2.71	58.78
13. B.B. STA.	**1,759**	**717,513**	**56.7**	**63.9**	**20.2**	**10,749**	**COAL**	**320,508**	**24,062,931**	**7,712,362.0**	**16,446,455**	**2.29**	**51.31**
14. PHILLIPS #1 (HVY OIL)	17	1,199	9.8	91.7	96.6	9,764	HVY OIL	1,864	6,280,848	11,707.5	57,024	4.76	30.59
15. PHILLIPS #2 (HVY OIL)	17	1,169	9.6	91.7	96.9	9,764	HVY OIL	1,818	6,278,603	11,414.5	55,617	4.76	30.59
16. SEB-PHILLIPS TOTAL	**34**	**2,368**	**9.7**	**91.7**	**48.4**	**9,764**	**HVY OIL**	**3,682**	**6,279,739**	**23,122.0**	**112,641**	**4.76**	**30.59**
17. POLK #1 GASIFIER	260	145,184	77.6	-	-	11,053	COAL	60,500	26,525,306	1,604,781.0	2,662,840	1.83	44.01
18. POLK #1 CT OIL	260	10,928	5.8	-	-	8,782	LGT OIL	16,600	5,781,205	95,968.0	575,232	5.26	34.65
19. POLK #1 TOTAL	**260**	**156,112**	**83.4**	**89.5**	**92.7**	**10,894**		**-**	**-**	**1,700,749.0**	**3,238,072**	**2.07**	**-**
20. POLK #2 CT GAS	180	7	0.0	-	-	12,714	GAS	100	890,000	89.0	622	8.89	6.22
21. POLK #2 CT OIL	180	2	0.0	-	-	15,000	LGT OIL	0	0	30.0	0	0.00	0.00
22. POLK #2 TOTAL	**180**	**9**	**0.0**	**92.2**	**0.0**	**13,222**		**-**	**-**	**119.0**	**622**	**6.91**	**-**
23. POLK #3 CT GAS	180	1	0.0	0.0	-	11,000	GAS	0	0	11.0	0	0.00	0.00
24. POLK #3 CT OIL	180	0	0.0	0.0	-	0	LGT OIL	0	0	4.0	0	0.00	0.00
25. POLK #3 TOTAL	**180**	**1**	**0.0**	**92.4**	**0.0**	**15,000**		**-**	**-**	**15.0**	**0**	**0.00**	**-**
26. CITY OF TAMPA GAS	**6**	**159**	**3.7**	**100.0**	**64.6**	**10,465**	**GAS**	**1,619**	**1,027,795**	**1,664.0**	**13,452**	**8.46**	**8.31**
27. BAYSIDE #1	779	172,390	30.7	95.5	69.2	7,591	GAS	1,273,000	1,028,005	1,308,650.0	7,913,986	4.59	6.22
28. BAYSIDE #2	1,045	417,244	55.5	95.9	66.8	7,491	GAS	3,040,300	1,028,020	3,125,490.0	18,900,937	4.53	6.22
29. BAYSIDE TOTAL	**1,824**	**589,634**	**44.9**	**95.7**	**35.2**	**7,520**	**GAS**	**4,313,300**	**1,028,016**	**4,434,140.0**	**26,814,923**	**4.55**	**6.22**
30. B.B.C.T.#1	15	1	0.0	72.2	0.0	22,000	LGT OIL	4	5,500,000	22.0	256	25.60	64.00
31. B.B.C.T.#2	80	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32. B.B.C.T.#3	70	0	0.0	72.2	0.0	0	LGT OIL	1	9,000,000	9.0	64	0.00	64.00
33. C.T. TOTAL (OIL)	**165**	**1**	**0.0**	**85.7**	**0.0**	**31,000**	**LGT OIL**	**5**	**6,200,000**	**31.0**	**320**	**32.00**	**64.00**
34. TOT COAL (GN,BB,POLK)	**2,019**	**862,697**	**59.3**	**55.7**	**21.2**	**10,800**	**COAL**	**381,008**	**24,453,930**	**9,317,143.0**	**19,109,295**	**2.22**	**50.15**
35. SYSTEM	**4,408**	**1,465,797**	**46.2**	**82.0**	**10.7**	**9,464**	**-**	**-**	**-**	**13,872,202.0**	**46,626,485**	**3.18**	**-**

LEGEND:

B.B. = BIG BEND
GAN. = GANNON
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM NET GENERATION AND FUEL COST
TAMPA ELECTRIC COMPANY

SCHEDULE E4

ESTIMATED FOR THE PERIOD: DECEMBER 2004

	(A) PLANT/UNIT	(B) NET CAPA-BILITY (MW)	(C) NET GENERATION (MWH)	(D) NET CAPACITY FACTOR (%)	(E) EQUIV. AVAIL. FACTOR (%)	(F) NET OUTPUT FACTOR (%)	(G) AVG. NET HEAT RATE (BTU/KWH)	(H) FUEL TYPE	(I) FUEL BURNED (UNITS)	(J) FUEL HEAT VALUE (BTU/UNIT)	(K) FUEL BURNED (MM BTU)	(L) AS BURNED *FUEL COST* ($)	(M) FUEL COST *PER KWH* (cents/KWH)	(N) COST OF *FUEL* ($/UNIT)
1.	GAN.#1	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
2.	GAN.#2	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
3.	GAN.#3	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
4.	GAN.#4	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
5.	GAN.#5	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
6.	GAN.#6	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
7.	GANNON STA.	0	0	0.0	0.0	0.0	0	COAL	0	0	0.0	0	0.00	0.00
8.	B.B.#1	428	172,317	54.1	64.3	78.2	11,060	COAL	77,116	24,714,067	1,905,850.0	3,630,896	2.11	47.08
9.	B.B.#2	433	206,850	64.2	70.7	79.8	10,910	COAL	91,313	24,714,115	2,256,720.0	4,299,341	2.08	47.08
10.	B.B.#3	438	206,159	63.3	71.7	78.6	10,747	COAL	89,645	24,714,039	2,215,490.0	4,220,806	2.05	47.08
11.	B.B. 1 - 3	1,299	585,326	60.6	69.0	26.3	10,897	COAL	258,074	24,714,074	6,378,060.0	12,151,043	2.08	47.08
12.	B.B.#4	460	253,610	74.1	82.9	83.5	10,500	COAL	116,456	22,867,177	2,663,020.0	6,803,544	2.68	58.42
13.	B.B. STA.	1,759	838,936	64.1	72.6	20.1	10,777	COAL	374,530	24,139,802	9,041,080.0	18,954,587	2.26	50.61
14.	PHILLIPS #1 (HVY OIL)	17	1,727	13.7	91.7	95.8	9,763	HVY OIL	2,686	6,277,178	16,860.5	81,055	4.69	30.18
15.	PHILLIPS #2 (HVY OIL)	17	1,710	13.5	91.7	96.7	9,763	HVY OIL	2,658	6,280,850	16,694.5	80,210	4.69	30.18
16.	SEB-PHILLIPS TOTAL	34	3,437	13.6	91.7	48.1	9,763	HVY OIL	5,344	6,279,004	33,555.0	161,265	4.69	30.18
17.	POLK #1 GASIFIER	260	150,895	78.0	-	-	11,053	COAL	62,900	26,515,914	1,667,851.0	2,748,151	1.82	43.69
18.	POLK #1 CT OIL	260	11,358	5.9	-	-	8,782	LGT OIL	17,200	5,798,953	99,742.0	596,224	5.25	34.66
19.	POLK #1 TOTAL	260	162,253	83.9	89.5	93.3	10,894		-	-	1,767,593.0	3,344,375	2.06	-
20.	POLK #2 CT GAS	180	81	0.1	-	-	13,346	GAS	1,100	982,727	1,081.0	7,050	8.70	6.41
21.	POLK #2 CT OIL	180	27	0.0	-	-	13,333	LGT OIL	100	3,600,000	360.0	3,469	12.85	34.69
22.	POLK #2 TOTAL	180	108	0.1	92.3	60.0	13,343		-	-	1,441.0	10,519	9.74	-
23.	POLK #3 CT GAS	180	26	0.0	0.0	-	12,846	GAS	300	1,113,333	334.0	1,923	7.40	6.41
24.	POLK #3 CT OIL	180	9	0.0	0.0	-	12,333	LGT OIL	0	0	111.0	0	0.00	0.00
25.	POLK #3 TOTAL	180	35	0.0	92.3	0.0	12,714		-	-	445.0	1,923	5.49	-
26.	CITY OF TAMPA GAS	6	247	5.5	100.0	71.0	10,478	GAS	2,517	1,028,208	2,588.0	21,399	8.66	8.50
27.	BAYSIDE #1	779	250,169	43.2	95.5	78.9	7,504	GAS	1,826,300	1,027,975	1,877,390.0	11,704,209	4.68	6.41
28.	BAYSIDE #2	1,045	316,415	40.7	74.2	70.4	7,555	GAS	2,325,300	1,028,014	2,390,440.0	14,902,150	4.71	6.41
29.	BAYSIDE TOTAL	1,824	566,584	41.8	83.3	37.1	7,533	GAS	4,151,600	1,027,996	4,267,830.0	26,606,359	4.70	6.41
30.	B.B.C.T.#1	15	4	0.0	72.2	0.0	21,750	LGT OIL	15	5,800,000	87.0	650	16.25	43.33
31.	B.B.C.T.#2	80	0	0.0	100.0	0.0	0	LGT OIL	0	0	0.0	0	0.00	0.00
32.	B.B.C.T.#3	70	0	0.0	72.3	0.0	0	LGT OIL	1	6,000,000	6.0	43	0.00	43.00
33.	C.T. TOTAL (OIL)	165	4	0.0	85.7	0.0	23,250	LGT OIL	16	5,812,500	93.0	693	17.33	43.31
34.	TOT COAL (GN,BB,POLK)	2,019	989,831	65.9	63.3	20.7	10,819	COAL	437,430	24,481,474	10,708,931.0	21,702,738	2.19	49.61
35.	SYSTEM	4,408	1,571,604	47.9	80.3	10.3	9,617	-	-	-	15,114,625.0	49,101,120	3.12	-

LEGEND:
B.B. = BIG BEND
GAN. = GANNON
SEB-PHIL = SEBRING-PHILLIPS
C.T. = COMBUSTION TURBINE

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04
HEAVY OIL						
1. PURCHASES:						
2. UNITS (BBL)	11,422	14,829	6,615	938	4,550	13,928
3. UNIT COST ($/BBL)	31.37	31.00	30.66	30.36	29.95	29.90
4. AMOUNT ($)	358,276	459,705	202,837	28,474	136,253	416,461
5. BURNED:						
6. UNITS (BBL)	11,422	14,829	6,615	938	4,550	13,928
7. UNIT COST ($/BBL)	32.71	32.06	32.06	32.66	31.89	30.93
8. AMOUNT ($)	373,604	475,381	212,107	30,632	145,092	430,831
9. ENDING INVENTORY:						
10. UNITS (BBL)	14,883	14,883	14,883	14,883	14,883	14,883
11. UNIT COST ($/BBL)	32.12	31.56	31.29	31.23	30.93	30.43
12. AMOUNT ($)	478,107	469,754	465,630	464,809	460,329	452,923
13. DAYS SUPPLY:	61	111	71	48	39	38
LIGHT OIL						
14. PURCHASES:						
15. UNITS (BBL)	24,465	20,800	24,527	16,789	28,266	21,952
16. UNIT COST ($/BBL)	38.50	38.06	36.76	35.26	34.25	33.63
17. AMOUNT ($)	941,977	791,719	901,496	591,933	968,020	738,315
18. BURNED:						
19. UNITS (BBL)	19,045	16,616	19,911	11,507	22,906	16,514
20. UNIT COST ($/BBL)	38.60	38.53	37.96	37.50	36.05	35.88
21. AMOUNT ($)	735,063	640,237	755,874	431,545	825,727	592,525
22. ENDING INVENTORY:						
23. UNITS (BBL)	77,076	77,076	77,076	77,076	77,076	77,076
24. UNIT COST ($/BBL)	37.72	37.70	37.41	37.01	36.37	35.77
25. AMOUNT ($)	2,907,445	2,905,899	2,883,170	2,852,651	2,803,435	2,757,136
26. DAYS SUPPLY: NORMAL	113	100	106	87	85	86
27. DAYS SUPPLY: EMERGENCY	11	11	11	11	11	11
COAL						
28. PURCHASES:						
29. UNITS (TONS)	336,000	336,000	351,000	376,000	391,000	381,000
30. UNIT COST ($/TON)	48.42	48.30	49.56	49.29	49.35	49.14
31. AMOUNT ($)	16,268,397	16,227,312	17,396,126	18,531,163	19,297,035	18,723,248
32. BURNED:						
33. UNITS (TONS)	459,695	379,708	387,964	406,134	436,080	425,303
34. UNIT COST ($/TON)	49.15	49.36	49.98	50.11	50.03	49.96
35. AMOUNT ($)	22,592,246	18,743,931	19,389,972	20,349,959	21,819,220	21,249,456
36. ENDING INVENTORY:						
37. UNITS (TONS)	753,080	709,372	672,408	642,274	597,194	552,891
38. UNIT COST ($/TON)	47.78	47.50	47.52	47.34	47.15	46.85
39. AMOUNT ($)	35,980,204	33,692,330	31,950,040	30,403,605	28,157,186	25,903,480
40. DAYS SUPPLY:	58	52	49	45	42	39
NATURAL GAS						
41. PURCHASES:						
42. UNITS (MCF)	3,392,280	3,667,252	4,268,447	4,214,514	5,309,093	5,557,919
43. UNIT COST ($/MCF)	7.05	6.99	6.81	6.16	6.01	6.01
44. AMOUNT ($)	23,915,167	25,619,063	29,063,944	25,955,113	31,906,347	33,422,327
45. BURNED:						
46. UNITS (MCF)	3,392,280	3,667,252	4,268,447	4,214,514	5,309,093	5,557,919
47. UNIT COST ($/MCF)	7.05	6.99	6.81	6.16	6.01	6.01
48. AMOUNT ($)	23,915,167	25,619,063	29,063,944	25,955,113	31,906,347	33,422,327
49. ENDING INVENTORY:						
50. UNITS (MCF)	0	0	0	0	0	0
51. UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00
52. AMOUNT ($)	0	0	0	0	0	0
53. DAYS SUPPLY:	0	0	0	0	0	0
NUCLEAR						
54. BURNED:						
55. UNITS (MMBTU)	0	0	0	0	0	0
56. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
57. AMOUNT ($)	0	0	0	0	0	0
OTHER						
58. PURCHASES:						
59. UNITS (MMBTU)	0	0	0	0	0	0
60. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
61. AMOUNT ($)	0	0	0	0	0	0
62. BURNED:						
63. UNITS (MMBTU)	0	0	0	0	0	0
64. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
65. AMOUNT ($)	0	0	0	0	0	0
66. ENDING INVENTORY:						
67. UNITS (MMBTU)	0	0	0	0	0	0
68. UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00
69. AMOUNT ($)	0	0	0	0	0	0
70. DAYS SUPPLY:	0	0	0	0	0	0

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

SYSTEM GENERATED FUEL COST INVENTORY ANALYSIS
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

		Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	TOTAL
	HEAVY OIL							
1.	PURCHASES:							
2.	UNITS (BBL)	9,939	11,117	14,790	10,398	3,682	5,344	107,552
3.	UNIT COST ($/BBL)	29.69	29.52	29.35	29.18	29.03	28.89	29.98
4.	AMOUNT ($)	295,122	328,125	434,054	303,408	106,893	154,404	3,224,012
5.	BURNED:							
6.	UNITS (BBL)	9,939	11,117	14,790	10,398	3,682	5,344	107,552
7.	UNIT COST ($/BBL)	30.76	30.45	30.06	30.04	30.59	30.18	31.08
8.	AMOUNT ($)	305,727	338,508	444,661	312,305	112,641	161,265	3,342,754
9.	ENDING INVENTORY:							
10.	UNITS (BBL)	14,883	14,883	14,883	14,883	14,883	14,883	14,883
11.	UNIT COST ($/BBL)	30.14	29.87	29.61	29.43	29.35	29.23	29.23
12.	AMOUNT ($)	448,516	444,564	440,682	438,045	436,859	435,049	435,049
13.	DAYS SUPPLY:	38	47	70	50	32	27	-
	LIGHT OIL							
14.	PURCHASES:							
15.	UNITS (BBL)	30,038	31,243	21,639	21,443	21,369	22,706	285,237
16.	UNIT COST ($/BBL)	33.63	33.68	33.75	34.01	34.21	34.41	34.95
17.	AMOUNT ($)	1,010,149	1,052,192	730,331	729,317	731,133	781,242	9,967,824
18.	BURNED:							
19.	UNITS (BBL)	24,618	25,818	16,612	16,719	16,605	17,316	224,187
20.	UNIT COST ($/BBL)	34.90	34.62	34.76	34.61	34.66	34.67	35.98
21.	AMOUNT ($)	859,223	893,797	577,392	578,643	575,552	600,386	8,065,964
22.	ENDING INVENTORY:							
23.	UNITS (BBL)	77,076	77,076	77,076	77,076	77,076	77,076	77,076
24.	UNIT COST ($/BBL)	35.28	34.90	34.64	34.50	34.41	34.38	34.38
25.	AMOUNT ($)	2,718,956	2,689,767	2,669,967	2,659,099	2,652,387	2,650,063	2,650,063
26.	DAYS SUPPLY: NORMAL	95	110	107	106	106	103	-
27.	DAYS SUPPLY: EMERGENCY	11	11	11	11	11	11	-
	COAL							
28.	PURCHASES:							
29.	UNITS (TONS)	425,000	420,000	415,000	400,000	361,000	381,000	4,573,000
30.	UNIT COST ($/TON)	49.02	49.78	49.61	48.58	49.05	48.43	49.06
31.	AMOUNT ($)	20,835,285	20,908,961	20,587,188	19,433,217	17,705,815	18,450,719	224,364,466
32.	BURNED:							
33.	UNITS (TONS)	437,651	440,076	426,762	352,749	381,008	437,430	4,970,560
34.	UNIT COST ($/TON)	50.04	50.36	50.42	47.92	50.15	49.61	49.78
35.	AMOUNT ($)	21,900,424	22,164,060	21,518,484	16,902,115	19,109,295	21,702,738	247,441,900
36.	ENDING INVENTORY:							
37.	UNITS (TONS)	540,240	520,164	508,402	555,653	535,645	479,215	479,215
38.	UNIT COST ($/TON)	46.48	46.38	46.12	47.19	46.79	46.07	46.07
39.	AMOUNT ($)	25,109,835	24,123,535	23,446,655	26,220,454	25,063,252	22,076,797	22,076,797
40.	DAYS SUPPLY:	41	41	40	41	39	36	-
	NATURAL GAS							
41.	PURCHASES:							
42.	UNITS (MCF)	6,022,454	6,152,907	5,615,152	6,019,337	4,315,019	4,155,517	58,689,891
43.	UNIT COST ($/MCF)	6.00	6.02	6.02	6.03	6.22	6.41	6.25
44.	AMOUNT ($)	36,137,796	37,013,497	33,777,962	36,321,071	26,828,997	26,636,730	366,598,014
45.	BURNED:							
46.	UNITS (MCF)	6,022,454	6,152,907	5,615,152	6,019,337	4,315,019	4,155,517	58,689,891
47.	UNIT COST ($/MCF)	6.00	6.02	6.02	6.03	6.22	6.41	6.25
48.	AMOUNT ($)	36,137,796	37,013,496	33,777,962	36,321,072	26,828,997	26,636,731	366,598,015
49.	ENDING INVENTORY:							
50.	UNITS (MCF)	0	0	0	0	0	0	0
51.	UNIT COST ($/MCF)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
52.	AMOUNT ($)	0	0	0	0	0	0	0
53.	DAYS SUPPLY:	0	0	0	0	0	0	-
	NUCLEAR							
54.	BURNED:							
55.	UNITS (MMBTU)	0	0	0	0	0	0	0
56.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
57.	AMOUNT ($)	0	0	0	0	0	0	0
	OTHER							
58.	PURCHASES:							
59.	UNITS (MMBTU)	0	0	0	0	0	0	0
60.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
61.	AMOUNT ($)	0	0	0	0	0	0	0
62.	BURNED:							
63.	UNITS (MMBTU)	0	0	0	0	0	0	0
64.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
65.	AMOUNT ($)	0	0	0	0	0	0	0
66.	ENDING INVENTORY:							
67.	UNITS (MMBTU)	0	0	0	0	0	0	0
68.	UNIT COST ($/MMBTU)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
69.	AMOUNT ($)	0	0	0	0	0	0	0
70.	DAYS SUPPLY:	0	0	0	0	0	0	-

NOTE: BEGINNING & ENDING INVENTORIES MAY NOT BALANCE BECAUSE OF THE FOLLOWING
(1) LIGHT OIL-OTHER USAGE NOT INCLUDED. (2) COAL-ADDITIVES, IGNITOR AND/OR INVENTORY ADJUSTMENT ARE INCLUDED.

POWER SOLD
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

(1)	(2)	(3)		(4)	(5)	(6)	(7)		(8)	(9)	(10)
MONTH	SOLD TO	TYPE & SCHEDULE		TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	CENTS/KWH (A) FUEL COST	CENTS/KWH (B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST $	GAINS ON MARKET BASED SALES
Jan-04											
	VARIOUS	JURISD.	SCH. -D	2,009.0	0.0	2,009.0	2.648	2.648	53,200.00	53,200.00	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	MKT. BASE	16,071.0	0.0	16,071.0	4.757	5.721	764,500.00	919,500.00	102,100.00
	TOTAL			18,080.0	0.0	18,080.0	4.523	5.380	817,700.00	972,700.00	102,100.00
Feb-04											
	VARIOUS	JURISD.	SCH. -D	1,879.0	0.0	1,879.0	2.485	2.485	46,700.00	46,700.00	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	MKT. BASE	31,700.0	0.0	31,700.0	4.836	5.917	1,533,100.00	1,875,700.00	238,300.00
	TOTAL			33,579.0	0.0	33,579.0	4.705	5.725	1,579,800.00	1,922,400.00	238,300.00
Mar-04											
	VARIOUS	JURISD.	SCH. -D	2,009.0	0.0	2,009.0	2.648	2.648	53,200.00	53,200.00	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	MKT. BASE	30,761.0	0.0	30,761.0	4.705	5.759	1,447,400.00	1,771,400.00	222,800.00
	TOTAL			32,770.0	0.0	32,770.0	4.579	5.568	1,500,600.00	1,824,600.00	222,800.00
Apr-04											
	VARIOUS	JURISD.	SCH. -D	1,944.0	0.0	1,944.0	2.567	2.567	49,900.00	49,900.00	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	MKT. BASE	32,296.0	0.0	32,296.0	4.264	5.396	1,377,100.00	1,742,600.00	259,200.00
	TOTAL			34,240.0	0.0	34,240.0	4.168	5.235	1,427,000.00	1,792,500.00	259,200.00
May-04											
	VARIOUS	JURISD.	SCH. -D	2,009.0	0.0	2,009.0	2.648	2.648	53,200.00	53,200.00	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	MKT. BASE	29,445.0	0.0	29,445.0	4.224	5.600	1,243,700.00	1,649,000.00	308,400.00
	TOTAL			31,454.0	0.0	31,454.0	4.123	5.412	1,296,900.00	1,702,200.00	308,400.00
Jun-04											
	VARIOUS	JURISD.	SCH. -D	1,944.0	0.0	1,944.0	2.567	2.567	49,900.00	49,900.00	
	HPP	SEPARATED	CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD.	MKT. BASE	15,135.0	0.0	15,135.0	4.376	5.419	662,300.00	820,200.00	106,100.00
	TOTAL			17,079.0	0.0	17,079.0	4.170	5.095	712,200.00	870,100.00	106,100.00

POWER SOLD
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)	(9)	(10)
						CENTS/KWH				
MONTH	SOLD TO	TYPE & SCHEDULE	TOTAL MWH SOLD	MWH WHEELED FROM OTHER SYSTEMS	MWH FROM OWN GENERATION	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT	TOTAL COST $	GAINS ON MARKET BASED SALES
Jul-04										
	VARIOUS	JURISD. SCH. -D	2,009.0	0.0	2,009.0	2.648	2.648	53,200.00	53,200.00	
	HPP	SEPARATED CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD. MKT. BASE	14,344.0	0.0	14,344.0	4.546	5.607	652,100.00	804,300.00	105,000.00
	TOTAL		16,353.0	0.0	16,353.0	4.313	5.244	705,300.00	857,500.00	105,000.00
Aug-04										
	VARIOUS	JURISD. SCH. -D	2,009.0	0.0	2,009.0	2.648	2.648	53,200.00	53,200.00	
	HPP	SEPARATED CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD. MKT. BASE	17,195.0	0.0	17,195.0	4.918	6.040	845,700.00	1,038,500.00	136,200.00
	TOTAL		19,204.0	0.0	19,204.0	4.681	5.685	898,900.00	1,091,700.00	136,200.00
Sep-04										
	VARIOUS	JURISD. SCH. -D	1,944.0	0.0	1,944.0	2.567	2.567	49,900.00	49,900.00	
	HPP	SEPARATED CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD. MKT. BASE	21,263.0	0.0	21,263.0	4.462	5.388	948,800.00	1,145,600.00	126,800.00
	TOTAL		23,207.0	0.0	23,207.0	4.303	5.151	998,700.00	1,195,500.00	126,800.00
Oct-04										
	VARIOUS	JURISD. SCH. -D	2,009.0	0.0	2,009.0	2.648	2.648	53,200.00	53,200.00	
	HPP	SEPARATED CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD. MKT. BASE	10,039.0	0.0	10,039.0	4.407	5.236	442,400.00	525,600.00	50,200.00
	TOTAL		12,048.0	0.0	12,048.0	4.114	4.804	495,600.00	578,800.00	50,200.00
Nov-04										
	VARIOUS	JURISD. SCH. -D	1,944.0	0.0	1,944.0	2.567	2.567	49,900.00	49,900.00	
	HPP	SEPARATED CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD. MKT. BASE	29,429.0	0.0	29,429.0	4.330	5.153	1,274,400.00	1,516,400.00	145,200.00
	TOTAL		31,373.0	0.0	31,373.0	4.221	4.993	1,324,300.00	1,566,300.00	145,200.00
Dec-04										
	VARIOUS	JURISD. SCH. -D	2,009.0	0.0	2,009.0	2.648	2.648	53,200.00	53,200.00	
	HPP	SEPARATED CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
	VARIOUS	JURISD. MKT. BASE	32,594.0	0.0	32,594.0	4.463	5.231	1,454,700.00	1,705,100.00	143,200.00
	TOTAL		34,603.0	0.0	34,603.0	4.358	5.081	1,507,900.00	1,758,300.00	143,200.00
Jan-04	VARIOUS	JURISD. SCH. -D	23,718.0	0.0	23,718.0	2.609	2.609	618,700.00	618,700.00	
THRU	HPP	SEPARATED CONTRACT	0.0	0.0	0.0	0.000	0.000	0.00	0.00	
Dec-04	VARIOUS	JURISD. MKT. BASE	280,272.0	0.0	280,272.0	4.512	5.535	12,646,200.00	15,513,900.00	1,945,500.00
	TOTAL		303,990.0	0.0	303,990.0	4.364	5.307	13,264,900.00	16,132,600.00	1,945,500.00

PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

(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
Jan-04									
	VARIOUS	SCH. J	315.0	0.0	129.0	186.0	8.011	8.011	14,900.00
	HPP	IPP	4,380.0	0.0	0.0	4,380.0	9.260	9.260	405,600.00
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	12,600.0	0.0	0.0	12,600.0	2.904	2.904	365,900.00
	TOTAL		17,295.0	0.0	129.0	17,166.0	4.581	4.581	786,400.00
Feb-04									
	VARIOUS	SCH. J	64.0	0.0	44.0	20.0	8.000	8.000	1,600.00
	HPP	IPP	5,292.0	0.0	0.0	5,292.0	8.369	8.369	442,900.00
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	12,882.0	0.0	0.0	12,882.0	4.259	4.259	548,600.00
	TOTAL		18,238.0	0.0	44.0	18,194.0	5.458	5.458	993,100.00
Mar-04									
	VARIOUS	SCH. J	223.0	0.0	166.0	57.0	7.544	7.544	4,300.00
	HPP	IPP	4,816.0	0.0	0.0	4,816.0	8.129	8.129	391,500.00
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	18,191.0	0.0	0.0	18,191.0	5.402	5.402	982,700.00
	TOTAL		23,230.0	0.0	166.0	23,064.0	5.977	5.977	1,378,500.00
Apr-04									
	VARIOUS	SCH. J	75.0	0.0	61.0	14.0	7.143	7.143	1,000.00
	HPP	IPP	9,188.0	0.0	0.0	9,188.0	6.611	6.611	607,400.00
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	13,063.0	0.0	0.0	13,063.0	3.522	3.522	460,100.00
	TOTAL		22,326.0	0.0	61.0	22,265.0	4.799	4.799	1,068,500.00
May-04									
	VARIOUS	SCH. J	890.0	0.0	647.0	243.0	7.819	7.819	19,000.00
	HPP	IPP	29,581.0	0.0	0.0	29,581.0	5.649	5.649	1,671,000.00
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	25,022.0	0.0	0.0	25,022.0	4.194	4.194	1,049,500.00
	TOTAL		55,493.0	0.0	647.0	54,846.0	4.995	4.995	2,739,500.00
Jun-04									
	VARIOUS	SCH. J	3,441.0	0.0	2,434.0	1,007.0	7.110	7.110	71,600.00
	HPP	IPP	50,894.0	0.0	0.0	50,894.0	5.376	5.376	2,735,900.00
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	86,825.0	0.0	0.0	86,825.0	4.993	4.993	4,335,500.00
	TOTAL		141,160.0	0.0	2,434.0	138,726.0	5.149	5.149	7,143,000.00

PURCHASED POWER
EXCLUSIVE OF ECONOMY AND QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)		(9)
				MWH	MWH		CENTS/KWH		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	FOR OTHER UTILITIES	FOR INTERRUP-TIBLE	MWH FOR FIRM	(A) FUEL COST	(B) TOTAL COST	TOTAL $ FOR FUEL ADJUSTMENT
Jul-04									
	VARIOUS	SCH. J	4,933.0	0.0	3,156.0	1,777.0	7.777	7.777	138,200.00
	HPP	IPP	39,199.0	0.0	0.0	39,199.0	5.609	5.609	2,198,500.00
	VARIOUS	OTHER	5,878.0	0.0	0.0	5,878.0	13.241	13.241	778,300.00
	VARIOUS	MKT BASED	101,971.0	0.0	0.0	101,971.0	5.290	5.290	5,394,200.00
	TOTAL		**151,981.0**	**0.0**	**3,156.0**	**148,825.0**	**5.718**	**5.718**	**8,509,200.00**
Aug-04									
	VARIOUS	SCH. J	4,455.0	0.0	2,604.0	1,851.0	7.947	7.947	147,100.00
	HPP	IPP	42,392.0	0.0	0.0	42,392.0	5.607	5.607	2,377,100.00
	VARIOUS	OTHER	6,474.0	0.0	0.0	6,474.0	13.295	13.295	860,700.00
	VARIOUS	MKT BASED	90,572.0	0.0	0.0	90,572.0	5.311	5.311	4,810,500.00
	TOTAL		**143,893.0**	**0.0**	**2,604.0**	**141,289.0**	**5.800**	**5.800**	**8,195,400.00**
Sep-04									
	VARIOUS	SCH. J	2,981.0	0.0	2,051.0	930.0	7.258	7.258	67,500.00
	HPP	IPP	52,285.0	0.0	0.0	52,285.0	5.389	5.389	2,817,600.00
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	70,606.0	0.0	0.0	70,606.0	5.393	5.393	3,807,900.00
	TOTAL		**125,872.0**	**0.0**	**2,051.0**	**123,821.0**	**5.405**	**5.405**	**6,693,000.00**
Oct-04									
	VARIOUS	SCH. J	4,665.0	0.0	3,019.0	1,646.0	7.175	7.175	118,100.00
	HPP	IPP	17,721.0	0.0	0.0	17,721.0	5.822	5.822	1,031,700.00
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	87,021.0	0.0	0.0	87,021.0	4.642	4.642	4,039,100.00
	TOTAL		**109,407.0**	**0.0**	**3,019.0**	**106,388.0**	**4.877**	**4.877**	**5,188,900.00**
Nov-04									
	VARIOUS	SCH. J	38.0	0.0	31.0	7.0	5.714	5.714	400.00
	HPP	IPP	4,579.0	0.0	0.0	4,579.0	7.801	7.801	357,200.00
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	12,064.0	0.0	0.0	12,064.0	3.958	3.958	477,500.00
	TOTAL		**16,681.0**	**0.0**	**31.0**	**16,650.0**	**5.016**	**5.016**	**835,100.00**
Dec-04									
	VARIOUS	SCH. J	64.0	0.0	48.0	16.0	6.875	6.875	1,100.00
	HPP	IPP	16,185.0	0.0	0.0	16,185.0	6.411	6.411	1,037,700.00
	VARIOUS	OTHER	0.0	0.0	0.0	0.0	0.000	0.000	0.00
	VARIOUS	MKT BASED	34,678.0	0.0	0.0	34,678.0	4.476	4.476	1,552,200.00
	TOTAL		**50,927.0**	**0.0**	**48.0**	**50,879.0**	**5.092**	**5.092**	**2,591,000.00**
Jan-04	VARIOUS	SCH. J	22,144.0	0.0	14,390.0	7,754.0	7.542	7.542	584,800.00
THRU	HPP	IPP	276,512.0	0.0	0.0	276,512.0	5.813	5.813	16,074,100.00
Dec-04	VARIOUS	OTHER	12,352.0	0.0	0.0	12,352.0	13.269	13.269	1,639,000.00
	VARIOUS	MKT BASED	565,495.0	0.0	0.0	565,495.0	4.920	4.920	27,823,700.00
	TOTAL		**876,503.0**	**0.0**	**14,390.0**	**862,113.0**	**5.350**	**5.350**	**46,121,600.00**

SCHEDULE E8

ENERGY PAYMENT TO QUALIFYING FACILITIES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

(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
Jan-04	VARIOUS	CO-GEN.	37,437.0	0.0	0.0	37,437.0	2.860	2.860	1,070,700.00
Feb-04	VARIOUS	CO-GEN.	35,025.0	0.0	0.0	35,025.0	2.889	2.889	1,012,000.00
Mar-04	VARIOUS	CO-GEN.	37,436.0	0.0	0.0	37,436.0	2.900	2.900	1,085,600.00
Apr-04	VARIOUS	CO-GEN.	38,136.0	0.0	0.0	38,136.0	2.879	2.879	1,097,900.00
May-04	VARIOUS	CO-GEN.	39,409.0	0.0	0.0	39,409.0	2.900	2.900	1,142,900.00
Jun-04	VARIOUS	CO-GEN.	38,136.0	0.0	0.0	38,136.0	2.952	2.952	1,125,800.00
Jul-04	VARIOUS	CO-GEN.	39,409.0	0.0	0.0	39,409.0	2.944	2.944	1,160,100.00
Aug-04	VARIOUS	CO-GEN.	39,409.0	0.0	0.0	39,409.0	2.963	2.963	1,167,700.00
Sep-04	VARIOUS	CO-GEN.	38,136.0	0.0	0.0	38,136.0	2.941	2.941	1,121,500.00
Oct-04	VARIOUS	CO-GEN.	39,409.0	0.0	0.0	39,409.0	2.838	2.838	1,118,300.00
Nov-04	VARIOUS	CO-GEN.	36,228.0	0.0	0.0	36,228.0	2.807	2.807	1,016,900.00
Dec-04	VARIOUS	CO-GEN.	37,437.0	0.0	0.0	37,437.0	2.793	2.793	1,045,800.00
TOTAL			**455,607.0**	**0.0**	**0.0**	**455,607.0**	**2.890**	**2.890**	**13,165,200.00**

ECONOMY ENERGY PURCHASES
TAMPA ELECTRIC COMPANY
ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

SCHEDULE E9

(1)	(2)	(3)	(4)	(5)	(6)	(7)		(8)
						COST IF GENERATED		
MONTH	PURCHASED FROM	TYPE & SCHEDULE	TOTAL MWH PURCHASED	TRANSACT. COST cents/KWH	TOTAL $ FOR FUEL ADJUSTMENT	(A) CENTS PER KWH	(B) ($000)	FUEL SAVINGS (7B)-(6)
Jan-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Feb-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Mar-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Apr-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
May-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Jun-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Jul-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Aug-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Sep-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Oct-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Nov-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
Dec-04	VARIOUS	ECON.	0.0	0.000	0.00	0.000	0.00	0.00
TOTAL			**0.0**	**0.000**	**0.00**	**0.000**	**0.00**	**0.00**

SCHEDULE E10

RESIDENTIAL BILL COMPARISON
FOR MONTHLY USAGE OF 1000 KWH
TAMPA ELECTRIC COMPANY

ESTIMATED FOR THE PERIOD: JANUARY 2004 THROUGH DECEMBER 2004

	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	TOTAL
Base Rate Revenue	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92	$ 51.92
Fuel Recovery Revenue	39.84	39.84	39.84	39.84	39.84	39.84	39.84	39.84	39.84	39.84	39.84	39.84	39.84
Conservation Revenue	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11	1.11
Capacity Revenue	2.67	2.67	2.67	2.67	2.67	2.67	2.67	2.67	2.67	2.67	2.67	2.67	2.67
Environmental Revenue	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44
Revenue Refund	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Florida Gross Receipts Tax Revenue	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49	2.49
TOTAL REVENUE	**$ 99.47**	**$ 99.47**	**$ 99.47**	**$ 99.47**	**$ 99.47**	**$ 99.47**	**$ 99.47**	**$ 99.47**	**$ 99.47**	**$ 99.47**	**$ 99.47**	**$ 99.47**	**$ 99.47**

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE
TAMPA ELECTRIC COMPANY

SCHEDULE H1

PERIOD: JANUARY THROUGH DECEMBER

		ACTUAL 2001	ACTUAL 2002	ACT/EST 2003	EST 2004	DIFFERENCE (%) 2002-2001	2003-2002	2004-2003
FUEL COST OF SYSTEM NET GENERATION ($)								
1	HEAVY OIL [1]	4,028,693	4,372,207	4,611,336	3,342,754	8.5%	5.5%	-27.5%
2	LIGHT OIL [1]	14,635,750	9,851,474	9,476,420	8,065,964	-32.7%	-3.8%	-14.9%
3	COAL	333,923,632	310,692,261	278,443,720	247,441,900	-7.0%	-10.4%	-11.1%
4	NATURAL GAS	16,308,870	31,676,384	230,292,424	366,598,015	94.2%	627.0%	59.2%
5	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
6	OTHER	0	0	0	0	0.0%	0.0%	0.0%
7	**TOTAL ($)**	**368,896,945**	**356,592,326**	**522,823,900**	**625,448,633**	**-3.3%**	**46.6%**	**19.6%**
SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL [1]	89,679	86,648	82,506	69,342	-3.4%	-4.8%	-16.0%
9	LIGHT OIL [1]	210,575	191,196	148,215	139,463	-9.2%	-22.5%	-5.9%
10	COAL	15,533,571	14,875,280	12,684,842	11,106,202	-4.2%	-14.7%	-12.4%
11	NATURAL GAS	311,518	473,450	4,042,359	7,935,228	52.0%	753.8%	96.3%
12	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
13	OTHER	0	0	0	0	0.0%	0.0%	0.0%
14	**TOTAL (MWH)**	**16,145,343**	**15,626,574**	**16,957,722**	**19,250,235**	**-3.2%**	**8.5%**	**13.5%**
UNITS OF FUEL BURNED								
15	HEAVY OIL (BBL) [1]	143,160	137,183	127,968	107,552	-4.2%	-6.7%	-16.0%
16	LIGHT OIL (BBL) [1]	414,884	322,371	246,917	224,187	-22.3%	-23.4%	-9.2%
17	COAL (TON)	7,288,712	7,100,139	5,824,388	4,970,560	-2.6%	-18.0%	-14.7%
18	NATURAL GAS (MCF)	3,387,801	5,151,423	32,923,837	58,689,891	52.1%	539.1%	78.3%
19	NUCLEAR (MMBTU)	0	0	0	0	0.0%	0.0%	0.0%
20	OTHER	0	0	0	0	0.0%	0.0%	0.0%
BTUS BURNED (MMBTU)								
21	HEAVY OIL [1]	898,474	860,634	803,125	675,330	-4.2%	-6.7%	-15.9%
22	LIGHT OIL [1]	2,374,840	1,855,534	1,641,306	1,300,800	-21.9%	-11.5%	-20.7%
23	COAL	167,785,452	165,425,948	140,487,037	120,749,207	-1.4%	-15.1%	-14.0%
24	NATURAL GAS	3,373,038	5,420,729	34,118,124	60,333,179	60.7%	529.4%	76.8%
25	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
26	OTHER	0	0	0	0	0.0%	0.0%	0.0%
27	**TOTAL (MMBTU)**	**174,431,804**	**173,562,845**	**177,049,592**	**183,058,516**	**-0.5%**	**2.0%**	**3.4%**
GENERATION MIX (% MWH)								
28	HEAVY OIL [1]	0.56	0.55	0.49	0.36	-	-	-
29	LIGHT OIL [1]	1.30	1.22	0.87	0.72	-	-	-
30	COAL	96.21	95.20	74.80	57.70	-	-	-
31	NATURAL GAS	1.93	3.03	23.84	41.22	-	-	-
32	NUCLEAR	0.00	0.00	0.00	0.00	-	-	-
33	OTHER	0.00	0.00	0.00	0.00	-	-	-
34	**TOTAL (%)**	100.00	100.00	100.00	100.00	-	-	-
FUEL COST PER UNIT								
35	HEAVY OIL ($/BBL) [1]	28.14	31.87	36.04	31.08	13.3%	13.1%	-13.8%
36	LIGHT OIL ($/BBL) [1]	35.28	30.56	38.38	35.98	-13.4%	25.6%	-6.3%
37	COAL ($/TON)	45.81	43.76	47.81	49.78	-4.5%	9.3%	4.1%
38	NATURAL GAS ($/MCF)	4.81	6.15	6.99	6.25	27.9%	13.7%	-10.6%
39	NUCLEAR ($/MMBTU)	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
40	OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
FUEL COST PER MMBTU ($/MMBTU)								
41	HEAVY OIL [1]	4.48	5.08	5.74	4.95	13.4%	13.0%	-13.8%
42	LIGHT OIL [1]	6.16	5.31	5.77	6.20	-13.8%	8.7%	7.5%
43	COAL	1.99	1.88	1.98	2.05	-5.5%	5.3%	3.5%
44	NATURAL GAS	4.84	5.84	6.75	6.06	20.7%	15.6%	-9.9%
45	NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
46	OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
47	**TOTAL ($/MMBTU)**	**2.11**	**2.05**	**2.95**	**3.42**	**-2.8%**	**43.9%**	**15.9%**
BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL [1]	10,019	9,933	9,734	9,739	-0.9%	-2.0%	0.1%
49	LIGHT OIL [1]	11,278	9,705	11,074	9,327	-13.9%	14.1%	-15.8%
50	COAL	10,801	11,121	11,075	10,872	3.0%	-0.4%	-1.8%
51	NATURAL GAS	10,828	11,449	8,440	7,603	5.7%	-26.3%	-9.9%
52	NUCLEAR	0	0	0	0	0.0%	0.0%	0.0%
53	OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
54	**TOTAL (BTU/KWH)**	10,804	11,107	10,441	9,509	2.8%	-6.0%	-8.9%
GENERATED FUEL COST PER KWH (cents/KWH)								
55	HEAVY OIL [1]	4.49	5.05	5.59	4.82	12.5%	10.7%	-13.8%
56	LIGHT OIL [1]	6.95	5.15	6.39	5.78	-25.9%	24.1%	-9.5%
57	COAL	2.15	2.09	2.20	2.23	-2.8%	5.3%	1.4%
58	NATURAL GAS	5.24	6.69	5.70	4.62	27.7%	-14.8%	-18.9%
59	NUCLEAR	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
60	OTHER	0.00	0.00	0.00	0.00	0.0%	0.0%	0.0%
61	**TOTAL (cents/KWH)**	2.28	2.28	3.08	3.25	0.0%	35.1%	5.5%

[1] *DISTILLATE (BBLS, MWH & $) USED FOR FIRING, HOT STANDBY, ETC. IS INCLUDED IN FOSSIL STEAM PLANTS.*

EXHIBITS TO THE TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 3

PROPOSED 2004 COST RECOVERY FACTORS
RESIDENTIAL BILL COMPOSITE EFFECT

EXHIBIT NO. _____
TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
(JDJ-3)
DOCUMENT NO. 3
PAGE 1 OF 1
FILED: 09/12/03

RESIDENTIAL BILL COMPARISON

1,000 kWh MONTHLY USAGE

Bill Component	Apr - Dec 2003	Jan - Dec 2004
Customer Charge	$8.50	$8.50
Energy Charge	43.42	43.42
Fuel	34.50	39.84
Capacity	2.77	2.67
Energy Conservation	1.16	1.11
Environmental	1.44	1.44
Subtotal	**$91.79**	**$96.98**
Gross Receipts Tax	2.35	2.49
TOTAL	**$94.14**	**$99.47**

Sheree L. Brown

Managing Principal

Professional Registration	Certified Public Accountant	
Education	B.S. in Accounting University of West Florida Pensacola, Florida	
	M.B.A. University of Central Florida Orlando, Florida	
Professional and Business History	AEIS/SVBK CONSULTING GROUP R.W. Beck & Associates	1985 - Present 1981 - 1985

Professional Experience

Ms. Brown has extensive experience in the emerging deregulation of the electric industry. She has provided expert testimony on behalf of clients on such issues as stranded cost calculation and recovery, market pricing, and public policy. In participating in deregulation proceedings, Ms. Brown has been responsible for the preparation of comments to regulatory commissions regarding policy issues on restructuring. She has participated in technical conferences held to set policy issues and assisted legal counsel in the preparation of legal positions regarding previous rate agreements and other agreements entered into relevant to the proceedings. In her experience, Ms. Brown has been responsible for the development of methodologies for determining and recovering interim stranded costs. Ms. Brown has also been called on to participate in panel discussions before the regulators regarding the many issues relative to the deregulation of the electric industry.

Ms. Brown served as a member of the Association of Higher Education Facilities Managers' Energy Task Force on deregulation issues. Further, she has been responsible for positioning clients to actively and successfully participate in a Retail Wheeling Pilot Program. In her capacity as lead financial consultant, Ms. Brown assisted in public information campaigns to encourage volunteers, filed comments with regulators to influence the selection process, and developed an aggregation program for eligible Pilot Program participants.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 31
COMPANY/ FIPUG
WITNESS: SLB-1 thru SLB-8
DATE: 11-12-03

Ms. Brown has developed qualified aggregation programs and participated in public workshops to encourage eligible businesses and residents to participate in municipal aggregation programs. Ms. Brown has negotiated and evaluated power supply arrangements for municipal electric systems, universities, and retail aggregation programs. Such negotiations have included joint ownership arrangements, block power purchases combined with supplemental partial requirements, formula rate contracts, economy purchases, full requirements and partial requirements combined with self-generation. She has evaluated the economic feasibility of peaking generating facilities and has negotiated terms and conditions with the electric supplier to enhance the economic benefits of peaking operations.

Ms. Brown has extensive experience in wholesale and retail ratemaking and has represented numerous municipal, cooperative, university, and regulatory clients in proceedings before the Federal Energy Regulatory Commission and various state and local commissions. She has negotiated the settlement of rate cases and has presented expert testimony as a witness in litigated proceedings. As an expert witness, Ms. Brown has presented testimony on revenue requirement issues, cost-of-service studies and allocation methodologies, rate design, utility valuations, and terms and conditions of service.

Ms. Brown has also developed cost recovery methodologies for least cost integrated resource programs, including the effects of demand side management programs on interim recovery of fixed costs. She has additionally developed innovative rate structures designed to provide performance based incentives for demand side management performance.

Ms. Brown has evaluated the effects of capacity and transmission equalization under combined utility operations and the allocation of costs under joint dispatch arrangements. She has provided expert testimony on the effects of a proposed merger on individual utility operations.

Ms. Brown has performed numerous retail rate studies, including the development of revenue requirements, allocated cost-of-

service studies, and rate design. She has developed load forecasts using econometric modeling and has developed proforma operating results for rate phase in plans. She has additionally reviewed transfer policies and interdepartmental service contracts.

Ms. Brown has performed feasibility studies for the installation and operation of cogeneration facilities. She has evaluated the benefits of retaining cogeneration to offset retail electric requirements. She has also evaluated the requirements for standby service or reserves. Ms. Brown has successfully challenged the development of standby rates and terms and conditions of service, resulting in enhanced cogeneration project value. She has performed avoided cost calculations and has negotiated arrangements to sell cogeneration capacity and energy to the electric supplier. In addition, she has reviewed market alternatives to selling cogeneration capacity and energy for resale, including the effect of transmission arrangements on project viability.

Ms. Brown has negotiated the sale or purchase of utility systems or facilities, including the purchase or sale agreements; management, operating, and maintenance agreements, and design/construction agreements. She has enhanced project value by negotiating contractual guarantees, including operational efficiency and price guarantees. She has additionally negotiated long term gas supply contracts and financial hedging instruments, including SWAP agreements. She has negotiated transportation contracts, including banking arrangements, whereby excess contract gas is sold back to the transporter at market rates.

Ms. Brown has served on municipal strategic planning committees and has provided capital budgeting analyses for the evaluation of long-term planning alternatives. She has been extensively involved in the development of utility system management studies, including the review of labor costs and efficiencies, organization structure and financial condition. She has additionally performed billing audits.

Sheree L. Brown

Managing Principal

Regulatory/Legal Appearances	Federal Energy Regulatory Commission ("FERC") Council of the City of New Orleans ("CCNO") Florida Public Service Commission ("FPSC") Illinois Commerce Commission ("ICC") Louisiana Public Service Commission ("LPSC") Massachusetts Department of Telecommunications & Energy ("DTI Minnesota Public Utilities Commission ("MPUC") New Hampshire Public Utilities Commission ("NHPUC") North Carolina Utilities Commission ("NCUC") Texas Public Utilities Commission ("TPUC") Circuit Court, Ninth Judicial Circuit, Orange County, Florida Circuit Court, Eighteenth Judicial Circuit, Seminole County, Florida
Papers, Publications, and Presentations	"Determining the Value of Your Municipal Utility" – Presented to the Florida Municipal Electric Association and Florida Municipal Power Agency Annual Conference, 2003. "Municipalization/Franchise Evaluation" - Presented to the Tri-County League of Cities, Casselberry, Florida, January 2001. "Opportunities and Challenges: Managing Energy Costs in a Deregulated Environment" - Presented to the Dallas Chapter of the National Association of Purchasing Managers, Dallas, Texas, October, 2000. "Unbundling - Identifying Strategies for a Smooth Transition to Competition" - Presented at the South Carolina Association of Municipal Power Systems Annual Conference, Hilton Head, South Carolina, June, 1999. "Preparing for Deregulation - Understanding Electric Restructuring Issues Affecting Local Government" - Presented at the Taking Control of Your Destiny: Assessing the Impact of Electric Utility Industry Deregulation on Local Government Conference, Minneapolis, Minnesota, June, 1999. "Electric Restructuring and Utilities Deregulation: A Facility Manager's Guide" - Coauthor with the APPA Energy Task Force, The Association of Higher Education Facilities Managers,

Alexandria, Virginia, 1998.

"Utilities and You: A New Playing Field" - Presented at the U.S. Department of Energy Rebuild America 1998 Annual Conference, San Antonio, Texas, March 1998.

"Preparing for Deregulation in the Electric Utility Industry" - Presented at the Municipal Association of South Carolina 1998 Winter Meeting, Columbia, South Carolina, February, 1998.

"Electric Utility Deregulation" - Presented at the South Carolina Association of Municipal Power Systems Annual Event, Columbia, South Carolina, April 1997.

"Problems & Solutions in Retail Implementation: An Overview of Issues in Electric Utility Restructuring" - Presented at the Energy Awareness: Competition in Electricity in South Carolina Conference, Columbia, South Carolina, March 1997.

"Municipalization of Electric Utility Systems Seminar" - Presented to the Municipal Association of South Carolina, Columbia, South Carolina, August 1996.

Professional and Business Affiliations

American Institute of Certified Public Accountants
Florida Institute of Certified Public Accountants
American Public Power Association ("APPA")
Florida Government Finance Officers' Association ("FGFOA")

September 15: Credit FAQ - TECO Energy Inc.

Location: **New York**
Author: **William Ferara, Standard & Poor''s Analyst**
Date: **Monday, September 15, 2003**

Print Article
Email Article

TECO Energy Inc (BBB-/Watch Neg/A-3) derives about 70% of its cash flow from its regulated utility operations, Tampa Electric Co and Peoples Gas System.

The remaining portion is provided by nonregulatedbusinesses, including independent power generation, water bulk transportation, and coal operations. The company's ratings were placed on CreditWatch with negative implications on July 10, 2003.

Frequently Asked Questions

Why were TECO's ratings placed on CreditWatch?

Standard & Poor's Ratings Services placed its ratings on TECO Energy and affiliates on CreditWatch with negative implications as a result of an IRS announcement creating potential complications related to the company's sale of interests in its synthetic fuel production facilities. The IRS stated it will suspend issuing new private

letter rulings (PLR) for plants producing synthetic fuels. The CreditWatch listing for the TECO family reflects the uncertainties regarding the company's ability to sell interests in its synfuel production facilities to raise cash to halt the erosion of the company's weakened financial profile. TECO has a pending transaction with a PLR as a condition of sale for a 49% interest in its synfuel production facilities and had anticipatedselling an additional 40% interest in its facilities. The sale of these interests is expectedto contribute about $70 million in cash flow in 2003 and $90 million to cash flow annually in 2004 through 2007. An unfavorable outcome, which either halts or significantly delays the sales or ultimately affects cash flow, could lead to lower credit ratings.

When will the CreditWatch listing be resolved?

The CreditWatch listing will be resolved upon completion, or abandonment of, of the company's pending sale of interests in its synthetic fuel production facilities. However, the timing of the IRS ruling is uncertain and may be prolonged. Because the company has other asset sales that it is expecting to complete in the near term that are crucial to credit quality, the CreditWatch listing will most likely not extend beyond late 2003.

What would cause Standard & Poor's to lower its ratings on TECO?

An unfavorable outcome relatedto the company's sale of interests in its synfuel facilities, which either halts or significantly delays the sales or ultimately affects cash flow, could lead to lower credit ratings. Also, the lack of execution in selling other assets (TECO Transport, Guatemalan assets, and other assets), which are intended to help reduce debt leverage, could affect ratings. The company's ability to rationalize its merchant power exposure and drastically reduce these higher-risk holdings is critical to the company maintaining ratings.

To avoid a ratings downgrade, the company will have to complete planned asset sales to meaningfully reduce debt leverage and rationalize its merchant power investments to reduce exposure to a weak power price environment. The company also needs to maintain an adequate liquidity position and produce a more consistent cash flow stream

commensurate with the ratings. Ratings are supported by the expecteddramatic reduction in the company's business risk profile, which will be supported by a lower-risk consolidatedbusiness mix that is expectedto produce a steady cash flow stream, mostly generatedfrom integratedutility operations. Without this reduction in its risk profile, TECO's credit quality would be in the noninvestment-grade 'BB' category.

How successful has TECO been in selling off assets, and what expectations does Standard & Poor's have for future near-term sales?

TECO's active asset sale program was triggered by the company's weakened financial performance and liquidity position. The program has had mixed results and some delays, with the more challenging sales still seemingly difficult to achieve. So far, TECO has been unable to sell Tampa Electric's gasifier unit, and its pending sale of interests in its synfuel facilities is unclear. Regarding TECO Transport, an existing above-market contract between Transport and Tampa Electric, which soon expires, has placed some uncertainty around the unit's ultimate value, which is expectedto delay any potential sale. The potential sale of the company's merchant power assets seems challenging given the projectedlow energy prices in the markets that these plants were expectedto serve. However, TECO has completedthe sale of its coalbed methane assets for $140 million, as planned. Also, TECO recently announced the sale of its Hardee power plant for $115 million, plus the assumption of $103 million of debt, with completion expectedin September 2003. Although these sales provide some minor supportto the company's asset-sale program, the other sales are expectedto be more challenging.

Why does Standard & Poor's assign the same ratings to TECO Energy and Tampa Electric instead of separating them?

Standard & Poor's employs the consolidatedratings methodology for TECO and its subsidiaries. TECO's corporate credit rating is based on the financial and business risk profile analysis of the consolidatedenterprise and recognizes a free flow of funds throughout the organization and the absence of sufficient regulatory insulation. Thus, the ratings on Tampa Electric are expectedto mirror those of TECO, given the absence of proscriptive authority by the regulators in Florida. Any regulatory insulation or structural separation imposed to legally ring-fence Tampa Electric would be favorable for the utility's ratings. However, this action would drastically hinder TECO's ability to access the utility's strong cash flows and use its overall financial health to its benefit, which would result in significantly lower ratings at the parent.

On a stand-alone basis, how is Tampa Electric operating?

Tampa Electric continues to operate adequately on a stand-alone basis. The utility benefits from a solid financial profile and a strong business profile. Tampa Electric's credit metrics are solid with adjustedfunds from operations (FFO) to average total debt of about 25% and adjustedFFO interest coverage of more than 4.5x, respectively.

Debt levels for the regulatedutility is moderate at about 45% of total capitalization.

Tampa Electric's business profile is supported by strong customer growth, minimal reliance on industrial load, competitive rates, expectations of supportive regulation, and a solid regulatedgas local distribution unit, Peoples Gas. The utilities' long-term prospects are buoyed by Florida's vibrant economy and natural gas expansion into the southwest and northeast parts of the state.

What has occurred at TECO Power Services?

Depressed profitability at TECO Power Services (TPS), combined with a weak environment for power prices, has greatly strained the company's financial profile. As such, TECO has decided to rethink its strategy to expand the nonregulatedpower development business and instead is currently rationalizing its investments in this area.

Recent write-downs have affectedthe company's equity layer, with more reductions possible due to asset dispositions and continued low power prices. The large, recently built plants are expectedto be a drag on financials in the future. Importantly, the use of nonrecourse financing at the project level for some investments (including the largest plants, Unionand Gila) and the issuance of equity to raise the necessary capital have buffered any further potential credit deterioration. However, while a large part of the financing is nonrecourse, Standard & Poor's considers stress scenarios with a degree of nonrecourse debt.

In late 2002, TPS decided to defer further investment in two gas-fired power plants (Dell in Arkansas and McAdams in Mississippi; both 599 MW), both of which are about 90% complete, due to projectedlow energy prices in the markets that these plants were expectedto serve. At the time of suspension, about $690 million had been investedin these plants. TPS also has an interest in two merchant power plants with a combined capacity of 4,345 MW in Arkansas(Union, 2,200 MW) and Arizona(Gila, 2,145 MW). TECO has investednearly $700 million, including an equity bridge loan, in these plants. TPS and former partner Panda Energy International Inc. financed the plants with a $2.2 billion power plant financing, which includes $1.7 billion in nonrecourse debt and a $500 million equity bridge loan that was paid by TECO Energy. The nonrecourse debt has a five-year term, through 2006, after which these projects are exposed to refinancing risk. TPS also has an interest in the Odessaand Guadalupe power stations (2,000 MW) through a venture with Panda Energy. These plants have performed poorly due to substantial overcapacity in the Texasmarket.

How is TECO's liquidity position?

TECO's liquidity is expected to improve over the coming months due to the expiration of LOCs posted to complete the Union and Gila power plants, asset sale proceeds such as the Hardee power plant, the upsizing of a credit line in October 2003, and minimal debt maturities over the next few years (assuming the company's $350 million term loan due November 2003 is refinanced). TECO's liquidity position has improved dramatically from an earlier stressed position in which a ratings downgrade triggered an equity bridge guarantee, which totaled $500 million in addition to an earlier contribution. The company has about $350 million of availability on its credit facilities (a $350 million unsecured multiyear facility due November 2004 and an unsecured $150 million facility due April 2004 containing a six-month extension at TECO's option).

Tampa Electric's $300 million credit facility due November 2003, which has minimal borrowings outstanding, provides additional flexibility to the consolidatedenterprise. The company has about $270 million of cash.

What is TECO's consolidated business position on Standard & Poor's business risk scale?

Standard & Poor's has assessed TECO Energy's business position as a '5', in the middle of the risk spectrum ('1' is the lowest risk, '10' is the highest). This assessment largely reflects the relative stability and low operating risk of the regulatedelectric and gas utility operations. However, a higher-risk, poorly performing merchant power business hinders the company's business risk score. The company's attempt to refocus its business strategy to rationalize its merchant power exposure and focus primarily on its utility (about 70% of

cash flow) and coal (about 20% of cash flow) businesses will create a lower-risk consolidatedbusiness mix that is expectedto produce a steady cash flow stream.

<<Previous ArticleTop of article Next Article>>

Global Credit Research
Rating Action
12 MAR 2003

Rating Action: TECO Energy, Inc.

MOODY'S PLACES THE DEBT RATINGS OF TECO ENERGY, TAMPA ELECTRIC COMPANY, AND
TECO FINANCE ON REVIEW FOR POSSIBLE DOWNGRADE.

Approximately $3.6 Billion of Debt Securities Affected.
New York, March 12, 2003 -- Moody's Investors Service has placed the debt ratings of TECO Energy, Inc. (TECO), Tampa Electric Company, and TECO Finance, Inc. on review for possible downgrade. Ratings under review include TECO Energy's Baa2 senior unsecured debt rating; Tampa Electric Company's A1 senior secured, A2 issuer, senior unsecured and pollution control revenue bond debt, and P-1 commercial paper rating; TECO Finance Inc.'s P-2 commercial paper rating; and the Baa3 rating of the trust preferred securities of TECO Capital Trust I and TECO Capital Trust II.

This review is prompted by Moody's concerns about the pace of the remaining activities associated with the execution of TECO's announced asset sales program, continued poor market conditions in the energy merchant markets that increase the likelihood of writedowns related to some TECO Power Services (TPS) projects; and concerns regarding the amount of cash flow likely to be generated from the TPS power project portfolio in both 2003 and 2004. In addition, Moody's notes the limited progress thus far in extending or otherwise replacing bank credit facilities which are due at both TECO and Tampa Electric in November 2003.

Moody's review will focus on TECO's contingency plans with regard its expiring bank credit facilities; the progress and expected completion dates of previously announced asset sales, including a coal gasification unit at Tampa Electric and synthetic fuel facilities at TECO Coal; additional actions the company may consider to bolster cash flow and increase liquidity during 2003; and the extent to which the TPS merchant generation portfolio may require writedowns in 2003 or early 2004. ***In our review, Moody's will also assess Tampa Electric's traditionally strong operating performance and robust financial measures and the degree to which Tampa Electric may be able to provide support to TECO.***

In addition, Moody's review will include the potential effects of TECO's significant contingent obligations with respect to the Union and Gila projects, which include equity contribution guarantees, equity bridge loan guarantees, letters of credit, and other related guarantees, most of which would be triggered by changes in TECO's credit ratings or by a failure to

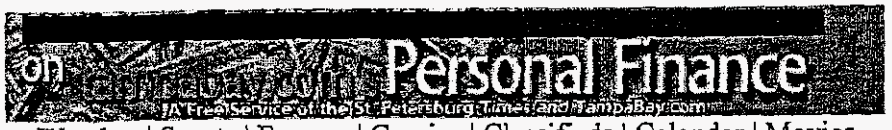
meet certain financial covenants. Moody's will also examine the impact, if any, that consolidation of $1.5 billion of nonrecourse TECO Panda Generating Company debt would have on TECO if required in the third quarter of 2003 pursuant to FASB Interpretation No. 46, which will become effective in the third quarter. Finally, Moody's will review TECO's obligations related to its partnership with Panda Energy International, which include a $60 million contingent purchase obligation related to the Union and Gila projects and the impact of the recent conversion of a $137 million Panda loan into an equity interest in the Odessa and Guadalupe projects. Moody's intends to meet with TECO senior management shortly to discuss these issues as part of our review process.

TECO Energy is a diversified energy company headquartered in Tampa, Florida.

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St. Petersburg Times ONLINE BUSINESS



TECO debt downgraded to 'junk'

A ratings agency sees risks from the utility's investments in wholesale power plants.

By LOUIS HAU, Times Staff Writer
© St. Petersburg Times, published April 22, 2003

TAMPA -- Moody's Investors Service cut TECO Energy Inc.'s long-term debt rating by two notches Monday to "junk" status, barely a week after the struggling utility initiated a dividend cut and other financial measures aimed in part at avoiding a downgrade.

Even at junk, or subinvestment, grade, Moody's doesn't deem TECO's debt rating secure. The ratings agency said it was leaving a negative outlook on the rating because of the Tampa company's "limited financial flexibility" for the rest of this year and 2004.

Moody's also reduced the debt rating of Tampa Electric Co., TECO's otherwise healthy flagship unit, which continues to be weighed down by troubles at its parent.

The rating would make it more difficult for TECO to secure new financing because companies issuing junk bonds must pay high yields to make up for the higher risk they pose.

Moody's attributed the downgrades to heightened risks from TECO's heavy investments in wholesale power plants, many of which are in markets that are saturated with generating capacity.

TECO's shares closed Monday at $10.93, down 28 cents on nearly twice the average trading volume. The downgrade came just ahead of TECO's annual shareholders meeting, which is scheduled for today at 11:30 a.m. at the company's headquarters at 702 N Franklin St. in downtown Tampa.

In a statement, TECO chief financial officer Gordon Gillette acknowledged the Moody's downgrades were "a significant change" for the company. But he also asserted, "We have the necessary liquidity available to meet the requirements brought on by this ratings change."

Among the requirements, the company has 15 days to repay, or post letters of credit for, $375-million remaining on a loan for construction of two giant gas-

fired power plants in Arizona and Arkansas. TECO also must arrange for an estimated $75-million in letters of credit to guarantee the completion of those two plants.

Also, the company will have to post an estimated $30-million in collateral with companies that purchase its power under contract. Finally, as part of financial covenants related to $380-million in five-year notes TECO issued last November, the company must now meet new accounting and earnings standards.

Moody's isn't certain that TECO's obligations end there. The ratings agency indicated it is worried about "uncertainty surrounding the actual amount" TECO will owe its lenders for the Arizona and Arkansas plants.

Moody's said that it expects TECO to take costly writedowns on its power plant projects and that continued poor conditions in TECO's wholesale power markets will severely limit the cash flow generated by its wholesale plants in 2003 and 2004. That, in turn, will make it "increasingly difficult for TECO to meet ... interest and dividend obligations without relying on additional asset sales or debt financings," Moody's said.

Over the short term, a junk rating on TECO's debt won't leave the company significantly worse off than a lesser downgrade because it doesn't have major loan payments coming due soon that it hasn't already prepared for. But the downgrade does increase pressure on the utility to issue more stock, something that would help improve its battered balance sheet but would also further dilute the value of its existing shares.

-- Louis Hau can be reached at hau@sptimes.com or (813) 226-3404.

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TECO Energy earnings slide, liquidity a concern

NEW YORK, April 22 (Reuters)

Cash-strapped power company TECO Energy Inc. on Tuesday reported sharply lower first-quarter net earnings a day after its credit ratings were slashed to "junk" status.

Though TECO responded to the action by Moody's Investors Service by saying the downgrade would not jeopardize its liquidity position, investors were skeptical and pushed its stock down.

"They have a difficult road ahead of them," said James Elliot, who helps manage the ELCO Energy Fund. "People are just not comfortable with their liquidity expectations."

TECO's stock was down 25 cents, or 2.3 percent, at $10.68 in midday trade on Tuesday on the New York Stock Exchange after falling as much as 4.3 percent to a session low of $10.46.

TECO's first-quarter net profit of $2.1 million, or 1 cent per share, was weighed down by its loss-making merchant energy business and charges for turbine purchase cancellations, a tax benefit deferral, and an accounting change. The company reported a net profit of $75.4 million, or 54 cents per share, a year ago.

Excluding one-time items, TECO earned 40 cents per share. On that basis, Wall Street analysts had expected the company to report earnings of 37 cents per share, according to research firm Thomson First Call.

TECO, the owner of Tampa Electric Co., is one of many U.S. utilities that have struggled with an industrywide credit crunch in the wake of energy trader Enron Corp.'s collapse.

Like several of its peers, TECO has decided to refocus on its reliable domestic utility business and scale back its exposure to the riskier merchant energy business. Moody's in a statement cited TECO's large exposure to the risky merchant energy business and the diminished value of its assets as reasons for the downgrade, which affected about $3.6 billion of debt.

TECO will have to collateralize or repay the $375 million balance of a bridge loan within the next 15 days as a result of the downgrade. The company earlier this month said it would slash its dividend as part of a plan to improve its financial health.

Going forward, TECO may be forced to take other, more aggressive actions to shore up its finances, according to one analyst. "TECO may have to issue equity and/or pursue additional asset sales to support the anticipated weak performance of its merchant generation fleet," Gerard Klauer Mattison analyst Mike Worms, who rates the stock "underperform" and owns no TECO shares, said in a report. "Unfortunately we do not believe this will be the last negative news in TECO's near-term future."

News Provided By

REUTERS

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of
the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported):

AUGUST 26, 2003

TECO ENERGY, INC.
(Exact name of registrant as specified in its charter)

FLORIDA	1-8180	59-2052286
(State or other jurisdiction of incorporation)	(Commission file Number)	(IRS Employer Identification No.)

702 North Franklin Street, Tampa Florida 33602
(Address of principal executive offices) (Zip code)

Registrant's telephone number, including area code: (813) 228-4111

Docket No.: 030001-
Witness: Sheree L. Bro
Exhibit No. ____, (SLB
Page 1 c

[TECO Energy, Inc. Logo]

FOR IMMEDIATE RELEASE

CONTACT: Media (Laura Plumb) 813.228.1572 Investors (Mark Kane) 813.228.1772

TECO POWER SERVICES REACHES AGREEMENT TO SELL HARDEE POWER STATION FOR $115 MILLION PLUS ASSUMPTION OF DEBT

Tampa, Florida – August 26, 2003 – TECO Energy's TECO Power Services subsidiary today announced that it has signed an agreement to sell its interest in the 370-megawatt Hardee Power Station in Florida to GTCR and Invenergy for $115 million and the assumption of all outstanding project-related debt. The transaction is expected to close by the end of September, subject to certain regulatory and lender approvals. TECO Energy expects to record an estimated $60-million book gain (pre-tax) on the sale and net incremental cash of approximately $110 million. Merrill Lynch is advising TPS in the transaction.

Chairman and CEO Robert D. Fagan said, "This transaction will further strengthen TECO Energy's financial position. In April, we identified a number of potential assets that could be sold to improve our financial position, including Hardee Power Station. With this agreement, we've demonstrated our commitment to the plan, and our continued refocus on our regulated utility operations."

The Hardee Power Station will continue to serve both Seminole Electric Cooperative and Tampa Electric under established long-term power purchase contracts. A TECO Power Services subsidiary will continue to operate the facility after the change of ownership.

TECO Power Services is a subsidiary of TECO Energy, Inc. (NYSE: TE), a diversified, energy-related holding company headquartered in Tampa, Florida. Other TECO Energy businesses include Tampa Electric, Peoples Gas System, TECO Transport, TECO Coal and TECO Solutions. For more information, visit online: www.tecoenergy.com.

Formed in 2001, Chicago-based Invenergy is a developer, owner and operator of power generation and energy delivery assets. Invenergy is led by Michael Polsky, previously CEO of SkyGen Energy. Partnered with GTCR Golder Rauner LLC, a leading private equity firm, Invenergy is pursuing acquisitions of large-scale power plants currently being divested by utilities, IPPs and financial institutions. For more information, visit www.invenervllc.com.

Founded in 1980, GTCR Golder Rauner is a leading private equity investment firm currently managing more than $6 billion of equity capital invested in a wide range of companies and industries. For more information, visit www.gtcr.com.

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TECO Power Services reaches agreement to sell Hardee Power Station for $115 million plus assumption of debt

Tampa, Florida August 26, 2003

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Formed in 2001, Chicago-based Invenergy is a developer, owner and operator of power generation and energy delivery assets. Invenergy is led by Michael Polsky, previously CEO of SkyGen Energy. Partnered with GTCR Golder Rauner LLC, a leading private equity firm, Invenergy is pursuing acquisitions of large-scale power plants currently being divested by utilities, IPPs and financial institutions. For more information, visit www.invenergyllc.com.

Founded in 1980, GTCR Golder Rauner is a leading private equity investment firm currently managing more than $6 billion of equity capital invested in a wide range of companies and industries. For more information, visit www.gtcr.com.

Closing the generation gap.℠



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Form 10-Q

TECO ENERGY INC - TE

Filed: August 14, 2003 (period: June 30, 2003)

Quarterly report which provides a continuing view of a company's financial position

Pro Forma Disclosure — Stock Options - continued

(millions, except per share amounts)	Three months ended June 30,		Six months ended June 30,	
	2003	2002	2003	2002
Net (loss) income from continuing operations - EPS, basic				
As reported	$ (0.58)	$ 0.56	$ (0.69)	$ 1.06
Pro forma	$ (0.58)	$ 0.55	$ (0.70)	$ 1.04
Net (loss) income from continuing operations - EPS, *diluted*				
As reported	$ (0.58)	$ 0.56	$ (0.69)	$ 1.06
Pro forma	$ (0.58)	$ 0.55	$ (0.70)	$ 1.04
Net (loss) income - EPS, basic				
As reported	$ (0.58)	$ 0.59	$ (0.56)	$ 1.13
Pro forma	$ (0.58)	$ 0.59	$ (0.57)	$ 1.12
Net (loss) income - EPS, diluted				
As reported	$ (0.58)	$ 0.59	$ (0.56)	$ 1.13
Pro forma	$ (0.58)	$ 0.58	$ (0.58)	$ 1.11
Assumptions				
Risk-free interest rate	4.33%	5.09%	4.33%	5.09%
Expected lives (in years)	6	6	6	6
Expected stock volatility	31.21%	25.92%	31.21%	25.92%
Dividend yield	5.08%	5.47%	5.08%	5.47%

(1) Compensation expense for stock options determined under fair-value based method, after-tax.

10. Asset Impairments

At Mar. 31, 2003, TECO Energy recorded a $64.2 million after-tax charge ($104.1 million pretax) to reflect the impact of the cancellation of turbine purchase commitments. This represented after-tax charges of $15.3 million ($24.5 million pretax) at TPS and $48.9 million ($79.6 million pretax) at Tampa Electric relating to installment payments made and capitalized in prior periods. As reported previously and in Note 15, certain turbine rights had been transferred from TPS to Tampa Electric in 2002 for use in Tampa Electric's generation expansion activities. These cancellations, made in April 2003, fully terminate all turbine purchase obligations for TPS and Tampa Electric.

11. TPGC Joint Venture Termination

In January 2002, TPS agreed to purchase the interests of Panda Energy in the TPGC projects in 2007 for $60 million, and TECO Energy guaranteed payment of TPS' obligation under this agreement. Panda Energy obtained bank financing using the purchase obligation and TECO Energy's guarantee as collateral. Under certain circumstances, the purchase obligation could have been accelerated for a reduced price based on the timing of the acceleration. In connection with TPS' purchase obligation, Panda Energy retained a cancellation right, exercisable in 2007 for $20 million by the holder, with early exercise permitted for a reduced price of $8 million.

On April 9, 2003, TECO Energy and Panda Energy amended the agreements related to the purchase obligation. The modified terms accelerated TPS' purchase obligation to on or before July 1, 2003, and reduced the overall purchase obligation to $58 million. Under the guarantee TECO Energy became obligated to make interest and certain principal payments to or on behalf of Panda related to the collateralized loan obligation of Panda. The purchase obligation of $58 million included $35 million for Panda Energy's interest in TPGC, and a short-term receivable from Panda, collateralized by Panda's remaining interests in PLC (see Note 1 for additional details on TECO Energy's ownership interest in PLC). Both modifications to the purchase obligation were subject to the condition, which TECO Energy could waive, that bank financing could be obtained by TECO Energy. Panda Energy's cancellation right was accelerated to expire on June 16, 2003. TECO Energy's guarantee of TPS' obligation was modified to reflect the amendments to the purchase obligation. In April 2003, TECO Energy recognized the fair value of the guarantee as an after-tax loss of $21.4 million ($35.0 million pretax), included in the "Loss on joint venture termination" caption in the Statements of Consolidated Income. From April 2003 through June 2003, TECO Energy made and accrued certain principal payments under the guarantee commitment, giving rise to a receivable from Panda of $9.0 million.

As a result of the amendments to these agreements in early April 2003, management believed the exercise of the modified guarantee and the related purchase obligation became highly probable at that time. The likelihood of the exercise of the purchase obligation created a presumption of effective control. When combined with TECO Energy's exposure to the majority of risk of loss under the previously disclosed letters of credit and contractor undertakings, management believed that consolidation of TPGC was

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Witness: Sheree L. Brow
Exhibit No. _____, (SLB-
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UNITED STATES DISTRICT COURT
MIDDLE DISTRICT OF FLORIDA

UNITED STATES OF AMERICA, Plaintiff, v. TAMPA ELECTRIC COMPANY, Defendant.	CIVIL ACTION NO. 99-2524 CIV-T-23F

CONSENT DECREE

WHEREAS, Plaintiff, the United States of America (Plaintiff or the United States), on behalf of the United States Environmental Protection Agency (EPA) filed a Complaint on November 3, 1999, alleging that Defendant, Tampa Electric Company (Tampa Electric) commenced construction of major modifications of major emitting facilities in violation of the Prevention of Significant Deterioration (PSD) requirements at Part C of the Clean Air Act (Act), 42 U.S.C. §§ 7470-7492;

WHEREAS, EPA issued a Notice of Violation with respect to such allegations to Tampa Electric on November 3, 1999 (the NOV);

WHEREAS, the parties recognize, and the Court by entering this Consent Decree finds, that this Consent Decree has been negotiated in good faith and at arm s length; that the parties have voluntarily agreed to this Consent Decree; that implementation of this Consent Decree will

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Exhibit No. ____ (SLB-
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avoid prolonged and complicated litigation between the parties; and that this Consent Decree is fair, reasonable, consistent with the goals of the Act, and in the public interest;

WHEREAS, the United States alleges that the Complaint states a claim upon which relief can be granted against Tampa Electric under Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477, and 28 U.S.C. § 1355;

WHEREAS, Tampa Electric has not answered or otherwise responded to the Complaint in light of the settlement memorialized in this Consent Decree;

WHEREAS, Tampa Electric has denied and continues to deny the violations alleged in the NOV and the Complaint; maintains that it has been and remains in compliance with the Clean Air Act and is not liable for civil penalties or injunctive relief; and states that it is agreeing to the obligations imposed by this Consent Decree solely to avoid the costs and uncertainties of litigation and to improve the environment in and around the Tampa Bay area of Florida;

WHEREAS, Tampa Electric is the first electric utility of those against which the United States brought enforcement actions in November, 1999, to come forward and invest time and effort sufficient to develop a settlement with the United States;

WHEREAS, Tampa Electric s decision to Re-Power some of its coal-fired electric generating Units with natural gas will significantly reduce emissions of both regulated and unregulated pollutants below levels that would have been achieved merely by installing appropriate pollution control technologies on Tampa Electric s existing coal-fired electric generating Units;

WHEREAS, prior to the filing of the Complaint or issuance of the Notice of Violation in this matter, Tampa Electric already had placed in service or installed both scrubbers and

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Exhibit No. ____ (SLE
Page 2 o

electrostatic precipitators that serve all existing coal-fired electric generating Units at the company s Big Bend electric generating plant;

WHEREAS, the United States recognizes that a BACT Analysis conducted under existing procedures most likely would not find it cost effective to replace Tampa Electric s existing control equipment at Big Bend for particulate matter, in light of the design and performance of that equipment;

WHEREAS, Tampa Electric and the United States have crafted this Consent Decree to take into account physical and operational constraints resulting from the unique, Riley Stoker wet bottom, turbo-fired boiler technology now in operation at Big Bend, which could limit the efficiency of nitrogen oxides emissions controls installed for those boilers;

WHEREAS, Tampa Electric regularly combusts coal with a sulphur content of five or six pounds per mmBTU heat input;

WHEREAS, Tampa Electric is a mid-sized electric utility and is smaller on a financial basis than some of the other electric utilities against which the United States brought similar enforcement actions in November 1999;

WHEREAS, Tampa Electric owns and operates fewer coal-fired electric generating plants than some of the other electric utilities against which the United States brought similar enforcement actions in November 1999;

WHEREAS, the two Tampa Electric plants addressed by this enforcement action constitute over ninety percent of the entire base load generating capacity of Tampa Electric;

WHEREAS, the United States and Tampa Electric have agreed that settlement of this action is in the best interest of the parties and in the public interest, and that entry of this Consent

Decree without further litigation is the most appropriate means of resolving this matter; and

WHEREAS, the United States and Tampa Electric have consented to entry of this Consent Decree without trial of any issue;

NOW, THEREFORE, without any admission of fact or law, and without any admission of the violations alleged in the Complaint or NOV, it is hereby ORDERED AND DECREED as follows:

I. JURISDICTION AND VENUE

1. This Court has jurisdiction over the subject matter herein and over the parties consenting hereto pursuant to 28 U.S.C. § 1345 and pursuant to Sections 113 and 167 of the Act, 42 U.S.C. §§ 7413 and 7477. Venue is proper under Section 113(b) of the Act, 42 U.S.C. § 7413(b), and under 28 U.S.C. § 1391(b) and (c). Solely for the purposes of this Consent Decree and the underlying Complaint, Tampa Electric waives all objections and defenses that it may have to the claims set forth in the Complaint, the jurisdiction of the Court or to venue in this District. Tampa Electric shall not challenge the terms of this Consent Decree or this Court s jurisdiction to enter and enforce this Consent Decree. Except as expressly provided for herein, this Consent Decree shall not create any rights in any party other than the United States and Tampa Electric. Tampa Electric consents to entry of this Consent Decree without further notice.

II. APPLICABILITY

2. The provisions of this Consent Decree shall apply to and be binding upon the United

States and upon Tampa Electric, its successors and assigns, and Tampa Electric s officers, employees and agents solely in their capacities as such If Tampa Electric proposes to sell or transfer any of its real property or operations subject to this Consent Decree, it shall advise the purchaser or transferee in writing of the existence of this Consent Decree, and shall send a copy of such written notification by certified mail, return receipt requested, to EPA sixty (60) days before such sale or transfer. Tampa Electric shall not be relieved of its responsibility to comply with all requirements of this Consent Decree unless the purchaser or transferee assumes responsibility for full performance of Tampa Electric s responsibilities under this Consent Decree, including liabilities for nonperformance. Tampa Electric shall not purchase or otherwise acquire capacity and/or energy from a third party in lieu of obtaining it from Gannon or Big Bend unless the seller or provider agrees that the facilities providing such capacity and/or energy will meet the emission control requirements set forth in this Consent Decree or equivalent requirements approved in advance by the United States.

3. Tampa Electric shall provide a copy of this Consent Decree to all vendors, suppliers, consultants, contractors, agents, and any other company or other organization performing any of the work described in Sections IV or VII of this Consent Decree. Notwithstanding any retention of contractors, subcontractors or agents to perform any work required under this Consent Decree, Tampa Electric shall be responsible for ensuring that all work is performed in accordance with the requirements of this Consent Decree. In any action to enforce this Consent Decree, Tampa Electric shall not assert as a defense the failure of its employees, servants, agents, or contractors to take actions

necessary to comply with this Consent Decree, unless Tampa Electric establishes that such failure resulted from a Force Majeure event as defined in this Consent Decree.

III. DEFINITIONS

4. Alternative Coal shall mean coal with a sulphur content of no more than 2.2 lb/mmBTU, on an as determined basis.

5. BACT Analysis shall mean the technical study, analysis, review, and selection of recommendations typically performed in connection with an application for a PSD permit. Except as otherwise provided in this Consent Decree, such study, analysis, review, and selection of recommendations shall be carried out in conformance with applicable federal and state regulations and guidance describing the process and analysis for determining Best Available Control Technology (BACT).

6. Big Bend shall mean the electric generating plant, presently coal-fired, owned and operated by Tampa Electric and located in Hillsborough County, Florida, which presently includes four steam generating boilers and associated and ancillary systems and equipment, known as Big Bend Units 1, 2, 3, and 4.

7. Consent Decree shall mean this Consent Decree and the Appendix thereto.

8. Emission Rate shall mean the average number of pounds of pollutant emitted per million BTU of heat input (lb/mmBTU) or the average concentration of a pollutant in parts per million by volume (ppm), as dictated by the unit of measure specified for the rate in question, where:

A. in the case of a coal-fired, steam electric generating unit, such rates shall be

calculated as a 30 day rolling average. A 30 day rolling average for an Emission Rate expressed as lb/mmBTU shall be determined by calculating the emission rate for a given operating day, and then arithmetically averaging the emission rates for the previous 29 operating days with that date. A new 30 day rolling average shall be calculated for each new operating day;

B. in the case of a gas-fired, electric generating unit, such rates shall be calculated as a 24-hour rolling average, excluding periods of start up, shutdown, and malfunction as provided by applicable Florida regulations at the time the Emission Rate is calculated. A rolling average for Emission Rates expressed as ppm shall be determined on a given day by summing hourly emission rates for the immediately preceding 24-hour period and dividing by 24;

C. the reference methods for determining Emission Rates for SO_2 and NO_x shall be those specified in 40 C.F.R. Part 75, Appendix F. The reference methods for determining Emission Rates for PM shall be those specified in 40 C.F.R. Part 60, Appendix A, Method 5, Method 5B, or Method 17; and

D. nothing in this Consent Decree is intended to nor shall alter applicable law concerning the use of data, for any purpose under the Clean Air Act, generated by methods other than the reference methods specified herein.

9. EPA shall mean the United States Environmental Protection Agency.

10. Gannon shall mean the electric generating plant, presently coal-fired, owned and operated by Tampa Electric, located in Hillsborough County, Florida, which presently includes six steam generating boilers and associated and ancillary systems and

equipment, known as Gannon Units 1, 2, 3, 4, 5, and 6. Tampa Electric intends to rename Gannon Bayside Power Station upon completion of the Re-Powering required under this Consent Decree.

11. lb/mmBTU shall mean pounds per million British Thermal Units of heat input.

12. NOx shall mean oxides of nitrogen.

13. NOV shall mean the Notice of Violation issued by EPA to Tampa Electric dated November 3, 1999.

14. PM shall mean total particulate matter, and the reference method for measuring PM shall be that specified in the definition of Emission Rate in this Consent Decree.

15. ppm shall mean parts per million by dry volume, corrected to 15% O_2.

16. Project Dollars shall mean Tampa Electric s expenditures and payments incurred or made in carrying out the dollar-limited projects identified in Paragraph 35 of Section IV of this Consent Decree (Early Reductions of NO_x from Big Bend Units 1 through 3) and in Section VII of this Consent Decree (NO_x Reduction Projects and Mitigation Projects), to the extent that such expenditures or payments both: (A) comply with the Project Dollar and other requirements set by this Consent Decree for such expenditures and payments in Section VII and in Paragraph 35 of Section IV of this Consent Decree, and (B) constitute either Tampa Electric s properly documented external costs for contractors, vendors, as well as equipment, or its internal costs consisting of employee time, travel, and other out-of-pocket expenses specifically attributable to these particular projects.

17. PSD shall mean Prevention of Significant Deterioration within the meaning of Part C of the Clean Air Act, 42 U.S.C. §§ 7470, et seq.

18. Re-Power shall mean the removal or permanent disabling of devices, systems, equipment, and ancillary or supporting systems at a Gannon or Big Bend Unit such that the Unit cannot be fired with coal, and the installation of all devices, systems, equipment, and ancillary or supporting systems needed to fire such Unit with natural gas under the limits set in this Consent Decree (or with No. 2 fuel oil, as a back up fuel only, and under the limits specified by this Consent Decree) plus installation of the control technology and compliance with the Emission Rates called for under this Consent Decree.

19. Reserve / Standby shall mean those devices, systems, equipment, and ancillary or supporting systems that: (1) are not used as part of the Units that must be Re-Powered under Paragraph 26, (2) are not in operation subsequent to the Re-Powering required under Paragraph 26, (3) are maintained and held by Tampa Electric for system reliability purposes, and (4) may be restarted only by Re-Powering.

20. SCR shall mean Selective Catalytic Reduction.

21. Shutdown shall mean the permanent disabling of a coal-fired boiler such that it cannot burn any fuel nor produce any steam for electricity production, other than through Re-Powering.

22. S O_2" shall mean sulphur dioxide.

23. Title V Permit shall mean the permit required under Subchapter V of the Clean Air Act, 42 U.S.C. § 7661, et seq.

24. Total Baseline Emissions shall mean calendar year 1998 emissions of NO_x, SO_2, and PM comprised of the following amounts for each pollutant:

A. for Gannon: 30,763 tons of NO_x, 64,620 tons of SO_2, and 1,914 tons of PM; and

B. for Big Bend: 36,077 tons of NO_x, 107,334 tons of SO_2, and 3,002 tons of PM.

25. Unit shall mean for the purpose of this Consent Decree a generator, the steam turbine that drives the generator, the boiler that produces the steam for the steam turbine, the equipment necessary to operate the generator, turbine and boiler, and all ancillary equipment, including pollution control equipment or systems necessary for the production of electricity. An electric generating plant may be comprised of one or more Units.

IV. EMISSIONS REDUCTIONS AND CONTROLS GANNON AND BIG BEND

A. GANNON

26. Consent Decree-Required Re-Powering of Gannon. Tampa Electric shall Re-Power Units at Gannon with a coal-fired generating capacity of no less than 550 MW (Megawatt), as follows.

A. On or before May 1, 2003, Tampa Electric shall Re-Power Units with a coal-fired generating capacity of no less than 200 MW. On or before December 31, 2004, Tampa Electric shall Re-Power additional Units with a coal-fired generating capacity equal to or greater than the difference between 550 MW of coal-fired generating capacity and the MW value of coal-fired generating capacity that Tampa Electric Re-Powered in complying with the first sentence of this

Subparagraph A.

B. All Re-Powering required by this Paragraph shall include installation and operation of SCR, other pollution control technology approved in advance and in writing by EPA, or any innovative technology demonstration project approved pursuant to Paragraph, 52.C to control Unit emissions. Each Re-Powered Unit shall, in conformance with the definition of Re-Power, use natural gas as its primary fuel and shall meet an Emission Rate for NO_x of no greater than 3.5 ppm.

C. A Unit Re-Powered under this or any other provision of this Consent Decree may be fired with No. 2 fuel oil if and only if: (1) the Unit cannot be fired with natural gas; (2) the Unit has not yet been fired with No. 2 fuel oil as a back up fuel for more than 875 full load equivalent hours in the calendar year in which Tampa Electric wishes to fire the Unit with such oil; (3) the oil to be used in firing the Unit has a sulphur content of less than 0.05 percent (by weight); (4) Tampa Electric uses all emission control equipment for that Unit when it is fired with such oil to the maximum extent possible; and (5) Tampa Electric complies with all applicable permit conditions, including emission rates for firing with No. 2 fuel oil, as set forth in applicable preconstruction and operating permits.

D. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing such Re-Powering. In applying for such permit Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA-approved control technology and a NO_x Emission Rate no greater than 3.5 ppm.

27. Schedule for Shutdown of Units. Tampa Electric shall Shutdown and cease any and all operation of all six (6) Gannon coal-fired boilers with a combined coal-fired capacity of not less than 1194 MW on or before December 31, 2004. Notwithstanding the requirements of this Paragraph, Tampa Electric may retain any Unit Shutdown pursuant to this Paragraph on Reserve / Standby, unless such Unit is to be, or has been, Re-Powered under Paragraph 26, above. If Tampa Electric later decides to restart any Shutdown Unit retained on Reserve / Standby, then prior to such re-start, Tampa Electric shall timely apply for a PSD permit for the Unit(s) to be Re-Powered, and Tampa Electric shall abide by the permit issued as a result of that application, including installation of BACT and its corresponding Emission Rate, as determined at the time of the restart. Tampa Electric shall operate the Re-Powered Unit to meet the NO_x Emission Rate established in the PSD Permit or an Emission Rate for NO_x of 3.5 ppm, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). For any Unit Shutdown and placed on Reserve / Standby under this Paragraph, and notwithstanding the definition of Re-Power in this Consent Decree, Tampa Electric also may elect to fuel such a Unit with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric: applies for and secures a PSD permit before using such fuel in any such Unit, complies with all requirements issued in such a permit, and complies with all other requirements of this Consent Decree applicable to Re-Powering.

28. Permanent Bar on Combustion of Coal. Commencing on January 1, 2005, Tampa

Electric shall not combust coal in the operation of any Unit at Gannon.

B. BIG BEND

29. Initial Reduction and Control of SO_2 Emissions from Big Bend Units 1 and 2 . Commencing upon the later of the date of entry of this Consent Decree or September 1, 2000, and except as provided in this Paragraph, Tampa Electric shall operate the existing scrubber that treats emissions of SO_2 from Big Bend Units 1 and 2 at all times that either Unit 1 or 2 is in operation. Tampa Electric shall operate the scrubber so that at least 95% of all the SO_2 contained in the flue gas entering the scrubber is removed. Notwithstanding the requirement to operate the scrubber at all times Unit 1 or 2 is operating, the following operating conditions shall apply:

A. Tampa Electric may operate Units 1 and/or 2 during outages of the scrubber serving Units 1 and 2, but only so long as Tampa Electric:

(1) in calendar year 2000, does not operate Unit 1 and/or 2, or any combination of the two of them, on more than sixty (60) calendar days, or any part thereof (providing that when both Units 1 and 2 operate on the same calendar day, such operation shall count as two days of the sixty (60) day limit), and in calendar years 2001 - 2009, does not operate Unit 1 and/or 2, or any combination of the two of them, on more than forty-five (45) calendar days, or any part thereof, in any calendar year (providing that when both Units 1 and 2 operate on the same calendar day, such operation shall count as two days of the forty-five (45) day limit) ; or

(2) must operate Unit 1 and/or 2 in any calendar year from 2000 through 2009 either to avoid interruption of electric service to its customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida under Section 366.055, F.S. (requiring availability of reserves), or under Section 377.703, F.S. (energy policy contingency plan), or under Section 252.36, F.S. (Emergency management powers of the Governor), in which Tampa Electric must generate power from Unit 1 and/or 2 to meet such emergency.

B. Whenever Tampa Electric operates Units 1 and/or 2 without all emissions from such Unit(s) being treated by the scrubber, Tampa Electric shall: (1) combust only Alternative Coal at the Unit(s) operating during the outage (except for coal already bunkered in the hopper(s) for Units 1 or 2 at the time the outage commences); (2) use all existing electric generating capacity at Big Bend and Gannon that is served by fully operational pollution control equipment before operating Big Bend Units1 and/or 2; and (3) continue to control SO_2 emissions from Big Bend Units 1 and/or 2 as required by Paragraph 31 (Optimizing Availability of Scrubbers Serving Big Bend Units 1, 2, and 3).

C. In calendar years 2010 through 2012, Tampa Electric may operate Units 1 and/or 2 during outages of the scrubber serving Units 1 and 2, but only so long as Tampa Electric complies with the requirements of Subparagraphs A and B, above, and uses only coal with a sulphur content of 1.2 lb/mmBTU, or less, in place of

Alternative Coal.

D. If Tampa Electric Re-Powers Big Bend Unit 1 or 2, or replaces the scrubber or provides additional scrubbing capacity to comply with Paragraph 40, then upon such compliance the provisions of Subparagraphs 29.A, 29.B, and 29.C shall not apply to the affected Unit.

30. Initial Reduction and Control of SO_2 Emissions from Big Bend Unit 3. Commencing upon entry of the Consent Decree, and except as provided in this Paragraph, Tampa Electric shall operate the existing scrubber that treats emissions of SO_2 from Big Bend Units 3 and 4 at all times that Unit 3 is in operation. When Big Bend Units 3 and 4 are both operating, Tampa Electric shall operate the scrubber so that at least 93% of all the SO_2 contained in the flue gas entering the scrubber is removed. When Big Bend Unit 3 alone is operating, until May 1, 2002, Tampa Electric shall operate the scrubber so that at least 93% of all SO_2 contained in the flue gas entering the scrubber is removed or the Emission Rate for SO_2 for Unit 3 does not exceed 0.35 lb/mmBTU. When Unit 3 alone is operating, from May 1, 2002 until January 1, 2010, Tampa Electric shall operate the scrubber so that at least 95% of the SO_2 contained in the flue gas entering the scrubber is removed or the Emission Rate for SO_2 does not exceed 0.30 lb/mmBTU. Notwithstanding the requirement to operate the scrubber at all times Unit 3 is operating, and providing Tampa Electric is otherwise in compliance with this Consent Decree, the following operating conditions shall apply:

A. In any calendar year from 2000 through 2009, Tampa Electric may operate Unit 3 in the case of outages of the scrubber serving Unit 3, but only so long as Tampa

Electric:

(1) does not operate Unit 3 during outages on more than thirty (30) calendar days, or any part thereof, in any calendar year; or

(2) must operate Unit 3 either: to avoid interruption of electric service to its customers under interruptible service tariffs, or to respond to a system-wide or state-wide emergency as declared by the Governor of Florida under Section 366.055, F.S. (requiring availability of reserves), or under Section 377.703, F.S. (energy policy contingency plan), or under Section 252.36, F.S. (Emergency management powers of the Governor), in which Tampa Electric must generate power from Unit 3 to meet such emergency.

B. Whenever Tampa Electric operates Unit 3 without treating all emissions from that Unit with the scrubber, Tampa Electric shall: (1) combust only Alternative Coal at Unit 3 during the outage (except for coal already bunkered in the hopper(s) for Unit 3 at the time the outage commences); (2) use all existing electric generating capacity at Big Bend and Gannon that is served by fully operational pollution control equipment before operating Big Bend Unit 3; and (3) continue to control SO_2 emissions from Big Bend Unit 3 as required by Paragraph 31 (Optimizing Availability of Scrubbers Serving Big Bend Units, 1, 2, and 3).

C. If Tampa Electric Re-Powers Big Bend Unit 3, or replaces the scrubber or provides additional scrubbing capacity to comply with Paragraph 40, then upon compliance with Paragraph 40 the provisions of Subparagraphs 30.A and 30.B

shall not apply to Unit 3.

D. Nothing in this Consent Decree shall alter requirements of the New Source Performance Standards (NSPS), 40 C.F.R. Part 60 Subpart Da, that apply to operation of the scrubber serving Unit 4.

31. Optimizing Availability of Scrubbers Serving Big Bend Units 1, 2, and 3. Tampa Electric shall maximize the availability of the scrubbers to treat the emissions of Big Bend Units 1, 2, and 3, as follows:

A. As soon as possible after entry of this Consent Decree, Tampa Electric shall submit to EPA for review and approval a plan addressing all operation and maintenance changes to be made that would maximize the availability of the existing scrubbers treating emissions of SO_2 from Big Bend Units 1 and 2, and from Unit 3. In order to improve operations and maintenance practices as soon as possible, Tampa Electric may submit the plan in two phases.

(1) Each phase of the plan proposed by Tampa Electric shall include a schedule pursuant to which Tampa Electric will implement measures relating to operation and maintenance of the scrubbers called for by that phase of the plan, within sixty days of its approval by EPA. Tampa Electric shall implement each phase of the plan as approved by EPA. Such plan may be modified from time to time with prior written approval of EPA.

(2) The proposed plan shall include operation and maintenance activities that will minimize instances during which SO_2 emissions are not scrubbed, including but not limited to improvements in the flexibility of scheduling maintenance on the

scrubbers, increases in the stock of spare parts kept on hand to repair the scrubbers, a commitment to use of overtime labor to perform work necessary to minimize periods when the scrubbers are not functioning, and use of all existing capacity at Big Bend and Gannon Units that are served by available, operational pollution control equipment to minimize pollutant emissions while meeting power needs.

(3) If Tampa Electric elects to submit the plan to EPA in two phases, the first phase to be submitted shall address, at a minimum, use of overtime hours to accomplish repairs and maintenance of the scrubber and increasing the stock of scrubber spare parts that Tampa Electric shall keep at Big Bend to speed future maintenance and repairs. If Tampa Electric elects to submit the plan in two phases, EPA shall complete review of the first phase within fifteen business days of receipt. For the second phase of the plan or submission of the plan in its entirety, EPA shall complete review of such plan or phase thereof within 60 days of receipt. Within sixty days after EPA s approval of the plan or any phase of the plan, Tampa Electric shall complete implementation of that plan or phase and continue operation under it subject only to the terms of this Consent Decree.

32. PM Emission Minimization and Monitoring at Big Bend.

A. Within twelve months after entry of this Consent Decree, Tampa Electric shall complete an optimization study which shall recommend the best operational practices to minimize emissions from each Electrostatic Precipitator (ESP) and shall deliver the completed study to EPA for review and approval. Tampa

Electric shall implement these recommendations within sixty days after EPA has approved them and shall operate each ESP in conformance with the study and its recommendations until otherwise specified under this Consent Decree.

B. Within twelve months after entry of this Consent Decree, Tampa Electric shall complete a BACT Analysis for upgrading each existing ESP now located at Big Bend and shall deliver the Analysis to EPA for review and approval. Notwithstanding the definition of BACT Analysis in this Consent Decree, Tampa Electric need not consider in this BACT Analysis the replacement of any existing ESP with a new ESP, scrubber, or baghouse, or the installation of a supplemental pollution control device of similar cost to a replacement ESP, scrubber, or baghouse. Tampa Electric shall simultaneously deliver to EPA all documents that support the BACT Analysis or that were considered in preparing the Analysis. Tampa Electric shall retain a qualified contractor to assist in the performance and completion of the BACT Analysis. On or before May 1, 2004, after EPA approval of the recommendation(s) made by the BACT Analysis, Tampa Electric shall complete installation of all equipment called for in the recommendation(s) of the Analysis and thereafter shall operate each ESP in conformance with the recommendation(s), including compliance with the Emission Rate(s) specified by the recommendation(s).

C. Within six months after Tampa Electric completes installation of the equipment called for by the BACT Analysis, as approved by EPA, Tampa Electric shall revise the previous optimization study and shall recommend the best operational

practices to *minimize* emissions from each ESP, taking into account the recommendations from the BACT Analysis required by this Paragraph, and shall deliver the completed study to EPA for review and approval. Commencing no later than 180 days after EPA approves the study and its recommendation(s), Tampa Electric shall operate each ESP in conformance with the study s recommendation.

D. Tampa Electric shall include the recommended operational practices for each ESP and the recommendations from the BACT Analysis in Tampa Electric s Title V Permit application and all other relevant applications for operating or construction permits.

E. Installation and Operation of a PM Monitor. On or before March 1, 2002, Defendant shall install, calibrate, and commence continuous operation of a continuous particulate matter emissions monitor (PM CEM) in the duct at Big Bend that services Unit 4. Data from the PM CEM shall be used by Tampa Electric, at a minimum, to monitor progress in reducing PM emissions.

F. Continuous operation of the PM CEM shall mean operation at all times that Unit 4 operates, except for periods of malfunction of the PM CEM or routine maintenance performed on the PM CEM. If after Tampa Electric operates this PM CEM for at least two years, and if the parties then agree that it is infeasible to sustain continuous operation of the PM CEM, Tampa Electric shall submit an alternative PM monitoring plan for review and approval by EPA. The plan shall include an explanation of the basis for stopping operation of the PM CEM and a

proposal for an alternative monitoring protocol. Until EPA approves such plan, Tampa Electric shall continue to operate the PM CEM.

G. Installation and Operation of Second PM Monitor. If Tampa Electric advises EPA, pursuant to Paragraph 36, that it has elected to continue to combust coal at Big Bend Units 1, 2, or 3, and Tampa Electric has not ceased operating the first PM CEM as described in Subparagraph F, above, then Tampa Electric shall install, calibrate, and commence continuous operation of a PM CEM on a second duct at Big Bend on or before May 1, 2007. The requirement to operate a PM CEM under any provision of this Paragraph shall terminate if and when the Unit monitored by the PM CEM is Re-Powered.

H. Testing and Reporting Requirement. Prior to installation of the PM CEM on each duct, Tampa Electric shall conduct a stack test on each stack at Big Bend on at least an annual basis and report its results to EPA as part of the quarterly report under Section V. The stack test requirement in this Subparagraph may be satisfied by Tampa Electric s annual stack tests conducted as required by its permit from the State of Florida. Following installation of each PM CEM, Defendant shall include in its quarterly reports to EPA pursuant to Section V all data recorded by the PM CEM, in electronic format, if available.

I. Nothing in this Consent Decree is intended to nor shall alter applicable law concerning the use of data, for any purpose under the Clean Air Act, generated by the PM CEMs.

33. Election for Big Bend Unit 4: Shutdown, Re-Power, or Continued Combustion of Coal.

Tampa Electric shall advise EPA in writing, on or before May 1, 2005, whether Big Bend Unit 4 will be Shutdown, will be Re-Powered, or will continue to be fired by coal.

34. Reduction of NO_x at Big Bend Unit 4 after 2005 Election. Based on Tampa Electric s election in Paragraph 33, Tampa Electric shall take one of the following actions:

A. If Tampa Electric elects to continue firing Unit 4 with coal, on or before June 1, 2007, Tampa Electric shall install and commence operation of SCR, or other technology if approved in writing by EPA in advance, sufficient to limit the coal-fired Emission Rate of NO_x from Unit 4 to no more than 0.10 lb/mmBTU. Thereafter, Tampa Electric shall continue operation of SCR or other EPA approved control technology, and Tampa Electric shall continue to meet an Emission Rate for NO_x from Unit 4 no greater than 0.10 lb/mmBTU; or

B. If Tampa Electric elects to Re-Power Unit 4, Tampa Electric shall not combust coal at Unit 4 on or after June 1, 2007. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing construction of the Re-Powering of Unit 4. In applying for such permit, Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA approved control technology and a NO_x Emission Rate no greater than 3.5 ppm. Tampa Electric shall operate the Re-Powered Unit 4 to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the rate established in the preconstruction permit, whichever is more stringent; or

C. If Tampa Electric elects to Shutdown Big Bend Unit 4, Tampa Electric shall complete Shutdown of Big Bend Unit 4 on or before June 1, 2007.

Notwithstanding the requirements of this Subparagraph, Tampa Electric may retain this Unit, after it is Shutdown pursuant to this Subparagraph, on Reserve / Standby. If Tampa Electric later decides to restart Unit 4 then, prior to such restart, Tampa Electric shall timely apply for a PSD permit, and Tampa Electric shall abide by the permit issued as a result of that application, including installation of BACT and its corresponding Emission Rate, as determined at the time of the restart. Tampa Electric shall operate the Re-Powered Unit 4 to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the Emission Rate established in the PSD permit, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). Upon Shutdown of a Unit under this Subparagraph, Tampa Electric may never again use coal to fire that Unit.

D. Notwithstanding the provisions of Subparagraphs B and C above or the definition of Re-Power in this Consent Decree, Tampa Electric may also elect to fuel Big Bend Unit 4 with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric applies for and secures a PSD permit before using such fuel in this Unit, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

35. Early Reductions of NO_x from Big Bend Units 1 through 3: On or before December 31, 2001, Tampa Electric shall submit to EPA for review and comment a plan to reduce NO_x emissions from Big Bend Units 1, 2 and 3, through the expenditure of up to $3 million

Project Dollars on combustion optimization using commercially available methods, techniques, systems, or equipment, or combinations thereof. Subject only to the financial limit stated in the previous sentence, for Units 1 and 2 the goal of the combustion optimization shall be to reduce the NO_x Emission Rate by at least 30% when compared against the NO_x Emissions Rate for these Units during calendar year 1998, which the United States and Tampa Electric agree was 0.86 lb/mmBTU. For Unit 3 the goal of the combustion optimization shall be to reduce the NO_x Emissions Rate by at least 15% when compared against the NO_x Emission Rate for this Unit during calendar year 1998, which the United States and Tampa Electric agree was 0.57 lb/mmBTU. If the financial limit in this Paragraph precludes designing and installing combustion controls that will meet the percentage reduction goals for the NO_x Emission Rates specified in this Paragraph for all three Units, then Tampa Electric s plan shall first maximize the Emission Rate reductions at Units 1 and 2 and then at Unit 3. Unless the United States has sought dispute resolution on Tampa Electric s plan on or before May 30, 2002, Tampa Electric shall implement all aspects of its plan at Big Bend Units 1, 2, and 3 on or before December 31, 2002. On or before April 1, 2003, Tampa Electric shall submit to EPA a report that documents the date(s) of complete implementation of the plan, the results obtained from implementing the plan, including the emission reductions or benefits achieved, and the Project Dollars expended by Tampa Electric in implementing the plan.

36. Election for Big Bend Units 1 through 3: Shutdown, Re-Power, or Continued Combustion of Coal. Tampa Electric shall advise EPA in writing, on or before May 1,

2007, whether Big Bend Units 1, 2, or 3, or any combination of them, will be Shutdown, will be Re-Powered, or will continue to be fired by coal.

37. Further NO_x Reduction Requirements if Big Bend Units 1, 2, and/or 3 Remain Coal-fired. If Tampa Electric advises EPA in writing, pursuant to Paragraph 36, above, that Tampa Electric will continue to combust coal at Units 1, 2, and/or 3, then:

A. Subject only to Subparagraphs B and D, Tampa Electric shall timely solicit contract proposals to acquire, install, and operate SCR, or other technology if approved in writing by EPA in advance, sufficient to limit the Emission Rate of NO_x to no more than 0.10 lb/mmBTU at each Unit that will combust coal. Tampa Electric shall install and operate such equipment on all Units that will continue to combust coal and shall achieve an Emission Rate of NO_x on each such Unit no less stringent than 0.10 lb/mmBTU.

B. Notwithstanding Subparagraph A, Tampa Electric shall not be required to install SCR to limit the Emission Rate of NO_x at Units 1, 2 and/or 3 to 0.10 lb/mmBTU if the installation cost ceiling contained in this Paragraph will be exceeded by such installation. If Tampa Electric decides to continue burning coal at Units 1, 2 and 3, the installation cost ceiling for SCR at Units 1, 2, and 3 shall be three times the cost of installing SCR at Big Bend Unit 4 plus forty-five (45%) percent of the cost of installing SCR at Big Bend 4. If Tampa Electric decides to continue burning coal at only two Units at Big Bend, the installation cost ceiling for SCR at those two Units shall be two times the cost of installing SCR at Big Bend 4 plus forty-five (45) percent of the cost of installing SCR at Big Bend Unit 4. If

Tampa Electric decides to continue burning coal at only one Unit at Big Bend, the installation cost ceiling for SCR at that Unit shall be the cost of installing SCR at Big Bend 4 plus forty five (45) percent.

C. If, based on the contract proposals obtained under Subparagraph A, Tampa Electric determines that the projected cost of proposed control equipment satisfying a 0.10 lb/mmBTU Emission Rate will not exceed the installation cost ceiling, Tampa Electric shall install and operate such equipment on all Units that will continue to combust coal and shall achieve a NO_x Emission Rate on each Unit no less stringent than 0.10 lb/mmBTU. If, based on the contract proposals, Tampa Electric determines that the projected cost will exceed the installation cost ceiling, Tampa Electric shall so advise EPA and shall provide EPA with the basis for Tampa Electric s determination, including all documentation sufficient to replicate and evaluate Tampa Electric s cost projections.

D. Unless EPA contests Tampa Electric s determination that the installation cost ceiling will be exceeded by installing control equipment to reduce NO_x emissions to 0.10 lb/mmBTU or less, Tampa Electric shall install, at each Unit that will continue to combust coal, the NO_x control technology designed to achieve the lowest Emission Rate that can be attained within the installation cost ceiling. Notwithstanding any provision of this Consent Decree, including the installation cost ceiling, Tampa Electric shall install NO_x control technology that is designed to achieve an Emission Rate no less stringent than 0.15 lb/mmBTU. Each Unit combusting coal and its NO_x controls shall meet the Emission Rate for which they

are designed.

E. Tampa Electric shall acquire, install, commence operating emission control equipment, and meet the applicable Emission Rate for NO_x at each of the Units to remain coal-fired, as follows: (1) for the first of the Units to remain coal-fired, or if only one Unit is to be coal-fired, on or before May 1, 2008; (2) for the second Unit, if there is one, on or before May 1, 2009; (3) for the third Unit, if there is one, on or before May 1, 2010.

38. Tampa Electric s NO_x Reduction Requirements if Tampa Electric Re-Powers Units 1, 2, and/or 3 . If, by May 1, 2007, Tampa Electric advises EPA that Tampa Electric has elected to Re-Power one or more of Units 1, 2, and 3 at Big Bend, then Tampa Electric shall complete all steps necessary to accomplish such Re-Powering in a time frame to commence operation of the Re-Powered Unit(s) no later than May 1, 2010. Any Unit(s) to be replaced by a Re-Powered Unit may continue to operate until the earlier of six months after the date the Re-Powered Unit begins commercial operation or December 31, 2010. Tampa Electric shall timely apply for a preconstruction permit under Rule 62-212, F.A.C., prior to commencing construction of any Re-Powered Unit at Big Bend. In applying for such permit Tampa Electric shall seek, as part of the permit, provisions requiring installation of SCR or other EPA approved control technology and a NO_x Emission Rate no greater than 3.5 ppm. Tampa Electric shall operate any Unit Re-Powered under this Paragraph to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the rate established in the preconstruction permit, whichever is more stringent. Notwithstanding the provisions of this Paragraph or the definition of Re-Power in this

Consent Decree, Tampa Electric may also elect to fuel Units 1, 2, or 3 with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric applies for and secures a PSD permit before using such fuel in any of these Units, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

39. Requirements Applicable to Big Bend Units 1, 2, and/or 3 if Shutdown. If Tampa Electric elects to Shutdown one or more of Units 1, 2, and 3, Tampa Electric shall complete Shutdown of the first such Unit on or before May 1, 2008; of the second Unit, if applicable, on or before May 1, 2009, and of the third Unit, if applicable, on or before May 1, 2010. Notwithstanding the requirements of this Paragraph, Tampa Electric may retain any Unit Shutdown pursuant to this Paragraph on Reserve / Standby. If Tampa Electric later decides to restart such Unit retained on Reserve / Standby by Re-Powering it then, prior to such restart, Tampa Electric shall timely apply for a PSD permit for the Unit(s) to be Re-Powered, and Tampa Electric shall abide by the permit issued as result of that application, including installation of BACT and its corresponding Emission Rate determined at the time of the restart. Tampa Electric shall operate each Unit Re-Powered under this Paragraph to meet an Emission Rate for NO_x of no greater than 3.5 ppm or the Emission Rate established in the PSD permit, whichever is more stringent. Tampa Electric shall provide a copy of any permit application(s), proposed permit(s), and permit(s) to the United States as specified in Paragraph 82 (Notice). Upon Shutdown of a Unit under this Paragraph, Tampa Electric may never again use coal to fire that Unit.

For any Unit Shutdown and placed on on Reserve / Standby under this Paragraph, and notwithstanding the definition of Re-Power in this Consent Decree, Tampa Electric also may elect to fuel such a Unit with a gaseous fuel other than or in addition to natural gas, if and only if Tampa Electric: applies for and secures a PSD permit before using such fuel in any of such Unit, complies with all requirements issued in such a permit, and complies with all requirements of this Consent Decree applicable to Re-Powering.

40. Further SO_2 Reduction Requirements if Big Bend Units 1, 2, or 3 Remains Coal-fired. If Tampa Electric elects under Paragraph 36 to continue combusting coal at Units 1, 2, and/or 3, Tampa Electric shall meet the following requirements.

A. Removal Efficiency or Emission Rate. Commencing on dates set forth in Subparagraph C and continuing thereafter, Tampa Electric shall operate coal-fired Units and the scrubbers that serve those Units so that emissions from the Units shall meet at least one of the following limits:

(1) the scrubber shall remove at least 95% of the SO_2 in the flue gas that entered the scrubber; or

(2) the Emission Rate for SO_2 from each Unit does not exceed 0.25 lb/mmBTU.

B. Availability Criteria. Commencing on the deadlines set in this Paragraph and continuing thereafter, Tampa Electric shall not allow emissions of SO_2 from Big Bend Units 1, 2, or 3 without scrubbing the flue gas from those Units and using other equipment designed to control SO_2 emissions. Notwithstanding the preceding sentence, to the extent that the Clean Air Act New Source Performance Standards identify circumstances during which Bend Unit 4 may operate without

its scrubber, this Consent Decree shall allow Big Bend Units1, 2, and/or 3 to operate when those same circumstances are present at Big Bend Units 1, 2, and/or 3.

C. Deadlines. Big Bend Unit 3 and the scrubber(s) serving it shall be subject to the requirements of this Paragraph beginning January 1, 2010 and continuing thereafter. Until January 1, 2010, Tampa Electric shall control SO_2 emissions from Unit 3 as required by Paragraphs 30 and 31. Big Bend Units 1 and 2 and the scrubber(s) serving them shall be subject to the requirements of this Paragraph beginning January 1, 2013 and continuing thereafter. Until January 1, 2013, Tampa Electric shall control SO_2 emissions from Units 1 and 2 as required by Paragraphs 29 and 31.

D. Nothing in this Consent Decree shall alter requirements of NSPS, 40 C.F.R. Part 60 Subpart Da, that apply to operation of Unit 4 and the scrubber serving it.

C. BIG BEND AND GANNON – PERMITS AND RESOLUTION OF CLAIMS

41. Timely Application for Permits. Except as otherwise stated in this Consent Decree, in any instance where otherwise applicable law or this Consent Decree requires Tampa Electric to secure a permit to authorize constructing or operating any device under this Consent Decree, Tampa Electric shall make such application in a timely manner. Such applications shall be completed and submitted to the appropriate authorities to allow sufficient time for all legally required processing and review of the permit request. Failure to comply with this provision shall bar any use by Tampa Electric of the Force

Majeure provisions of this Consent Decree.

42. Title V Permits.

A. On or before January 1, 2004, Tampa Electric shall apply for a Title V Permit(s), or for an amendment to an existing Title V Permit(s), to include all performance, operational, maintenance, and control technology requirements established by or determined under this Consent Decree for Gannon, including but not limited to Emission Rates, removal efficiencies, limits on fuel use (including those imposed on Re-Powered or Shutdown Units), and operation and maintenance optimization requirements.

B. On or before January 1, 2009, Tampa Electric shall apply for a Title V Permit(s), or for an amendment to an existing Title V Permit(s), to include all performance, operational, maintenance, and control technology requirements established by or determined under this Consent Decree for Big Bend, including but not limited to Emission Rates, removal efficiencies, limits on fuel use (including those imposed on Re-Powered or Shutdown Units), and operation and maintenance optimization requirements.

C. Except as this Consent Decree expressly requires otherwise, this Consent Decree shall not be construed to require Tampa Electric to apply for or obtain a permit pursuant to the Prevention of Significant Deterioration requirements of the Clean Air Act for any work performed by Tampa Electric within the scope of the Resolution of Claims provisions of Paragraphs 43 and 44, below.

43. Resolution of Past Claims - This Consent Decree resolves all of Plaintiff s civil claims

for liability arising from violations of either: (1) the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401, et seq at Units at Big Bend or Gannon, or (2) 40 C.F.R. Section 60.14 at Units at Big Bend or Gannon, that :

A. are alleged in the Complaint filed November 3, 1999, or in the NOV issued on that date;

B. could have been alleged by the United States in the Complaint filed November 3, 1999, or in the NOV issued on that date; or

C. have arisen from Tampa Electric s actions that occurred between November 3, 1999 and the date on which this Consent Decree is entered by the Court.

44. Resolution of Future Claims - Covenant not to Sue . The United States covenants not to sue Tampa Electric for civil claims arising from the Prevention of Significant Deterioration or Non-Attainment provisions of Parts C and D of the Clean Air Act, 42 U.S.C. § 7401 et seq., at Big Bend or Gannon Units and that are based on failure to obtain PSD or nonattainment New Source Review (NSR) permits for:

A. work that this Consent Decree expressly directs Tampa Electric to undertake; or

B. physical changes or changes in the method of operation of Big Bend or Gannon Units not required by this Consent Decree, if and only if:

(1) such change is commenced after Tampa Electric is implementing the plan, or the first phase of the plan if applicable, approved by EPA under Paragraph 31 (Optimizing Availability of Scrubbers),

(2) such change is commenced, within the meaning of 40 C.F.R. Section

52.21(b)(9), during the time this Consent Decree applies to the Unit at which this change has been made ;

(3) Tampa Electric is otherwise in compliance with this Consent Decree;

(4) hourly Emission Rates of NO_x, SO_2, or PM at the changed Unit(s) do not exceed their respective hourly Emission Rates prior to the change, as measured by 40 C.F.R. § 60.14(h); and

(5) in any calendar year following the change, emissions of no pollutant within the scope of Total Baseline Emissions exceed the emissions of that pollutant in the Total Baseline Emissions.

45. Separate Limitation on Resolution of Claims. Notwithstanding the provisions of Section XIII (Termination), the provisions of Paragraph 44 (Resolution of Future Claims - Covenant Not to Sue) shall terminate at Gannon and Big Bend, as follows. On December 31, 2006, the provisions of Paragraph 44 shall terminate and be of no further effect as to physical changes or changes in the method of operation at Gannon. On December 31, 2012, the provisions of Paragraph 44 shall terminate and be of no further effect as to physical changes or changes in the method of operation at Big Bend. If Tampa Electric Re-Powers any Unit at Big Bend under the terms provided by this Consent Decree, then for each such Unit the provisions of Paragraph 44 shall terminate two years after each such Unit is Re-Powered or on December 31, 2012, whichever is earlier.

46. Exclusion of Certain Emission Allowances. For any and all actions taken by Tampa Electric pursuant to the terms of this Consent Decree, including but not limited to

upgrading of ESPs and scrubbers, installation of NO_x controls, Re-Powering, and Shutdown, Tampa Electric shall not use or sell any resulting NO_x or SO_2 emission allowances or credits in any emission trading or marketing program of any kind; provided, however, that:

A. SO_2 credits allocated to Tampa Electric by the Administrator of EPA under the Act, due to the Re-Powering or Shutdown of Gannon, may be retained by Tampa Electric during the year in which they are allocated, but only for Tampa Electric s own use in meeting any acid rain requirement imposed under the Act. For any such allowances not used by Tampa Electric for this purpose by June 30 of the following calendar year, Tampa Electric shall not use, sell, trade, or otherwise transfer these allowances for its benefit or the benefit of a third party unless such a transfer would result in the retiring of such allowances without their ever being used.

B. If Tampa Electric decides to Re-Power any Unit at Big Bend, then Tampa Electric shall be entitled to retain for any purpose under law the difference between the emission allowances that would have resulted from installing BACT-level NO_x and SO_2 controls at the existing coal-fired Unit and the emission allowances that result from Re-Powering that Unit. Before Tampa Electric uses any allowances within the scope of this Subparagraph, Tampa Electric shall submit the calculation of the net emission allowances for approval by the United States.

C. Nothing in this Consent Decree shall preclude Tampa Electric from using or

selling emission allowances arising from Tampa Electric s activities occurring prior to December 31, 1999, or Tampa Electric s activities after that date that are not related to actions required of Tampa Electric under this Consent Decree. The United States and Tampa Electric agree that the operation of the SO_2 scrubber serving Big Bend Units 1 and 2 meets the requirements of this Subparagraph, and that emission allowances resulting from the operation of this scrubber shall not be treated as an activity related to or required under this Consent Decree.

V. REPORTING AND RECORD KEEPING

47. Beginning at the end of the first calendar quarter after entry of this Consent Decree, and in addition to any other express reporting requirement in this Consent Decree, Tampa Electric shall submit to EPA a quarterly report, consistent with the form attached to this Consent Decree as the Appendix, within thirty (30) days after the end of each calendar quarter until this Consent Decree is terminated.

48. Tampa Electric s report shall be signed by Tampa Electric s Vice President, Environmental and Fuels, or, in his or her absence, Vice President, Energy Supply, or higher ranking official, and shall contain the following certification:

> I certify under penalty of law that this information was prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my directions and my inquiry of the person(s) who manage the system, or the person(s) directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I understand that there are significant penalties for making misrepresentations to or misleading the United States.

VI. CIVIL PENALTY

49. Within thirty (30) calendar days of entry of this Consent Decree, Tampa Electric shall pay to the United States a civil penalty in the amount of $3.5 million. The civil penalty shall be paid by Electronic Funds Transfer ("EFT") to the United States Department of Justice, in accordance with current EFT procedures, referencing the USAO File Number and DOJ Case Number 90-5-2-1-06932 and the civil action case name and case number of this action. The costs of such EFT shall be Tampa Electric s responsibility. Payment shall be made in accordance with instructions provided by the Financial Litigation Unit of the U.S. Attorney's Office for the Middle District of Florida. Any funds received after 11:00 a.m. (EST) shall be credited on the next business day. Tampa Electric shall provide notice of payment, referencing the USAO File Number, DOJ Case Number 90-5-2-1- 06932, and the civil action case name and case number, to the Department of Justice and to EPA, as provided in Paragraph 82 (Notice). Failure to timely pay the civil penalty shall subject Tampa Electric to interest accruing from the date payment is due until the date payment is made at the rate prescribed by 28 U.S.C. § 1961, and shall render Tampa Electric liable for all charges, costs, fees, and penalties established by law for the benefit of a creditor or of the United States in securing payment.

VII. NO_x REDUCTION PROJECTS AND MITIGATION PROJECTS

50. Tampa Electric shall submit plans for and shall implement the NO_x Reduction and Other Mitigation Projects (referred to together as Projects) described in this Section, and in Paragraph 35 of this Consent Decree, in compliance with the schedules and terms of this

Consent Decree. In performing these Projects, Tampa Electric shall spend no less than $10 million in Project Dollars, in total, unless the Additional NO_x Reduction Project(s) selected under Paragraph 52.C is estimated to cost more than $5 million, in which case Tampa Electric shall spend no less than $10 million but no more than $11 million in Project Dollars, in total. Tampa Electric shall expend the full amount of the Project Dollars required by this Paragraph on or before May 1, 2010. Tampa Electric shall maintain for review by EPA, upon its request, all documents identifying Project Dollars spent by Tampa Electric.

51. All plans and reports prepared by Tampa Electric pursuant to the requirements of Paragraph 35 and this Section of the Consent Decree shall be publicly available without charge.

52. Tampa Electric shall submit the required plans for and complete the following Projects:

A. Early NO_x reductions through combustion optimization as described in Paragraph 35 of this Consent Decree.

B. Performance of Air Chemistry Work in Tampa Bay Estuary. Tampa Electric shall expend no more than $2 million Project Dollars in conducting or financing stack tests, emissions estimation, ambient air monitoring, data acquisition and analysis, and any combination thereof that: (1) is not otherwise required by law, (2) will provide data or analysis that is not already available, (3) will complement work carried out by other persons examining the air chemistry of Tampa Bay Estuary, and (4) will help close gaps in current understanding of air chemistry in the Tampa Bay Estuary. Tampa Electric shall either conduct this

work itself, fund other persons already conducting such work on a non-profit basis, or both. For work Tampa Electric intends to conduct itself, the company shall describe the proposed work and a schedule for completion to EPA, in writing, at least 90 days prior to the date on which Tampa Electric intends to start such work, including an explanation of why the proposed work meets all the requirements of this Subparagraph. Unless EPA objects to the proposed work on the grounds it does not comply with the requirements of this Subparagraph, Tampa Electric shall undertake and complete the work according to the proposed schedule. If Tampa Electric elects to spend some or all of the $2 million Project Dollars to finance work to be performed by other persons or organizations, the company shall provide to EPA for review and approval a plan that describes the work to be performed, the persons or organizations conducting the work, the schedule for its completion, the schedule for Tampa Electric s payments, and an explanation of why the proposed payment(s) meets all the requirements of this Subparagraph. The plan shall be provided to EPA at least 90 days prior to the date on which Tampa Electric will begin transferring the money to finance such work. All payments to persons or organizations under such a plan shall be completed by Tampa Electric no later than June 30, 2002. Before Tampa Electric makes such payments for the benefit of any person or organization carrying out work under this Paragraph, Tampa Electric shall secure a written, signed commitment from such person to provide Tampa Electric and EPA with the results of the work.

C. Additional NO_x Reductions Project(s).

(1) General Requirement. Tampa Electric shall expend the remainder of the Project Dollars required under this Consent Decree to: (i) demonstrate innovative NO_x control technologies on any of its Units or boilers at Gannon or Big Bend not Shutdown or on Reserve / Standby; and/or (ii) reduce the NO_x Emission Rate for any Big Bend coal-combusting Unit below the lowest rate otherwise applicable to it under this Consent Decree.

(2) For any Project(s) at Gannon. If Tampa Electric elects to undertake a project on an eligible Gannon Unit(s) to demonstrate any innovative NO_x control technology, within six months after entry of this Consent Decree Tampa Electric shall submit a plan to EPA, for review and approval, which sets forth: (a) the NO_x demonstration or innovative control technology projects being proposed; (b) the anticipated cost of the projects; (c) the reduction in NO_x or other environmental benefits anticipated to result from the project, and (d) a schedule for implementation of the project providing for commencement and completion in accordance with the requirements of this Subparagraph. . EPA shall complete its review of this plan within 60 days after receipt. If such project is approved, Tampa Electric shall complete installation of the technology no later than December 31, 2004 as part of the Re-Powering of such Units; provided, however, that nothing in this Paragraph

alters Tampa Electric s obligation under Paragraph 26 of this Consent Decree.

(3) For any Project(s) at Big Bend. At least three (3) years prior to the date on which the expenditure of any Project Dollars is to commence on Big Bend under this Subparagraph C, Tampa Electric shall submit a plan to EPA for review and approval which sets forth: (a) the NO_x demonstration or innovative control technology projects being proposed; (b) the anticipated cost of the projects; (c) the reduction in NO_x or other environmental benefits anticipated to result from the project, and (d) a schedule for implementation of the project providing for commencement and completion in accordance with the requirements of this Subparagraph. If EPA approves the projects contained in the plan, Tampa Electric shall implement the project(s). Projects that would demonstrate innovative NO_x control technology or reduce the NO_x Emission Rate for any Big Bend coal-fired or Re-Powered Unit shall be operating and achieving reductions or demonstrating the performance of the innovative technology, as applicable, not later than May 1, 2010.

(4) Follow-up Report(s). Within sixty (60) days following the implementation of each EPA-approved project, Tampa Electric shall submit to EPA a report that documents the date that all aspects of the project were implemented, Tampa Electric s results in implementing the project, including the emission reductions or other environmental benefits

achieved, and the Project Dollars expended by Tampa Electric in implementing the project.

VIII. STIPULATED PENALTIES

53. For purposes of this Consent Decree, within thirty days after written demand from the United States, and subject to the provisions of Sections X (Force Majeure) and XI (Dispute Resolution), Tampa Electric shall pay the following stipulated penalties to the United States for each failure by Tampa Electric to comply with the terms of this Consent Decree.

A. For failure to pay timely the civil penalty as specified in Section VI of this Consent Decree, $10,000 per day.

B. For all violations of a 24 hour Emission Rate (1) Less than 5% in excess of limit: $4,000 per day, per violation; (2) more than 5% but less than 10% in excess of limit: $9,000 per day per violation; (3) equal to or greater than 10% in excess of limit: $27,500 per day, per violation

C. For all violations of 30-day rolling average Emission Rates (1) Less than 5% in excess of limit: $150 per day per violation; (2) more than 5% but less than 10% in excess of limit: $300 per day per violation; (3) equal to or greater than 10% in excess of limit: $800 per day per violation. Violation of an Emission Rate that is based on a 30 day rolling average is a violation on every day of the 30 day period on which the average is based . Where a violation of a 30 day rolling monthly average Emission Rate (for the same pollutant and from the same

source) recurs within periods less than 30 days, Tampa Electric shall not pay a daily stipulated penalty for any day of the recurrence for which a stipulated penalty has already been paid.

D. For all violations of a 95% removal efficiency requirement (1) For removal efficiency less than 95% but greater than or equal to 94%, $4,000 per day, per violation; (2) for removal efficiency less than 94% but greater than or equal to 91%, $9,000 per day, per violation; (3) for removal efficiency less than 91%, $27,500 per day, per violation. For all violations of a 93% removal efficiency requirement (1) For removal efficiency less than 93% but greater than or equal to 92%, $4,000 per day, per violation; (2) for removal efficiency less than 92% but greater than or equal to 90%, $9,000 per day, per violation; (3) for removal efficiency less than 90%, $27,500 per day, per violation;

E. Violation of deadlines for Shutdown of boilers or Units or megawatt capacity $27,500 per day, per violation.

F. Failure to apply for the permits required by Paragraphs 26, 27, 34, 38, and 42 $1,000 per day, per violation.

G. Failure to implement the recommendations of the PM BACT Analysis or the PM optimization study by May 1, 2004 $5,000 per day, per violation for first 30 days; $15,000 per day, per violation, for next 30 days; $27,500 per day, per violation, thereafter.

H. Failure to commence combustion optimization at Big Bend Units 1, 2, or 3 on or before May 30, 2003 as required by Paragraph 35, $10,000 per day, per violation.

I. Failure to operate the scrubbers at Big Bend Units 1, 2, or 3 on any day except as permitted by Paragraphs 29, 30, or 31, $27,500 per day, per violation.

J. Failure to submit quarterly progress and monitoring report $100 per day, per violation, for first ten days late, and $500 per day for each day thereafter.

K. Failure to complete timely any action or payment required by or established under Subparagraph 52(B) (Performance of Air Chemistry Work in Tampa Bay Estuary), $5,000 per day, per violation

L. Failure to perform NO_x reduction or demonstration project(s), by the deadline(s) established in Subparagraph 52.C (Additional NO_x Reductions Project(s)), $10,000 per day, per violation;

M. For failure to spend at least the number of Project Dollars required by this Consent Decree by date specified in Paragraph 50, $5,000 per day, per violation;

N. Violation of any Consent Decree prohibition on use of allowances as provided in Paragraph 46 three times the market value of the improperly used allowance as measured at the time of the improper use.

54. Should Tampa Electric dispute its obligation to pay part or all of a stipulated penalty demanded by the United States, it may avoid the imposition of a separate stipulated penalty for the failure to pay the disputed penalty by depositing the disputed amount in a commercial escrow account pending resolution of the matter and by invoking the Dispute Resolution provisions of this Consent Decree within the time provided in this Section VIII of the Consent Decree for payment of the disputed penalty. If the dispute is thereafter resolved in Tampa Electric's favor, the escrowed amount plus accrued interest

shall be returned to Tampa Electric. If the dispute is resolved in favor of the United States, it shall be entitled to the escrowed amount determined to be due by the Court, plus accrued interest. The balance in the escrow account, if any, shall be returned to Tampa Electric.

55. The United States reserves the right to pursue any other remedies to which it is entitled, including, but not limited to, a new civil enforcement action and additional injunctive relief for Tampa Electric's violations of this Consent Decree. If the United States elects to seek civil or contempt penalties after having collected stipulated penalties for the same violation, any further penalty awarded shall be reduced by the amount of the stipulated penalty timely paid or escrowed by Tampa Electric. Tampa Electric shall not be required to remit any stipulated penalty to the United States that is disputed in compliance with Part XI of this Consent Decree until the dispute is resolved in favor of the United States. However, nothing in this Paragraph shall be construed to cease the accrual of the stipulated penalties until the dispute is resolved.

IX. RIGHT OF ENTRY

56. Any authorized representative of EPA or an appropriate state agency, including independent contractors, upon presentation of credentials, shall have a right of entry upon the premises of Tampa Electric's plants identified herein at any reasonable time for the purpose of monitoring compliance with the provisions of this Consent Decree, including inspecting plant equipment and inspecting and copying all records maintained by Tampa Electric required by this Consent Decree. Tampa Electric shall retain such records for a

period of twelve (12) years from the date of entry of this Consent Decree. Nothing in this Consent Decree shall limit the authority of EPA to conduct tests and inspections at Tampa Electric s facilities under Section 114 of the Act, 42 U.S.C. § 7414.

X. FORCE MAJEURE

57. If any event occurs which causes or may cause a delay in complying with any provision of this Consent Decree, Tampa Electric shall notify the United States in writing as soon as practicable, but in no event later than seven (7) business days following the date Tampa Electric first knew, or within ten (10) business days following the date Tampa Electric should have known by the exercise of due diligence, that the event caused or may cause such delay. In this notice Tampa Electric shall reference this Paragraph of this Consent Decree and describe the anticipated length of time the delay may persist, the cause or causes of the delay, the measures taken or to be taken by Tampa Electric to prevent or minimize the delay, and the schedule by which those measures will be implemented. Tampa Electric shall adopt all reasonable measures to avoid or minimize such delays.

58. Failure by Tampa Electric to comply with the notice requirements of Paragraph 57 shall render this Section X voidable by the United States as to the specific event for which Tampa Electric has failed to comply with such notice requirement. If voided, the provisions of this Section shall have no effect as to the particular event involved.

59. The United States shall notify Tampa Electric in writing regarding Tampa Electric's claim of a delay in performance within (15) fifteen business days of receipt of the Force

Majeure notice provided under Paragraph 57. If the United States agrees that the delay in performance has been or will be caused by circumstances beyond the control of Tampa Electric, including any entity controlled by Tampa Electric, and that Tampa Electric could not have prevented the delay through the exercise of due diligence, the parties shall stipulate to an extension of the required deadline(s) for all requirement(s) affected by the delay for a period equivalent to the delay actually caused by such circumstances. Such stipulation shall be filed as a modification to this Consent Decree in order to be effective. Tampa Electric shall not be liable for stipulated penalties for the period of any such delay.

60. If the United States does not accept Tampa Electric's claim of a delay in performance, to avoid the imposition of stipulated penalties Tampa Electric must submit the matter to this Court for resolution by filing a petition for determination. Once Tampa Electric has submitted the matter, the United States shall have fifteen business days to file its response. If Tampa Electric submits the matter to this Court for resolution, and the Court determines that the delay in performance has been or will be caused by circumstances beyond the control of Tampa Electric, including any entity controlled by Tampa Electric, and that Tampa Electric could not have prevented the delay by the exercise of due diligence, Tampa Electric shall be excused as to that event(s) and delay (including stipulated penalties otherwise applicable), but only for the period of time equivalent to the delay caused by such circumstances.

61. Tampa Electric shall bear the burden of proving that any delay in performance of any requirement of this Consent Decree was caused by or will be caused by circumstances

beyond its control, including any entity controlled by it, and that Tampa Electric could not have prevented the delay by the exercise of due diligence. Tampa Electric shall also bear the burden of proving the duration and extent of any delay(s) attributable to such circumstances. An extension of one compliance date based on a particular event may, but will not necessarily, result in an extension of a subsequent compliance date.

62. Unanticipated or increased costs or expenses associated with the performance of Tampa Electric's obligations under this Consent Decree shall not constitute circumstances beyond the control of Tampa Electric or serve as a basis for an extension of time under this Section. However, failure of a permitting authority to issue a necessary permit in a timely fashion may constitute a Force Majeure event where the failure of the permitting authority to act is beyond the control of Tampa Electric and Tampa Electric has taken all steps available to it to obtain the necessary permit, including, but not limited to, submitting a complete permit application, responding to requests for additional information by the permitting authority in a timely fashion, accepting lawful permit terms and conditions, and prosecuting appeals of any allegedly unlawful terms and conditions imposed by the permitting authority in an expeditious fashion.

63. The parties agree that, depending upon the circumstances related to an event and Tampa Electric s response to such circumstances, the kinds of events listed below could also qualify as Force Majeure events within the meaning of this Section X of the Consent Decree: Construction, labor, or equipment delays; natural gas and gas transportation availability delays;acts of God; and the failure of an innovative technology approved under Paragraph 26.B and 52.C.

64. Notwithstanding any other provision of this Consent Decree, this Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of Tampa Electric delivering a notice pursuant to this Section or the parties' inability to reach agreement on a dispute under this Part.

65. As part of the resolution of any matter submitted to this Court under this Section, the parties by agreement, or this Court by order, may in appropriate circumstances extend or modify the schedule for completion of work under this Consent Decree to account for the delay in the work that occurred as a result of any delay agreed to by the United States or approved by this Court. Tampa Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

XI. DISPUTE RESOLUTION

66. The dispute resolution procedure provided by this Section XI shall be available to resolve all disputes arising under this Consent Decree, except as provided in Section X regarding Force Majeure, or in this Section XI, provided that the party making such application has made a good faith attempt to resolve the matter with the other party.

67. The dispute resolution procedure required herein shall be invoked by one party to this Consent Decree giving written notice to another advising of a dispute pursuant to this Section XI. The notice shall describe the nature of the dispute and shall state the noticing party's position with regard to such dispute. The party receiving such a notice shall acknowledge receipt of the notice, and the parties shall expeditiously schedule a meeting

to discuss the dispute informally not later than fourteen (14) days following receipt of such notice.

68. Disputes submitted to dispute resolution under this Section shall, in the first instance, be the subject of informal negotiations between the parties. Such period of informal negotiations shall not extend beyond thirty (30) calendar days from the date of the first meeting between representatives of the United States and Tampa Electric unless the parties' representatives agree to shorten or extend this period.

69. If the parties are unable to reach agreement during the informal negotiation period, the United States shall provide Tampa Electric with a written summary of its position regarding the dispute. The written position provided by the United States shall be considered binding unless, within thirty (30) calendar days thereafter, Tampa Electric files with this Court a petition which describes the nature of the dispute and seeks resolution. The United States may respond to the petition within forty-five (45) calendar days of filing.

70. Where the nature of the dispute is such that a more timely resolution of the issue is required, the time periods set out in this Section may be shortened upon motion of one of the parties to the dispute.

71. This Court shall not draw any inferences nor establish any presumptions adverse to either party as a result of invocation of this Section or the parties' inability to reach agreement.

72. As part of the resolution of any dispute under this Section, in appropriate circumstances the parties may agree, or this Court may order, an extension or modification of the schedule for completion of work under this Consent Decree to account for the delay that

occurred as a result of dispute resolution. Tampa Electric shall be liable for stipulated penalties for its failure thereafter to complete the work in accordance with the extended or modified schedule.

73. The Court shall decide all disputes pursuant to applicable principles of law for resolving such disputes; provided, however, that the United States and Tampa Electric reserve their rights to argue for what the applicable standard of law should be for resolving any particular dispute. Notwithstanding the preceding sentence of this Paragraph, as to disputes arising under Paragraph 32, the Court shall sustain the position of the United States as to the BACT Analysis recommendations and the optimization study measures that should be installed and implemented, unless Tampa Electric demonstrates that the position of the United States is arbitrary or capricious.

XII. GENERAL PROVISIONS

74. Effect of Settlement. This Consent Decree is not a permit; compliance with its terms does not guarantee compliance with all applicable Federal, State or Local laws or regulations.

75. Satisfaction of all of the requirements of this Consent Decree constitutes full settlement of and shall resolve and release Tampa Electric from all civil liability of Tampa Electric to the United States for the claims referred to in Paragraphs 43 and 44 of this Consent Decree. This Consent Decree does not apply to any claim(s) of alleged criminal liability, which are reserved.

76. In any subsequent administrative or judicial action initiated by the United States for

injunctive relief or civil penalties relating to the facilities covered by this Consent Decree, Tampa Electric shall not assert any defense or claim based upon principles of waiver, res judicata, collateral estoppel, issue preclusion, claim splitting, or other defense based upon any contention that the claims raised by the United States in the subsequent proceeding were brought, or should have been brought, in the instant case; provided, however, that nothing in this Paragraph is intended to affect the enforceability of the Resolution of Claims provisions of Paragraphs 43 and 44 of this Consent Decree..

77. Other Laws. Except as specifically provided by this Consent Decree, nothing in this Consent Decree shall relieve Tampa Electric of its obligation to comply with all applicable Federal, State and Local laws and regulations. Subject to Paragraph 43 and 44, nothing contained in this Consent Decree shall be construed to prevent or limit the United States' rights to obtain penalties or injunctive relief under the Clean Air Act or other federal, state or local statutes or regulations.

78. Third Parties. This Consent Decree does not limit, enlarge or affect the rights of any party to this Consent Decree as against any third parties.

79. Costs. Each party to this action shall bear its own costs and attorneys' fees.

80. Public Documents. All information and documents submitted by Tampa Electric to the United States pursuant to this Consent Decree shall be subject to public inspection, unless subject to legal privileges or protection or identified and supported as business confidential by Tampa Electric in accordance with 40 C.F.R. Part 2.

81. Public Comments. The parties agree and acknowledge that final approval by the United States and entry of this Consent Decree is subject to the requirements of 28 C.F.R. §

50.7, which provides for notice of the lodging of this Consent Decree in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Consent Decree is inappropriate, improper, or inadequate.

82. Notice. Unless otherwise provided herein, notifications to or communications with the United States or Tampa Electric shall be deemed submitted on the date they are postmarked and sent either by overnight mail, return receipt requested, or by certified or registered mail, return receipt requested. Except as otherwise provided herein, when written notification to or communication with the United States, EPA, or Tampa Electric is required by the terms of this Consent Decree, it shall be addressed as follows:

As to the United States of America:

For U.S. DOJ

Chief
Environmental Enforcement Section
Environment and Natural Resources Division
U.S. Department of Justice
P.O. Box 7611, Ben Franklin Station
Washington, D.C. 20044-7611
DJ# 90-5-2-1-06932

Whitney L. Schmidt
Coordinator, Affirmative Civil Enforcement Program
Office of the United States Attorney
Middle District of Florida
400 N. Tampa Street
Tampa, FL 33602

For U.S. EPA

Director, Air Enforcement Division

Office of Enforcement and Compliance Assurance
U.S. Environmental Protection Agency
Ariel Rios Building [2242A]
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

and

Regional Administrator
U.S. EPA Region IV
61 Forsyth Street, S.E.
Atlanta, GA 30303

As to Tampa Electric:

Sheila M. McDevitt
General Counsel
Tampa Electric Company
P.O. Box 111
Tampa, FL 333601-0111

83. Any party may change either the notice recipient or the address for providing notices to it by serving all other parties with a notice setting forth such new notice recipient or address.

84. Modification. Except as otherwise allowed by law, there shall be no modification of this Consent Decree without written approval by the United States and Tampa Electric, and approval of such modification by the Court.

85. Continuing Jurisdiction. The Court shall retain jurisdiction of this case after entry of this Consent Decree to enforce compliance with the terms and conditions of this Consent Decree and to take any action necessary or appropriate for its interpretation, construction, execution, or modification. During the term of this Consent Decree, any party may apply

to the Court for any relief necessary to construe or effectuate this Consent Decree.

86. Complete Agreement. This Consent Decree constitutes the final, complete and exclusive agreement and understanding among the parties with respect to the settlement embodied in this Consent Decree. The parties acknowledge that there are no representations, agreements or understandings relating to the settlement other than those expressly contained in this Consent Decree. An Appendix is attached to and incorporated into this Consent Decree by this reference.

XIII. TERMINATION

87. Except as provided in Paragraphs 43, 44, and 45 (involving resolution of claims), this Consent Decree shall be subject to termination upon motion by either party after Tampa Electric satisfies all requirements of this Consent Decree, including payment of all stipulated penalties that may be due, installation of control technology systems as specified herein, the receipt of all permits specified herein, securing valid Title V Permits for Gannon and Big Bend that incorporate all emission and fuel limits from this Consent Decree as well as all operational limits established under this Consent Decree, and the submission of all final reports indicating satisfaction of the requirements for implementation of all acts called for under Part VII of this Consent Decree.

88. If Tampa Electric believes it has achieved compliance with the requirements of this Consent Decree, then Tampa Electric shall so certify to the United States. Unless the United States objects in writing with specific reasons within 60 days of receipt of Tampa Electric s certification, the Court shall order that this Consent Decree be terminated on

Tampa Electric's motion. If the United States objects to Tampa Electric's certification, then the matter shall be submitted to the Court for resolution under Section XI of this Consent Decree. In such case, Tampa Electric shall bear the burden of proving that this Consent Decree should be terminated.

SO ORDERED, THIS _____ DAY OF _____ 2000.

_____

UNITED STATES DISTRICT JUDGE

Calculation of Replacement Fuel Costs for 2003 and 2004 Based on 2002 Generation

2002 Total Generation (Total Replaced in 2004)

Gannon #1 - Year 2002 Net Capacity - 114 MW				
Month	Net Generation (MWH)		Net Generation (MWH)	Fuel Cost
Jan	35,443	$	0.0260	921,518
Feb	32,948	$	0.0178	586,474
March	53,089	$	0.0199	1,056,471
April	48,902	$	0.0204	997,601
May	45,994	$	0.0204	938,278
June	42,306	$	0.0202	854,581
July	53,279	$	0.0228	1,214,761
August	44,015	$	0.0213	937,520
September	40,940	$	0.0213	872,022
October	51,079	$	0.0202	1,031,796
November	36,494	$	0.0186	678,788
December	27,043	$	0.0209	565,199
Total	511,532	$	0.0208	10,655,009

Gannon #2 - Year 2002 Net Capacity - 98 MW				
Month	Net Generation (MWH)		Net Generation (MWH)	Fuel Cost
Jan	23,260	$	0.0270	628,020
Feb	18,304	$	0.0192	351,437
March	49,384	$	0.0205	1,012,372
April	43,565	$	0.0217	945,361
May	45,722	$	0.0204	932,729
June	41,350	$	0.0204	843,540
July	48,092	$	0.0244	1,173,445
August	44,471	$	0.0218	969,468
September	39,108	$	0.0214	836,911
October	52,415	$	0.0216	1,132,164
November	37,407	$	0.0183	684,548
December	24,678	$	0.0214	528,109
Total	467,756	$	0.0215	10,038,103

Generation Replaced in 2003

Gannon #1 - Year 2002 Net Capacity - 114 MW	
Month	Net Generation (MWH)
Jan	0
Feb	0
March	0
April	48,902
May	45,994
June	42,306
July	53,279
August	44,015
September	40,940
October	51,079
November	36,494
December	27,043
Total	390,052

Gannon #2 - Year 2002 Net Capacity - 98 MW	
Month	Net Generation (MWH)
Jan	0
Feb	0
March	0
April	43,565
May	45,722
June	41,350
July	48,092
August	44,471
September	39,108
October	52,415
November	37,407
December	24,678
Total	376,808

Calculation of Replacement Fuel Costs
for 2003 and 2004
Based on 2002 Generation

Gannon #3 - Year 2002 Net Capacity - 98 MW			
Month	Net Generation (MWH)	Cost of Fuel (cents/kWh)	Fuel Cost
Jan	58,009	$ 0.0330	1,914,297
Feb	47,989	$ 0.0231	1,108,546
March	71,380	$ 0.0240	1,713,120
April	75,890	$ 0.0256	1,942,784
May	71,839	$ 0.0260	1,867,814
June	17,829	$ 0.0291	518,824
July	83,695	$ 0.0282	2,360,199
August	64,750	$ 0.0272	1,761,200
September	65,992	$ 0.0246	1,623,403
October	57,911	$ 0.0264	1,528,850
November	23,448	$ 0.0177	415,030
December	39,051	$ 0.0234	913,793
Total	677,783	$ 0.0261	17,667,860

Gannon #3 - Year 2002 Net Capacity - 98 MW	
Month	Net Generation (MWH)
Jan	0
Feb	0
March	0
April	0
May	0
June	0
July	0
August	0
September	0
October	28,021
November	23,448
December	39,051
Total	90,520

Gannon #4 - Year 2002 Net Capacity - 98 MW			
Month	Net Generation MWH)	Cost of Fuel (cents/kWh)	Fuel Cost
Jan	40,730	$ 0.0347	1,413,331
Feb	41,861	$ 0.0223	933,500
March	1,726	$ 0.0296	51,090
April	32,648	$ 0.0252	822,730
May	79,840	$ 0.0266	2,123,744
June	67,869	$ 0.0272	1,846,037
July	75,796	$ 0.0305	2,311,778
August	67,872	$ 0.0269	1,825,757
September	61,896	$ 0.0262	1,621,675
October	60,861	$ 0.0270	1,643,247
November	55,035	$ 0.0215	1,183,253
December	51,249	$ 0.0208	1,065,979
Total	637,383	$ 0.0264	16,842,120

Gannon #4 - Year 2002 Net Capacity - 98 MW	
Month	Net Generation MWH)
Jan	0
Feb	0
March	0
April	0
May	0
June	0
July	0
August	0
September	0
October	29,449
November	55,035
December	51,249
Total	135,733

Calculation of Replacement Fuel Costs
for 2003 and 2004
Based on 2002 Generation

Gannon #5 - Year 2002 Net Capacity - 98 MW				
Month	Net Generation (MWH)		Cost of Fuel (cents/kWh)	Fuel Cost
Jan	72,050	$	0.0240	1,729,200
Feb	34,488	$	0.0161	555,257
March	0	$	-	0
April	573	$	0.0388	22,232
May	99,739	$	0.0180	1,795,302
June	110,417	$	0.0182	2,009,589
July	94,688	$	0.0206	1,950,573
August	122,031	$	0.0187	2,281,980
September	89,300	$	0.0199	1,777,070
October	83,099	$	0.0191	1,587,191
November	102,728	$	0.0169	1,736,103
December	99,138	$	0.0193	1,913,363
Total	908,251	$	0.0191	17,357,861

Gannon #5 - Year 2002 Net Capacity - 98 MW	
Month	Net Generation (MWH)
Jan	0
Feb	34,488
March	0
April	573
May	99,739
June	110,417
July	94,688
August	122,031
September	89,300
October	83,099
November	102,728
December	99,138
Total	836,201

Gannon #6 - Year 2002 Net Capacity - 98 MW				
Month	Net Generation (MWH)		Cost of Fuel (cents/kWh)	Fuel Cost
Jan	153,653	$	0.0226	3,472,558
Feb	169,401	$	0.0162	2,744,296
March	153,458	$	0.0182	2,792,936
April	165,068	$	0.0190	3,136,292
May	189,537	$	0.0183	3,468,527
June	171,501	$	0.0182	3,121,318
July	154,914	$	0.0199	3,082,789
August	179,658	$	0.0180	3,233,844
September	178,356	$	0.0182	3,246,079
October	39,227	$	0.0179	702,163
November	0	$	-	0
December	57,508	$	0.0230	1,322,684
Total	1,612,281	$	0.0188	30,323,486

Gannon #6 - Year 2002 Net Capacity - 98 MW	
Month	Net Generation (MWH)
Jan	0
Feb	0
March	0
April	0
May	0
June	0
July	0
August	0
September	0
October	39,227
November	0
December	57,508
Total	96,735

Calculation of Replacement Fuel Costs
for 2003 and 2004
Based on 2002 Generation

Total 2002	4,814,986	$	0.0214	102,884,439	1,926,049			
Calculation of Savings Using BS1 Cost of $.046/kWh								
Total 1-4	2,294,454	$	0.0246	56,518,031	993,113	$	0.0246	24,462,817
Total 6	1,612,281	$	0.0246	39,714,436	96,735	$	0.0246	2,382,820
Total 1-6	4,814,986	$	0.0246	118,604,917	1,926,049	$	0.0246	47,443,320

Tampa Electric Company
Final Dismantling Study
in 2002 Dollars and
includes 15% Contingency

	LABOR	MATERIALS & EQUIPMENT	DISPOSAL	SALVAGE	TOTAL	2003 ACCRUAL
Retiring Coal Related Assets						
Gannon Common	1,827,488	403,767	407,982	(49,974)	2,589,263	3,688,028
Gannon Coal Field	2,603,184	536,322	508,494	(73,000)	3,575,000	N/A
Gannon Unit 3	3,056,977	766,441	487,203	(146,620)	4,164,001	567,820
Gannon Unit 4	3,524,289	894,144	561,585	(166,165)	4,813,853	1,463,847
Gannon Unit 5	3,226,609	813,337	509,543	(145,603)	4,403,886	2,157,925
Gannon Unit 6	2,246,035	1,455,097	16,359	(237,274)	3,480,217	926,621
Retiring Units						
Gannon Unit 1	3,342,563	831,213	540,225	(167,001)	4,547,000	(1,343,882)
Gannon Unit 2	3,342,563	831,213	540,225	(167,001)	4,547,000	(101,038)
	23,169,708	6,531,534	3,571,616	(1,152,638)	32,120,220	7,359,321

NOTE: The 2003 accruals have been calculated to reflect a 2007 start for dismantling. Current dismantling estimates were escalated to 2007 and then reduced to present day cost. The results are the total dismantling estimate less the total accrual as of 12/31/2002.
The accrual for Gannon Coal Field is included with Gannon Common.

Tampa Electric Focuses on Plans for 2002, 2003

TAMPA, Fla., Sep 24, 2002 /PRNewswire-FirstCall via COMTEX/ -- TECO Energy (NYSE: TE) announced Monday that it expects 2002 earnings per share to increase over 2001, and that net income is expected to grow by more than 10 percent. The company also provided its initial 2003 outlook.

Tampa Electric Company, the principal subsidiary of TECO Energy, is projected to complete its third straight year of increased net income. In 1999, Tampa Electric's net income, excluding one-time charges, was $138.8 million. In 2000, it increased net income by 4 percent to $144.5 million. In 2001, it increased net income to $154 million, a 6.6 percent increase over the previous year. For 2002, Tampa Electric expects net income to increase again by more than 6 percent.

Restructuring activity at Tampa Electric is also part of TECO Energy's 2003 business plan. The company will be making personnel reductions of about 5 percent, on top of a 2 percent reduction earlier this year. Personnel reductions at Tampa Electric are not expected to affect service to customers.

President John Ramil said, "Our reductions are largely in line with what others in the industry are doing to as a result of productivity improvements and technology applications. We are primarily eliminating managerial and administrative jobs. It's possible that some of those whose jobs are being eliminated will be placed in our Customer Service area, where we are planning to add employees soon to serve our customers better and improve our operation."

In 2003, Tampa Electric expects continued retail energy sales growth of about 2.5 percent and significant operations and maintenance cost savings from the reduction in the number of coal-fired units at Gannon Station, and the completion of Bayside Unit 1.

"We have made a large financial commitment to construction, including $1 billion for our Bayside project and state-of-the-art emissions control technology at our Big Bend power plant, in order to meet the most stringent environmental requirements," said Ramil.

"With the Bayside conversion to natural gas, we can expect to reduce sulfur dioxide and nitrogen oxide emissions at that plant by over 95 percent each from 1998 levels. The environmental equipment added to our Big Bend Station will achieve a 95 percent sulfur dioxide removal efficiency. By 2010, nitrogen oxide (NOx) emissions from Big Bend will be reduced by over 85 percent from 1998 emission levels. Besides that, we will invest up to $11 million for early NOx reductions and for demonstrating innovative technologies for reducing NOx emissions at Big Bend and our other plants. We are continuing these and other technology and expansion-related investments, because it helps us serve our growing customer base in a way that is highly efficient and that meets modern-day environmental standards," Ramil added.

Long-term, the company feels it is well-positioned with assets that will serve future energy needs. "Though 2003 is going to be a transitional year for us, that is in keeping with the long-term view we have taken about our business and our proven core assets," said Bob Fagan, chairman and CEO of Tampa Electric's parent company, TECO Energy.

TAMPA, Fla., Jan. 22 /PRNewswire-FirstCall/ -- TECO Energy, Inc. (NYSE: TE) today reported that its full-year 2002 net income from continuing operations rose 9 percent to $298.2 million, up from $273.8 million in 2001.

Fourth quarter net income from continuing operations decreased 41 percent to $34.6 million, down from $59.1 million in 2001. Full-year 2002 revenues rose 8 percent to almost $2.7 billion, up from $2.5 billion in 2001.

Full-year 2002 earnings per share from continuing operations were $1.95, down 4 percent, compared with 2001 earnings per share of $2.04. Earnings per share from continuing operations for the quarter were $0.20, compared to $0.43 in 2001. The number of common shares outstanding was 14 percent and 23 percent higher for the year and the quarter, respectively, than for the same periods in 2001.

Results from continuing operations for the year and the fourth quarter include a $34-million pre-tax ($20.9 million after-tax) charge related to a debt refinancing transaction executed by TECO Energy in the fourth quarter, and a $5.8-million after-tax charge for an asset valuation adjustment for TECO Power Services' (TPS) proposed sale of generating facilities in the Czech Republic. Absent these charges, net income from continuing operations rose 19 percent to $324.9 million for the year, and earnings per share rose 4 percent to $2.12 per share for the year. Results from continuing operations exclude the results from TECO Coalbed Methane, which was sold in December and is reported as discontinued operations.

Total net income and earnings, including continuing operations and recently discontinued operations were $330.1 million and $2.15 per share, respectively. Total non-GAAP net income and earnings, excluding the $20.9 million debt refinancing and $5.8 million asset valuation charges and the $7.7 million gain on the sale of TECO Coalbed Methane, were $349.1 million and $2.28 per share, respectively.

TECO Energy Chairman and CEO Robert Fagan said, "TECO Energy had another good year for net income in 2002, despite a soft economy and tough energy markets. Except for the two unusual items, we delivered the double-digit net income growth we projected earlier in the year. While earnings per share were diluted by the new shares issued during the year, the share issuance was important to strengthen the balance sheet and improve our cash position.

"We will have our challenges in 2003, but we are making good progress on our $900 million cash generation plan, which we announced in September to fund the completion of the construction programs at TPS and Tampa Electric without raising incremental debt. We have already accounted for more than 70 percent of the targeted $900 million of cash generation from capital expenditure reductions, non-core asset sales and monetization of Section 29 tax credits, and other financial transactions or asset sales. I expect our Florida utilities to have a good year in 2003, contributing strong earnings and cash flow, thanks to continuing growth in the state's economy. TECO Energy's mix of profitable regulated and unregulated businesses helps mitigate the impact of the weak energy markets that TPS is experiencing," Fagan added.

Operating Segment Results:*

	Three Months Ended Dec. 31		Twelve Months Ended Dec. 31	
(in millions) Net Income Summary	2002	2001	2002	2001
Tampa Electric	$27.3	$28.6	$171.8	$154.0
Peoples Gas System	6.9	5.8	24.2	23.1
Total regulated	$34.2	$34.4	$196.0	$177.1
TECO Power Services	$(5.3)	$2.1	$34.1	$26.9
TECO Transport	5.2	6.0	21.0	27.5
TECO Coal	17.7	18.4	76.5	59.0
Other unregulated companies	3.2	1.6	6.8	4.0

Parent / other	(20.4)	(3.4)	(36.2)	(20.8)
Total unregulated	$0.4	$24.7	$102.2	$96.7
Net income from continuing operations	$34.6	$59.1	$298.2	$273.8
Discontinued operations	$15.5	$5.7	$31.9	$29.9
Total net income	$50.1	$64.8	$330.1	$303.7

- Segment net income includes internally allocated financing costs.

Tampa Electric's net income for the fourth quarter was $27.3 million, compared with $28.6 million for the same period in 2001. The equity component of allowance for funds used during construction (AFUDC, which represents allowed equity cost capitalized to construction costs), primarily from the Gannon to Bayside Units 1 and 2 repowering project, increased to $8.0 million for the quarter, from $2.6 million for the same period in 2001. Average customer growth of 2.2 percent for the quarter and more favorable weather increased retail energy sales 14.7 percent in the quarter. Total energy sales, including sales to other utilities, rose 15.8 percent in the fourth quarter due to favorable weather. Higher operating expenses for the quarter reflected higher depreciation from normal electric plant additions to support customer growth and higher non-fuel operations and maintenance expenses relating to generating plant maintenance and costs associated with a workforce reduction.

Tampa Electric's full-year net income was $171.8 million, compared with $154.0 million in 2001. The equity component of AFUDC increased to $24.9 million from $6.7 million in 2001. Full-year retail sales were 5.6 percent above 2001 levels, driven by 2.5 percent average customer growth, and increased usage by residential and commercial customers. Tampa Electric also benefited from lower interest rates on short-term borrowing. Higher operating expenses for the year included increased depreciation from normal plant additions to support customer growth and the addition of the Polk Unit 3 combustion turbine in May 2002, and higher operations and maintenance expenses reflecting increased generating plant maintenance and costs associated with a 7-percent workforce reduction in 2002.

Peoples Gas System reported net income of $6.9 million for the quarter, up 19 percent from the $5.8 million recorded in the same period in 2001. Quarterly results reflected customer growth of 4.0 percent and increased volumes for the residential and commercial customers as a result of early winter weather. Gas sales volumes for electric power generators increased in the quarter as gas prices relative to alternative fuels made gas utilization more attractive.

Full-year results at Peoples Gas System improved almost 5 percent over 2001, with net income increasing to $24.2 million from $23.1 million. Full- year customer growth of more than 4 percent contributed to higher gas sales to residential and commercial customers. Lower gas prices early in the year increased sales to larger interruptible and power generation customers, many of whom have the ability to switch to alternative fuels or alter consumption patterns based on gas prices. Operations and maintenance expenses were lower in 2002, reflecting aggressive cost containment measures taken to offset the impact of lower sales early in the year due to mild weather.

TECO Power Services' (TPS) net loss for the quarter was $5.3 million, compared with net income of $2.1 million in 2001, while full-year net income of $34.1 million was 27 percent higher than the $26.9 million reported in 2001. Results for the fourth quarter reflect the $5.8 million after-tax asset valuation adjustment for the proposed sale of generating assets in the Czech Republic, and additional taxes on the $55 million of cash repatriated from Guatemala. In addition, the results reflect higher allocated interest costs based on increased investment levels in power projects. These factors more than offset improved results in the fourth quarter from the San Jose Power Station in Guatemala and the Frontera Power Station in Texas and increased earnings from construction-related and loan agreements with Panda Energy in 2002.

Full-year results at TPS reflected higher earnings from the Alborada and San Jose generating stations in

Guatemala, increased earnings from construction-related and loan agreements with Panda Energy, increased earnings from sales of ancillary services from the Frontera Power Station in the second and third quarters and a reliability-must-run (RMR) contract in the fourth quarter with the Electric Reliability Council of Texas (ERCOT). The improved operating performance over 2001 was partially offset by the factors described for the fourth quarter as well as higher operating costs associated with a full year of operation of TPS' energy marketing and management operations.

On Jan. 3, 2003, the $137-million loan to Panda Energy related to the Odessa and Guadalupe power stations in Texas converted to a TPS ownership interest in those plants. TPS is evaluating its options relative to its ownership interest in these projects and is targeting to structure its interest in such a manner that it will be cash flow neutral in 2003 and have minimal impact on earnings. Since the Frontera RMR contract was not renewed for the first quarter of 2003, the plant has been taken off-line for planned maintenance. The first quarter has lower opportunities than other quarters for sales to ERCOT, Mexico or other customers due to weather.

TECO Transport reported net income of $5.2 million in the quarter, compared to $6.0 million for the same period in 2001. In the fourth quarter, weak pricing for river shipments and lower northbound river shipments more than offset lower labor and repair costs. For the year, net income was $21.0 million, compared to $27.5 million in 2001. The lack of northbound cargoes on the river system and generally weak pricing for river freight, lower petroleum coke and other product volumes through the transfer terminal, lower Tampa Electric tonnage, and lower spot cargo at TECO Ocean Shipping more than offset increased phosphate shipments and lower repair and fuel costs.

TECO Coal achieved fourth quarter net income of $17.7 million, compared to $18.4 million reported in 2001; full-year net income was $76.5 million, compared with $59.0 million in 2001. Results for the quarter were driven primarily by lower volumes of synthetic fuel and metallurgical and steam coals, offsetting better margins and higher prices across the product line. For the year, results were driven by higher synthetic fuel production and sales, resulting in higher Section 29 tax credits, better synfuel margins and improved pricing for all coal types, which more than offset higher production costs.

TECO Energy's other unregulated companies recorded net income of $3.2 million and $6.8 million for the fourth quarter and full year, respectively, compared to $1.6 million and $4.0 million for the same periods in 2001. These results reflect primarily a full year of results from Prior Energy, TECO Energy's end-use gas marketing company, which was acquired in November 2001, the sale of properties at TECO Properties, and increased distributions from TECO Propane Ventures, more than offsetting a $3.0-million after-tax third quarter write-off of an aircraft leased to US Airways, which has filed for bankruptcy.

Discontinued operations reflect results from TECO Coalbed Methane, which was sold in December for $140 million; $42 million was paid in 2002, with the remainder to be paid in early 2003. For the year, TECO Coalbed Methane produced 14.2 billion cubic feet (Bcf) of gas on lower realized gas prices of about $2.80 per thousand cubic feet (Mcf), compared with production of 15 Bcf on realized gas prices of $3.66 per Mcf in 2001. Fourth quarter results also reflect the $7.7-million after-tax gain on the portion of the sale recognized in 2002.

Non-Operating Items

Interest expense was essentially unchanged for the quarter and lower for the full year due to higher capitalized interest at TPS, increased interest expense credit for AFUDC-borrowed funds at Tampa Electric, and a refund and a reversal of interest expense related to prior year tax deficiencies previously recorded at Tampa Electric and TECO Energy based on an IRS tax settlement, which offset the effect of interest expense on higher overall levels of debt and preferred securities in support of TECO Energy's capital investment program.

Cash from operations was $156.4 million for the quarter, compared with $103.8 million in 2001. Cash used for investing activities was $350.7 million, which was net of proceeds from the sale of TECO Coalbed Methane and $56.2 million of proceeds from a sale-lease-back transaction at TECO Transport, compared with $351.2 million in 2001. Net cash received from financing activities was $418.0 million,

including $209.7 million from the sale of common equity and $373.9 million from a long-term debt issuance, compared with $279.8 million in 2001. Cash from financing activities is net of dividend payments of $62.4 million in the fourth quarter of 2002, compared with $48.1 million in 2001.

Year-to-date cash from operations was $655.7 million, compared with $502.7 million in 2001. Cash used for investing activities was $1.7 billion, compared with $1.1 billion in 2001. Net cash received from financing activities was $1.3 billion, compared with $613.6 million in 2001, net of dividend payments of $215.8 million in 2002, and $184.2 million in 2001. At Dec. 31, 2002, TECO Energy had $411.1 million of cash on hand compared to $108.5 million in 2001. In addition, there was $460 million of unused capacity available under the bank credit facilities at Tampa Electric and TECO Energy at Dec. 31, 2002.

Outlook

TECO Energy is planning to provide updates on its cash generation plan and 2003 outlook by early March.

Additional financial information related to the company's results through December 31, 2002, including unaudited financial statements, segment information, and electric and gas volumes is available at the Investor Relations section of TECO Energy's web site at www.tecoenergy.com.

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SECTION: MONEYSENSE, Pg. 1

LENGTH: 470 words

HEADLINE: TECO Layoffs Sending Workers Job Hunting

BYLINE: CHERIE JACOBS , cjacobs@tampatrib.com; Reporter Cherie Jacobs can be reached at (813) 259-7668.

BODY:
COMPANY SAYS CHANGES WON'T HURT CUSTOMERS

TAMPA - Tampa Electric laid off 5 percent of its work force this week as part of the utility's effort to conserve cash.

About 130 employees in a half-dozen offices learned Tuesday that their jobs were cut. They began working with a job placement service Wednesday.

"Times in the energy industry are pretty tough," John Ramil, president of Tampa Electric, said Thursday. "It was the first time in a long time I had an employee cry in front of me."

Those laid-off workers will remain on Tampa Electric's payroll until Dec. 31. Employees who have worked for the utility for more than six years will get a lump-sum payment in January based on their longevity. Some workers also will get incentives to retire early.

The cuts will not affect customers, Ramil said, because no jobs were cut from power plants, repair crews or customer service. Twenty jobs are being added to customer service.

Nor will customer rates be affected, he said.

The layoffs leave the remaining workers - whom Ramil calls "the survivors" - with low morale.

"It's hard for people because this is not a common thing for our company," he said.

The layoffs come after several blows to the work force.

Tampa Electric has been scaling back jobs at its Gannon plant through attrition, preparing for the day when the plant reopens with natural gas as its fuel instead of coal. The plant will require 55 workers then, compared with 196 now.

About 50 employees took voluntary early retirement this spring, to save money.

Tampa Electric employs about 2,500.

Ramil said the cuts were primarily because of Gannon's fuel change to natural gas. The $700 million project will carry an annual debt payment of $70 million.

Tampa Electric also constitutes 60 percent of its parent company, TECO Energy.

But the layoffs are only part of TECO Energy's problems.

Shares of TECO have been hammered on Wall Street because of financial uncertainty. They closed at $11.36 Thursday, down 65 cents or 5 percent, a new 13-year low.

Last month, a handful of analysts and bond-rating agencies downgraded TECO's ratings because of turmoil with its wholesale power subsidiary, TECO Power Services. Investors feared the company would be unable to sell its excess power in an uncertain market, when prices are depressed.

On Sept. 23, the company announced its plan to save cash, which included selling assets and postponing two power plants outside Florida.

This week, TECO said it would sell 15 million shares of stock, but they had not been sold as of Thursday, spokeswoman Laura Plumb said.

Now, the company has hit bottom, Ramil said.

"My job is to pick everybody up from here," Ramil said. "Everybody else who's here [needs to] focus on keeping the lights on, moving ahead."

GRAPHIC: PHOTO (C)
John Ramil

(C) Tampa Electric president: "Times in the energy industry are ... tough," as TECO cuts 130 employees.

LOAD-DATE: October 12, 2002

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing Revised Direct Testimony and Exhibits of Sheree L. Brown has been furnished by (*) hand delivery, or U.S. Mail this 5th day of November 2003, to the following:

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FLORIDA PUBLIC SERVICE COMMISSION
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NO. D30001-EI EXHIBIT NO 32
COMPANY/ OPC
WITNESS: MJM-1 thru MJM-9
DATE 11-12-03

EXHIBIT MJM-1
Page 1 of 1

From: Bill Whale
To: Karen Sheffield
Date: 5/20/02 10:58AM
Subject: Base Plan

Karen

For the 2003/2004/2005/2006 budgets that are being asked for use the following operating schdule as your base plan.

Gan 1 through 4 continue coal operation until Sept 30, 2004

Gan 5 will continue coal operation until Feb 7, 2003

Gan 6 will continue coal operation until August 31, 2003

Plan on building staffing, maintenance, and budget plans around this base plan. This is the same plan that has been put in the rate case.

Thanks

Bill

CC: Bill Smotherman; Charles R. Black; Charles Shelnut; Craig Cameron; Hugh Smith; John Knight; Scott A. Cannon; Tom Berry

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EXHIBIT NO. MJM-2, PAGE 1

BY

TAMPA ELECTRIC

ENERGY SUPPLY

- What Are Our Resources, Where Do They Go?
- Operational Strategies
- Changes and Consequences

EXHIBIT MJM-3
Page 1 of 34

What Are Our Resources?

(2002 Budget) ($ millions)	O&M	NRF	Total Resources
Operations	$ 127.1	$ 13.9	$ 141.0
Trading & Services	8.3	-	8.3
Construction & Engineering	2.9	-	2.9
	$ 138.3	$ 13.9	$ 152.2

EXHIBIT MJM-3
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Where Do They Go?

- Station / Services
- Type (Labor, Services, Materials & Supplies, etc.)
- Activity (Operations Maintenance, Compliance, Services)

EXHIBIT MJM-3
Page 3 of 34

Resources - Stations

(2002 Budget) ($ million)	BIG BEND	GANNON / HOOKERS	POLK	SEBRING
O&M	$ 62.1	$ 37.4	$ 19.3	$ 1.3
NRF	5.0	4.4	4.3	.2
TOTAL	$ 67.1	$ 41.8	$ 23.6	$ 1.5

EXHIBIT MJM-3
Page 4 of 34

Resources - Services

	Support Services	Shared Services
O&M	$ 13.1	$ 5.1

EXHIBIT MJM-3
Page 5 of 34

Resources - Type

(O&M and NRF)

Energy Supply	Millions	Percentage
Payroll/Fringe	66.4	44%
Contractors/Services	44.7	29%
Materials / Supplies / Stores Issues	31.2	20%
Vehicles / Other Mobile Equipment	2.7	2%
Shared Service Allocation	5.1	3%
All Other	2.1	2%
Total	**$ 152.2**	**100%**

EXHIBIT MJM-3
Page 6 of 34

Resources - Activity

(O&M and NRF)

Administration			
Support Services	13.1		
Shared Services	5.1	18.2	12%
Plant Operations			
Labor / Fringe	19.9		
Consumables	3.8		
Non-recoverable Fuel	13.9		
Other	7.7	45.3	30%
Plant Maintenance			
Unit Specific	26.9		
CSAs	2.2		
Common	41.9	71.0	47%
FGD			
Operations	10.9		
Maintenance	6.8	17.7	11%
Total Activities		152.2	100%

EXHIBIT MJM-3
Page 7 of 34

Plant Operations

- Labor
  - Driver = Equipment / Safety
  - Cost Reduction Strategies
    - Contractor Usage
    - Shifts
    - Technology
- Consumables / NRF
  - Driver = Equipment Operations
  - Cost Reduction Strategies / Cost Increases
    - Efficiencies
    - Increase Performance Expectations
    - New Requirements

EXHIBIT MJM-3
Page 8 of 34

Plant Maintenance

- Forced Outages
- Planned Outages
  - Fuel Systems
  - Major Outages
- Routine Maintenance

EXHIBIT MJM-3
Page 9 of 34

Forced Outages

- Best Guess Estimate
  - $25,000 / Day - Gannon
  - $35,000 / Day - Big Bend
- Cost Reduction Strategies
  - Contractor Usage
  - No Overtime
  - Operational Strategies
  - Rule of Thumb
    - 1% Increase in EFOR ~ 3% Increase in Cost

Planned Outages

Fuel System Outages	vs	Major Outages
• Performed Annually		Performed once every 4 yrs.
• Duration of 14-21 Days		Duration of 50-70 Days
• Clean-Up		Clean-Up
• Inspection		Inspection
• Minor Repairs / Patches		Major Repairs
• O&M Intensive		Major Component Replacement
		O&M and Capital Intensive

Planned Outages

- Cost Guidelines
  - $45,000 / Day - Fuel Systems
  - $60,000 / Day - Major
- Cost Reduction Strategies
  - Increase Contractor Usage
  - Limit Overtime
    - No Outage Overlap
    - Time Between Majors
  - Component Replacement Timing

EXHIBIT MJM-3
Page 12 of 34

Forecasted Outages

		2002	2003	2004	2005	2006	2007
Big Bend	Fuel	2	3	4	2	2	3
	Major	2	0	0	2	1	1
Polk	Fuel	1	1	2	2	2	1
	Major	0	1	0	1	1	0

Page 13 of 34

Routine Maintenance

- Priority
  - Safety
  - Compliance with Law
  - Efficiency
  - Reliability Centered Maintenance
- Cost Reduction Strategies
  - Increased Contractor Usage
  - Run to Failure
  - Minimal Replacement Parts

EXHIBIT MJM-3
Page 14 of 34

Operating Capital (millions)

	Big Bend	Gannon/ Hookers	Bayside	Polk	Sebring
Installed MW	1,934MW	1,165MW	1,750MW	615MW	18MW
2002 Fcst	$37.3	$4.3	$0.0	$18.9	$0.7
2003 Plug	18.1	2.3	7.2	12.0	0.2
2004 Plug	17.1	0.0	17.1	10.6	0.3

EXHIBIT MJM-3
Page 15 of 34

Changes & Consequences

Reductions to Achieve 2003 & 2004 Plug

Gannon - Accelerated Shutdown

550

EXHIBIT MJM-3
Page 16 of 34

Changes & Consequences

Gannon - Accelerated Shutdown (Implementation)

- Units 1 & 2 - Shutdown with Bayside 1 Start-up
- Units 3 & 4 - Shutdown September 1, 2003.

(Anticipates depletion of available funding)

- 2003 Savings $ 11.2 million
- 2004 Savings $ 16.0 million
- Big Bend to reduce Contractors, Overtime, Unit Header Pressures. 2003 Savings $ 2.0 million.

Page 17 of 34

Station Performance

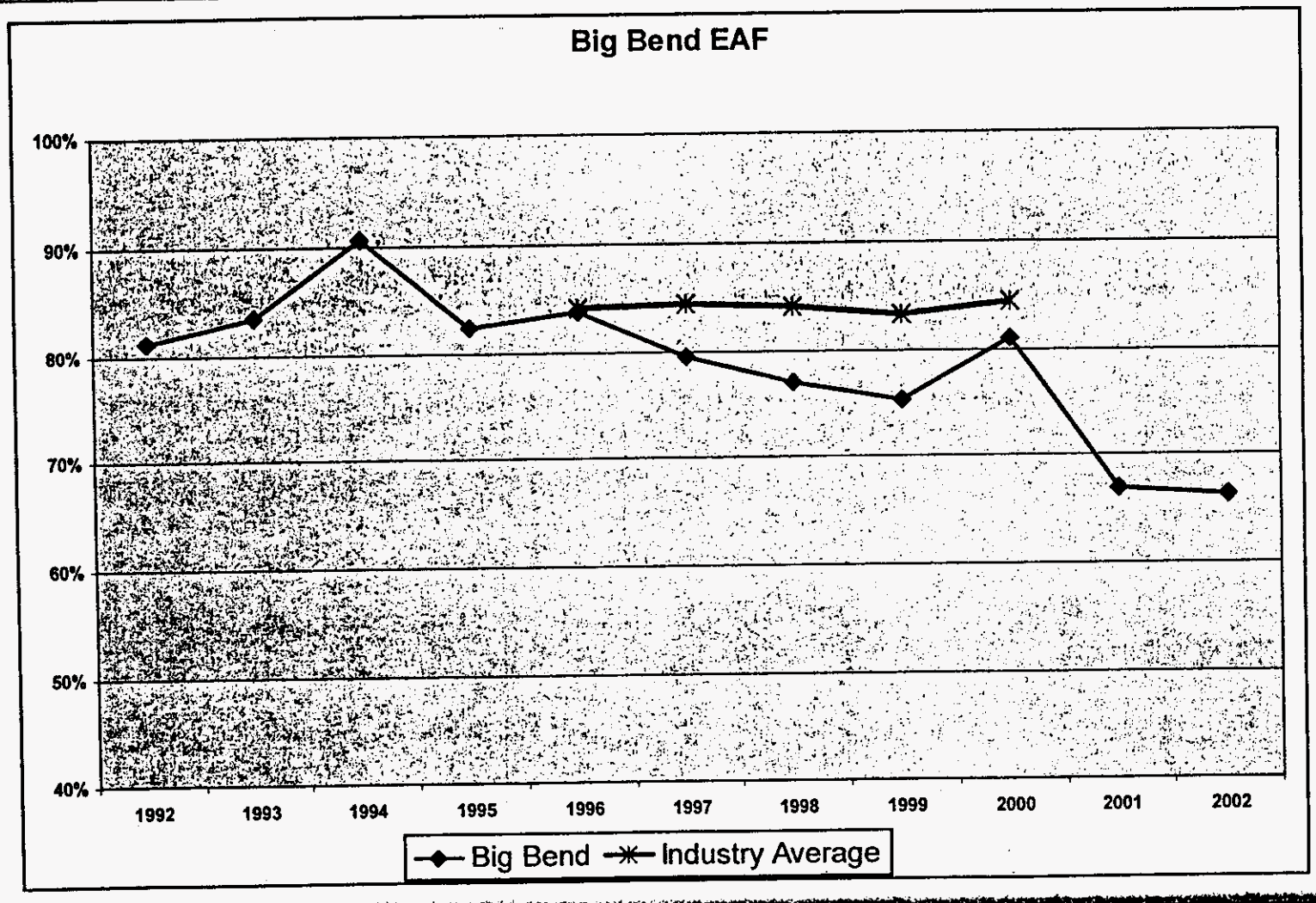


EXHIBIT MJM-3
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Station Performance

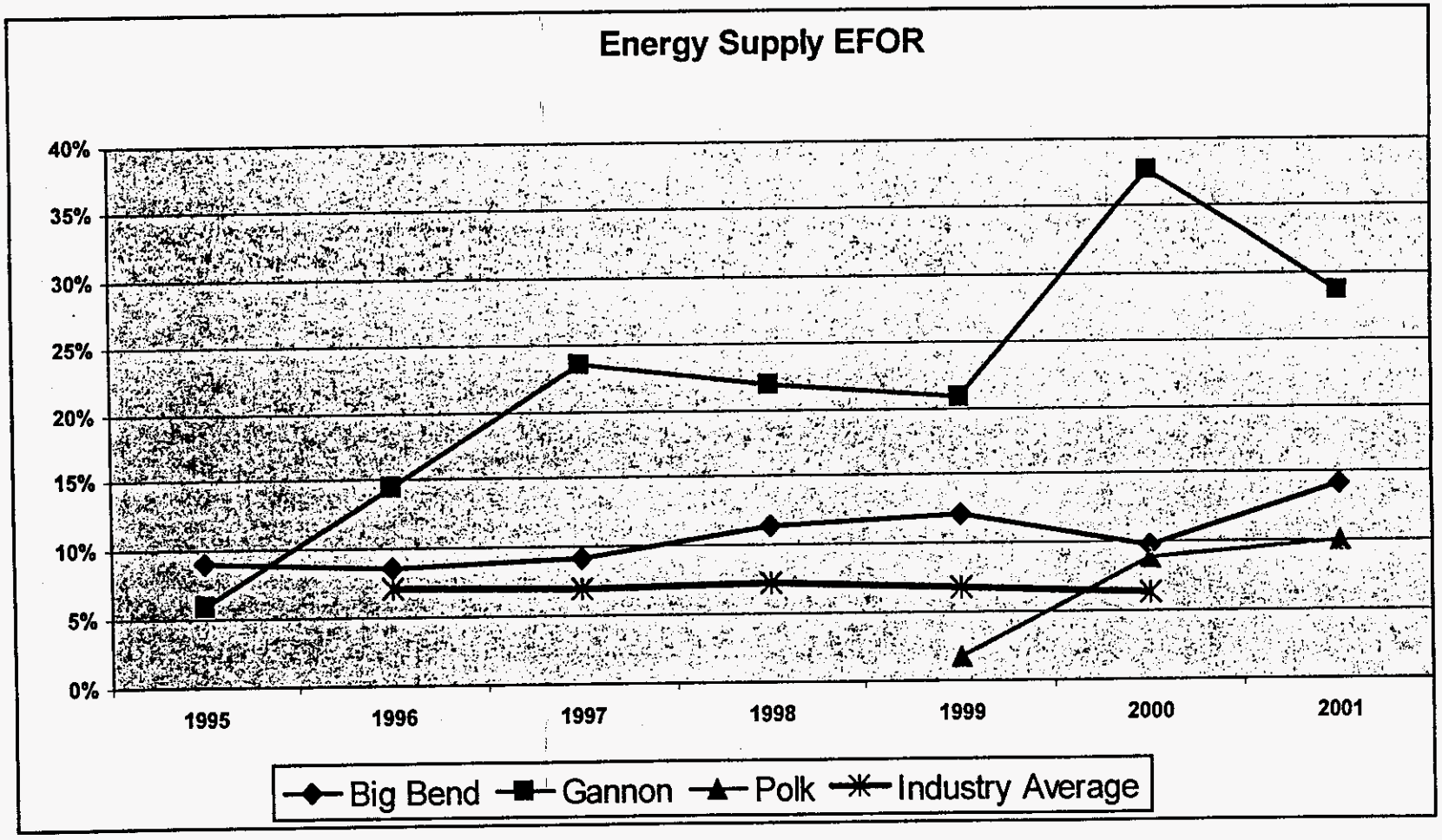


EXHIBIT MJM-3
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Station Performance

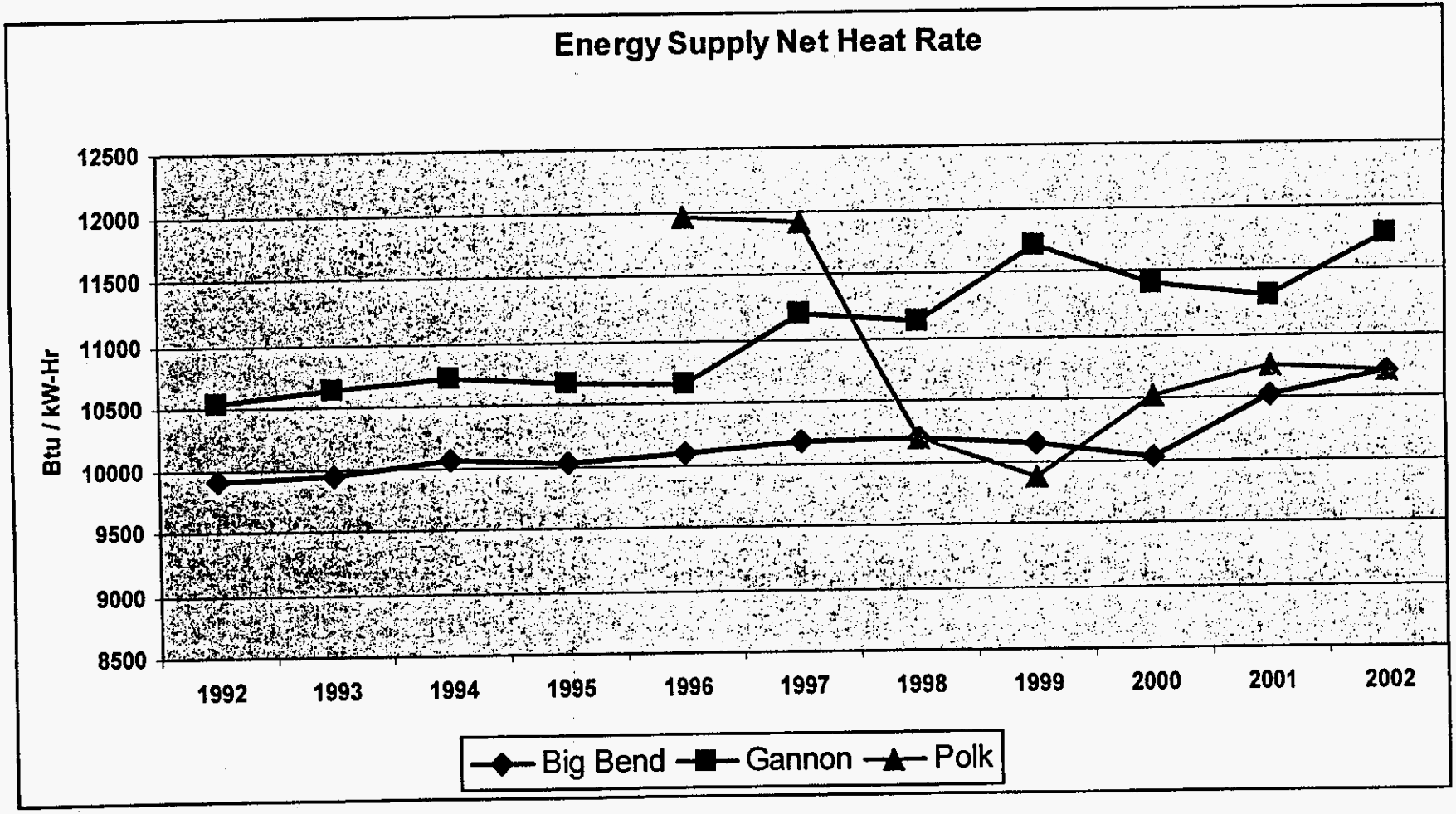


EXHIBIT MJM-3
Page 20 of 34

Changes & Consequences

Gannon - Accelerated Shutdown (Consequences)

- Higher Purchase Power Costs
- TECO Transport coal movements reduced
- Wholesale Sales Impact
- At Big Bend, slower Unit turnaround times from outages.

EXHIBIT MJM-3
Page 21 of 34

Resources - Stations

	BIG BEND	GANNON	POLK	SEBRING
Installed Capacity (Summer Rating)	1934	1165	615	36
Number of Units	4 Coal Fired 3 CTs	6 Coal Fired	1 Combined Cycle 2 CTs	2 Diesel Engines
Fuel Type	Coal	Coal	CC-Synfuel CTs - Gas / Oil	Diesel
Constructed	1969	1957	1995	1982
Average Unit Age	27	40	3	20
Major Support Sys.	2 FGD Systems		Gasifier Air Separation Unit Acid Plant	
Operating Profile	Baseload	Baseload	Baseload / Peaking	Peaking
Operating Strategy	Sustain L-T Reliability	Patch and Go/ Run to Failure	Unit 1 - Baseload Unit 2/3 - Peaking	Peaking

EXHIBIT MJM-3
Page 22 of 34

Resources - Services

ENIRONMENTAL
Permitting
Monitoring
Communities
Legal / Compliance
Land & Water Projects

FUELS
By Products
Management

RESOURCE PLANNING
System
Planning

WHOLESALE MARKETING
Wholesale
Energy
Purchase/Sales

AUDIT MANAGEMENT
Administration
Finance
Human Resources
Safety
Technical Administration

ENGINEERING & CONSTRUCTION
Engineering
Project Management
Construction

EXHIBIT MJM-3
Page 23 of 34

Life Cycles & Outage Strategies

OPERATING STRATEGIES

• Big Bend	Baseload	10 year horizon SCR / Consent Decree FGD / Interlock
• Gannon	Intermediate	Patch & Go Run to Failure

Life Cycles & Outage Strategies (Continued)

OPERATING STRATEGIES

• Polk	Unit 1	Baseload
		Demonstrate Gasifier
		Low Cost Fuel Dispatch
	Unit 2 & 3	Peaking
• Sebring		Peaking

EXHIBIT MJM-3
Page 25 of 34

What Are Our Resources?

(2002 Budget) ($ millions)	O&M	NRF	Operational Capital	Total Resources
Operations	$ 127.1	$ 13.9	$ 62.3	$ 203.3
Trading & Services	8.3	-	6.1	14.4
Construction & Engineering	2.9	-	-	2.9
	$ 138.3	$ 13.9	$ 68.4	$ 220.6

EXHIBIT MJM-3
Page 26 of 34

Resources - Stations

(2002 Budget) ($ million)	BIG BEND	GANNON / HOOKERS	POLK	SEBRING
O&M	$ 62.1	$ 37.4	$ 19.3	$ 1.3
NRF	5.0	4.4	4.3	.2
Operational Capital	37.3	4.3	18.9	.7
	$ 104.4	$ 46.1	$ 42.5	$ 2.2

561

Resources - Type

Energy Supply	Millions	Percentage
Payroll/Fringe	69.9	32%
Contractors/Services	86.8	39%
Materials / Supplies / Stores Issues	53.9	25%
Vehicles / Other Mobile Equipment	2.7	1%
Shared Service Allocation	5.1	2%
All Other	2.2	1%
Total	**$ 220.6**	**100%**

Resources - Activity

Administration		
Support Services	14.2	
Shared Services	5.1	19.3
Plant Operations		
Labor / Fringe	19.9	
Consumables	3.8	
Non-recoverable Fuel	13.9	
Other	7.7	45.3
Plant Maintenance		
Unit Specific	54.5	
CSAs	15.6	
Common	53.3	123.4
FGD		
Operations	10.9	
Maintenance	15.6	26.5
Environmental Projects		6.1
Total Activities		220.6

EXHIBIT MJM-3
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Significant Capital Projects

Capital Budgeting Schedule - 2003

Project Title	Budget ($ Thousands)
BB Lined Solid Waste management unit	$ 4,000
Repair/Replace BB4 economizer ash liner	3,273
GE Combustion Turbine LSTA Agreements (unit 1)	2,543
GE Combustion Turbine LSTA Agreements (unit 2)	2,418
Close out DA2 Cell B	2,000
BB Dissolved Oxygen Environmental issues	2,000
BB Lined recycle pond	2,000
BB Gypsum conveyor relocation	2,000
FGD (3&4) REPL COMMON INLET DUCT RE	1,952
GE Combustion Turbine LSTA Agreements (unit 3)	1,841
POLK Cooling reservoir water	1,700
BB4 BOILER FURNACE FLOOR/SLOPE REPL	1,616
Water cannons or wall blowers BB3	1,134
BB Lined stormwater collection pond	1,000
BB Big Bend pipe replacements	1,000
BB1 Under Deck Fire protection Units (1-4)	1,000

EXHIBIT MJM-3
Page 30 of 34

Significant Capital Projects

Capital Budgeting Schedule - 2004

Project Title	Budget ($ Thousands)
Polk Cooling reservoir water quality study	$ 4,000
BB Lined Slag Sluice and settling ponds	4,000
BB lined recycle pond	4,000
BB Gypsum storage dome	3,000
GE Combustion Turbine LSTA Agreements (unit 1)	2,881
Polk Lined Landfill	2,713
SOFA BB4	1,900
GE Combustion Turbine CSA Agreements (unit 2)	1,725
GE Combustion Turbine CSA Agreements (unit 3)	1,712
BB WASTE MANAGE/LINING RECYLE POND	1,000
BB Lined stormwater collection pond	1,000

EXHIBIT MJM-3
Page 31 of 34

Operational Strategies

Maintenance

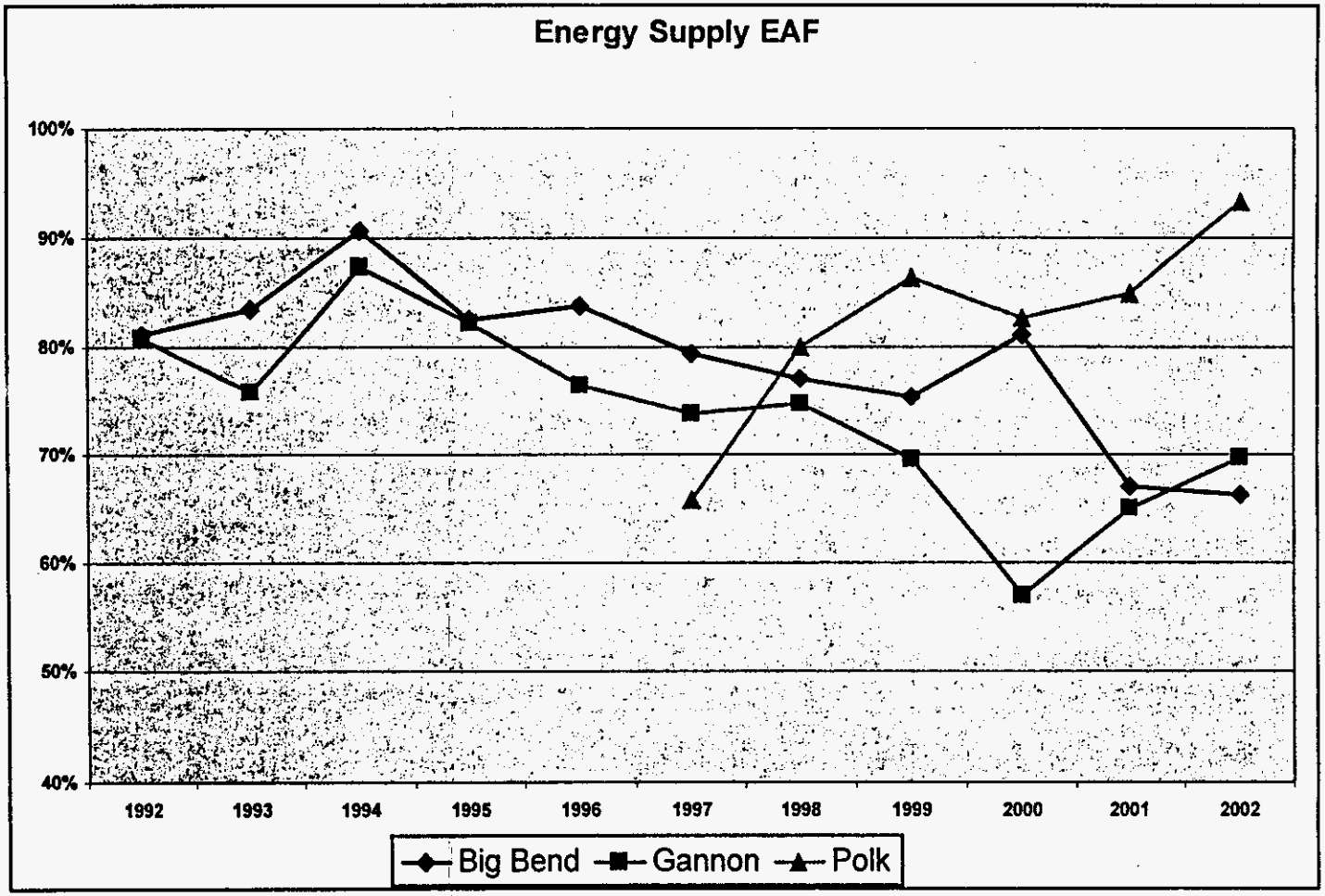
- Outages - Fuel System / Major
- Forced Outages - Return to Service ASAP without compromising safety or environmental compliance using Contractors.

Labor

- Hold the workforce to a minimal level, sustaining operations and keeping a preventative maintenance workforce. Use Contracted labor to handle increased workload (outages) and unique specialized services.

EXHIBIT MJM-3
Page 32 of 34

Station Performance



567

EXHIBIT MJM-3
Page 33 of 34

Labor Strategy

- **In-house Labor**
  - Operations
  - Preventative / Operational Maintenance Activities
  - Project and Cost Management Engineering
  - Management and Administration
- **Contracted Activities and Services**
-
  - Maintenance Activities
    - Clean-up / Grounds Maintenance "Core Contractors"
    - Forced Outage Maintenance
    - Planned Outage Maintenance
    - Specialized Activities (Painting, Insulation, Equipment Overhauls)
  - **Specialized Services**
    - Technical Services
    - Performance Engineering and Testing
    - Major Engineering

DOCKET NO. 030001
EXHIBIT NO. MJM-4
PAGE 1 & 2

THIS INFORMATION CLAIMED

CONFIDENTIAL

EXHIBIT NO. MJM-4 PAGE 1 & 2

BY

TAMPA ELECTRIC

THIS INFORMATION CLAIMED

CONFIDENTIAL

EXHIBIT NO. MJM-5 PAGE 1

BY

TAMPA ELECTRIC

From: John Knight
To: Bill Whale; Buddy Maye; Craig Cameron; Dee Brown; Denise Jordan
Date: Mon, Mar 3, 2003 4:24 PM
Subject: Gannon 1 - 4 (options)

Print each TAB. If you have any questions please call.

Energy Supply
Gannon Station - Operations Thru 2004
Achieve 80 - 85% Availability

Activities	Unit 1	Unit 2	Unit 3	Unit 4	Other	
Cyclone work (49 day outage)	4,500	4,500	6,000	6,000		21,000
Rear wall replacement		2,300				2,300
Expansion Joints	60	60	60	60		240
Insulation and Lagging	200	200	200	200		800
Slag Tank neck			150			150
Coal Field Eqp.					250	250
Additional Requirements	4,760	7,060	6,410	6,260	250	24,740
2003 28 day outage	500	500	250	250	-	1,500
2003 staff requirements	-	-	-	-	3,200	3,200
Stevedores	-	-	-	-	400	400
Required O&M (Consumables / Other)	-	-	-	-	1,600	1,600
Additional Ops. Costs	500	500	250	250	5,200	6,700
Total Costs 2003	**5,260**	**7,560**	**6,660**	**6,510**	**5,450**	**31,440**
2004 28 day outage	500	500	500	500	-	2,000
2004 staff requirements					12,200	12,200
Stevedores	-	-	-	-	1,200	1,200
Required O&M (Consumables / Other)					7,100	7,100
Total Costs 2004	**500**	**500**	**500**	**500**	**20,500**	**22,500**
Total Project Costs	**5,760**	**8,060**	**7,160**	**7,010**	**25,950**	**53,940**

Prepared March 3, 2003

Energy Supply
Gannon Station - Operations Thru 2004
Achieve 60% Availability

Activities	Unit 1	Unit 2	Unit 3	Unit 4	Other	
Rear wall replacement		2,300				2,300
Expansion Joints	60	60	60	60		240
Insulation and Lagging	200	200	200	200		800
Slag Tank neck			150			150
Coal Field Eqp.					250	250
Additional Requirements	260	2,560	410	260	250	3,740
2003 28 day outage	500	500	250	250	-	1,500
Forced outage costs (Cyclone driven)	500	500	500	500	-	2,000
2003 staff requirements	-	-	-	-	3,200	3,200
Stevedores	-	-	-	-	400	400
Required O&M (Consumables / Other)	-	-	-	-	1,600	1,600
Additional Ops. Costs	1,000	1,000	750	750	5,200	8,700
Total Costs 2003	**1,260**	**3,560**	**1,160**	**1,010**	**5,450**	**12,440**
2004 28 day outage	500	500	500	500	-	2,000
Forced outage costs (Cyclone driven)	500	500	500	500	-	2,000
2004 staff requirements					12,200	12,200
Stevedores	-	-	-	-	1,200	1,200
Required O&M (Consumables / Other)					7,100	7,100
Total Costs 2004	**1,000**	**1,000**	**1,000**	**1,000**	**20,500**	**24,500**
Total Project Costs	**2,260**	**4,560**	**2,160**	**2,010**	**25,950**	**36,940**

Prepared March 3, 2003

Tampa Electric Company

Calculation of Incremental Fuel and Purchased Power Costs
Related to the Early Shutdown of Gannon Units 1 Through 4

Line No.	2003 Total Fuel & Net Power Transactions	Amount
1	Per Denise Jordan, August 12, 2003 Schedule E2, Line 9 Assumes shutdown of Gannon 1 & 2 and tie-in of repowered Bayside 1	$ 680,265,173
2	Per Response to OPC Interrogatory, 3rd Set, Qustion No. 46. *Assumes Gannon Units 1-4 run through December 31, 2003*	$ 563,897,100
3	Difference Due To Early Shutdown Line 1 - Line 2	$ 116,368,073

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Fuel and Purchased Power Cost Recovery Clause with Generating Performance Incentive Factor	))))	DOCKET NO. 030001-EI FILED: AUGUST 25, 2003

TAMPA ELECTRIC COMPANY'S

ANSWERS TO THIRD SET OF INTERROGATORIES (NO. 46)

OF

THE OFFICE OF PUBLIC COUNSEL

Tampa Electric files this its Answers to Interrogatories (No. 46) propounded and served on July 21, 2003, by the Office of Public Counsel.

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
INDEX TO OPC'S 3RD SET OF INTERROGATORIES (NO. 46)

Number	Witness	Subject	Page
46	William A. Smotherman	Total fuel costs and net power transaction costs using September 2002 assumptions if Gannon units were available through 2003	1

William A. Smotherman
Director, Resource Planning
Tampa Electric Company
702 N. Franklin Street
Tampa, FL 33602

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
OPC'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 46
PAGE 1 OF 2
FILED: AUGUST 25, 2003

46. Calculate the total fuel costs and net power transaction costs as if Gannon Units 1 - 4 were still dispatchable on Tampa Electric's system through year end 2003, using the same assumptions contained in Denise Jordan's testimony filed in September of 2002.

A. Tampa Electric prefaces its answer to this interrogatory with the observation that a number of significant factors negate the substantive value and usefulness of the results of the calculation requested in this interrogatory. The assumption that Gannon Units 1 - 4 could remain dispatchable on Tampa Electric's system through the end of 2003 is hypothetical and is premised on the highly doubtful assumption that these units could be safely and reliably operated on a dispatchable basis over the time frame in question. Before selecting its current shutdown schedule for Gannon Units 1 - 4, Tampa Electric's management carefully considered many factors including those relating to safety, reliability, employee utilization, the ages and condition of the units and the significant amount of delay and expense the company would risk in an effort to keep them operational for only a short period of time given the requirements of the Consent Decree and the Consent Final Judgment to shut down or repower all coal-fired generation units at Gannon Station by the end of 2004. Any hypothetical dispatchability of Gannon Units 1 - 4 beyond the current shutdown schedule would erroneously and without justification simply dismiss all of these factors as being irrelevant.

In addition, Interrogatory No. 46 asks Tampa Electric to perform the present day cost calculation using old assumptions that were fresh at one time but which are stale now and which do not reflect the current outlook or the intervening events which have shaped the current outlook. Tampa Electric properly updated all assumptions that had changed between the time it filed 2003 projections in September 2002 and its February 2003 revised mid-course correction filing, including the Gannon Units 1 - 4 shutdown dates. Applying historical assumptions in a cost calculation performed later in time invalidates the results of the calculation. Modeling tools such as those the company uses to estimate projected net fuel and power transactions are aids for considering potential impacts, but they do not reflect actual results. Therefore, conclusions drawn based on the hypothetical value requested here are likely to be incorrect.

Subject to these qualifications, Tampa Electric has estimated its system net fuel and power transaction amounts as requested, using the September 2002 filing assumptions, with the exception that the Gannon shutdown dates reflect the actual and current planned shutdown dates. The information filed in September 2002 was modeled with the assumption that Gannon Units 1 - 4 would be able to run through the end of 2003. The result of the requested

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
OPC'S 3RD SET OF INTERROGATORIES
INTERROGATORY NO. 46
PAGE 2 OF 2
FILED: AUGUST 25, 2003

analysis is total fuel and net power transactions cost of $563,897,100[1] prior to jurisdictional separation or accounting for losses and taxes.

[1] The analysis assumes that Unit 6 is shut down October 1, 2003, and Units 3 and 4 are shut down October 15, 2003.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority, personally appeared J. Denise Jordan who deposed that the individuals listed in Tampa Electric Company's Index in response to Office of Public Counsel's Third Set of Interrogatories, (No. 46) and Third Set of Production of Documents, (Nos. 30-36), filed on July 21, 2003, in Docket No. 030001- EI, prepared or assisted with the responses to these interrogatories and production of documents to the best of her information and belief.

Dated at Tampa, Florida this 22nd day of August, 2003

J. Denise Jordan

Sworn to and subscribed before me this 22nd day of August, 2003

Paula K. Brown

My Commission expires December 4, 2004

Paula K Brown
My Commission DD0125068
Expires December 04, 2004

EXHIBIT MJM - 8
Page 1 or 1

Gannon O / NRF
Scenario Analysis

CONFIDENTIAL

2003 (millions)	*Gannon O&M / NRF*	*Bayside Incremental*	*Total*	*Plan Savings*	
Scenario 1	$ 23.0	$ 0.9	$ 23.9	$ (14.5)	GN 1-4 May 1, 2003
Scenario 2	21.0	1.1	22.1	(16.3)	GN 1-4 March 16, 2003
Scenario 3	28.5	0.5	29.0	(9.4)	GN 1-2 May 1, 2003 and GN 3-4 Sept 1
Scenario 4	22.0	1.0	23.0	(15.4)	GN 1-2 March 16, 2003 and GN 3-4 May 1, 2003
Scenario 5	27.5	0.5	28.0	(10.4)	GN 1-2 March 16, 2003 and GN 3-4 Sept 1, 2003
2004					
All Scenarios	$ 9.0				No Gannon Units Operating (Includes Inventory Write-Off $3.3m, HP $0.3, Lay-up, Safety Demo $1.5, Facility Clean-up $.4) Labor / Fringe $1.3, Contingency $2.2)

	2003	*2004*	
Base Gannon	$ 38.4	$ 25.6	GN 1-4 Retired Sept 2004

705

Gannon O&M Scenario Savings.xls
09/16/2002

Tampa Electric Company

Calculation of O&M Savings
Related to the Early Shutdown of Gannon Units 1 Through 4

Line No.	Description		Amount	
1	2003 Estimated O&M Savings		$	11,200,000
2	Additional Cost to Run Gannon 1 & 2 per week	153,846		
3	Annualized for actual 3 week extension Line 2 * 3			461,538
4	Additional Cost to Run Gannon 3 & 4 per week	277,777		
5	Annualized for actual 6 week extension Line 4 * 6			1,666,662
6	Estimated 2003 O&M Savings Line 1 - Line 3 - Line 5		$	9,071,800
7	Estimated 2004 O&M Savings		$	16,000,000

Line 1 per Bill Whale's August 26, 2002 presentation to officers, B.S. 551.

Line 2 per B.S. 705.
Scenario 3 vs. 5 shows $1 million difference in savings, with Gannon 1 & 2 operational until May 1, 2003 (Scenario 3) versus Gannon 1 & 2 operational until March 16, 2003 (Scenario 5). Difference is 6.5 weeks @ $1 million, or 1 week =$153,846 per week.
3 weeks X $153,846 = $461,538 less savings than originally projected

Line 4 per B.S. 705.
Scenario 4 vs. 5 shows $5 million difference in savings, with Gannon 3 & 4 operational until May 1, 2004 (Scenario 4) versus Gannon 3 & 4 operational until September 1 (Scenario 5). Difference is 18 weeks @ $5 million or 1 week =$277,777
6 weeks X $277,777 = $1,666,662 less savings than originally projected.

Line 7 per Bill Whale's August 26, 2002 presentation to officers, B.S. 551.
Note: B.S. 705 shows the Base Case O&M expense for Gannon as $25.6 million in 2004, as opposed to $9.0 million expense for "All Scenarios" which produces $15.6 million in savings for year 2004.

ORIGINAL

JAMES E. "JIM" KING, JR.
PRESIDENT

JOHNNIE BYRD
SPEAKER

STATE OF FLORIDA
OFFICE OF THE PUBLIC COUNSEL

c/o THE FLORIDA LEGISLATURE
111 WEST MADISON ST.
ROOM 812
TALLAHASSEE, FLORIDA 32399-1400
850-488-9330

Charles J. Beck
Interim
Public Counsel

October 3, 2003

RECEIVED-FPSC
03 OCT -3 PM 3:45
COMMISSION CLERK

Ms. Blanca S. Bayó, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0870

RE: Docket No. 030001-EI

Dear Ms. Bayó:

Appendix "A" to the testimony witness Majoros and Zaetz were inadvertently omitted from yesterday's filing. An original and 15 copies of each are enclosed. I apologize for any inconvenience this may have caused.

Sincerely,

Robert D. Vandiver
Associate Public Counsel

RDV/pwd

Enclosures

AUS 2
CAF
CMP
COM 5+1
CTR
ECR
GCL 1
OPC 1
OTH

cc: Parties of Record

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 32
COMPANY/ OPC
WITNESS: Appendix A to MJM-1 thru MJM-9
DATE: 11-12-03

Zaetz
DOCUMENT NUMBER-DATE
09611 OCT-3 03
FPSC-COMMISSION CLERK

Majoros
DOCUMENT NUMBER-DATE
09610 OCT-3 03
FPSC-COMMISSION CLERK

Experience

Snavely King Majoros O'Connor & Lee, Inc.

Vice President and Treasurer (1988 to Present)
Senior Consultant (1981-1987)

Mr. Majoros provides consultation specializing in accounting, financial, and management issues. He has testified as an expert witness or negotiated on behalf of clients in more than one hundred thirty regulatory proceedings involving telephone, electric, gas, water, and sewerage companies. Mr. Majoros has appeared before Federal and state agencies. His testimony has encompassed a wide variety of complex issues including taxation, divestiture accounting, revenue requirements, rate base, nuclear decommissioning, plant lives, and capital recovery. Mr. Majoros has also provided consultation to the U.S. Department of Justice.

Mr. Majoros has been responsible for developing the firm's consulting services on depreciation and other capital recovery issues into a major area of practice. He has also developed the firm's capabilities in the management audit area.

Van Scoyoc & Wiskup, Inc., *Consultant (1978-1981)*

Mr. Majoros performed various management and regulatory consulting projects in the public utility field, including preparation of electric system load projections for a group of municipally and cooperatively owned electric systems; preparation of a system of accounts and reporting of gas and oil pipelines to be used by a state regulatory commission; accounting system analysis and design for rate proceedings involving electric, gas, and telephone utilities. Mr. Majoros also assisted in an antitrust proceeding involving a major electric utility. He submitted expert testimony in FERC Docket No. RP79-12 (El Paso Natural Gas Company). In addition, he co-authored a study entitled Analysis of Staff Study on Comprehensive Tax Normalization that was submitted to FERC in Docket No. RM 80-42.

Handling Equipment Sales Company, Inc.
Treasurer (1976-1978)

Mr. Majoros' responsibilities included financial management, general accounting and reporting, and income taxes.

Ernst & Ernst, *Auditor (1973-1976)*

Mr. Majoros was a member of the audit staff where his responsibilities included auditing, supervision, business systems analysis, report preparation, and corporate income taxes.

University of Baltimore - *(1971-1973)*

Mr. Majoros was a full-time student in the School of Business.

During this period Mr. Majoros worked consistently on a part-time basis in the following positions: Assistant Legislative Auditor – State of Maryland, Staff Accountant – Robert M. Carney & Co., CPA's, Staff Accountant – Naron & Wegad, CPA's, Credit Clerk – Montgomery Wards.

Central Savings Bank, *(1969-1971)*

Mr. Majoros was an Assistant Branch Manager at the time he left the bank to attend college as a full-time student. During his tenure at the bank, Mr. Majoros gained experience in each department of the bank. In addition, he attended night school at the University of Baltimore.

Education

University of Baltimore, School of Business, B.S. – Concentration in Accounting

Professional Affiliations

American Institute of Certified Public Accountants
Maryland Association of C.P.A.s
Society of Depreciation Professionals

Publications, Papers, and Panels

"Analysis of Staff Study on Comprehensive Tax Normalization," FERC Docket No. RM 80-42, 1980.

"Telephone Company Deferred Taxes and Investment Tax Credits – A Capital Loss for Ratepayers," Public Utility Fortnightly, September 27, 1984.

"The Use of Customer Discount Rates in Revenue Requirement Comparisons," Proceedings of the 25th Annual Iowa State Regulatory Conference, 1986

"The Regulatory Dilemma Created By Emerging Revenue Streams of Independent Telephone Companies," Proceedings of NARUC 101st Annual Convention and Regulatory Symposium, 1989.

"BOC Depreciation Issues in the States," National Association of State Utility Consumer Advocates, 1990 Mid-Year Meeting, 1990.

"Current Issues in Capital Recovery" 30th Annual Iowa State Regulatory Conference, 1991.

"Impaired Assets Under SFAS No. 121," National Association of State Utility consumer Advocates, 1996 Mid-Year Meeting, 1996.

"What's 'Sunk' Ain't Stranded: Why Excessive Utility Depreciation is Avoidable," with James Campbell, Public Utilities Fortnightly, April 1, 1999.

"Local Exchange Carrier Depreciation Reserve Percents," with Richard B. Lee, Journal of the Society of Depreciation Professionals, Volume 10, Number 1, 2000-2001

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Michael J. Majoros, Jr.

Federal Regulatory Agencies

Date	Agency	Docket	Utility
1979	FERC-US 19/	RR79-12	El Paso Natural Gas Co.
1980	FERC-US 19/	RM80-42	Generic Tax Normalization
1996	CRTC-Canada 30/	97-9	All Canadian Telecoms
1997	CRTC-Canada 31/	97-11	All Canadian Telecoms
1999	FCC 32/	98-137 (Ex Parte)	All LECs
1999	FCC 32/	98-91 (Ex Parte)	All LECs
1999	FCC 32/	98-177 (Ex Parte)	All LECs
1999	FCC 32/	98-45 (Ex Parte)	All LECs
2000	EPA 35/	CAA-00-6	Tennessee Valley Authority
2003	FERC 48/	RM02-7	All Utilities

State Regulatory Agencies

1982	Massachusetts 17/	DPU 557/558	Western Mass Elec. Co.
1982	Illinois 16/	ICC81-8115	Illinois Bell Telephone Co.
1983	Maryland 8/	7574-Direct	Baltimore Gas & Electric Co.
1983	Maryland 8/	7574-Surrebuttal	Baltimore Gas & Electric Co.
1983	Connecticut 15/	810911	Woodlake Water Co.
1983	New Jersey 1/	815-458	New Jersey Bell Tel. Co.
1983	New Jersey 14/	8011-827	Atlantic City Sewerage Co.
1984	Dist. Of Columbia 7/	785	Potomac Electric Power Co.
1984	Maryland 8/	7689	Washington Gas Light Co.
1984	Dist. Of Columbia 7/	798	C&P Tel. Co.
1984	Pennsylvania 13/	R-832316	Bell Telephone Co. of PA
1984	New Mexico 12/	1032	Mt. States Tel. & Telegraph
1984	Idaho 18/	U-1000-70	Mt. States Tel. & Telegraph
1984	Colorado 11/	1655	Mt. States Tel. & Telegraph
1984	Dist. Of Columbia 7/	813	Potomac Electric Power Co.
1984	Pennsylvania 3/	R842621-R842625	Western Pa. Water Co.
1985	Maryland 8/	7743	Potomac Electric Power Co.
1985	New Jersey 1/	848-856	New Jersey Bell Tel. Co.
1985	Maryland 8/	7851	C&P Tel. Co.
1985	California 10/	I-85-03-78	Pacific Bell Telephone Co.
1985	Pennsylvania 3/	R-850174	Phila. Suburban Water Co.
1985	Pennsylvania 3/	R850178	Pennsylvania Gas & Water Co.
1985	Pennsylvania 3/	R-850299	General Tel. Co. of PA
1986	Maryland 8/	7899	Delmarva Power & Light Co.
1986	Maryland 8/	7754	Chesapeake Utilities Corp.
1986	Pennsylvania 3/	R-850268	York Water Co.
1986	Maryland 8/	7953	Southern Md. Electric Corp.
1986	Idaho 9/	U-1002-59	General Tel. Of the Northwest
1986	Maryland 8/	7973	Baltimore Gas & Electric Co.

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1987	Pennsylvania 3/	R-860350	Dauphin Cons. Water Supply
1987	Pennsylvania 3/	C-860923	Bell Telephone Co. of PA
1987	Iowa 6/	DPU-86-2	Northwestern Bell Tel. Co.
1987	Dist. Of Columbia 7/	842	Washington Gas Light Co.
1988	Florida 4/	880069-TL	Southern Bell Telephone
1988	Iowa 6/	RPU-87-3	Iowa Public Service Company
1988	Iowa 6/	RPU-87-6	Northwestern Bell Tel. Co.
1988	Dist. Of Columbia 7/	869	Potomac Electric Power Co.
1989	Iowa 6/	RPU-88-6	Northwestern Bell Tel. Co.
1990	New Jersey 1/	1487-88	Morris City Transfer Station
1990	New Jersey 5/	WR 88-80967	Toms River Water Company
1990	Florida 4/	890256-TL	Southern Bell Company
1990	New Jersey 1/	ER89110912J	Jersey Central Power & Light
1990	New Jersey 1/	WR90050497J	Elizabethtown Water Co.
1991	Pennsylvania 3/	P900465	United Tel. Co. of Pa.
1991	West Virginia 2/	90-564-T-D	C&P Telephone Co.
1991	New Jersey 1/	90080792J	Hackensack Water Co.
1991	New Jersey 1/	WR90080884J	Middlesex Water Co.
1991	Pennsylvania 3/	R-911892	Phil. Suburban Water Co.
1991	Kansas 20/	176, 716-U	Kansas Power & Light Co.
1991	Indiana 29/	39017	Indiana Bell Telephone
1991	Nevada 21/	91-5054	Central Tele. Co. – Nevada
1992	New Jersey 1/	EE91081428	Public Service Electric & Gas
1992	Maryland 8/	8462	C&P Telephone Co.
1992	West Virginia 2/	91-1037-E-D	Appalachian Power Co.
1993	Maryland 8/	8464	Potomac Electric Power Co.
1993	South Carolina 22/	92-227-C	Southern Bell Telephone
1993	Maryland 8/	8485	Baltimore Gas & Electric Co.
1993	Georgia 23/	4451-U	Atlanta Gas Light Co.
1993	New Jersey 1/	GR93040114	New Jersey Natural Gas. Co.
1994	Iowa 6/	RPU-93-9	U.S. West – Iowa
1994	Iowa 6/	RPU-94-3	Midwest Gas
1995	Delaware 24/	94-149	Wilm. Suburban Water Corp.
1995	Connecticut 25/	94-10-03	So. New England Telephone
1995	Connecticut 25/	95-03-01	So. New England Telephone
1995	Pennsylvania 3/	R-00953300	Citizens Utilities Company
1995	Georgia 23/	5503-0	Southern Bell
1996	Maryland 8/	8715	Bell Atlantic
1996	Arizona 26/	E-1032-95-417	Citizens Utilities Company
1996	New Hampshire 27/	DE 96-252	New England Telephone
1997	Iowa 6/	DPU-96-1	U S West – Iowa
1997	Ohio 28/	96-922-TP-UNC	Ameritech – Ohio
1997	Michigan 28/	U-11280	Ameritech – Michigan
1997	Michigan 28/	U-112 81	GTE North
1997	Wyoming 27/	7000-ztr-96-323	US West – Wyoming
1997	Iowa 6/	RPU-96-9	US West – Iowa

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1997	Illinois 28/	96-0486-0569	Ameritech – Illinois
1997	Indiana 28/	40611	Ameritech – Indiana
1997	Indiana 27/	40734	GTE North
1997	Utah 27/	97-049-08	US West – Utah
1997	Georgia 28/	7061-U	BellSouth – Georgia
1997	Connecticut 25/	96-04-07	So. New England Telephone
1998	Florida 28/	960833-TP et. al.	BellSouth – Florida
1998	Illinois 27/	97-0355	GTE North/South
1998	Michigan 33/	U-11726	Detroit Edison
1999	Maryland 8/	8794	Baltimore Gas & Electric Co.
1999	Maryland 8/	8795	Delmarva Power & Light Co.
1999	Maryland 8/	8797	Potomac Edison Company
1999	West Virginia 2/	98-0452-E-GI	Electric Restructuring
1999	Delaware 24/	98-98	United Water Company
1999	Pennsylvania 3/	R-00994638	Pennsylvania American Water
1999	West Virginia 2/	98-0985-W-D	West Virginia American Water
1999	Michigan 33/	U-11495	Detroit Edison
2000	Delaware 24/	99-466	Tidewater Utilities
2000	New Mexico 34/	3008	US WEST Communications, Inc.
2000	Florida 28/	990649-TP	BellSouth -Florida
2000	New Jersey 1/	WR30174	Consumer New Jersey Water
2000	Pennsylvania 3/	R-00994868	Philadelphia Suburban Water
2000	Pennsylvania 3/	R-0005212	Pennsylvania American Sewerage
2000	Connecticut 25/	00-07-17	Southern New England Telephone
2001	Kentucky 36/	2000-373	Jackson Energy Cooperative
2001	Kansas 38/39/40/	01-WSRE-436-RTS	Western Resources
2001	South Carolina 22/	2001-93-E	Carolina Power & Light Co.
2001	North Dakota 37/	PU-400-00-521	Northern States Power/Xcel Energy
2001	Indiana 29/41/	41746	Northern Indiana Power Company
2001	New Jersey 1/	GR01050328	Public Service Electric and Gas
2001	Pennsylvania 3/	R-00016236	York Water Company
2001	Pennsylvania 3/	R-00016339	Pennsylvania America Water
2001	Pennsylvania 3/	R-00016356	Wellsboro Electric Coop.
2001	Florida 4/	010949-EL	Gulf Power Company
2001	Hawaii 42/	00-309	The Gas Company
2002	Pennsylvania 3/	R-00016750	Philadelphia Suburban
2002	Nevada 43/	01-10001 &10002	Nevada Power Company
2002	Kentucky 36/	2001-244	Fleming Mason Electric Coop.
2002	Nevada 43/	01-11031	Sierra Pacific Power Company
2002	Georgia 27/	14361-U	BellSouth-Georgia
2002	Alaska 44/	U-01-34,82-87,66	Alaska Communications Systems
2002	Wisconsin 45/	2055-TR-102	CenturyTel
2002	Wisconsin 45/	5846-TR-102	TelUSA
2002	Vermont 46/	6596	Citizen's Energy Services
2002	North Dakota 37/	PU-399-02-183	Montana Dakota Utilities
2002	Kansas 38/	02-MDWG-922-RTS	Midwest Energy

Michael J. Majoros, Jr.

2002	Kentucky 36/	2002-00145	Columbia Gas
2002	Oklahoma 47/	200200166	Reliant Energy ARKLA
2002	New Jersey 1/	GR02040245	Elizabethtown Gas Company
2003	New Jersey 1/	ER02050303	Public Service Electric and Gas Co.
2003	Hawaii 42/	01-0255	Young Brothers Tug & Barge
2003	New Jersey 1/	ER02080506	Jersey Central Power & Light
2003	New Jersey 1/	ER02100724	Rockland Electric Co.
2003	Pennsylvania 3/	R-00027975	The York Water Co.
2003	Pennsylvania /3	R-00038304	Pennsylvania-American Water Co.
2003	Kansas 20/ 40/	03-KGSG-602-RTS	Kansas Gas Service

Michael J. Majoros, Jr.

PARTICIPATION AS NEGOTIATOR IN FCC TELEPHONE DEPRECIATION RATE REPRESCRIPTION CONFERENCES

COMPANY	YEARS	CLIENT
Diamond State Telephone Co. 24/	1985 + 1988	Delaware Public Service Comm
Bell Telephone of Pennsylvania 3/	1986 + 1989	PA Consumer Advocate
Chesapeake & Potomac Telephone Co. - Md. 8/	1986	Maryland People's Counsel
Southwestern Bell Telephone – Kansas 20/	1986	Kansas Corp. Commission
Southern Bell – Florida 4/	1986	Florida Consumer Advocate
Chesapeake & Potomac Telephone Co.-W.Va. 2/	1987 + 1990	West VA Consumer Advocate
New Jersey Bell Telephone Co. 1/	1985 + 1988	New Jersey Rate Counsel
Southern Bell - South Carolina 22/	1986 + 1989 + 1992	S. Carolina Consumer Advocate
GTE-North – Pennsylvania 3/	1989	PA Consumer Advocate

Michael J. Majoros, Jr.

PARTICIPATION IN PROCEEDINGS WHICH WERE SETTLED BEFORE TESTIMONY WAS SUBMITTED

STATE	DOCKET NO.	UTILITY
Maryland 8/	7878	Potomac Edison
Nevada 21/	88-728	Southwest Gas
New Jersey 1/	WR90090950J	New Jersey American Water
New Jersey 1/	WR900050497J	Elizabethtown Water
New Jersey 1/	WR91091483	Garden State Water
West Virginia 2/	91-1037-E	Appalachian Power Co.
Nevada 21/	92-7002	Central Telephone - Nevada
Pennsylvania 3/	R-00932873	Blue Mountain Water
West Virginia2/	93-1165-E-D	Potomac Edison
West Virginia2/	94-0013-E-D	Monongahela Power
New Jersey 1/	WR94030059	New Jersey American Water
New Jersey 1/	WR95080346	Elizabethtown Water
New Jersey 1/	WR95050219	Toms River Water Co.
Maryland 8/	8796	Potomac Electric Power Co.
South Carolina 22/	1999-077-E	Carolina Power & Light Co.
South Carolina 22/	1999-072-E	Carolina Power & Light Co.
Kentucky 36/	2001-104 & 141	Kentucky Utilities, Louisville Gas and Electric
Kentucky 36/	2002-485	Jackson Purchase Energy Corporation

Michael J. Majoros, Jr.

Clients

1/ New Jersey Rate Counsel/Advocate
2/ West Virginia Consumer Advocate
3/ Pennsylvania OCA
4/ Florida Office of Public Advocate
5/ Toms River Fire Commissioner's
6/ Iowa Office of Consumer Advocate
7/ D.C. People's Counsel
8/ Maryland's People's Counsel
9/ Idaho Public Service Commission
10/ Western Burglar and Fire Alarm
11/ U.S. Dept. of Defense
12/ N.M. State Corporation Comm.
13/ City of Philadelphia
14/ Resorts International
15/ Woodlake Condominium Association
16/ Illinois Attorney General
17/ Mass Coalition of Municipalities
18/ U.S. Department of Energy
19/ Arizona Electric Power Corp.
20/ Kansas Corporation Commission
21/ Public Service Comm. – Nevada
22/ SC Dept. of Consumer Affairs
23/ Georgia Public Service Comm.
24/ Delaware Public Service Comm.
25/ Conn. Ofc. Of Consumer Counsel
26/ Arizona Corp. Commission
27/ AT&T
28/ AT&T/MCI
29/ IN Office of Utility Consumer Counselor
30/ Unitel (AT&T – Canada)
31/ Public Interest Advocacy Centre
32/ U.S. General Services Administration
33/ Michigan Attorney General
34/ New Mexico Attorney General
35/ Environmental Protection Agency Enforcement Staff
36/ Kentucky Attorney General
37/ North Dakota Public Service Commission
38/ Kansas Industrial Group
39/ City of Witchita
40/ Kansas Citizens' Utility Rate Board
41/ NIPSCO Industrial Group
42/ Hawaii Division of Consumer Advocacy
43/ Nevada Bureau of Consumer Protection
44/ GCI
45/ Wisc. Citizens' Utility Rate Board
46/ Vermont Department of Public Service
47/ Oklahoma Corporation Commission
48/ National Association of Utility Consumer Advocates ("NASUCA")

WILLIAM M. ZAETZ

INDEX OF EXHIBITS

EXHIBIT NO.

Gannon Station
Business Plan ..... WMZ - 1

Hazardous Energy Control Program ..... WMZ - 2

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 030001-EI EXHIBIT NO. 33
COMPANY/ OPC
WITNESS: WMZ-1 + WMZ-2
DATE: 11-12-03

DOCKET NO. 030001
EXHIBIT NO. WMZ-1
PAGES 1-45

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EXHIBIT NO. WMZ-1, PAGES 1-45

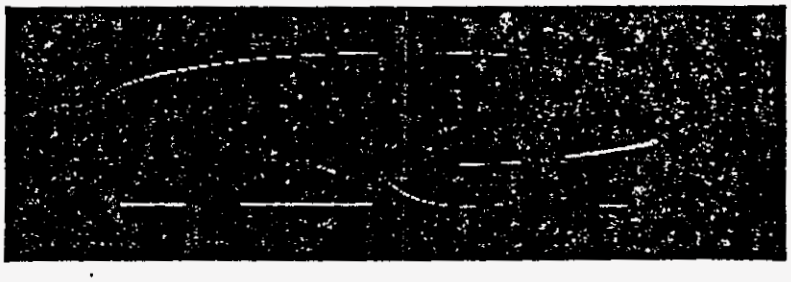
BY

TAMPA ELECTRIC

Hazardous Energy Control Program

Energy Supply Department

October 23, 2000



TAMPA ELECTRIC

Hazardous Energy Control Program					
Tampa Electric Company					
Energy Supply Department					
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I. BASIC REQUIREMENT

The Tampa Electric Company - Energy Supply Department - Hazardous Energy Control Program has been established, in accordance with OSHA Standards to prevent the unexpected release of potentially hazardous energy (e.g. electrical, hydraulic, thermal, chemical, pneumatic, potential, or radiation) during the maintenance and servicing of equipment. This Hazardous Energy Control Program consists of a comprehensive set of equipment-specific Hazardous Energy Control Procedures, employee training requirements, and guidelines for the periodic inspection of the Hazardous Energy Control procedures and program.

II. SCOPE

The Energy Supply Hazardous Control Program applies to the servicing and maintenance of equipment at all Tampa Electric Company facilities under the jurisdiction of the Energy Supply Department.

The Hazardous Energy Control Supervisor has tagout authority and control over the equipment in all generation stations.

The division of responsibility between the Energy Supply Department and the Energy Delivery Department will be the centerline of the unit transformers at the generation stations, unless otherwise indicated in specific tagout procedures or switching orders.

III. RESPONSIBILITY

A. It is the responsibility of Energy Supply Management to approve, implement, monitor and enforce the Energy Supply Hazardous Energy Control Program. Joint responsibility for continuous improvement of the Program is shared between craft and management through a partnership dedicated to protection of workers and compliance with regulations.

B. Each facility shall establish specific Hazardous Energy Control Procedures for the shutdown, isolation, tagout, verification and setup for return to service for the control of hazardous energy for each piece of equipment and/or system. An Authorized Employee shall review these procedures for accuracy at least annually, or, upon equipment changes/additions. Facility management is responsible for the development and maintenance of the HEC procedures.

C. All employees are responsible for assuring that all applicable procedures and Safe Work Practices are followed in the control of hazardous energy.

D. It is the responsibility of the Plant General Manager or Plant Manager to select competent and qualified employees to act as Hazardous Energy Control Supervisors. The Hazardous Energy Control Supervisor is the person under whose orders the Hazardous Energy Control Procedures are performed.

E. It is the responsibility of the Hazardous Energy Control Supervisor to assure that competent and qualified employees are assigned to act as Hazardous Energy Control Operators. The Hazardous Energy Control Operator is the person performing the shutdown, isolation, tagout, verification and set-up for each piece of equipment and/or system, as directed by the Hazardous Energy Control

Supervisor. Coordination between Energy Supply and Energy Delivery:

1. When the Energy Supply Department requests clearance on a circuit or piece of equipment that is under the jurisdiction of the Energy Delivery Department, the switching and tagging shall be done under the orders of the System Dispatcher and shall follow Tampa Electric Company's Safe Work Practices, sections 218 and 522, which shall comply with OSHA standard 1910.269 paragraphs (l), (m), (n) and others that may be applicable.

2. System Dispatchers shall be informed of all Hazardous Energy Control requests that will make generating equipment unavailable or that will curtail station capability.

3. When the System Dispatcher requests a circuit or piece of equipment that is under the jurisdiction of the Energy Supply Department, the tagout shall be done under the orders of the Hazardous Energy Control Supervisor in accordance with Energy Supply's Hazardous Energy Control Program.

F. Tampa Electric Company's Positive Discipline Program applies to any violation of the mandatory provisions of this Program.

G. Departmental Safety Staff shall periodically monitor all areas for compliance with this program.

H. Station management is responsible for coordinating work of outside contractors and will work jointly with the Hazardous Energy Control Supervisor in the implementation of the Hazardous Energy Control Program for outside contractors.

IV. HAZARDOUS ENERGY CONTROL APPLICATION and REMOVAL

Prior to performing servicing and/or maintenance on any system or equipment under the jurisdiction of Tampa Electric Company, Energy Supply Department, all elements of the Hazardous Energy Control Program must be satisfied.

A. Preparation for Shutdown

1. The Hazardous Energy Control supervisor, or designee, will validate the written tagging request.

2. The Hazardous Energy Control Supervisor and the Primary Authorized Employee will jointly determine the scope of tagging requirements.

3. Prior to beginning a Hazardous Energy Control Procedure, the Hazardous Energy Control Supervisor, or their qualified designee, shall verbally notify all affected personnel.

B. Shutdown

The HEC operator shall assure the state of shut down by utilizing the specific

HEC procedure.

The Hazardous Energy Control Operator shall turn OFF or shut down the equipment in an orderly manner, utilizing the specific Hazardous Energy Control Procedure..

C. **Isolation**

The Hazardous Energy Control Operator isolate the equipment/system from the energy source(s), as described in the Hazardous Energy Control Procedure. All energy isolating devices that are needed to control the energy to the machine or equipment shall be physically located and operated in such a manner as to isolate the machine or equipment from energy sources.

D. **Application of Tagout Devices (Individual or Group)**

1. Tagout Devices

NOTE: *Tagout devices are essentially warning devices attached to energy isolating devices and do not provide physical restraint on those devices.*

a. *Only approved tagout devices, including means of attachment,* ordered through Tampa Electric Company Materials Management System, Appendix D, shall be used for the control of hazardous energy.

b. Tagout devices applied to energy isolating devices shall identify:

1. the Hazardous Energy Control Operator applying it;

2. the Master Tag number, and;

3. a description of the Hazardous Energy Control device to which the tag is being attached.

~~2.~~ A Danger tag must be affixed to EACH energy isolating device by the Hazardous Energy Control Operator, as described in the Hazardous Energy Control Procedure, in the following manner.

3. Tagout devices will be securely affixed to each energy-isolating device so that they cannot be inadvertently or accidentally detached during use.

a. Tagout devices shall be attached in such a manner as will clearly indicate that the operation or movement of energy isolating devices from the "safe" or OFF position is prohibited.

b. Tagout devices shall be fastened at the same point at which a lock would be attached.

~~c.~~ Where there is no point at which a lock may be fastened, additional hardware will be utilized to eliminated the likelihood of inadvertent energization, such as "clamshells", chains, and switch

covers.

d. Tagout devices shall not be removed until they are properly signed off.

e. Tagout devices shall not be by-passed, ignored, or otherwise defeated.

4. Only the Hazardous Energy Control Operator, under the authority of the Hazardous Energy Control Supervisor, utilizing equipment/system specific procedures, may apply tags to equipment energy isolating devices.

5. If the Hazardous Energy Control Operator finds the procedure inadequate during the isolation of the system or equipment, the tagout is to cease.

   a. The Hazardous Energy Control Supervisor will be notified to inspect the system or equipment.

   b. He/she will record any required changes to the Hazardous Energy Control Procedure, in writing, on the procedure form, and all authorized and affected employees shall be made aware of the changes.

   c. A safety work order will be generated by the Hazardous Energy Control Supervisor to ensure that the changes, if permanent, are made to the master copy of the Hazardous Energy Control Procedure.

6. If the tagging request or list specifies that certain equipment not be tagged until a later time, those tags for the equipment shall be hung behind the Master Job Tag, on the Master Board, until the equipment is secured for tagging.

E. Stored/Hazardous Energy

1. Following the application of tags to energy isolating devices, all potentially hazardous stored or residual energy shall be relieved, disconnected, restrained, and otherwise rendered safe.

2. If there is a possibility of re-accumulation of stored energy to a hazardous level, verification of isolation shall be continued, by the Primary Authorized Employee or their designee, until the servicing or maintenance is completed, or until the possibility of accumulation no longer exists.

F. Initial Verification/Test

After application of tags, and prior to commencement of work, the Hazardous Energy Control Operator shall, according to the equipment specific procedures:

1. operate the equipment/process controls (push buttons, switches, etc.) to

verify that energy isolation has been accomplished,

2. and check the equipment/system by use of test instruments when appropriate, and visually inspect to verify that potentially hazardous energy isolation has been accomplished.

G. **Notification**

Upon successful isolation of the system, the Hazardous Energy Control Supervisor shall verbally communicate to the Primary Authorized Employee that isolation and tagout are complete, so that verification by the Primary Authorized Employee may begin. The Hazardous Energy Control Supervisor's initials on the Master Job Tag shall signify that verbal communication has taken place.

H. **Individual Verification**

Upon receiving notification from the Hazardous Energy Control Supervisor, each Primary Authorized Employee, upon verification of isolation, shall sign on to the Master Tag..

An Authorized Employee shall verify Hazardous Energy Control prior to signing on to the Master Job Tag.

NOTE: An individual's signature on and off the Master Job Tag or the Master Job Tag Work Permit represents the affixation and removal of a personal tagout device.

If the situation arises that a Primary Authorized Employee, who remains signed on to the Master Job Tag, finds themselves working alone on a later shift as an Authorized Employee, he/she will sign off the Master Job Tag, verify, and sign on the Master Job Tag.

I. **Release from Tagout**

1. Prior to removing their personal tagout device (signing off), each Authorized Employee must ensure the equipment/system is completely reassembled and all tools/materials have been removed from and are clear of the machine/equipment.

2. Each tagout device shall be removed (signed off) by the Authorized Employee applying it (signed on) at the end of their shift.

   a. No person may sign on or sign off for another person.

   b. If the work is completed, and the Authorized Employee/contractor failed to sign off from their personal tagout device, the personal tagout devices may be removed by using the Committeeing procedure:

3. When working under Group Protection, the Primary Authorized Employee must ensure that the work is complete, all tools removed, and that each of their crew has signed off on the Master Job Tag Work Permit or Master

Job Tag.

4. The Hazardous Energy Control Operator shall be notified by the Hazardous Energy Control Supervisor when the work is complete and and all personal tagout devices have been signed off.

5. Only after the Hazardous Energy Control Operator has verified, through a visual inspection, that the work area is clear of all personnel, and that nonessential items have been removed and components are operationally intact, may the Danger tags be removed from the equipment/system.

6. Prior to startup, all equipment guards shall be in place and properly adjusted.

7. The Hazardous Energy Control Operator shall verbally notify affected employees that the servicing and/or maintenance is complete, and the equipment/system is ready for use.

J. Committeeing a Tagout Device

1. The Hazardous Energy Control Supervisor must first verify that the employee who remains signed on to the tagout device is not at the facility.

2. All reasonable efforts to contact the employee shall be made in order for that person to sign off of the personal tagout device.

3. The Hazardous Energy Control Supervisor initiates the completion of the *Committeeing Form*, Appendix C.

4. Prior to removal of tags, the Hazardous Energy Control Supervisor shall:

   a. obtain written consent from the facility Superintendent of Plant Operations, or equivalent; and

   b. obtain written consent from the Production Supervisor, or equivalent; and

   c. notifiy the Duty person/manager.

   NOTE: At facilities where production supervisors do not exist, a competent representative of the craft performing work on the equipment/system will be identified.

5. MJTWP & Tagout Device(s) shall be signed by all Committee members.

6. If a system is tagged to a contractor employee, a competent representative of that organization must be contacted for consent.

7. The immediate supervisor of the employee shall be informed of the tag removal, and will inform and review the incident with the employee when that employee returns to work.

8. All committee tags go behind MJT;

9. The committeeing form, once completed, must be routed to the station general manager, and finally to the station safety coordinator.

K Special Situations

Whenever any changes take place during the control of hazardous energy sources, all Authorized Employees shall be verbally notified. The Master Job Tag Work Permit shall be signed off by each employee to indicate notification of the changes, and a new Master Job Tag Work Permit shall be issued prior to starting work.

1. Testing or positioning of machines

   In situations where the energy isolating device(s) are tagged, and there is a need for testing or positioning of the equipment/system, the following sequence shall apply:

   a. The work area shall be inspected to ensure that nonessential items have been removed and that machine or equipment components are operationally intact.

   b. All affected and Authorized Employees shall be notified of the intended changes, and Authorized Employees shall be required to sign off of the Master Job Tag Work Permit. A new Master Job Tag Work Permit shall be issued, as required, indicating modifications, in writing, to the Hazardous Energy Control Procedure.

   c. The work area shall be checked to ensure that all employees have been safely positioned or removed.

   d. When the tagout device has been signed off by all primary authorized employees, the tags may be removed. Indicate reason for removal, in writing, on tag, and place behind the Master Job Tag.

   e. Proceed with testing.

   f. If equipment is re-tagged after testing, numbers for the new local tags shall correspond to the numbers on the removed tags. The word "reissue" will be written on the new local tag. When the 'new' tag is issued the tag that was signed & removed shall then be taken from behind the Master Job Tag and placed in the facility Hazardous Energy Control Tagging file.

   g. De-energize and re-tag energy isolating devices to continue work.

   h. Operate controls, switches, etc. to verify energy isolation as outlined in Section IV, A through H and L of the HEC Program.

2. Physical Removal of Isolation Equipment/Devices that are Tagged:

In situations where a device with a Danger tag must be removed for maintenance, the following provisions shall be made:

a. Electrical Breakers: If a breaker must be removed that has an Electrical Danger Tag affixed to it:

i. Additional tagging shall be performed to isolate the device safely prior to removal.

ii. The tag on the breaker will then be signed off by all Primary Authorized Employees.

iii. The Primary Authorized Employee must reinspect for compliance with the plant's Energy Control Program and insure that other Authorized Employees are aware of their rights to reinspect the tagging procedure.

iv. All affected and Authorized Employees shall be notified of the intended changes, and Authorized Employees shall be required to sign off of the Master Job Tag Work Permit. A new Master Job Tag Work Permit shall be issued, as required, indicating modifications, in writing, to the Hazardous Energy Control Procedure.

v. Any tags removed will be placed behind the Master Job Tag.

vi. A new tag shall be re-issued, labeled "re-issue", and the same tag number.

b. Valves: If a valve must be removed that has a Mechanical Danger Tag affixed to it.

i. Additional tagging shall be performed to isolate the device safely prior to removal.

ii. The tag on the valve will then be signed off by all Primary Authorized Employees.

iii. Any tags removed will be placed behind the Master Job Tag.

iv. the Primary Authorized Employee must reinspect for compliance with the plant's Energy Control Program and insure that other Authorized Employees are aware of their rights to reinspect the tagging procedure.

3. When troubleshooting or performing routine/repetitive servicing energized

equipment/systems during servicing/repairs, safety-related work practices shall be employed. The specific safety-related work practices shall be consistent with the nature and extent of the associated hazards.

4. Work on cord and plug connected electric equipment for which exposure to the hazards of unexpected energization or start up of the equipment is controlled by the unplugging of the equipment from the energy source and by the plug being under the exclusive control of the employee performing the servicing or maintenance.

L. ***Group Protection Procedures***

1. The Hazardous Energy Control Supervisor has overall responsibility for the adherence to the Energy Supply Hazardous Energy Control Program. He/she will coordinate Group Protection procedures with the Production Supervisor or equivalent and/or the Primary Authorized Employee, who oversees each crew or group, to ensure continuity of protection.

2. The Master Job Tag will be used on ALL jobs.

3. Master Job Tags will be assigned a number by the Hazardous Energy Control Supervisor.

   a. This Master Job Tag number will be written on all Energy Supply Department Electrical Danger or Mechanical Danger tags related to this job.

   b. Each of these tags will be numbered in numerical order. The Master Job Tag number, the individual tag number, the equipment name, the energy isolating device to which it will be attached, and the name of the Hazardous Energy Control Operator applying the tag will be required on these related tags.

   c. Master Job Tag boards will be located at designated areas within each station.

4. Utilization to the Master Job Tag/Master Job Tag Work Permit

   a. A Master Job Tag Work Permit will be used as an extension of the Master Job Tag, when one or more employees are working under the jurisdiction of a Primary Authorized Employee.

   b. Hazardous Energy Control Operators shall follow specific Hazardous Energy Control Procedures to shutdown, isolate and secure the system/equipment.

   c. Upon completion of the shutdown, the Hazardous Energy Control Supervisor identifies the Production Supervisor and/or the Primary Authorized Employee and enters their name in the "tagged to" column of the Master Job Tag, indicating the equipment has been shutdown, isolated, and tagged as requested.

d. The Hazardous Energy Control Supervisor will indicate that the equipment/system is in a "hold condition", being held by the Production Supervisor, or equivalent, by writing "Holder" in the sign on column of the Master Job Tag.

1. The Production Supervisor, or equivalent, may, upon verification of hazardous energy isolating devices, sign on to the Master Job Tag.

2. The Production Supervisor, or equivalent, may do equipment/system inspections as needed by signing on and signing off the Master Job Tag Work Permit, as an Authorized Employee, without signing on to the Master Job Tag. This allows the inspection without the Production Supervisor having to give up their "Holder" status on the Master Job Tag.

e. Each Primary Authorized Employee shall verify that the hazardous energy controls are in place. Upon verification, he/she will sign on to the Master Job Tag.

f. The Primary Authorized Employee shall then sign and date the Master Job Tag Work Permit, the group protection device for their crew.

g. Each Authorized Employee is assured the right to verify that the hazardous energy has been effectively isolated and controlled prior to signing the Master Job Tag Work Permit.

h. Further verification may be necessary as outlined in IV.E.2 "Stored/Hazardous Energy".

i. Each employee working on the machine or equipment shall sign on and sign off the Master Job Tag Work Permit or related Master Job Tag.

j. The Master Job Tag or Master Job Tag Work Permit shall clearly identify each employee who is being protected by it.

k. Signature, date, and time for sign-in and sign-out are recorded and retained by the Primary Authorized Employee for that group on the Master Job Tag Work Permit.

l. Upon completion of the Master Job Tag Work Permit, the Primary Authorized Employee will retain the Master Job Tag Work Permit in their respective shop.

m. Prior to beginning work and every shift thereafter, upon verification of energy controls, each Primary Authorized Employee must initiate a new Master Job Tag Work Permit.

n. Upon completion of job requirements, the Primary Authorized

Employee shall sign off the Master Job Tag, only after all Authorized Employees in their crew have signed off the Master Job Tag Work Permit.

o. The *Production Supervisor (Holder)*, or equivalent, shall return each completed Master Job Tag Work Permit to the Hazardous Energy Control Supervisor.

p. The Master Job Tag Work Permits shall then be attached to the Master Job Tag and filed along with the Hazardous Energy Control Procedural forms and related tags.

q. These documents shall be placed in the facility Hazardous Energy Control tagging file for a minimum of 30 days

r. During the progress of work, the Primary Authorized Employee shall ensure the Master Job Tag Work Permit accurately represents exposed employees.

M. Transition of Tagout at Shift Change

If the tagout continues beyond the end of the shift:

1. The Primary Authorized Employee shall not sign off the Master Job Tag Work Permit until all Authorized Employees on the Master Job Tag Work Permit have signed off.

2. The Primary Authorized Employee shall not sign off the Master Job Tag until:

   a. the Master Job Tag Work Permit has been signed off by all Authorized Employees and,

   b. Protection is provided by another Primary Authorized Employee, or, another "Holder", as indicated in the "Tagged To" column, or, the work has been completed.

3. Each departing Authorized Employee shall sign off the Master Job Tag or Master Job Tag Work Permit at the end of each shift.

   a. In the event an Authorized Employee does not sign off the Master Job Tag Work Permit, the procedures for committeeing shall be followed.

4. The "Holder" of a Master Job Tag (as outlined in section IV.L, Group Protection Procedures) and their designated Primary Authorized Employees are the only employees who do not have to sign off the Master Job Tag at the end of the shift.

V. TRAINING

Tampa Electric Company, Energy Supply Department, will implement a Hazardous Energy Control Training Program, which will include authorized, affected and other employees. Training shall be provided prior to assignment. Training may be classroom or on-the-job format.

A. Authorized Employee training shall include:

1. The purpose and use of the Hazardous Energy Control Program.
2. The recognition of hazardous energy sources.
3. The type and magnitude of the energy present or available in the workplace.
4. The methods and means necessary for energy isolation and control.
5. Means of verification of effective energy control and the purpose of the procedures to be used.
6. The limitations of tags.

B. Affected employee and other employee training shall include:

1. The purpose and use of the Hazardous Energy Control Procedures.
2. The prohibitions to attempt to re-start or re-energize any machines/equipment that are tagged out.
3. The limitations of tags.

C. Upon successful completion, a record of this training, including employee's name and date of training shall be maintained in a centralized recordkeeping system.

D. Retraining shall take place annually, or, as needed, based upon equipment changes, employee transfer or employee performance.

VI. HAZARDOUS ENERGY CONTROL PROCEDURAL INSPECTIONS

A. Hazardous Energy Control Procedures (Appendix B) will be stored in controlled files at each facility. Each of the facility's active Hazardous Energy Control Procedures shall be inspected at least annually to assure accuracy and effectiveness.

1. Periodic Procedural Inspections – Utilizing Appendix E, each Hazardous Energy Control Procedure, when used at least once a year, shall be inspected, at least annually, under the administration of the facility Safety Coordinator, by an Authorized Employee who is not using the procedure at the time, and shall include:

   a. The equipment/system specific Hazardous Energy Control Procedure.

   b. The employees involved in the inspection, and the date.

   c. Whether the procedural steps are being followed.

   d. A review between the inspector and each authorized and affected *employee of that employee's* responsibility under the Hazardous Energy Control Program.

   e. Identification and corrective action taken on any deviations or inadequacies of the procedure to provide protection equivalent to lockout.

   f. The Hazardous Energy Control Procedure Periodic/Annual Inspection Form will be kept on file by the facility Safety Coordinator.

2. The facility Safety Coordinator will certify that the required inspections have been accomplished by reviewing and signing the Hazardous Energy Control Procedure Periodic/Annual Inspection Form, Appendix E.

VII. OUTSIDE CONTRACTOR COMPLIANCE PROCEDURES

A. **General**

1. Outside contractors are required to abide by all applicable OSHA Control of Hazardous Energy Standards as well as Tampa Electric Company, Energy Supply requirements.

2. Tampa Electric Company, Energy Supply, shall inform the contractor of the applicable hazardous energy sources, the type and magnitude of energy available, and the means and methods necessary for energy isolation and control.

3. Tampa Electric Company and outside contractors shall exchange information regarding the Energy Supply Hazardous Energy Control Program to be used by each employer's workers. Each employer shall ensure that their personnel understand and comply with restrictions and

prohibitions of the energy control program being used.

4. Outside contractors shall utilize their own "Hazardous Energy Control Program" for protection of their employees only after hazardous energy control on equipment/systems has been provided to them by Tampa Electric Company.

B. **Implementation**

1. At the request of the contractor's authorized representative, Tampa Electric Company, Energy Supply Department, shall implement appropriate Hazardous Energy Controls on machines and/or equipment utilizing specific Hazardous Energy Control Procedures.

   a. Each contractor shall provide Tampa Electric Company, Energy Supply Department with a list of Primary Authorized Employees that may request equipment to be tagged for their organization. This list will be updated annually.

   b. These authorized personnel must fully comprehend Tampa Electric Company, Energy Supply's, Hazardous Energy Control Program.

2. Upon shutdown, isolation, tagout, and verification that all energy sources are controlled, the Hazardous Energy Control Supervisor shall notify the contractor Primary Authorized Employee that isolation and tagout is complete.

3. The Contractor Primary Authorized Employee, upon verifying energy control, shall sign on to the Master Job Tag.

4. The contractor, upon signing the Master Job Tag, shall ensure individual protection of each of their Authorized Employees through the implementation of that organization's Hazardous Energy Control Program.

C. **Coordination**

1. The contractor shall monitor compliance of their employee.

2. The contractor shall provide all necessary lockout/tagout training and equipment (devices) necessary for the implementation of their own Hazardous Energy Control Program.

D. **Termination of Tagout**

1. Upon completion of their work, the Contractor Primary Authorized Employee shall inspect the area, verify that their servicing and/or maintenance is complete.

2. All affected employees in the area shall be notified by the Contractor Primary Authorized Employee of the intention to remove tagout devices.

3. All contractor lockout/tagout devices shall be removed by the Authorized Employees who affixed them.

4. Upon notification from the Contractor Primary Authorized Employee, the Tampa Electric Company Hazardous Energy Control Supervisor will inspect and verify that all contractor lockout/tagout devices have been properly removed from the machine or equipment prior to removal of the Company's tagout devices and subsequent return to service.

E. **Removal of Tagout Device**

In an emergency, or when the Contractor's Primary Authorized Employee is unavailable to sign off or remove lockout/tagout device(s), a committeeing procedure shall be used (refer to section IV. J. Committeeing a Tagout Device)

F. **Discipline for Non-Compliance**

Enforcement of the Hazardous Energy Control Program shall be in accordance with the contract and will be enforced up to and including immediate termination of the contract.

VIII. EQUIPMENT DESIGN

New machines/equipment or, existing equipment that is retrofitted, must be designed to accept a lockout device.

IX. DISCIPLINE FOR NON-COMPLIANCE

The following guidelines apply to ALL employees:

A. Any employee who fails to follow this Hazardous Energy Control Program shall be subject to disciplinary action.

B. Disciplinary actions shall be consistent with the Tampa Electric Company policies and shall follow Positive Discipline guidelines.

APPENDIX A

DEFINITIONS

Affected Employee – A person whose job requires them to operate or use a machine or equipment on which servicing or maintenance is being performed under tagout or whose job requires them to work in an area in which such servicing or maintenance is being performed.

Authorized Employee – A person who tags out machines or equipment to perform the servicing or maintenance on that machine or equipment. When working alone, an Authorized Employee shall coordinate with the Hazardous Energy Control Supervisor to ensure adherence with Energy Supply Hazardous Energy Control procedures. An Affected Employee becomes an Authorized Employee when that employee's duties include performing servicing or maintenance covered under this Program.

Competent Person – One who is capable of identifying existing and predictable hazards in the surroundings or working conditions which are hazardous or dangerous to employees, and who has authorization to take prompt corrective measures to eliminate them.

Energy Isolating Device – A physical device that prevents the transmission or release of energy, including: manually operated circuit breakers, disconnect switches, line valves, blocks, and any similar device with a visible indication of the position (on/off or open/closed) of the device. Push buttons, selector switches and other control circuit type devices are not energy isolating devices.

Group Tagout Device – Administrative device to account for each Authorized Employee protected from unexpected release of hazardous energy signified by affixing their name as their personal tagout device.

Group Protection – Methods and procedures designed to afford a crew or group of employees a level of protection equivalent to that provided by use of a personal tagout device.

Hazardous Energy Control Operator – Energy Supply qualified person responsible for the initial physical isolation and application of the Danger Tagout devices to the energy isolation devices.

Hazardous Energy Control Supervisor – Energy Supply employee with the overall responsibility and jurisdiction for the Tagout of equipment/systems. The person under whose orders Hazardous Energy Control is performed.

Hazardous Energy Source - Any source of electrical, mechanical, hydraulic, pneumatic, chemical, thermal, potential or other energy source that may pose a hazard to individuals.

Hold Condition – A condition in which equipment is isolated, tagged but not verified nor signed on. This condition requires signing off before the tag is removed. No work shall be done under this state.

Holder – The person for which a hold condition is established.

Primary Authorized Employee - An Authorized Employee who exercises overall job responsibility for a group or crew of Authorized Employees, and coordinates with the Hazardous Energy Control Supervisor to ensure adherence with Energy Supply's Hazardous Energy Control Procedures.

Qualified person – A person who is specially qualified to do a specific job because of education, training, and/or experience.

Servicing and/or Maintenance – Workplace activities such as constructing, installing, setting up, adjusting, inspecting, modifying, and maintaining and/or servicing machines or equipment. These activities include lubrication, cleaning, or unjamming of machines or equipment and making adjustments or tool changes, where the employee may be exposed to the unexpected energization or start-up of the equipment or release of hazardous energy.

Switch – A device for opening and closing or for changing the connection of a circuit. In this section, a switch is understood to be manually operable, unless otherwise stated.

Tag – An openly displayed card, ticket, plastic marker, etc. securely attached to something as a label to give information, warning or instruction. Accident prevention tags have standard signal works, symbols and colors to convey a danger, warning, caution or information.

Tag, Electrical Danger Tag – Tagout device used only on electrical Hazardous Energy Control devices, such as circuit breakers, motor starters, and disconnects.

Tag, Master Job Tag- Group/individual tagout device used as an administrative control and accountability device for group or individual protection. This device is controlled by the Hazardous Energy Control Supervisor, and is a personal tagout device if each employee personally signs on and signs off of it.

Tag, Master Job Tag Work Permit - Group tagout device used in conjunction with master job tag and is a personal tagout device as well as an administrative control and accountability device for Authorized Employees who sign on to it. It is administered by the Primary Authorizied employee.

Tag, Mechanical Danger Tag: Tagout device used on mechanical Hazardous Energy Control devices, such as valves, valve wheels, levers, and all other operating mechanisms.

Tagout - The placement of a tagout device on an energy isolating device, in accordance with an established procedure, to indicate that the energy isolating device and the equipment being controlled shall not be operated until the tagout device is properly signed off and removed.

Tagout device – A prominent warning device, such as a tag and a means of attachment, which can be securely fastened to an energy-isolating device in accordance with an established procedure, to indicate that the energy isolating device and the equipment being controlled shall not be operated until the tagout device is properly signed off and removed.

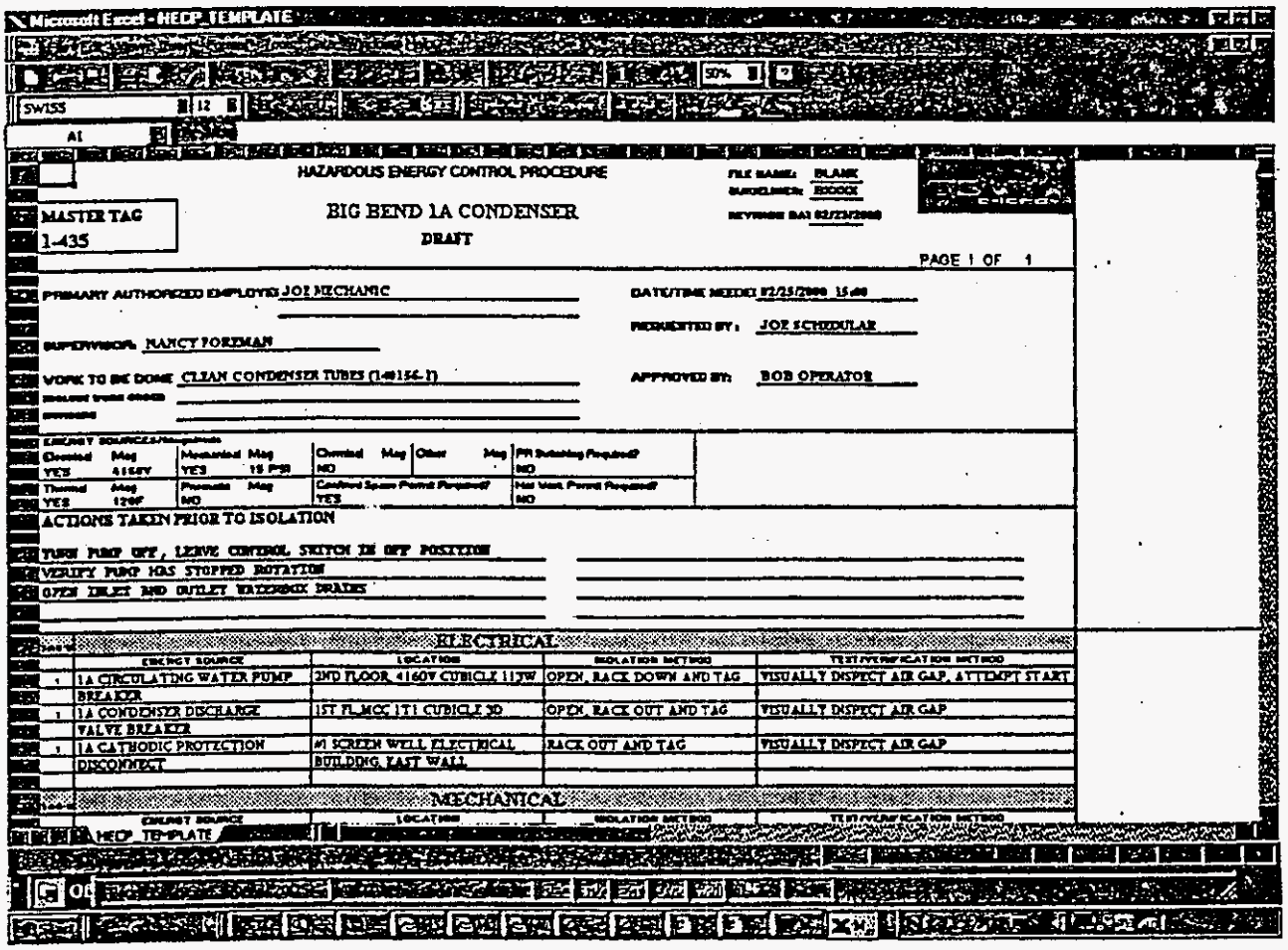
Verification – A confirmation of the certainty that a system/equipment has been properly tagged out, and all energy sources have been controlled.

Verify – Proving something to be true and establishing the certainty of it. Also, to determine or

test the accuracy of a state or condition. This can range from a visual determination to a physical examination and inspection.

APPENDIX B

HAZARDOUS ENERGY CONTROL PROCEDURE



HAZARDOUS ENERGY CONTROL PROCEDURE

MASTER TAG
1-435

BIG BEND 1A CONDENSER
DRAFT

PAGE 1 OF 1

PRIMARY AUTHORIZED EMPLOYEE: JOE MECHANIC
SUPERVISOR: NANCY FOREMAN
WORK TO BE DONE: CLEAN CONDENSER TUBES (1-M156-I)
DATE/TIME NEEDED: 02/25/2000 15:00
PRESENTED BY: JOE SCHEDULAR
APPROVED BY: BOB OPERATOR

Chemical	Mag	Mechanical	Mag	Chemical	Mag	Other	Mag	PPI Switching Required?
YES	4160V	YES	15 PSI	NO				NO
Thermal	Mag	Pneumatic	Mag	Confined Space Permit Required?				Hot Work Permit Required?
YES	120F	NO		YES				NO

ACTIONS TAKEN PRIOR TO ISOLATION

TURN PUMP OFF, LEAVE CONTROL SWITCH IN OFF POSITION
VERIFY PUMP HAS STOPPED ROTATION
OPEN INLET AND OUTLET WATERBOX DRAINS

ELECTRICAL

	ENERGY SOURCE	LOCATION	ISOLATION METHOD	TEST/VERIFICATION METHOD
1	1A CIRCULATING WATER PUMP BREAKER	2ND FLOOR, 4160V CUBICLE 117W	OPEN, RACK DOWN AND TAG	VISUALLY INSPECT AIR GAP, ATTEMPT START
1	1A CONDENSER DISCHARGE VALVE BREAKER	1ST FLMCC 1T1 CUBICLE 3D	OPEN, RACK OUT AND TAG	VISUALLY INSPECT AIR GAP
1	1A CATHODIC PROTECTION DISCONNECT	#1 SCREEN WELL ELECTRICAL BUILDING, EAST WALL	RACK OUT AND TAG	VISUALLY INSPECT AIR GAP

MECHANICAL

ENERGY SOURCE	LOCATION	ISOLATION METHOD	TEST/VERIFICATION METHOD

APPENDIX C

Energy Supply Department

Hazardous Energy Control Committeeing Form

Location :_____ Organization:_____

Hazardous Energy Control Supervisor:_____

Date_____ Time:_____Master Job Tag #:_____

Identify the equipment to which the Tagout Device was attached:_____

Reason for Hazardous Energy Control Device removal: _____

_____

Name indicated on Hazardous Energy Control Device_____

What attempt was made to contact the person who applied the Hazardous Energy Control Device?_____

Has equipment been checked by a competent representative of the department doing the work to verify equipment and energy sources are in useable condition? Yes ☐ No ☐

Has immediate supervisor of employee been notified? Yes ☐ No ☐

Signed:_____
SPO/Equivalent

Signed_____
Production Supervisor or Equivalent

☐ Notification
☐ Verbal

Signed_____
Manager/Duty Person

___Yes ___No Authorized employee has been informed of tag removal prior to resuming work at the station

_____ _____ _____

Time Date Signature, Authorized Employee

_____ _____ _____

Time Date Supervisor/Designee

Time Date General Manager

Route completed form to Facility Safety Coordinator.

APPENDIX D

Tagging Device Requirements/Ordering Information

Tagging Device Requirements

1. Tagging devices specify "DO NOT OPERATE".
2. Tagging devices are standard in size and able to withstand plant conditions.
3. Tagging device attachment means shall be of a non-reusable type, attachable by hand, self-locking; with a minimum breaking strength of no less than 50 pounds.
4. Tagging devices shall be constructed and printed so that exposure will not cause the tag to deteriorate or cause the tag message to become illegible. All information required on the tag shall be properly entered and legible so that exposure to the elements will not cause the message to deteriorate.

Ordering Information

DESCRIPTION			STOCK NO
TAG, ATTACHER – check on		P/N AR-159	6013153
TAG, DANGER MASTER	ORANGE 4 1/8 X 8	H-210	5858030
TAG, DANGER PRODUCTION ELECTRICAL WHITE LAMINATED		H222B	6013622
TAG, DANGER PRODUCTION ELECTRICAL WHITE PAPER		P/N H222	6013623
TAG, DANGER PRODUCTION MECHANICAL WHITE LAMINATED		H221B	6013624
TAG, DANGER PRODUCTION MECHANICAL WHITE PAPER		H221	6013625
MASTER JOB TAG WORK PERMIT			

APPENDIX E

Tampa Electric Company

Energy Supply

Hazardous Energy Control Procedure

Periodic/Annual Inspection Form

Facility:_____ Area:_____ Date:_____

Equipment/System: _____ Inspector:_____

Authorized Employees:_____

Affected Employees:_____

a. Has every energy source been identified on the procedure? Yes____ No____

b. Are all energy sources tagged? Yes____ No____

c. Are all Authorized Employees protected from all energy sources by a personal tagout device? Yes____ No____

d. Was equipment verified as having been tagged out effectively? Yes____ No____

e. What date was the procedure last reviewed? _____

f. Do procedures specify equipment with appropriate disconnects? Yes____ No____

g. Are tags and devices available that are designated for tagout use only? Yes____ No____

h. Do tags identify the person applying the tagout device? Yes___ No____

i. Do the authorized and affected employees understand their responsibilities under the Hazardous Energy Control Program? Yes____ No____

j. Are they following the specific Hazardous Energy Control Procedure? Yes____ No____

k. Identification of any deviations or inadequacies of the procedure to provide protection equivalent to lockout?

l. Corrective actions taken:

Certification of Inspection by: _____ Date: _____

Facility Safety Coordinator

cc: Facility Safety Coordinator

APPENDIX F

Group Protection

Master Job Tag Work Permit

Master Job Tag #_____ Work Order #_____

Job Description _____

Energy Controls ***Visually Inspected By:***

_____

Print Name: Primary Authorized Employee

_____ Date: _____ Time: _____

Signature of Primary Authorized Employee

Authorized Employees: (My signature represents that I understand the purpose and use of the Tampa Electric, Energy Supply, Hazardous Energy Control Program; recognize the hazardous energy sources, type and magnitude of energy, and the methods and means necessary for energy isolation and control of these energy sources; the means of verification, the purpose of the specific procedure being used, and the limitations of tags.)

Name: [Print]	Sign On	Time	Sign Off	Time

_____ Date_____ Time _____

Sign Off: Primary Authorized Employee

ORIGINAL

JAMES E. "JIM" KING, JR.
PRESIDENT

JOHNNIE BYRD
SPEAKER

STATE OF FLORIDA
OFFICE OF THE PUBLIC COUNSEL
c/o THE FLORIDA LEGISLATURE
111 WEST MADISON ST.
ROOM 812
TALLAHASSEE, FLORIDA 32399-1400
850-488-9330

Charles J. Beck
Interim
Public Counsel

October 3, 2003

RECEIVED-FPSC
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COMMISSION
CLERK

Ms. Blanca S. Bayó, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0870

RE: Docket No. 030001-EI

Dear Ms. Bayó:

Appendix "A" to the testimony witness Majoros and Zaetz were inadvertently omitted from yesterday's filing. An original and 15 copies of each are enclosed. I apologize for any inconvenience this may have caused.

Sincerely,

Robert D. Vandiver
Associate Public Counsel

RDV/pwd

Enclosures

AUS 2
CAF ___
CMP ___
COM 5+1
CTR ___
ECR ___
GCL 1
OPC ___
RMS ___
SEC 1
OTH ___

cc: Parties of Record

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 33
COMPANY/ OPC WMZ-1 +
WITNESS: Appendix A to WMZ-2
DATE 11-12-03

Zaetz
DOCUMENT NUMBER-DATE
09611 OCT-3 03
FPSC-COMMISSION CLERK

Majoros
DOCUMENT NUMBER-DATE
09610 OCT-3 03
FPSC-COMMISSION CLERK

Experience

Snavely King Majoros O'Connor & Lee, Inc., Washington D.C.

Senior Consultant (2000 to present)

Mr. Zaetz provides technical expertise in all of the firm's projects involving the engineering, costing, operation, valuation, depreciation and dismantlement of electric and gas facilities. Mr. Zaetz has assisted in several electric and gas depreciation studies.

Independent Consultant (2000-2001)

Mr. Zaetz provided consultation to the U.S. Department of Justice in connection with several units to enforce the nitrogen oxide ("NOX") abatement regulations of the Environmental Protection Agency. Mr. Zaetz reviewed engineering plans and work orders to determine the nature and objectives of modifications to the generation plants subject to the suit. He prepared summaries of his findings in anticipation of possible testimony before Federal Courts.

Boilermaker Local 193 Severn, MD

General Foreman
Foreman (1973-2000)

Mr. Zaetz supervised the fabrication, installation, repair and dismantlement of boiler plant, synthetic natural gas, fuel handling equipment, and environmental abatement facilities in electric generating plants operated by both public utilities and private industrial and commercial enterprises. In the course of 180 separate projects, Mr. Zaetz supervised operations in most of the major power plants throughout the Maryland, Northern Virginia and Southern Delaware area.

Shop Steward

Mr. Zaetz represented over 100 boilermakers in labor arbitrations, safety disputes and the implementation of Federal worker protection provisions.

Legislative Education Action Committee

Mr. Zaetz participated as committeeman and Chairman of the Education Committee in the Union's efforts to facilitate and enhance the technical training of its members.

Education

University of Baltimore: B.S. in Business Management

Boilermaker Apprentice Program

DOCUMENT NUMBER-DATE
09611 OCT-3 08
FPSC-COMMISSION CLERK

William M. Zaetz

Testimony

Date	State	Docket	Utility
2001	Georgia 1/	14000-U	Georgia Power Company
2002	Florida 7/	010949-EL	Gulf Power Company

Plant Tours

Date	State/Client Code	Docket	Utility
2001	Kansas 2/ 3/ 4/	01-WSRE-436-RTS	Kansas Power & Light
2001	Kansas 2/ 3/ 4/	01-WSRE-436-RTS	Kansas Gas & Electric
2001	New Jersey 5/	GR0105029	Public Service Electric & Gas
2001	Georgia 1/	14000-U	Georgia Power Company
2001	Michigan 6/	U-12999	Consumers Energy
2001	Florida 7/	010949-EL	Gulf Power Company
2002	Nevada 8/	01-11031	Sierra Pacific & Nevada Power

Clients

1/ Georgia Public Service Commission
2/ Kansas Citizens' Utility Rate Board
3/ Kansas Industrial Group
4/ City of Wichita
5/ New Jersey Rate Advocate
6/ Michigan Attorney General
7/ Florida Office of Public Counsel
8/ Nevada Bureau of Consumer Protection

DOCKET NO. 030001-EI: Fuel and purchased power cost recovery clause and generating performance incentive factor.

WITNESS: **Direct Testimony Of Joseph W. Rohrbacher,** Appearing On Behalf Of Staff

EXHIBIT: JWR-1 - Audit of Base Year Costs For Security and Hedging

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 34
COMPANY/ FPSC Staff
WITNESS: JWR-1 thru JWR-5
DATE 11-12-03

FLORIDA PUBLIC SERVICE COMMISSION

DIVISION OF AUDITING AND SAFETY
BUREAU OF AUDITING

TAMPA DISTRICT OFFICE

PROGRESS ENERGY FLORIDA
(FORMALLY FLORIDA POWER CORPORATION)

BASE YEAR SECURITY AND HEDGING COST AUDIT

FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2001

DOCKET NO. 030001-EI

AUDIT CONTROL NO. 02-340-2-2

Joseph W. Rohrbacher, Audit Manager

James A. McPherson, Tampa District Supervisor

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DIVISION OF AUDITING AND SAFETY
AUDITOR'S REPORT

March 17, 2003

TO: FLORIDA PUBLIC SERVICE COMMISSION AND OTHER INTERESTED PARTIES

We have applied the procedures described later in this report to audit the base year security and hedging costs to be used in the fuel and capacity cost recovery clause proceedings for the historical twelve month period ended December 31, 2001 for Progress Energy Florida (formerly Florida Power Corporation). There is no confidential information associated with this audit.

This is an internal accounting report prepared after performing a limited scope audit. Accordingly, this report should not be relied upon for any purpose except to assist the Commission staff in the performance of their duties. Substantial additional work would have to be performed to satisfy generally accepted auditing standards and produce audited financial statements for public use.

SUMMARY OF SIGNIFICANT PROCEDURES

Our audit was performed by examining, on a test basis, certain transactions and account balances which we believe are sufficient to base our opinion. Our examination did not entail a complete review of all financial transactions of the company. Our more important audit procedures are summarized below. The following definitions apply when used in this report:

Compiled - The exhibit amounts were reconciled with the general ledger, and accounts were scanned for error or inconsistency.

Verify - The item was tested for accuracy, and substantiating documentation was examined.

HEDGING: The utility stated it did not incur hedging costs until 2003. Therefore, no further audit work was performed to determine base year costs.

SECURITY: Obtained security costs by function for the years 2000, 2001 and 2002. Determined base year costs on calendar year 2001 and also on year ending September 30, 2001 and 2002 for comparative purposes. Tested a randomly selected sample of security charges to supporting documentation.

DISCLOSURES

Disclosure No. 1

Subject: **Hedging Costs**

Statement of Fact: Commission Order No. PSC - 02 -1484 -FOF -EI recognized the importance of managing price volatility in the fuel and purchased power that each investor-owned electric utility purchases to provide electric service to its customers.

The settlement further allowed that each investor-owned electric utility shall be authorized to recover through the fuel and purchased power cost recovery clause its non-speculative, prudently-incurred gains and losses and incremental operating and maintenance expenses associated with financial and/or physical hedging programs.

In response to Staff's Second Set of Interrogatories, Number 36, the utility responded it would not incur hedging costs until 2003.

Auditor Opinion: Since the utility stated it did not incur hedging costs during 2002, we did not perform any audit work on hedging costs.

Disclosure No. 2

Subject: Security Costs

Statement of Fact: The Nuclear Regulatory Commission (NRC) issued Order No. EA-02-026, dated February 25, 2002, requiring electric utilities to implement certain security measures as a result of the September 11, 2001 attacks.

Progress Energy Florida (formerly Florida Power Corporation) recorded $9,114,435 for security expenses on its books and records during 2001.

Audit Opinion: A review of the 2001 security expenses revealed that liability claims and administration costs were recorded as security costs in error. Progress Energy Florida staff agreed and determined that the security costs should have been $8,192,926. The 2001 security expenses originally provided to the auditor were overstated by $921,509.

The utility's base rates were established in its rate case by Order No. PSC-02-0655-AS-EI, issued May 14, 2002, and were based in part on budgeted security costs of $7,074,068 for 2001. Since the actual expenditures are greater than budgeted, the $8,192,926 should be used for the base year.

Schedule of Base Year Costs

	Actual 2001	Budget 2001
Generation	$ 6,750,175	
Transmission	6,150	
Distribution	1,255	
Other	1,435,346	
Total	$ 8,192,926	$ 7,074,068

DOCKET NO. 030001-EI: Fuel and purchased power cost recovery clause and generating performance incentive factor.

WITNESS: **Direct Testimony Of Joseph W. Rohrbacher,** Appearing On Behalf Of Staff

EXHIBIT: JWR-2 - 2002 Fuel Cost Recovery Clause Audit

FLORIDA PUBLIC SERVICE COMMISSION

DIVISION OF AUDITING AND SAFETY
BUREAU OF AUDITING

TAMPA DISTRICT OFFICE

PROGRESS ENERGY FLORIDA

(FORMERLY FLORIDA POWER CORPORATION)

FUEL ADJUSTMENT CLAUSE AUDIT

FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2002

DOCKET NO. 030001-EI

AUDIT CONTROL NO. 03-034-2-2

Thomas E. Stambaugh, Audit Manager

Joseph W. Rohrbacher, Audit Staff Member

Tomer Kopelovich, Audit Staff Member

James A. McPherson, Tampa District Supervisor

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(AS OF 12/31/2002)

CALCULATION OF FINAL TRUE-UP AND INTEREST (SCH A-2)....6
(AS OF 12/31/2002)

DIVISION OF AUDITING AND SAFETY
AUDITOR'S REPORT

Docket No. 030001-EI
Exhibit JWR-2 (Page 3 of 8)
Fuel Adjustment Audit Report

APRIL 16, 2003

TO: FLORIDA PUBLIC SERVICE COMMISSION AND OTHER INTERESTED PARTIES

We have applied the procedures described later in this report to audit the accompanying Fuel Adjustment Clause True-up schedules for the historical twelve month period ended December 31, 2002 for Progress Energy Florida (formerly Florida Power Corporation). These schedules were prepared by the Utility as part of its petition for cost recovery in Docket 020001-EI. This audit does include confidential information. There are no audit staff minority opinions. The audit exit conference was held on Wednesday, April 16, 2003.

This is an internal accounting report prepared after performing a limited scope audit. Accordingly, this report should not be relied upon for any purpose except to assist the Commission staff in the performance of their duties. Substantial additional work would have to be performed to satisfy generally accepted auditing standards and produce audited financial statements for public use.

SUMMARY OF SIGNIFICANT PROCEDURES

Our audit was performed by examining, on a test basis, certain transactions and account balances which we believe are sufficient to base our opinion. Our examination did not entail a complete review of all financial transactions of the company. Our more important audit procedures are summarized below. The following definitions apply when used in this report.

Compiled - The exhibit amounts were reconciled with the general ledger. Accounts were scanned for error or inconsistency.

Verify - The item was tested for accuracy and substantiating documentation was examined.

REVENUE: Compiled Fuel Adjustment Clause (FAC) revenue and agreed to the filing. Recomputed FAC revenues using approved FPSC rate factors and company-provided KWH sales. Reconciled Utility "revenue recap" report to the general ledger on a test basis.

EXPENSES: Compiled fuel and purchased power costs. Tested the purchases of coal, heavy oil, light oil and natural gas by tracing to the general ledger and journal entries.

TRUE-UP: Recomputed FAC true-up and interest using FPSC approved amounts and interest rates.

INTEREXCHANGE PURCHASES AND SALES: Scheduled monthly activity of interexchange schedules (Sch. A-6, A-7, A-8, A-9). Judgementally selected three months of Schedule A-8, Payments to Qualifying Facilities, for further analysis. Activity of selected months was traced to source documentation.

OTHER: Analyzed the "short cut" method of determining the equity and revenue requirement of Progress Energy Fuels (formerly Electric Fuels Corp). Investigated the benchmark price and its annual escalation for the waterborne transportation costs of coal. Verified that heat rates for Generation Performance Incentive Factor (GPIF) determination were also used on the FAC A-5. Traced GPIF heat rates, service hours, reserve shutdown hours, and unavailable hours to the July and year-to-date Micro-GADS (Generating Availability Data System) reports published by the Utility. Verified that semi-annual adjustments to the coal inventory were performed according to FPSC Order PSC-97-0359-FOF-EI.

DISCLOSURE NO. 1

SUBJECT: FUEL COST OF SUPPLEMENTAL SALES

STATEMENT OF FACT:

In the 2002 Fuel Adjustment Clause filing, the Utility's FAC A-1, line 17, stated its Fuel Cost of Supplemental Sales was $68,144,269.

AUDIT OPINION:

The Fuel Cost of Supplemental Sales was found to have two formula errors in its computation which led to reductions in the total of Fuel Cost of Supplemental Sales.

On a "system" basis, the two amounts were $2,202,031 and $13,039, for a total of $2,215,070. The effect of these differences changes the Fuel Cost of Supplemental Sales from $68,144,269 to $65,929,198 on the FAC A-1, line 17.

The Fuel Cost of Supplemental Sales is a reduction in recoverable fuel dollars. The customers to whom the supplemental sales are delivered pay a portion of the recoverable cost of fuel. Therefore, a reduction in this category increases the amount recoverable from other customers.

Jurisdictionally, the total recoverable amount increases by $2,198,475, including $29,276 of interest.

AUDIT CONCLUSION: Increase the recoverable jurisdictional fuel dollars for 2002 by $2,198,475.

DISCLOSURE NO. 2

SUBJECT: WATERBORNE COAL TRANSPORTATION COSTS

STATEMENT OF FACT:

In FPSC order PSC-93-1331-FOF-EI, the Utility was authorized to use a base year waterborne transportation cost of $23.00, effective January 1, 1993. This per-ton price was to be escalated each year on a weighted average of the change in five economic indexes published by the US Bureau of Labor Statistics (BLS). We were told by the utility that the BLS adjusts each quarterly index three times (preliminary, advanced and final). On the BLS website and in other computer databases, each set of numbers is overwritten by the following set of numbers.

[redacted]

AUDIT OPINION: A Utility representative stated that the change in indexes and the subsequent change in the per-ton transportation price is agreed each year between the Utility and FPSC Staff.

[redacted]

[redacted]

[redacted]

The periodic increases in the cost per gallon of the waterway user tax was analyzed and verified using published information. We were not able to determine the accuracy of the original per ton equivalent used in the base year cost effective at January 1, 1993. All subsequent increases were determined to be accurately computed.

AUDIT CONCLUSION: We were not able to verify the current benchmark price using the preliminary index amounts. However, the current amount is less than what it would be if final index numbers were used.

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION
TWELVE MONTH PERIOD ENDING - DECEMBER, 2002

	$				MWH				CENTS/KWH			
	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%	ACTUAL	ESTIMATED	DIFFERENCE AMOUNT	%
1 FUEL COST OF SYSTEM NET GENERATION (SCH A3)	856,890,122	848,829,151	7,060,971	0.8	34,481,078	32,645,940	1,835,138	5.6	2.4822	2.6081	(0.1179)	(4.5)
2 SPENT NUCLEAR FUEL DISPOSAL COST	6,342,975	6,164,382	178,593	2.9	6,700,267	6,592,923	107,344	1.6	0.0947	0.0935	0.0012	1.3
3 COAL CAR INVESTMENT	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
3b NUCLEAR DECOMMISSIONING AND DECONTAMINATION	1,729,044	0	1,729,044	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
4 ADJUSTMENTS TO FUEL COST - MISCELLANEOUS	(30,574,817)	10,962,000	(41,536,817)	(378.9)	(1,412,706)	0	(1,412,706)	0.0	2.1643	0.0000	2.1643	0.0
4a ADJUSTMENTS TO FUEL COST - DISPOSAL COST REFUND	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
5 TOTAL COST OF GENERATED POWER	833,387,324	865,956,533	(32,568,209)	(3.8)	33,068,372	32,645,940	422,432	1.3	2.5202	2.6526	(0.1324)	(5.0)
6 ENERGY COST OF PURCHASED POWER - FIRM (SCH A7)	57,767,866	59,300,216	(1,532,350)	(2.6)	3,202,373	3,319,365	(116,992)	(3.5)	1.8039	1.7865	0.0174	1.0
7 ENERGY COST OF SCH C,X ECONOMY PURCHASES - BROKER (SCH A9)	1,707,361	0	1,707,361	0.0	31,657	0	31,657	0.0	5.3933	0.0000	5.3933	0.0
8 ENERGY COST OF ECONOMY PURCHASES - NON-BROKER (SCH A9)	38,488,012	20,107,161	18,380,851	91.4	742,865	678,000	64,865	9.6	5.1810	2.9657	2.2153	74.7
9 ENERGY COST OF SCH E PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
10 CAPACITY COST OF ECONOMY PURCHASES (SCH A9)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
11 PAYMENTS TO QUALIFYING FACILITIES (SCH A8)	159,374,840	158,644,508	730,332	0.5	6,476,107	6,510,148	(34,041)	(0.5)	2.4610	2.4369	0.0241	1.0
12 TOTAL COST OF PURCHASED POWER	257,338,079	238,051,885	19,286,194	8.1	10,453,002	10,507,513	(54,511)	(0.5)	2.4619	2.2655	0.1964	8.7
13 TOTAL AVAILABLE MWH					43,521,374	43,153,453	367,921	0.9				
14 FUEL COST OF ECONOMY SALES (BROKER) (SCH A6)	(165,155)	0	(165,155)	0.0	(9,798)	0	(9,798)	0.0	1.6856	0.0000	1.6856	0.0
14a GAIN ON ECONOMY SALES (BROKER) - 80% (SCH A6)	0	0	0	0.0	(9,798)	0	(9,798)	0.0	0.0000	0.0000	0.0000	0.0
15 FUEL COST OF OTHER POWER SALES (SCH A6)	(25,472,095)	(34,059,150)	8,587,055	(25.2)	(996,742)	(1,035,000)	38,258	(3.7)	2.5555	3.2907	(0.7352)	(22.3)
15a GAIN ON OTHER POWER SALES - 100% (SCH A6)	(5,628,586)	(4,765,728)	(862,858)	18.1	(996,742)	(1,035,000)	38,258	(3.7)	0.5647	0.4605	0.1042	22.6
16 FUEL COST OF SEMINOLE BACK-UP SALES (SCH A6)	0	0	0	0.0	0	0	0	0.0	0.0000	0.0000	0.0000	0.0
17 FUEL COST OF SUPPLEMENTAL SALES	(68,144,269)	(71,009,729)	2,865,460	(4.0)	(2,279,110)	(1,800,987)	(478,123)	26.6	2.9900	3.9428	(0.9528)	(24.2)
18 TOTAL FUEL COST AND GAINS ON POWER SALES	(99,410,105)	(109,834,607)	10,424,502	(9.5)	(3,285,650)	(2,835,987)	(449,663)	15.9	3.0256	3.8729	(0.8473)	(21.9)
19 NET INADVERTENT AND WHEELED INTERCHANGE					23,660	0	23,660					
20 TOTAL FUEL AND NET POWER TRANSACTIONS	991,315,297	994,172,811	(2,857,514)	(0.3)	40,259,384	40,317,466	(58,082)	(0.1)	2.4623	2.4659	(0.0036)	(0.2)
21 NET UNBILLED	114,497	(2,650,036)	2,764,533	(104.3)	(4,650)	140,165	(144,815)	(103.3)	0.0003	(0.0069)	0.0072	(104.4)
22 COMPANY USE	2,866,770	3,509,127	(642,357)	(18.3)	(116,427)	(144,000)	27,573	(19.2)	0.0076	0.0092	(0.0016)	(17.4)
23 T & D LOSSES	59,416,087	53,867,853	5,548,234	10.3	(2,413,032)	(2,183,046)	(229,986)	10.5	0.1575	0.1413	0.0162	11.5
24 ADJUSTED SYSTEM KWH SALES (SCH A2 PG 1 OF 4)	991,315,297	994,172,811	(2,857,514)	(0.3)	37,725,275	38,130,585	(405,310)	(1.1)	2.6277	2.6073	0.0204	0.8
25 WHOLESALE KWH SALES (EXCLUDING SUPPLEMENTAL SALES)	(23,360,110)	(26,252,740)	2,892,630	(11.0)	(893,156)	(1,014,477)	121,321	(12.0)	2.6155	2.5878	0.0277	1.1
26 JURISDICTIONAL KWH SALES	967,955,187	967,920,071	35,116	0.0	36,832,119	37,116,108	(283,989)	(0.8)	2.6280	2.6078	0.0202	0.8
27 JURISDICTIONAL KWH SALES ADJUSTED FOR LINE LOSS - 1.00235	970,220,678	972,856,464	(2,635,786)	(0.3)	36,832,119	37,116,108	(283,989)	(0.8)	2.6342	2.6211	0.0131	0.5
28 PRIOR PERIOD TRUE-UP	(1,500,794)	23,640,300	(25,141,094)	(106.4)	36,832,119	37,116,108	(283,989)	(0.8)	(0.0041)	0.0637	(0.0678)	(106.4)
28a MARKET PRICE TRUE-UP	0	0	0	0.0	36,832,119	37,116,108	(283,989)	(0.8)	0.0000	0.0000	0.0000	0.0
28b RECOVERY OF PRIOR PERIOD NUCLEAR REPLACEMENT COST	0	0	0	0.0	36,832,119	37,116,108	(283,989)	(0.8)	0.0000	0.0000	0.0000	0.0
29 TOTAL JURISDICTIONAL FUEL COST	968,719,884	996,496,764	(27,776,880)	(2.8)	36,832,119	37,116,108	(283,989)	(0.8)	2.6301	2.6848	(0.0547)	(2.0)
30 REVENUE TAX FACTOR									1.00072	1.00072	0.0000	0.0
31 FUEL COST ADJUSTED FOR TAXES									2.6320	2.6867	(0.0547)	(2.0)
32 GPIF	266,918	266,919			36,832,119	37,116,108			0.0007	0.0007	0.0000	100.0
33 TOTAL FUEL COST FACTOR ROUNDED TO THE NEAREST .001 CENTS/KWH									2.633	2.687	(0.055)	(2.0)

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Docket No. 030001-EI
Exhibit JWR-2 (Page 7 of 8)
Fuel Adjustment Audit Report

CALCULATION OF TRUE-UP AND INTEREST PRO
FLORIDA POWER CORPORATION
DECEMBER 2002

SCHEDULE A2
PAGE 3 OF 4

		CURRENT MONTH				PERIOD TO DATE			
		ACTUAL	ESTIMATED	DIFFERENCE	PERCENT	ACTUAL	ESTIMATED	DIFFERENCE	PERCENT
D .	TRUE UP CALCULATION								
1 .	JURISDICTIONAL FUEL REVENUE (LINE B1c)	$70,100,479.98	$76,448,251	($6,347,771)	(8.3)	$937,157,783.56	$996,762,732	($59,604,948)	(6.0)
2 .	ADJUSTMENTS: PRIOR PERIOD ADJ	0.00	0	0	0.0	0.00	0	0	0.0
2a.	TRUE UP PROVISION	23,171,068.79	(1,970,025)	25,141,094	(1,276.2)	(1,500,793.79	(23,640,300)	25,141,094	(106.4)
2b.	INCENTIVE PROVISION	(22,242.17)	(22,246)	4	(0.0)	(266,917.92)	(266,919)	1	0.0
2c.	OTHER: MARKET PRICE TRUE UP	0.00	0	0	0.0	0.00	0	0	0.0
3 .	TOTAL JURISDICTIONAL FUEL REVENUE	93,249,306.60	74,455,980	18,793,327	25.2	936,391,659.43	972,855,513	(34,463,854)	(3.5)
4 .	ADJ TOTAL FUEL & NET PWR TRNS (LINE A7)	72,700,785.14	77,797,548	(5,096,763)	(6.6)	991,315,297.44	994,172,811	(2,857,514)	(0.3)
5 .	JURISDICTIONAL SALES % OF TOT SALES (LINE C4)	98.07	97.57	0.50	0.5				
6 .	JURISDICTIONAL FUEL & NET POWER TRANSACTIONS (LINE D4 * LINE D5 * .235% "LINE LOSSES")	71,465,209.49	76,293,882	(4,828,673)	(6.3)	970,220,678.11	972,856,464	(2,635,786)	(0.3)
7 .	TRUE UP PROVISION FOR THE MONTH OVER(UNDER) COLLECTION (LINE D3 - D6)	21,784,097.11	(1,837,902)	23,621,999	0.0	(31,829,018.68)	(951)	(31,828,068)	0.0
8 .	INTEREST PROVISION FOR THE MONTH (LINE E10)	(33,435.49)				143,306.29			
9 .	TRUE UP & INT PROVISION BEG OF MONTH/PERIOD	(30,265,305.18)				1,500,793.82			
10.	TRUE UP COLLECTED (REFUNDED)	(23,171,068.79)				(1,500,793.79)	23,640,300	(25,141,094)	0.0
11.	END OF PERIOD TOTAL NET TRUE UP (LINES D7 + D8 + D9 + D10)	(31,685,712.35)				(31,685,712.54)			
12.	OTHER:								
					0.19				
13.	END OF PERIOD TOTAL NET TRUE UP (LINES D11 + D12)	(31,685,712.35)				(31,685,712.54)			

Docket No. 030001-EI
Exhibit JWR-2 (Page 8 of 8)
Fuel Adjustment Audit Report

DOCKET NO. 030001-EI: Fuel and purchased power cost recovery clause and generating performance incentive factor.

WITNESS: **Direct Testimony Of Joseph W. Rohrbacher,** Appearing On Behalf Of Staff

EXHIBIT: JWR-3 - 2002 Capacity Cost Recovery Clause Audit

FLORIDA PUBLIC SERVICE COMMISSION

DIVISION OF AUDITING AND SAFETY
BUREAU OF AUDITING

TAMPA DISTRICT OFFICE

PROGRESS ENERGY FLORIDA
(FORMERLY FLORIDA POWER CORPORATION)

CAPACITY COST RECOVERY AUDIT

FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2002

DOCKET NO. 030001-EI

AUDIT CONTROL NO. 03-036-2-2

Thomas E. Stambaugh, Audit Manager

Joseph W. Rohrbacher, Audit Staff

James A. McPherson, Tampa District Supervisor

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DIVISION OF AUDITING AND SAFETY
AUDITOR'S REPORT

March 5, 2003

TO: FLORIDA PUBLIC SERVICE COMMISSION AND OTHER INTERESTED PARTIES

We have applied the procedures described later in this report to audit the accompanying Capacity Cost Recovery Clause True-up schedules for the historical twelve month period ended December 31, 2002 for Progress Energy Florida, formerly Florida Power Corporation (FPC). These schedules were prepared by the Utility as part of its petition for cost recovery in Docket 030001-EI. There is no confidential information associated with this audit, and there are no audit staff minority opinions.

This is an internal accounting report prepared after performing a limited scope audit. Accordingly, this report should not be relied upon for any purpose except to assist the Commission staff in the performance of their duties. Substantial additional work would have to be performed to satisfy generally accepted auditing standards and produce audited financial statements for public use.

SUMMARY OF SIGNIFICANT PROCEDURES

Our audit was performed by examining, on a test basis, certain transactions and account balances which we believe are sufficient to base our opinion. Our examination did not entail a complete review of all financial transactions of the company. Our more important audit procedures are summarized below. The following definitions apply when used in this report:

Compiled - The exhibit amounts were reconciled with the general ledger, and accounts were scanned for error or *inconsistency*.

Verify - The item was tested for accuracy, and substantiating documentation was examined.

REVENUE: Compiled CCR revenue and agreed to the filing. Recomputed CCR revenues using approved FPSC rate factors and company-provided KWH sales. Reconciled Utility "revenue recap" report to the general ledger on a test basis.

EXPENSES: Performed analysis of capacity costs based on prior years charges and verified variances. Compiled capacity costs. Agreed capacity costs to FPC billing statements. Performed audit test work of capacity cost payments to verify that Qualifying Facilities were paid according to contract for electric power supplied to the utility. Reconciled capacity charges to the General Ledger.

TRUE-UP: Recomputed CCRC true-up and interest using FPSC approved amounts and interest rates.

OTHER: Verified that security costs recovered in the capacity clause are incremental to the security costs included in base rates.

Disclosure No. 1

Subject: **Security Costs**

Statement of Fact: The Nuclear Regulatory Commission (NRC) issued Order No. EA-02-026, dated February 25, 2002, requiring electric utilities to implement certain security measures as a result of the September 11, 2001 attacks.

Progress Energy Florida (formerly Florida Power Corporation) recorded $9,114,435 for security expenses on its books and records for 2001. In our audit of the 2001 base year costs, we determined this amount was overstated by $921,509 and should be $8,192,926. The utility incurred $14,118,094 of security expenses in 2002, an increase of $5,925,168 over the base year amount. The Utility is seeking to recover only $4,831,124 in its 2002 Capacity Cost Recovery filing.

Audit Opinion: The 2002 incremental security expenses of $4,831,124 were a result of the utility's compliance with NRC Order No. EA-02-026 and are properly recovered through the Capacity Cost Recovery Clause.

FLORIDA POWER CORPORATION
CAPACITY COST RECOVERY CLAUSE
TRUE-UP CALCULATION

FOR THE PERIOD JANUARY 2002 THROUGH DECEMBER 2002

Florida Power Corporation
Docket 020001-EI
Witness: Scardino

Exhibit No (JS-2)
Sheet 2 of 3

	Description	2002 JANUARY	2002 FEBRUARY	2002 MARCH	2002 APRIL	2002 MAY	2002 JUNE	2002 JULY	2002 AUGUST	2002 SEPTEMBER	2002 OCTOBER	2002 NOVEMBER	2002 DECEMBER	(a) 12 Months Cumulative
	Base Production Level Capacity Charges:													
1	Auburndale Power Partners, LP (AUBROLAB)	0	0	0	0	0	0	0	0	0	0	0	0	$0
2	Auburndale Power Partners, LP (AUBROLFC)	394,350	419,050	419,050	419,050	419,050	419,050	419,050	419,050	419,050	419,050	419,050	419,050	$5,009,760
3	Auburndale Power Partners, LP (AUBSET)	1,882,798	2,080,880	2,080,880	2,080,880	2,080,880	2,080,880	2,080,880	2,080,880	2,080,880	2,080,880	2,080,880	2,080,880	$24,974,575
4	Bay County (BAYCOUNT)	184,760	205,910	205,910	205,910	205,910	205,910	205,910	205,910	205,910	205,910	205,910	205,910	$2,470,710
5	Cargill Fertilizer, Inc (CARGILLF)	412,080	432,780	432,780	432,780	432,780	432,780	432,780	432,780	432,780	432,780	432,780	432,780	$5,172,360
6	Central Power & Lime (PLACRUSH)	16,800	16,800	16,940	16,800	16,800	0	0	0	0	0	0	0	$99,220
7	Chiles World	0	0	0	0	0	0	0	0	0	0	0	0	$0
8	Jefferson Power LC (JEFFPOWER)	0	0	0	0	0	0	0	128,000	66,848	66,848	66,848	66,848	$574,841
9	Lake Cogen (LAKCOGNT)	388,885	392,885	388,888	388,885	388,885	388,885	392,885	392,885	392,885	392,885	392,885	392,885	$4,692,188
10	Lake Cogen Limited (LAKECOGL)	2,889,277	2,811,880	2,808,434	2,808,887	2,808,888	2,808,888	2,808,870	2,188,487	2,182,888	2,088,887	2,167,878	2,164,884	$28,881,204
11	Metro-Dade County (METRDADE)	757,887	811,418	765,887	767,888	885,122	765,848	765,888	744,878	748,887	783,840	748,840	778,817	$9,248,192
12	Metro-Dade County (METRDAB)	0	0	0	0	0	0	0	0	0	0	0	0	$0
13	Orange Cogen (ORANGEAS)	0	0	0	0	0	0	0	0	0	0	0	0	$0
14	Orange Cogen (ORANGECO)	1,796,040	1,873,889	1,873,889	1,873,889	1,873,889	1,873,889	1,873,889	1,873,889	1,873,889	1,873,889	1,873,889	1,873,889	$22,387,803
15	Orlando Cogen Limited (ORLACOGL)	1,584,957	1,888,182	1,888,182	1,888,182	1,888,182	1,888,182	1,888,182	1,888,182	1,888,182	1,888,182	1,888,351	1,888,182	$18,886,287
16	Orlando Cogen Limited (ORLACOGAS)	0	0	0	0	0	0	0	0	0	0	0	0	$0
17	Pasco Cogen Limited (PASCOGL)	2,778,800	2,937,446	2,937,446	2,937,446	2,937,446	2,937,446	2,937,446	2,937,446	2,937,446	2,937,446	2,937,446	2,937,446	$34,761,727
18	Pasco County Resource Recovery (PASCOUNT)	688,840	708,880	708,880	708,880	708,880	708,880	708,880	708,880	708,880	708,880	708,880	708,880	$8,484,000
19	PCS Phosphate (DCSWPCRR)	0	0	0	0	0	0	0	0	0	0	0	0	$0
20	PCS Phosphate (DCSWHSPRR)	0	0	0	0	0	0	0	0	0	0	0	0	$0
21	Perpetual Energy (PPETUAL)	0	0	0	0	0	0	0	0	0	0	0	0	$0
22	Pinellas County Resource Recovery (PINCOUNT)	1,888,888	1,887,388	1,887,388	1,887,388	1,887,388	1,887,388	1,887,388	1,887,388	1,887,388	1,887,388	1,887,388	1,887,388	$20,148,000
23	Polk Power Partners, L P (MULBERY)	2,338,000	2,338,911	2,338,911	2,338,911	2,338,911	2,338,911	2,332,461	1,832,888	1,818,888	1,881,548	1,884,402	1,878,783	$25,150,537
24	Polk Power Partners, L P (ROYSTER)	824,804	888,887	888,887	888,887	888,887	888,887	888,887	778,948	778,874	767,908	761,985	761,488	$9,774,753
25	St Joe Forest Products (ST JOSFOR)	0	0	0	0	0	0	0	0	0	0	0	0	$0
26	Tiger Bay Limited Partnership (RIOPEAT)	1,180,133	1,180,133	1,180,133	1,180,133	1,180,133	1,180,133	1,180,133	1,180,133	1,180,133	1,180,133	1,180,133	1,180,133	$13,921,996
27	Tiger Bay Limited Partnership (SENPEAT)	4,228,940	4,228,940	4,228,940	4,228,940	4,228,940	4,228,940	4,228,940	4,228,940	4,228,940	4,228,940	4,228,940	4,228,940	$50,764,280
28	Tiger Bay Limited Partnership (TIMBER3)	147,500	147,500	147,500	147,500	147,500	147,500	147,500	147,500	147,500	147,500	147,500	147,500	$1,774,000
29	Timber Energy Resources, Inc (TIMBER)	388,780	388,780	388,780	388,780	41,888	41,888	41,888	41,888	41,888	41,888	41,888	41,888	$2,747,188
30	U S Agri-Chemicals (AGRICHEM)	39,388	40,880	41,888	41,888	744,888	738,888	737,295	744,715	750,388	745,048	704,128	747,882	$8,975,079
31	Wheelabrator Ridge Energy, Inc. (RIDGEGEN)	764,280	788,812	783,983	787,870	748,382	738,888	(88,887)	(88,887)	(88,887)	(88,887)	(88,887)	(88,887)	($1,158,004)
32	Tiger Bay (EcoPost lease credit)	(88,887)	(88,887)	(88,887)	(416,887)	(88,887)	(88,887)	0	0	0	0	0	0	$0
33	UPS Purchase (469 total mw)	2,888,838	3,808,481	2,737,287	3,888,883	3,848,888	3,788,884	3,888,784	4,884,884	8,711,885	3,888,448	3,888,388	4,881,184	4,881,184
34	Incremental Security Costs (5880001 & 5840001)	0	0	0	0	0	0	0	0	0	0	0	0	$0
35	Subtotal - Base Level Capacity Charges	28,883,448	29,180,287	28,884,441	28,708,974	28,448,788	28,488,188	27,884,787	28,888,748	28,188,884	28,141,888	28,148,388	33,188,188	344,282,865
36	Base Production Jurisdictional Responsibility	88.887%	88.887%	88.887%	88.887%	88.887%	88.887%	88.887%	88.887%	88.887%	88.887%	88.887%	88.887%	100.000%
37	Base Level Jurisdictional Capacity Charges	25,318,781	25,818,888	27,882,188	27,848,478	27,288,708	27,287,883	28,884,488	27,287,881	28,880,888	27,813,484	27,811,887	31,841,888	330,304,712
	Intermediate Production Level Capacity Charges:													
38	TECO Power Purchase (80 mw)	888,887	888,887	888,887	888,887	888,887	888,887	888,887	888,887	888,887	888,887	888,887	888,887	$8,788,884
39	Schedule H Capacity Sales	(8,888)	(8,477)	(3,888)	(3,388)	(3,888)	(3,477)	(8,888)	(3,888)	(3,888)	(8,477)	(3,888)	(3,888)	($48,484)
40	FPSL , Ready Cit	0	0	0	0	0	0	0	0	0	0	0	0	$0
41	Subtotal - Intermediate Level Capacity Charges	882,888	888,888	882,172	881,874	882,888	881,874	881,874	881,874	882,888	881,874	882,888	881,874	8,741,320
42	Intermediate Production Jurisdict. Responsibility	88.874%	88.874%	88.874%	88.874%	88.874%	88.874%	88.874%	88.874%	88.874%	88.874%	88.874%	88.874%	88.888%
43	Intermediate Level Jurisdict. Capacity Charges	488,887	488,888	488,887	488,888	488,888	488,824	488,888	488,884	488,884	488,884	488,884	488,888	5,888,888
44	Peaking Production Level Capacity Charges	88,888	88,888	0	0	0	0	0	142,788	0	0	0	734,887	988,887
45	Solomy Base Rate Credits	(414,781)	(288,888)	(321,882)	(328,288)	0	0	0	0	0	0	0	0	(1,288,881)
46	Adjustments - 2001 FPSC AUDIT				(2,282)								(887,882)	(2,282)
47	Retail Wheeling	(188,848)	(43,888)	(148,342)	(88,888)	(38,881)	(15,878)	(14,888)	(8,882)	(124,818)	(41,838)	(377,708)	(887,882)	(1,438,888)
48	Jurisdictional Capacity Charges	27,888,888	28,218,888	27,848,888	27,888,218	27,748,248	27,778,128	27,388,887	27,387,488	27,388,874	27,488,118	27,128,888	33,704,447	334,878,881
49														
50	Capacity Cost Recovery Revenues (net of tax)	27,888,888	22,780,888	28,448,888	24,884,818	28,748,180	28,818,288	32,884,181	88,887,887	88,881,881	28,888,883	28,888,318	88,881,885	341,888,842
51	Capacity Cost Revenues Adjustment (Net of Tax)	(888,848)	(888,848)	(888,848)	(888,848)	(888,848)	(888,848)	(888,848)	(888,848)	(888,848)	(888,848)	(888,848)	(8,888,887)	(11,488,888)
52	Prior Period True-Up Provision													
53	Current Period Capacity Cost Recovery Revenues (net of tax) (Sum of lines 48 through 49)	27,848,888	22,488,881	28,181,818	23,744,874	28,488,888	28,788,811	31,744,817	31,887,888	88,872,887	28,814,888	28,888,888	88,184,888	330,188,888
54	True-Up Provision - Over/(Under) Recovery (line 49 - line 48)	2,284,284	(8,781,708)	(8,788,888)	(8,848,888)	2,888,488	888,778	4,448,188	8,888,888	8,718,818	8,888,448	1,878,888	(14,888,811)	(4,211,888)
55	Interest Provision for the Month	(88,188)	(87,178)	(84,888)	(82,818)	(88,748)	(87,888)	(4,188,887)	(88,178)	(2,811)	(2,187)	1,348	(1,888)	(188,178)
56	Current Cycle Balance (line 50 + line 51) Cumulative	2,888,181	(8,888,788)	(8,878,871)	(13,182,888)	(8,488,888)	(8,888,718)	(11,488,888)	(11,488,888)	(11,488,888)	(11,488,888)	(11,488,888)	(11,488,888)	
57	True-Up & Interest Provision (beginning)	(11,488,888)	(11,488,888)	(11,488,888)	(11,488,888)	(11,488,888)	(11,488,888)	(11,488,888)	(11,488,888)	(11,488,888)	(11,488,888)	(11,488,888)	(11,488,888)	
58	Prior Period True-Up Collected/(Refunded) Cumulative	888,844	818,888	188,888	1,287,287	1,848,822	1,888,888	2,888,818	2,874,784	2,784,888	2,888,448	8,482,787	11,488,888	
59	Other	0	0	0	0	0	0	0	0	0	0	0	0	
60	End of Period Net True-Up (lines 55 through 59) Over / (Under)	(88,881,181)	($14,488,781)	($18,844,884)	($22,414,788)	($18,848,748)	($18,887,888)	($18,888,778.08)	($8,888,878)	($8,888,188)	$184,488	$2,888,784	($4,488,188)	$0

Docket No. 020001-EI
Exhibit JWR-3 (Page 6 of 6)
Capacity Cost Audit Report

DOCKET NO. 030001-EI: Fuel and purchased power cost recovery clause and generating performance incentive factor.

WITNESS: **Supplemental Direct Testimony Of Joseph W. Rohrbacher,** Appearing On Behalf Of Staff

EXHIBIT: JWR-4 - Progress Energy Florida, Inc. Waterborne Transportation Cost Audit

FLORIDA PUBLIC SERVICE COMMISSION

DIVISION OF AUDITING AND SAFETY
BUREAU OF AUDITING

TAMPA DISTRICT OFFICE

PROGRESS ENERGY FLORIDA
(FORMERLY FLORIDA POWER CORPORATION)

WATERBORNE TRANSPORTATION AUDIT

FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2002

DOCKET NO. 030001-EI

AUDIT CONTROL NO. 03-045-2-1

Joseph W. Rohrbacher, Audit Manager

James A. McPherson, Tampa District Supervisor

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DIVISION OF AUDITING AND SAFETY
AUDITOR'S REPORT

MAY 5, 2003

TO: FLORIDA PUBLIC SERVICE COMMISSION AND OTHER INTERESTED PARTIES

We have applied the procedures described later in this report to determine the difference between the 2002 benchmark price paid by Progress Energy Florida (PEF) for waterborne coal transportation service and the actual cost of providing the service by Progress Fuels Corporation (PFC) for the historical twelve month period ended December 31, 2002. The attached schedules were prepared by the auditor as part of our work in Docket No. 030001-EI. There is confidential information associated with this audit.

This is an internal accounting report prepared after performing a limited scope audit. Accordingly, this report should not be relied upon for any purpose except to assist the Commission staff in the performance of their duties. Substantial additional work would have to be performed to satisfy generally accepted auditing standards and produce audited financial statements for public use.

SUMMARY OF SIGNIFICANT FINDINGS

Progress Energy Florida purchases coal and other related fuels for the production of electricity from Progress Fuels Corporation, an affiliate company under Progress Energy, Inc. Progress Fuels Corporation, in turn, purchases some of the coal and transportation services from other affiliate companies.

SUMMARY OF SIGNIFICANT PROCEDURES

Our audit was performed by examining, on a test basis, certain transactions and account balances which we believe are sufficient to base our opinion. Our examination did not entail a complete review of all financial transactions of the company. Our more important audit procedures are summarized below. The following definitions apply when used in this report:

Compiled - The exhibit amounts were reconciled with the general ledger, and accounts were scanned for error or inconsistency.

Verify - The item was tested for accuracy, and substantiating documentation was examined.

Work Performed: Determined the relationship of the companies involved in procuring fuel for Progress Energy Florida's Crystal River power plant. Read contracts for fuel purchases and waterborne transportation services and verified invoice prices to contract amounts. Tested randomly selected items for same. Reconciled coal purchases by Progress Energy Florida (PEF) to coal sales of Progress Fuels Corporation (PFC). Verified that the pricing for the waterborne transportation services provided by PFC to PEF was in compliance with the market pricing mechanism authorized by Commission Order No. PSC-93-1331-FOF-EI. Calculated the average waterborne transportation costs for PFC and PEF. Read PFC coal pricing procedures to PEF. Scheduled responses to Request For Proposal for bids on coal purchases by PFC. Verified that General and Administrative expenses included in the price computation of PFC for procuring and transporting fuel to PEF's Crystal River plant were consistent with the agreements. Tested randomly selected G&A expenses to verify same.

DISCLOSURES

Disclosure No. 1

Subject: Affiliate Companies

Progress Energy Florida (PEF) purchases coal and other related fuels for the production of electricity from Progress Fuels Corporation (PFC), an affiliate company under Progress Energy, Inc.

Progress Fuels Corporation purchases the coal and other related fuels from various suppliers. In 2002 the bulk of these purchases were from Black Hawk Synfuel LLC, Marmet Synfuel LLC, and New River Synfuel LLC. All of these companies are affiliates under Progress Energy, Inc.

The fuel is trucked from the mines to an upriver terminal by Kanawha River Terminals, Inc. (KRT), for transloading to river barges which will transport the fuel down river to the New Orleans, Louisiana area. From here the coal will be shipped across the Gulf of Mexico to PEF's Crystal River complex by Dixie Fuels Limited.

KRT and Dixie Fuels are also affiliates of PEF under Progress Energy, Inc.

Disclosure No. 2

Subject: Coal Purchases

Statement of Fact:

Progress Fuels Corporation (PFC) purchases its coal from various suppliers and through its affiliates acting as agents. The per ton coal prices reviewed ranged from $[redacted] per ton from Pen Coal Corporation, a non-affiliated entity, under a contract originating in 1998 to $[redacted] per ton from Black Hawk Synfuel, an affiliated company, under a 2001 contract. The coal specifications in both contracts were similar.

In May 2001 PFC issued a Request For Proposal for bids on 2002 coal purchases. Progress Fuels Corporation has contracts with its suppliers, setting the prices and terms of delivery. The prices under the contracts reviewed varied but all were FOB dock..

The waterborne coal purchased by PEF is blended with different per ton costs at the terminals upriver or in New Orleans, Louisiana prior to loading and shipment on barges to Crystal River. PFC accrues the coal inventory and computes an average cost per ton, including transportation costs, when billing PEF.

Auditor Opinion:

The cost to PFC is at the contracted price. In reviewing the invoices for PFC from its suppliers, the auditor noted that prior to delivery to PEF a portion of the invoice cost is charged to "non-regulated" operations with the remainder charged to PEF. The utility spokesperson stated this non regulated portion was for the trucking of the coal from the mine to the KRT dock. This adjustment recognizes that the proxy price for transportation, in accordance with Order No. PSC-93-1331-FOF-EI, includes the cost from the mine to the generating plant .

Disclosure No. 3

Subject: Waterborne Transportation Cost

Statement of Fact:

Commission Order No. PSC-93-1331-FOF-EI authorized a market pricing mechanism for water borne transportation services provided by Electric Fuels Corporation (now called Progress Fuels Corporation) to Florida Power Corporation (now Progress Energy Florida). The base price of $23.00 per ton was effective January 1, 1993 adjusted January 1 of each year, thereafter, using a composite index approved by the Commission. Based on the escalation, the rate charged by PFC to PEF for 2002 was $[redacted] per ton. PFC estimates that $[redacted] of this amount relates to transportation from the mine to the Gulf terminal and $[redacted] is for transportation across the Gulf to Crystal River.

The market price for PFC's deliveries cover the transportation components from the coal mine to the Crystal River plant site. This includes short-haul rail/truck transportation from the mine to the up-river dock, up-river barge transloading, river barge transportation, Gulf barge transloading, Gulf barge transportation and transportation to the Crystal River plant, as well as other charges, such as port fees and assist tug.

Auditor Opinion:

We determined the average cost of waterborne transportation for Progress Fuels Corporation for 2002 was $[redacted] based on company records.

The companies providing transportation from the mines to the up-river dock and transloading to river barges and Gulf barge transportation to Crystal River is provided by Kanawha River Terminals, Inc. and Dixie Fuels Limited, both affiliated companies. Since the contracts were not put out for bid, we are unable to determine if the costs reflect a true market price.

Market proxy charged to PEF	$[redacted]
Average direct cost for PFC	[redacted]
Gross Profit	$[redacted]

DOCKET NO. 030001-EI: Fuel and purchased power cost recovery clause and generating performance incentive factor.

WITNESS: **Supplemental Direct Testimony Of Joseph W. Rohrbacher,** Appearing On Behalf Of Staff

EXHIBIT: JWR-5 - Selected Audit Work Papers from the Progress Energy Florida, Inc. Waterborne Transportation Cost Audit

Exhibit JWR-5
List of Selected Audit Work Papers from the Progress Energy Florida, Inc. Waterborne Transportation Audit
Docket No. 030001-EI
Audit Control No. 03-045-2-1

Workpaper Title	Staff Workpaper Number	Company Workpaper Number
PFC Income Statement Jan-Jun 2002	2A , 5 pages	3-7
PFC Income Statement Jul-Dec 2002	2B , 5 pages	8-12
Summary Transportation Contracts	42, 42-1	33, 34
Coal Purchase Contracts	42-2, 2 pages	35, 36
Waterborne Transportation Contracts	42-3, 5 pages	39-43
Dixie Fuels - Crew Cost & Insurance Adjustment	42-3/1	44
Inventory Accrual	45-1, 12 pages	50-61
Average Transportation Costs	45-3	71
Adjustment for Mine to Dock Trucking	46-3	75
Average Coal & Transportation Charges to PEF	47-1	79
Coal Solicitation Proposals	47-2	80
Analysis of the Escalation of the costs of Waterborne Coal Transportation	48	81
Utility Calculation of the Transportation Rate	48-1	82

PROGRESS FUELS CORPORATION
INCOME STATEMENT DETAIL
FOR THE PERIOD ENDED DECEMBER 31, 2002
EFC REGULATED SUMMARY

REPORT ID: DELIST
UNIT CODE: R

	ACCOUNT NUMBER	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
INCOME -							
COAL SALES	3000-100						
REVENUE ADJUSTMENT	3000-400						
TOTAL OPERATING REVENUES	OPERREV						
EQUITY EARNINGS -							
OTHER INCOME							
INTEREST INCOME - LOCOMOTIVES	4230-030						
TOTAL INTEREST INCOME							
GAIN/(LOSS) ON DISPOSAL ASSET	4300-200						
MISCELLANEOUS INCOME	MISCINC						
TOTAL REVENUES	REVENUES						
EXPENSES -							
COAL COGS - INVENTORY	5310-010						
COAL COGS - PRICE ADJUSTMENT	5310-020						
COAL COGS - PRICE ADJ. P/P	5310-025						
COAL COGS - TONNAGE ADJ	5310-050						
COAL COGS - OTHER COST	5310-100						
COAL COGS - QUALITY ADJUSTMENT	5310-110						
COAL COGS - QUALITY ANALYSIS	5310-120						
COAL COST OF GOODS SOLD	COALCOGS						
RAIL COGS - INVENTORY	5320-010						
RAIL COGS - PRICE ADJUSTMENT	5320-020						
RAIL COGS - PRICE ADJ P/P	5320-025						
COGS - RAIL - OTHER COST	5320-100						
COGS-WATER TRANSPORTATION	5360-010						
FREIGHT COST OF GOODS SOLD	FRTCOST						

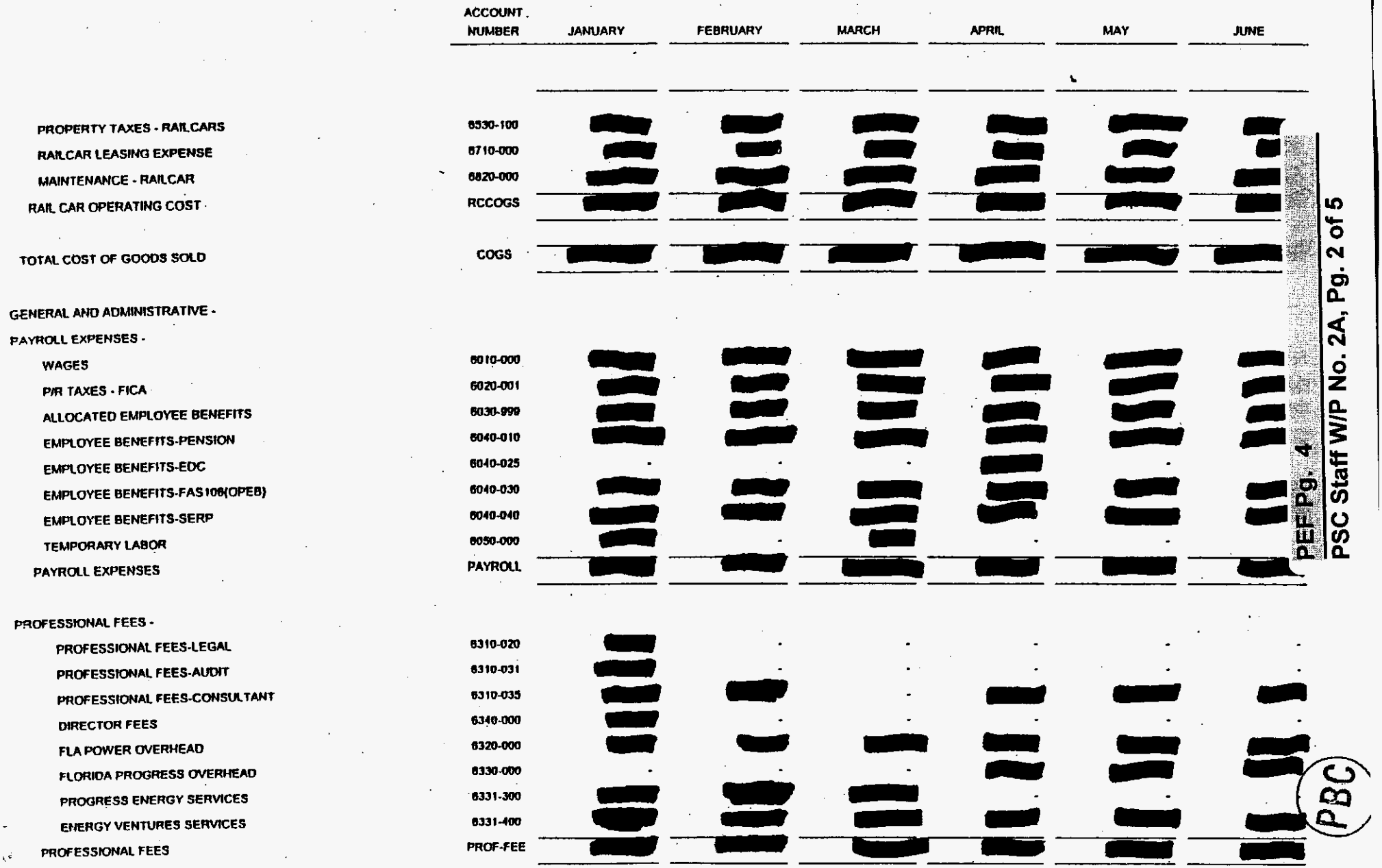
PEF Pg. 3
PSC Staff W/P No. 2A, Pg. 1 of 5

PBC

Docket No. 030001-EI
Exhibit JWR-5 (Page 3 of 39)
Selected Audit Work Papers

PROGRESS FUELS CORPORATION
INCOME STATEMENT DETAIL
FOR THE PERIOD ENDED DECEMBER 31, 2002
EFC REGULATED SUMMARY

REPORT ID: DELI
UNIT CODE:



	ACCOUNT NUMBER	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
PROPERTY TAXES - RAILCARS	6530-100						
RAILCAR LEASING EXPENSE	6710-000						
MAINTENANCE - RAILCAR	6820-000						
RAIL CAR OPERATING COST	RCCOGS						
TOTAL COST OF GOODS SOLD	COGS						
GENERAL AND ADMINISTRATIVE -							
PAYROLL EXPENSES -							
WAGES	6010-000						
P/R TAXES - FICA	6020-001						
ALLOCATED EMPLOYEE BENEFITS	6030-999						
EMPLOYEE BENEFITS-PENSION	6040-010						
EMPLOYEE BENEFITS-EDC	6040-025						
EMPLOYEE BENEFITS-FAS106(OPEB)	6040-030						
EMPLOYEE BENEFITS-SERP	6040-040						
TEMPORARY LABOR	6050-000						
PAYROLL EXPENSES	PAYROLL						
PROFESSIONAL FEES -							
PROFESSIONAL FEES-LEGAL	6310-020						
PROFESSIONAL FEES-AUDIT	6310-031						
PROFESSIONAL FEES-CONSULTANT	6310-035						
DIRECTOR FEES	6340-000						
FLA POWER OVERHEAD	6320-000						
FLORIDA PROGRESS OVERHEAD	6330-000						
PROGRESS ENERGY SERVICES	6331-300						
ENERGY VENTURES SERVICES	6331-400						
PROFESSIONAL FEES	PROF-FEE						
BUILDING & OFFICE EXPENSE -							

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PROGRESS FUELS CORPORATION
INCOME STATEMENT DETAIL
FOR THE PERIOD ENDED DECEMBER 31, 2002
EFC REGULATED SUMMARY

REPORT ID: DELIS
UNIT CODE: R

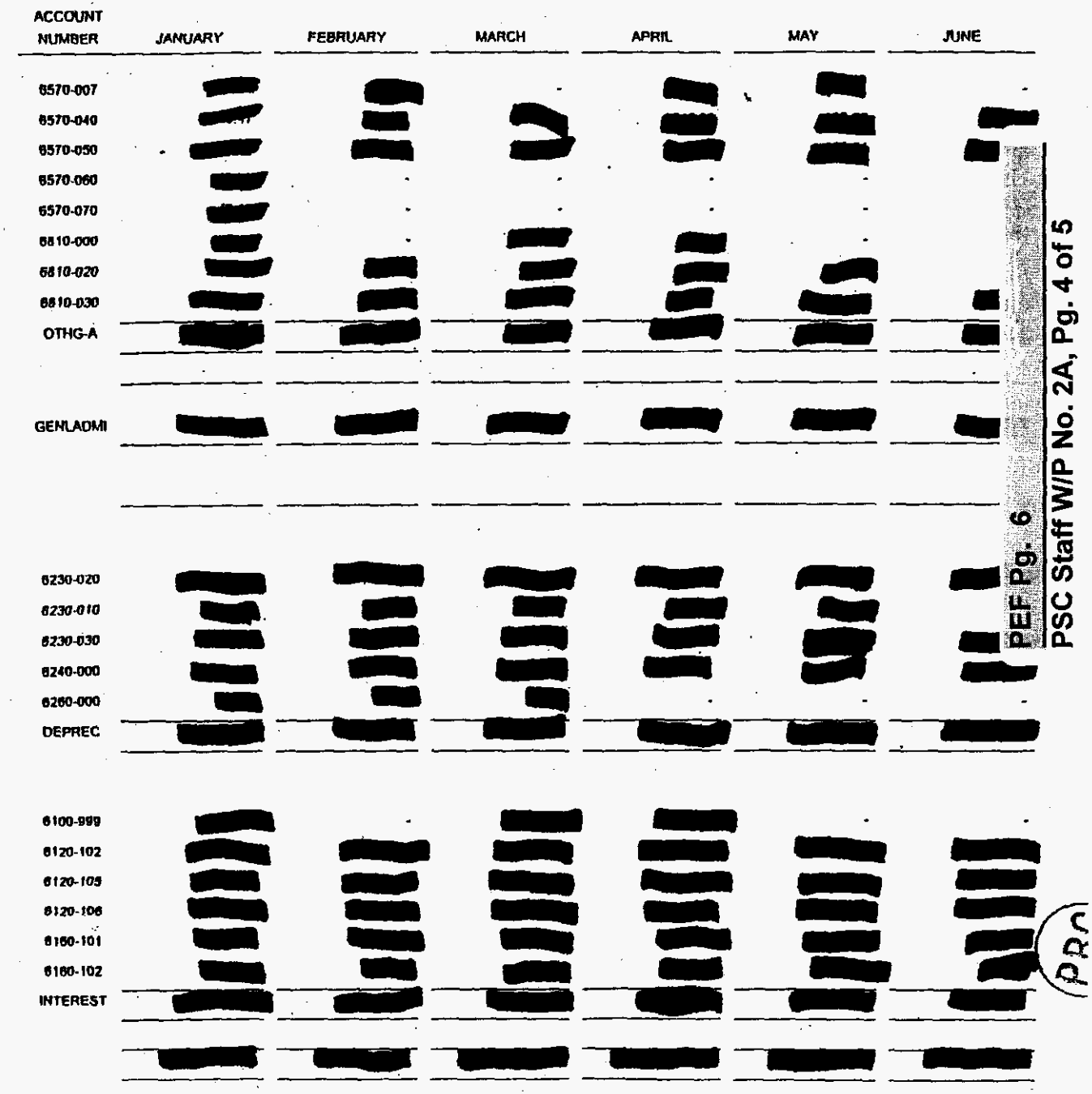
	ACCOUNT NUMBER	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
RENT EXPENSE	6410-000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BUILDING SERVICES	6420-000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
UTILITIES	6430-000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OFFICE SERVICES	6440-005	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OFFICE SUPPLY - GENERAL	6440-010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OFFICE SUPPLY - SUPPLIES	6440-020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OFFICE SUPPLY - COPY RENTAL	6440-025	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SUBSCRIPTION & PUBLICATIONS	6440-030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OFFICE SUPPLY - EQUIPMENT	6440-040	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OFFICE SUPPLY-DATA PROCESSING	6440-050	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
BUILDING & OFFICE EXPENSE	BUILD-OF	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OTHER GENERAL & ADMINISTRATIVE -							
EXPENSE ACCT & TRAVEL - TAX	6510-100	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NONTAX MEALS/ENTERTAINMENT	6510-210	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
NONTAXABLE OTHER	6510-220	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
CORPORATE AIRCRAFT EXPENSE	6510-225	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
INSURANCE EXPENSE	6520-000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EXCESS LIABILITY INSURANCE	6520-010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OFFICER & DIRECTOR LIAB. INS.	6520-011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PROPERTY & CRIME INSURANCE	6520-013	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MARINE CARGO INSURANCE	6520-014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PROPERTY TAX REAL ESTATE	6530-200	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
LICENSES	6540-000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
OTHER TAXES	6550-000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EMPLOYEE DEVELOPMENT	6560-000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
SEMINARS	6560-010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TUITION REIMBURSEMENT	6560-015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
PROFESSIONAL AFFILIATIONS	6560-020	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EMPLOYMENT - ADVERTISING	6565-010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EMPLOYMENT - MOVING EXPENSE	6565-030	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
EMPLOYMENT - MISC EXPENSE	6565-040	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
MISCELLANEOUS EXPENSE	6570-000	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

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PROGRESS FUELS CORPORATION
INCOME STATEMENT DETAIL
FOR THE PERIOD ENDED DECEMBER 31, 2002
EFC REGULATED SUMMARY

REPORT ID: DELI
UNIT CODE:



	ACCOUNT NUMBER	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
MISC EXPENSE - RECORD STORAGE	6570-007						
AUTO OPERATING EXPENSE	6570-040						
AUTO EXPENSE REIMBURSEMENTS	6570-050						
CONTRIBUTION	6570-060						
PENALTIES	6570-070						
MAINTENANCE - GENERAL	6810-000						
MAINTENANCE - AUTO	6810-020						
MAINTENANCE - DP EQUIPMENT	6810-030						
OTHER GENERAL & ADMINISTRATION	OTHG-A						
TOTAL GENERAL & ADMINISTRATION	GENLADMI						
OTHER EXPENSES -							
DEPRECIATION EXPENSES -							
DEPRECIATION - RAILCARS	6230-020						
DEPRECIATION - EQUIPMT GENERAL	6230-010						
DEPRECIATION - DP EQUIPMENT	6230-030						
DEPRECIATION - FURN & FIXTURES	6240-000						
AMORTIZATION - LEASEHOLDS	6260-000						
DEPRECIATION EXPENSES	DEPREC						
INTEREST EXPENSE -							
ALLOCATION INTEREST EXPENSE	6100-999						
INTEREST EXPENSE - PCH MTN	6120-102						
INTEREST EXPENSE - PEC LINE	6120-105						
INTEREST EXPENSE - PEC L/T NOTE PAY	6120-106						
COMMITMENT FEE - PCH	6160-101						
COMMITMENT FEE - MTN	6160-102						
INTEREST EXPENSE	INTEREST						
TOTAL EXPENSES							

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PSC Staff W/P No. 2A, Pg. 4 of 5

PROGRESS FUELS CORPORATION
WATERBORNE TRANSPORTATION AUDIT
INCOME STATEMENT - JAN TO JUN 2002
12 MONTHS ENDED 12/31/02

PROGRESS FUELS CORPORATION
INCOME STATEMENT DETAIL
FOR THE PERIOD ENDED DECEMBER 31, 2002
EFC REGULATED SUMMARY

REPORT ID: DELISR01
UNIT CODE: REG

ACCOUNT NUMBER		JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
	INCOME BEFORE INCOME TAXES	[redacted]					
	PROVISION (BENEFIT) FOR INC TAXES -						
	CURRENT FIT - CURRENT YEAR						
	CURRENT FEDERAL INCOME TAXES						
6900-101	CUR-FED	[redacted]					
	CURRENT SIT - CURRENT YEAR						
	CURRENT STATE INCOME TAXES						
6900-111	CUR-STAT	[redacted]					
	DEFERRED FIT - CURRENT YEAR						
	DEFERRED FEDERAL INCOME TAXES						
6900-201	DEF-FED	[redacted]					
	DEFERRED SIT - CURRENT YEAR						
	DEFERRED STATE INCOME TAXES						
6900-211	DEF-STAT	[redacted]					
	REGULAR DEFERRED TAX CREDITS						
	INVESTMENT TAX CREDIT						
RDEFTC		[redacted]					
ITC							
	TOTAL INCOME TAXES						
TAXES		[redacted]					
	INCOME FROM CONTINUING OPERATIONS						
	NET INCOME	[redacted]					

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SOURCE: PEC
PBC

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PROGRESS FUELS CORPORATION
INCOME STATEMENT DETAIL
FOR THE PERIOD ENDED DECEMBER 31, 2002
EFC REGULATED SUMMARY

REPORT ID: DELIS
UNIT CODE:

	ACCOUNT NUMBER	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
INCOME -							
COAL SALES	3000-100						
REVENUE ADJUSTMENT	3000-400						
TOTAL OPERATING REVENUES	OPERREV						
EQUITY EARNINGS -							
OTHER INCOME							
INTEREST INCOME - LOCOMOTIVES	4230-030						
TOTAL INTEREST INCOME							
MISCELLANEOUS OTHER INCOME	4300-100						
GAIN/(LOSS) ON DISPOSAL ASSET	4300-200						
MISCELLANEOUS INCOME	MISCINC						
TOTAL REVENUES	REVENUES						
EXPENSES -							
COAL COGS - INVENTORY	5310-010						
COAL COGS - PRICE ADJUSTMENT	5310-020						
COAL COGS - TONNAGE ADJ	5310-050						
COAL COGS - OTHER COST	5310-100						
COAL COGS - QUALITY ADJUSTMENT	5310-110						
COAL COGS - QUALITY ANALYSIS	5310-120						
COAL COST OF GOODS SOLD	COALCOGS						
RAIL COGS - INVENTORY	5320-010						
RAIL COGS - PRICE ADJUSTMENT	5320-020						
RAIL COGS - PRICE ADJ P/P	5320-025						
COGS-WATER TRANSPORTATION	5380-010						
FREIGHT COST OF GOODS SOLD	FRTCOST						



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PSC Staff W/P No. 2B, Pg. 1 of 5

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PROGRESS FUELS CORPORATION
INCOME STATEMENT DETAIL
FOR THE PERIOD ENDED DECEMBER 31, 2002
EFC REGULATED SUMMARY

REPORT ID: DELI
UNIT CODE:

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	ACCOUNT NUMBER	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
PROPERTY TAXES - RAILCARS	6530-100						
RAILCAR LEASING EXPENSE	6710-000						
MAINTENANCE - RAILCAR	6820-000						
RAIL CAR OPERATING COST	RCCOGS						
TOTAL COST OF GOODS SOLD	COGS						
GENERAL AND ADMINISTRATIVE -							
PAYROLL EXPENSES -							
WAGES	6010-000						
P/R TAXES - FICA	6020-001						
ALLOCATED EMPLOYEE BENEFITS	6030-999						
EMPLOYEE BENEFITS-PENSION	6040-010						
EMPLOYEE BENEFITS-EOC	6040-025						
EMPLOYEE BENEFITS-FAS106(OPEB)	6040-030						
EMPLOYEE BENEFITS-SERP	6040-040						
TEMPORARY LABOR	6050-000						
PAYROLL EXPENSES	PAYROLL						
PROFESSIONAL FEES -							
PROFESSIONAL FEES-LEGAL	6310-020						
PROFESSIONAL FEES-AUDIT	6310-031						
PROFESSIONAL FEES-CONSULTANT	6310-035						
DIRECTOR FEES	6340-000						
FLA POWER OVERHEAD	6320-000						
FLA POWER SERVICE - OTHER	6320-090						
FLORIDA PROGRESS OVERHEAD	6330-000						
ENERGY VENTURES SERVICES	6331-400						
PROFESSIONAL FEES	PROF-FEE						
BUILDING & OFFICE EXPENSE -							
RENT EXPENSE	6410-000						

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PROGRESS FUELS CORPORATION
INCOME STATEMENT DETAIL
FOR THE PERIOD ENDED DECEMBER 31, 2002
EFC REGULATED SUMMARY

REPORT ID: DELIS
UNIT CODE: I

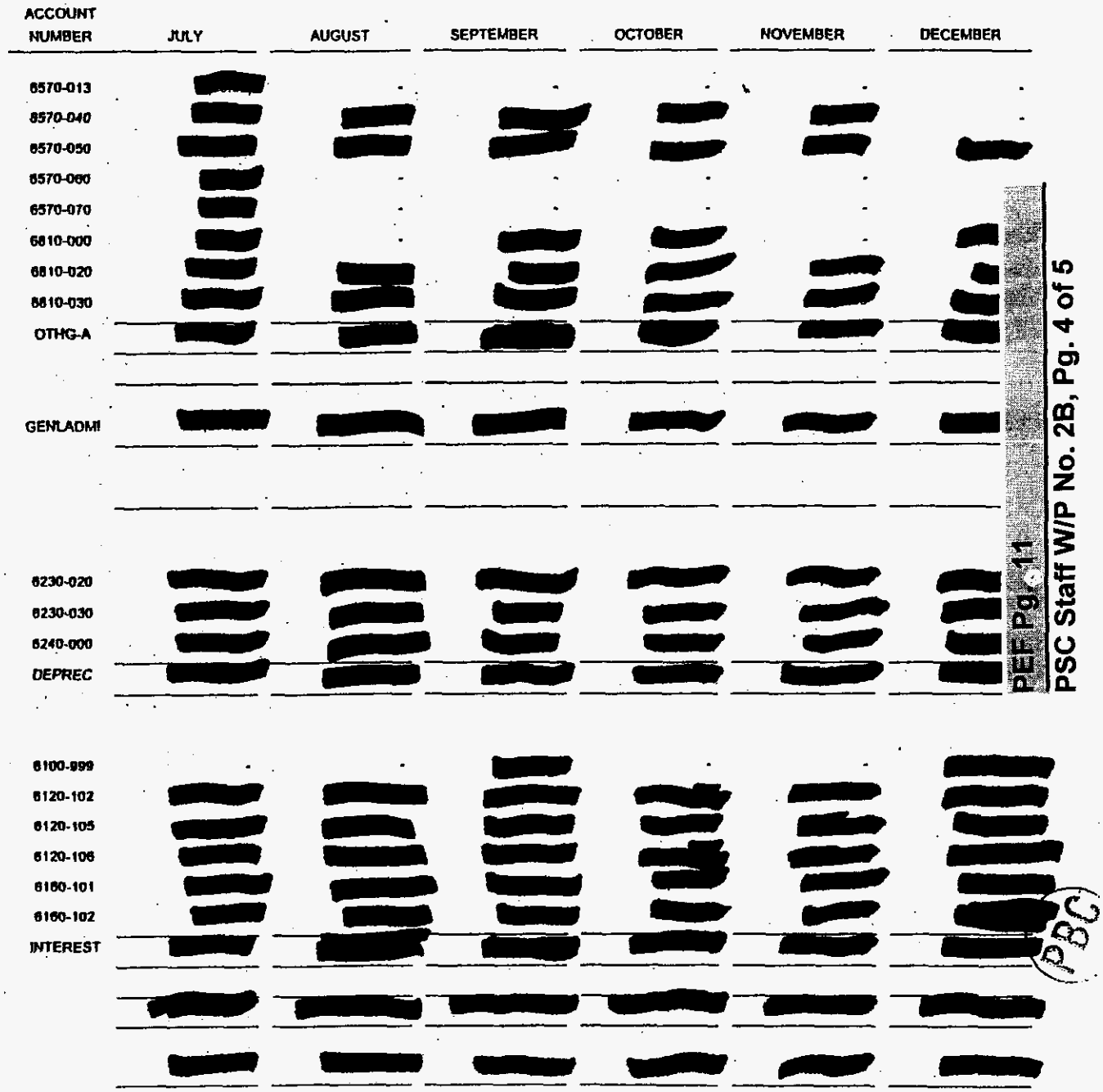
PEF Pg. 10
PSC Staff W/P No. 2B, Pg. 3 of 5

	ACCOUNT NUMBER	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
BUILDING SERVICES	6420-000						
UTILITIES	6430-000						
OFFICE SERVICES	6440-005						
OFFICE SUPPLY - GENERAL	6440-010						
OFFICE SUPPLY - SUPPLIES	6440-020						
OFFICE SUPPLY - COPY RENTAL	6440-025						
SUBSCRIPTION & PUBLICATIONS	6440-030						
OFFICE SUPPLY - EQUIPMENT	6440-040						
OFFICE SUPPLY-DATA PROCESSING	6440-050						
BUILDING & OFFICE EXPENSE	BUILD-OF						
OTHER GENERAL & ADMINISTRATIVE -							
EXPENSE ACCT & TRAVEL - TAX	6510-100						
NONTAX MEALS/ENTERTAINMENT	6510-210						
NONTAXABLE OTHER	6510-220						
CORPORATE AIRCRAFT EXPENSE	6510-225						
INSURANCE EXPENSE	6520-000						
EXCESS LIABILITY INSURANCE	6520-010						
OFFICER & DIRECTOR LIAB. INS.	6520-011						
PROPERTY & CRIME INSURANCE	6520-013						
MARINE CARGO INSURANCE	6520-014						
PROPERTY TAX REAL ESTATE	6530-200						
LICENSES	6540-000						
OTHER TAXES	6550-000						
FRANCHISE TAX	6550-010						
EMPLOYEE DEVELOPMENT	6560-000						
SEMINARS	6560-010						
PROFESSIONAL AFFILIATIONS	6560-020						
EMPLOYMENT - ADVERTISING	6565-010						
EMPLOYMENT - MOVING EXPENSE	6565-030						
EMPLOYMENT - MISC EXPENSE	6565-040						
MISCELLANEOUS EXPENSE	6570-000						
MISC EXPENSE - RECORD STORAGE	6570-007						

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PROGRESS FUELS CORPORATION
INCOME STATEMENT DETAIL
FOR THE PERIOD ENDED DECEMBER 31, 2002
EFC REGULATED SUMMARY

REPORT ID: DELIS
UNIT CODE:



	ACCOUNT NUMBER	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
MISC EXPENSE-EQUIPMENT RENTAL	6570-013						
AUTO OPERATING EXPENSE	6570-040						
AUTO EXPENSE REIMBURSEMENTS	6570-050						
CONTRIBUTION	6570-060						
PENALTIES	6570-070						
MAINTENANCE - GENERAL	6810-000						
MAINTENANCE - AUTO	6810-020						
MAINTENANCE - DP EQUIPMENT	6810-030						
OTHER GENERAL & ADMINISTRATION	OTHG-A						
TOTAL GENERAL & ADMINISTRATION	GENLADMI						
OTHER EXPENSES -							
DEPRECIATION EXPENSES -							
DEPRECIATION - RAILCARS	6230-020						
DEPRECIATION - DP EQUIPMENT	6230-030						
DEPRECIATION - FURN & FIXTURES	6240-000						
DEPRECIATION EXPENSES	DEPREC						
INTEREST EXPENSE -							
ALLOCATION INTEREST EXPENSE	6100-999						
INTEREST EXPENSE - PCH MTN	6120-102						
INTEREST EXPENSE - PEC LINE	6120-105						
INTEREST EXPENSE - PEC L/T NOTE PAY	6120-106						
COMMITMENT FEE - PCH	6160-101						
COMMITMENT FEE - MTN	6160-102						
INTEREST EXPENSE	INTEREST						
TOTAL EXPENSES							
INCOME BEFORE INCOME TAXES							

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PROGRESS FUELS CORPORATION
WATERBORNE TRANSPORTATION AUDIT
INCOME STATEMENT - JUL TO DEC 2002
12 MONTHS ENDED 12/31/02

PROGRESS FUELS CORPORATION
INCOME STATEMENT DETAIL
FOR THE PERIOD ENDED DECEMBER 31, 2002
EFC REGULATED SUMMARY

REPORT ID: DELISR02
UNIT CODE: REG

ACCOUNT NUMBER		JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER
	PROVISION (BENEFIT) FOR INC TAXES -						
6900-101	CURRENT FIT - CURRENT YEAR	[redacted]					
6900-102	CURRENT FIT - PRIOR YEAR						
CUR-FED	CURRENT FEDERAL INCOME TAXES						
6900-111	CURRENT SIT - CURRENT YEAR						
6900-112	CURRENT SIT - PRIOR YEAR						
CUR-STAT	CURRENT STATE INCOME TAXES						
6900-201	DEFERRED FIT - CURRENT YEAR						
6900-202	DEFERRED FIT - PRIOR YEAR						
DEF-FED	DEFERRED FEDERAL INCOME TAXES						
6900-211	DEFERRED SIT - CURRENT YEAR						
6900-212	DEFERRED SIT - PRIOR YEAR						
DEF-STAT	DEFERRED STATE INCOME TAXES						
RDEFTC	REGULAR DEFERRED TAX CREDITS						
ITC	INVESTMENT TAX CREDIT						
TAXES	TOTAL INCOME TAXES						
	INCOME FROM CONTINUING OPERATIONS						
	NET INCOME						

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SOURCE: PEC

PEF Pg. 12
PSC Staff W/P No. 2B, Pg. 5 of 5

COMPANY: PROGRESS FUELS CORPORTAION
SUBJECT: SUMMARY TRANSPORTATION CONTRACTS
PERIOD: 12 MONTHS ENDED DECEMBER 31, 2002
AUDITOR: J. W. ROHRBACHER JWR 1/7/15

AUDIT: WATERBORNE TRANSPORTATION
FILENAME: CONTRACTS
SHEET: CONTRACT SUMMARY

Vendor	Contract Amount	Utility Summary	Comments
Kanawha River Terminals (KRT)	[redacted]		
International Marine Terminals (IMT)			
Despatch Calculations 1/1-12/31/02			
Dockage	[redacted]		Contract for 12 hour period, utility based 6 hours
Line Handling			@ transfer 15,000 tons
Direct Unload			
Storage			
Conveyor Discharge			
Plaquemines Harbor Fee			
MEMCO			
Demurrage	[redacted]		@10,000 tons
Freight - Kanawha River - Dec			
July			
Dixie Fuels Limited			
Demurrage	[redacted]		
Charter of Dixie Rebel			
Freight - Dec			Rate for less than initial 1.6 mm tons
July			Rate greater than initial 1.6mm tons

The Dixie Fuels contract has rate adjustment for increases/decreases in various areas

NOTE: All rates are per ton unless otherwise noted

[redacted]

SOURCE: Transportation Contracts

PROGRESS FUELS CORPORATION
WATERBORNE TRANSPORTATION AUDIT
UTILITY SUMMARY OF TRANSPORTATION CONTRACTS
12 MONTHS ENDED 12/31/02

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CONFIDENTIAL

Progress Fuels Corporation
Summary of Transportation Contracts for Shipments to Crystal River

Line		Contract Term	Contract Rates per Ton 2001	2002	2003	Estimated Charges Kanawha River 2003/2004	2005	Notes
1	Rail & Truck - Kanawha River Terminals (KRT)	01/02-12/03						
2	Elk Run to KRT Kanawha River Docks							
3	Martin County to KRT Big Sandy River Dock							
4								
5	River - MEMCO	07/01-07/04						
6	Kanawha River							
7	Big Sandy River							
8	Ohio River							
9	Demurrage							
10								
11	Terminal at New Orleans - International Marine Terminals (IMT)	01/02-10/04						
12	Storage							
13	Direct							
14	Import of Foreign Coal							
15	- Terminal crane discharge through storage including barge charges							
16	- Terminal crane discharge through storage excluding barge charges							
17	- Terminal crane discharge through CBU direct to gulf barge							
18	- Full service package for vessel crane discharge through storage							
19	- Terminal crane discharge through CBU direct to gulf barge							
20	- Vessel crane discharge through storage							
21	- Vessel crane discharge through CBU direct to gulf barge							
22	- Vessel conveyor discharge through inbound hopper through storage							
23	Harbor Fee							
24	Additional charges							
25	- Demurrage							
26	- Line Handling							
27	- Port Fees							
28	- Dockage							
29								
30	Gulf - Dixie Fuels Limited (Dixie)	4/02-4/08						
31	Rate less than initial 1.6 million tons							
32	Rate greater than initial 1.6 million tons							
33	Average adjusted rate actually paid							
34	Additional charges							
35	- Port Fees							
36	- Assist Tug							
37	- Demurrage/Repairs							
38	- Insurance/Labor Adjustment							
39	- Customs/Surveys							
40								
41								
42	Notes:							
43								
44								
45								
46								
47								
48								
49								
50								
51								
52								
53								

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SOURCE: PBC

PEF Pg. 34
PSC Staff W/P No. 42-1

INTEGRITY BUSINESS FORMS, INC. (847) 566-2626 FAX (847) 566-4608

PROGRESS FUELS CORPORATION
WATERBORNE TRANSPORTATION AUDIT
COAL PURCHASE CONTRACTS
12 MONTHS ENDED 12/31/02

Docket No. 030001-EI
Exhibit JWR-5 (Page 14 of 39)
Selected Audit Work Papers

COAL PURCHASE CONTRACTS

[redacted]

1082

SOURCE: Real Contracts

INTEGRITY BUSINESS FORMS, INC. (847) 698-2626 FAX (847) 698-4606

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PSC Staff W/P No. 42-2, Pg. 1of 2

PROGRESS FUELS CORPORATION
WATERBORNE TRANSPORTATION AUDIT
COAL PURCHASE CONTRACTS
12 MONTHS ENDED 12/31/02

Docket No. 030001-EI
Exhibit JWR-5 (Page 15 of 39)
Selected Audit Work Papers

[redacted]

SOURCE: Real Contracts

PEF Pg. 36
PSC Staff W/P No. 42-2, Pg. 2 of 2

INTEGRITY BUSINESS FORMS, INC. (847) 566-2825 FAX (847) 566-4606

WATERBORNE TRANSPORTATION CONTRACTS

Kanawha River Terminals, Inc. (KRT) and Electric Fuels Corporation (now PFC)

Term - January 1, 2002 through December 31, 2003

Services Provided:

Ohio River Rail facility - Ceredo Dock

1) Coordinate with CSXT and Shipper's barge carriers the scheduling in of trains and barges to the KRT facility.
2) Receive coal in railcars at the KRT facility.
3) Unload railcars and directly load coal into river barges.
4) Thaw frozen coal as required using existing equipment.

Kanawha River Truck Facilities

1) Coordinate with truck companies and shipper's barge carriers the scheduling in of trucks and barges to the KRT facilities.
2) Crush coal received to 2" x 0" in size.
3) Load coal into barges.
4) Determine weight of coal loaded into barges and maintain accurate weight records.

Big Sandy River Truck Facility

1) Coordinate with truck companies and shipper's barge carriers the scheduling in of trucks and barges to the KRT facilities.
2) Crush coal received to 2" x 0" in size.
3) Load coal into barges.
4) Determine weight of coal loaded into barges and maintain accurate weight records.

Fee - For each ton of coal transported by truck or received by rail and loaded into barges, the following fees are fixed and firm for calendar year 2002 except for any surcharges, assessments, or increased fees which may be assessed by transportation or independent hauling companies.

[redacted]

AEP MEMCO LLC and Electric Fuels Corporation (now PCF)

Term - August 1, 2001 - July 31, 2004

Services Provided - Move Dry Bulk Fuel (DBF), such as coal, petcoke, synfuel, etc.from certain origin docks on the Inland Waterways System to the New Orleans, Louisiana area for transfer to and trans-shipment across the Gulf of Mexico by other carriers.

"Origin docks" shall mean docks or terminals located at various Mile points on the Kanawha, Big Sandy and Ohio Rivers or other docks or terminals mutually acceptable to the parties.

"Transfer point" shall mean the International Marine Terminals Partnership transfer facility, Mile 57, Lower Mississippi River, or other mutually agreeable transfer terminal on the Mississippi River between Mile 30 AHP and Mile 230 AHP, Baton Rouge.

[redacted] (a "Contact Year"). In any Contract Year, PFC will tender no less than 90% of the base quantity and MEMCO shall not be obligated to transport more than 110% of the base quantity.

[redacted]

Freight Rates - the following rates are per net ton for the transportation and delivery of DBF from the following origin docks to the transfer point:

Rates	Origin	Milepoint
	Kanawha river	
[redacted]	Kanawha River Terminals	69.0
	Amherst	74.0
	Hughes Creek	81.5
	Cannelton	84.3
	Eagle/Hawks Nest	87.1
	Big Sandy River	
[redacted]	All docks	
	Ohio River	
[redacted]	ORC Huntington	306.5
	Ceredo	315.0
	TTI	406.0
	Louisville & Jefferson Riverport	618.5
	CBT Cincinnati	471.8

The initial base price for raw fuel is [redacted] per gallon, excluding any applicable taxes. The Initial

[redacted]

Dixie Fuels Limited and Progress Fuels Corporation

Term - [redacted]

[redacted]

[redacted]

International Marine Terminals Partnership (Terminal) and Electric Fuels Corporation (PFC)

[redacted]

Docket No. 030001-EI
Exhibit JWR-5 (Page 20 of 39)
Selected Audit Work Papers

[redacted]

3

5 of 5

SOURCE: Red Contracts

INTEGRITY BUSINESS FORMS, INC. (847) 698-2826 FAX (847) 698-4808

PROGRESS FUELS CORPORATION
WATERBORNE TRANSPORTATION AUDIT
DIXIE FUELS - CREW COST & INSURANCE ADJUSTMENT
12 MONTHS ENDED 12/31/02

EXHIBIT A
Dixie Fuels

CREW COST ADJUSTMENT EXAMPLE

[redacted]

	Historical Man count in Base Freight Rate Man/Days Per Tow (A)	% of Cost (B)	Manning Man/Day Per Tow (C)	Percent Change (D)	Crew Cost Change (E)	% Days in DBF Service (F)	EFC Credit/ Debit (G)
Wheelhouse	[redacted]						
Engineers							
Deckhands							
Total							

INSURANCE COST ADJUSTMENT EXAMPLE

The following examples of Insurance Cost Adjustments pursuant to Section 14 are based on the Insurance Allowance of [redacted]

	Example A	Example B
Actual Insurance Costs	[redacted]	[redacted]
Insurance Allowance		
% Days in DBF service		
EFC Credit		
Invoice to EFC		

PBC

SOURCE: PBC - Contract

INTEGRITY BUSINESS FORMS, INC. (847) 698-2525 FAX (847) 698-4606

Electric Fuels Corporation
Regulated (FPC) Business
Inventory Accrual
January 2002

04-Feb-02
05:37 PM

CRYSTAL RIVER 4 AND 5

* denotes I/C

	COST OF COAL		Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
A	CBT/S to KCT						
A	CBT/Replace to KCT						
A	CBT/S to KCT						
A	KMay/S to KCT						
	Sandy River/S to Cyrus Dock						
B	Peabody/S to Rvr Eagle						
BB	KMay/S to KCT Dock						
C	OMay/S to KCT						
CC	Sandy Rvr(Pen) to Cyrus Dock					0.00	0.00
D	Pen to Pen Dock		3,390.20				
E	Pen to Placer Dock						
E	Coal Net/S to WhiteCreek					3,390.20	
F	Massey to Caredo						
G	Mapco/S to Caredo						
G	Franklin to Caredo						
G	Quaker to Caredo						
H	BlackHawk/S to Caredo	#6					
I	OMay/S to Caredo					0.00	0.00
J	KRT/Eagle to KRT/Quincy		36,701.50				
J	KRT/Eagle to KRT/Quincy						
J	BlackHawk/Spot to Quincy		27,122.28				
K	Black Hawk/S to KRT/Quincy	#5	20,041.01				
K	Black Hawk/S to KRT/Quincy	#6	19,683.99				
L	New River/S to KRT/Quincy		84,241.05			167,789.83	
S	Glencore/S to IMT						
S	Glencore/S to IMT					0.00	0.00
T	InterAmer/S to IMT						
			171,180.03				

Average Rate

	RIVER TERMINAL	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
M	CBT/S to KCT			0.00		
M	KMay/S to KCT			0.00		
M	Sandy River/S to Cyrus Dock			0.00		
M	KMay/S to KCT Dock			0.00		
M	OMay/S to KCT			0.00		
M	Sandy Rvr(Pen) to Cyrus Dock			0.00	0.00	0.00
N	Pen to Pen Dock	3,390.20		0.00		
N	Pen to Placer Dock			0.00	3,390.20	0.00
N	Massey to Caredo			0.00		
O	Mapco/S to Caredo			0.00		
O	Frkln to Caredo			0.00		
O	Quaker to Caredo			0.00		
O	BlackHawk/S to Caredo			0.00		
O	OMay/S to Caredo			0.00	0.00	0.00
	T/Eagle to KRT/Quincy	36,701.50		0.00		
	JctHawk/Spot to Quincy	27,122.28		0.00		
S	Black Hawk/S to KRT/Quincy	39,725.00		0.00		
S	New River/S to KRT/Quincy	84,241.05		0.00	167,789.83	0.00
		171,180.03	0.00	0.00	171,180.03	0.00

Average Rate

	RIVER FREIGHT	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
I	From KCT/Cyrus Memco			0.00		
I	From KCT/Rvr Eagle ACBL/S			0.00		
I	From KCT/Rvr Eagle OHRV/S			0.00	0.00	0.00
	From Pen/Whitcrk on ACBL/S			0.00		
	From Pen/Placer on Memco	3,390.20		0.00		
	From Pen/Whitcrk on OHRV/S			0.00	3,390.20	0.00
	From Caredo on Memco			0.00		
	From Caredo on OHRV/S			0.00		
	From Caredo on ACBL/S			0.00	0.00	0.00
	From KRT/Quincy on OHRV/S			0.00		
	From KRT/Quincy on Memco	167,789.83		0.00		
	From Kanawha on ACBL/S			0.00	167,789.83	0.00
		171,180.03	0.00	0.00	171,180.03	0.00

Average Rate

	GULF TERMINAL - IMT	Tons	Cost/Ton	Dollars
	From KCT OK/Cyrus Dock			
	From Pen Dock/Placer Dk	11,021.23		
	From Caredo/Ohio Rvr Dk	26,742.86		
	From Kanawha/Quincy	129,641.72		
	From Glencore/S			
	From InterAmer/S			
		167,405.81		

Average Rate

	GULF TERM-ECT&OTHER	Tons	Cost/Ton	Dollars
R	From KCT Dock			0.00
R	From Pen Dock			0.00
R	From Caredo/Ohio Rvr Dk			0.00
R	From Kanawha/Quincy			0.00
R	From Glencore/S			0.00
R	From InterAmer/S			0.00
		0.00		0.00

Average Rate

	GULF FREIGHT	Tons	Cost/Ton	Dollars
	From IMT	161,530.85	0.00	0.00
	From Electro-Coal & Other		0.00	0.00
				0.00
				0.00
		161,530.85	0.00	0.00

Average Rate

	ILF FREIGHT	Tons	Cost/Ton	Dollars
	As delivered-IMT	160,131.70		
	Tons delivered-Electro & Other			
		160,131.70		

PBC

PEF Pg. 50

PSC Staff W/P No. 45-1, Pg. 1 of 12

1 of 12

Electric Fuels Corporation
Regulated (FPC) Business
Inventory Accrual
February 2002

04-Mar-02
07:23 PM

CRYSTAL RIVER 4 AND 5

* denotes I/C

	COST OF COAL		Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
A	CBT/S to KCT				0.00 *		
A	CBT/Replace to KCT				0.00 *		
A	CBT/S to KCT				0.00 *		
A	*May/S to KCT				0.00 *		
	dy River/S to Cyrus Dock				0.00		
	bbody/S to Rvr Eagle				0.00		
BB	KMay/S to KCT Dock				0.00 *		
C	DMay/S to KCT				0.00 *		
CC	Sandy Rvr(Pen) to Cyrus Dock				0.00	0.00	0.00
D	Pen to Pen Dock		7,106.27		[redacted]		
E	Pen to Placer Dock						
E	Coal Net/S to WhiteCreek				0.00	7,106.27	[redacted]
F	Massey to Ceredo				0.00		
G	Mapco/S to Ceredo				0.00		
G	Franklin to Ceredo				0.00		
G	Quaker to Ceredo				0.00		
H	BlackHawk/S to Ceredo	#6			0.00 *		
I	DMay/S to Ceredo				0.00 *	0.00	0.00
J	KRT/Eagle to KRT/Quincy		35,684.84				
J	KRT/Eagle to KRT/Quincy						
J	BlackHawk/Spot to Quincy		39,509.14				
K	Black Hawk/S to KRT/Quincy	#5	19,542.08				
K	Black Hawk/S to KRT/Quincy	#6	19,560.17				
L	New River/S to KRT/Quincy		46,696.28			160,992.51	[redacted]
S	Glencore/S to IMT						
S	Glencore/S to IMT					0.00	0.00
T	InterAmer/S to IMT					0.00	0.00
			168,098.78			168,098.78	[redacted]
				Average Rate			

	RIVER TERMINAL	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
M	CBT/S to KCT			0.00		
M	KMay/S to KCT			0.00		
M	Sandy River/S to Cyrus Dock			0.00		
M	KMay/S to KCT Dock			0.00		
M	DMay/S to KCT			0.00		
M	Sandy Rvr(Pen) to Cyrus Dock			0.00	0.00	0.00
N	Pen to Pen Dock	7,106.27		0.00		
N	Pen to Placer Dock			0.00	7,106.27	0.00
N	Massey to Ceredo			0.00		
O	Mapco/S to Ceredo			0.00		
O	Frdn to Ceredo			0.00		
O	Quaker to Ceredo			0.00		
O	BlackHawk/S to Ceredo			0.00		
O	DMay/S to Ceredo			0.00	0.00	0.00
	IT/Eagle to KRT/Quincy	35,684.84		0.00		
	ckHawk/Spot to Quincy	39,509.14		0.00		
P	Black Hawk/S to KRT/Quincy	39,102.25		0.00		
P	New River/S to KRT/Quincy	46,696.28		0.00	160,992.51	0.00
		168,098.78	0.00	0.00	168,098.78	0.00
			Average Rate			

	RIVER FREIGHT	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
M	From KCT/Cyrus Memco			0.00		
M	From KCT/Rvr Eagle ACBL/S			0.00		
M	From KCT/Rvr Eagle OHRV/S			0.00	0.00	0.00
N	From Pen/Whitark on ACBL/S			0.00		
N	From Pen/Placer on Memco	7,106.27		0.00		
N	From Pen/Whitark on OHRV/S			0.00	7,106.27	0.00
O	From Ceredo on Memco			0.00		
O	From Ceredo on OHRV/S			0.00		
O	From Ceredo on ACBL/S			0.00	0.00	0.00
[illegible]	From KRT/Quincy on OHRV/S			0.00		
[illegible]	From KRT/Quincy on Memco	160,992.51		0.00		
[illegible]	From Kanawha on ACBL/S			0.00	160,992.51	0.00
		168,098.78	0.00	0.00	168,098.78	0.00
			Average Rate			

	GULF TERMINAL - IMT	Tons	Cost/Ton	Dollars
[illegible]	From KCT Dk/Cyrus Dock			
[illegible]	From Pen Dock/Placer Dk	3,449.26		
[illegible]	From Ceredo/Ohio Rvr Dk			
[illegible]	From Kanawha/Quincy	131,923.69		
[illegible]	From Glencore/S			
	From InterAmer/S			
		135,372.95		[redacted]
			Average Rate	

	GULF TERM-ECT&OTHER	Tons	Cost/Ton	Dollars
R	From KCT Dock			0.00
R	From Pen Dock			0.00
R	From Ceredo/Ohio Rvr Dk			0.00
R	From Kanawha/Quincy			0.00
R	From Glencore/S			0.00
R	From InterAmer/S			0.00
		0.00		[redacted]
			Average Rate	

GULF FREIGHT	Tons	Cost/Ton	Dollars
From IMT	157,941.17	0.00	0.00
From Electro-Coal & Other		0.00	0.00
			0.00
			0.00
	157,941.17	0.00	0.00
		Average Rate	

ILF FREIGHT	Tons	Cost/Ton	Dollars
ns delivered-IMT	190,207.54		[redacted]
Tons delivered-Electro & Other			
	190,207.54		
		Average Rate	

PSC

PEF Pg. 51

PSC Staff W/P No. 45-1, Pg. 2 of 12

2 of 12

Electric Fuels Corporation
Regulated (FPC) Business
Inventory Accrual
March 2002

02-Apr-02
12:00 PM

CRYSTAL RIVER 4 AND 5

* denotes I/C

	COST OF COAL		Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
A	CBT/S to KCT				0.00 *		
A	CBT/Replace to KCT				0.00 *		
A	CBT/S to KCT				0.00 *		
A/	KMay/S to KCT				0.00 *		
7	ldy River/S to Cyrus Dock				0.00		
	lbody/S to Rvr Eagle				0.00		
Bla	...ay/S to KCT Dock				0.00 *		
C	OMay/S to KCT				0.00 *		
CC	Sandy Rvr(Pen) to Cyrus Dock				0.00	0.00	0.00
O	Pen to Pen Dock		1,830.76				
E	Pen to Placer Dock						
E	Coal Net/S to WhiteCreek				0.00	1,830.76	
F	Massey to Caredo				0.00		
G	Mapco/S to Caredo				0.00		
G	Franklin to Caredo				0.00		
G	Quaker to Caredo				0.00		
H	BlackHawk/S to Caredo	#6			0.00 *		
I	OMay/S to Caredo				0.00 *	0.00	0.00
J	KRT/Eagle to KRT/Quincy		36,276.58				
J	KRT/Eagle to KRT/Quincy						
J	BlackHawk/Spot to Quincy		43,882.80				
K	Black Hawk/S to KRT/Quincy	#5	19,804.82 *				
K	Black Hawk/S to KRT/Quincy	#6	21,327.36 /				
L	New River/S to KRT/Quincy		56,449.42 /			177,740.98	
S	Guasare/S to IMT		47,873.14				
S	Guasare/S to IMT					47,873.14	
T	InterAmer/S to IMT					0.00	
			227,444.88			227,444.88	

	RIVER TERMINAL	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
M	CBT/S to KCT			0.00		
M	KMay/S to KCT			0.00		
M	Sandy River/S to Cyrus Dock			0.00		
M	KMay/S to KCT Dock			0.00		
M	OMay/S to KCT			0.00		
M	Sandy Rvr(Pen) to Cyrus Dock			0.00	0.00	0.00
N	Pen to Pen Dock	1,830.76		0.00		
N	Pen to Placer Dock			0.00	1,830.76	0.00
N	Massey to Caredo			0.00		
O	Mapco/S to Caredo			0.00		
O	Fridn to Caredo			0.00		
O	Quaker to Caredo			0.00		
O	BlackHawk/S to Caredo			0.00		
O	OMay/S to Caredo			0.00	0.00	0.00
?	...T/Eagle to KRT/Quincy	36,276.58		0.00		
	...kHawk/Spot to Quincy	43,882.80		0.00		
>	...ack Hawk/S to KRT/Quincy	41,132.18		0.00		
>	New River/S to KRT/Quincy	56,449.42		0.00	177,740.98	0.00
		179,571.74	0.00	0.00	179,571.74	0.00
			Average Rate			

	RIVER FREIGHT	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
t	From KCT/Cyrus Memco			0.00		
t	From KCT/Rvr Eagle ACBL/S			0.00		
t	From KCT/Rvr Eagle OHRV/S			0.00	0.00	0.00
i	From Pen/Whitark on ACBL/S			0.00		
	From Pen/Placer on Memco	1,830.76		0.00		
	From Pen/Whitark on OHRV/S			0.00	1,830.76	0.00
	From Caredo on Memco			0.00		
	From Caredo on OHRV/S			0.00		
	From Caredo on ACBL/S			0.00	0.00	0.00
	From KRT/Quincy on OHRV/S			0.00		
	From KRT/Quincy on Memco	177,740.98		0.00		
	From Kanawha on ACBL/S			0.00	177,740.98	0.00
		179,571.74	0.00	0.00	179,571.74	0.00
			Average Rate			

GULF TERMINAL - IMT	Tons	Cost/Ton	Dollars
From KCT DK/Cyrus Dock			
From Pen Dock/Placer Dk	7,177.65		
From Caredo/Ohio Rvr Dk			
From Kanawha/Quincy	154,431.38		
From Guasare/S	47,873.14		
From InterAmer/S			
	209,482.17		
		Average Rate	

	GULF TERM-ECT&OTHER	Tons	Cost/Ton	Dollars
R	From KCT Dock			0.00
R	From Pen Dock			0.00
R	From Caredo/Ohio Rvr Dk			0.00
R	From Kanawha/Quincy			0.00
R	From Guasare/S			0.00
R	From InterAmer/S			0.00
		0.00		0.00
			Average Rate	

GULF FREIGHT	Tons	Cost/Ton	Dollars
From IMT	176,109.48	0.00	0.00
From Electro-Coal & Other		0.00	0.00
			0.00
			0.00
	176,109.48	0.00	0.00
		Average Rate	

...F FREIGHT	Tons	Cost/Ton	Dollars
...s delivered-IMT	159,646.43		
...s delivered-Electro & Other			
	159,646.43		
		Average Rate	

PBC

PEF Pg. 52

PSC Staff W/P No. 45-1, Pg. 3 of 12

Electric Fuels Corporation
Regulated (FPC) Business
Inventory Accrual
April 2002

02-May-02
03:48 PM

CRYSTAL RIVER 4 AND 5

* denotes I/C

	COST OF COAL		Tons	Cost/Ton	Dollars		Total Tons	Total Dollars
A	CBT/S to KCT				0.00	*		
A	CBT/Replace to KCT				0.00	*		
A	CBT/S to KCT				0.00	*		
A	KMay/S to KCT				0.00	*		
	Sandy River/S to Cyrus Dock				0.00			
	Peabody/S to Rvr Eagle				0.00			
Ba	KMay/S to KCT Dock				0.00	*		
C	DMay/S to KCT				0.00	*		
CC	Sandy Rvr(Pen) to Cyrus Dock				0.00		0.00	0.00
D	Pen to Pen Dock				0.00			
E	Pen to Placer Dock				0.00			
E	Coal Net/S to WhiteCreek				0.00		0.00	0.00
F	Massey to Ceredo				0.00			
G	Mapco/S to Ceredo				0.00			
G	Franklin to Ceredo				0.00			
G	Quaker to Ceredo				0.00			
H	BlackHawk/S to Ceredo	#6			0.00	*		
I	DMay/S to Ceredo				0.00	*	0.00	0.00
J	KRT/Eagle to KRT/Quincy		23,380.48			*		
J	Marmet/Eagle to KRT/Quincy		10,462.63			*		
K	BlackHawk/Spot to Quincy		1,727.27			*		
K	Black Hawk/S to KRT/Quincy	#5	12,642.05			*		
K	Black Hawk/S to KRT/Quincy	#6	12,947.81			*		
L	New River/S to KRT/Quincy		55,787.48				116,947.72	
S	Guasare/S to IMT							
S	Guasare/S to IMT						0.00	0.00
T	InterAmer/S to IMT						0.00	0.00
			116,947.72				116,947.72	

Average Rate

	RIVER TERMINAL	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
M	CBT/S to KCT			0.00		
M	KMay/S to KCT			0.00		
M	Sandy River/S to Cyrus Dock			0.00		
M	KMay/S to KCT Dock			0.00		
M	DMay/S to KCT			0.00		
M	Sandy Rvr(Pen) to Cyrus Dock			0.00	0.00	0.00
N	Pen to Pen Dock			0.00		
N	Pen to Placer Dock			0.00	0.00	0.00
N	Massey to Ceredo			0.00		
O	Mapco/S to Ceredo			0.00		
O	Frkln to Ceredo			0.00		
O	Quaker to Ceredo			0.00		
O	BlackHawk/S to Ceredo			0.00		
O	DMay/S to Ceredo			0.00	0.00	0.00
	Marmet/Eagle to Quincy	33,843.11		0.00		
	Black Hawk/Spot to Quincy	1,727.27		0.00		
P	Black Hawk/S to KRT/Quincy	25,589.86		0.00		
P	New River/S to KRT/Quincy	55,787.48		0.00	116,947.72	0.00
		116,947.72	0.00	0.00	116,947.72	0.00

Average Rate

	RIVER FREIGHT	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
I	From KCT/Cyrus Memco			0.00		
I	From KCT/Rvr Eagle ACBL/S			0.00		
I	From KCT/Rvr Eagle OHRV/S			0.00	0.00	0.00
	From Pen/Whitcrk on ACBL/S			0.00		
	From Pen/Placer on Memco			0.00		
	From Pen/Whitcrk on OHRV/S			0.00	0.00	0.00
	From Ceredo on Memco			0.00		
	From Ceredo on OHRV/S			0.00		
	From Ceredo on ACBL/S			0.00	0.00	0.00
	From KRT/Quincy on OHRV/S			0.00		
	From KRT/Quincy on Memco	116,947.72		0.00		
	From Kanawha on ACBL/S			0.00	116,947.72	0.00
		116,947.72	0.00	0.00	116,947.72	0.00

Average Rate

	GULF TERMINAL - IMT	Tons	Cost/Ton	Dollars
	From KCT OK/Cyrus Dock			0.00
	From Pen Dock/Placer Dk			0.00
	From Ceredo/Ohio Rvr Dk			0.00
	From Kanawha/Quincy	213,116.60		
	From Guasare/S			
	From InterAmer/S			0.00
		213,116.60		

Average Rate

	GULF TERM-ECT&OTHER	Tons	Cost/Ton	Dollars
R	From KCT Dock			0.00
R	From Pen Dock			0.00
R	From Ceredo/Ohio Rvr Dk			0.00
R	From Kanawha/Quincy			0.00
R	From Guasare/S			0.00
R	From InterAmer/S			0.00
		0.00		0.00

Average Rate

GULF FREIGHT	Tons	Cost/Ton	Dollars
From IMT	179,917.80	0.00	0.00
From Electro-Coal & Other		0.00	0.00
			0.00
			0.00
	179,917.80	0.00	0.00

Average Rate

T FREIGHT	Tons	Cost/Ton	Dollars
delivered-IMT	178,833.38		
ns delivered-Electro & Other			
	178,833.38		

PEF Pg. 53

PSC Staff W/P No. 45-1, Pg. 4 of 12

Electric Fuels Corporation
Regulated (FPC) Business
Inventory Accrual
May 2002

04-Jun-02
01:34 PM

CRYSTAL RIVER 4 AND 5

* denotes I/C

	COST OF COAL		Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
A	CBT/S to KCT				0.00 *		
A	CBT/Replace to KCT				0.00 *		
A	CBT/S to KCT				0.00 *		
	y/S to KCT				0.00 *		
	dy River/S to Cyrus Dock				0.00		
B	Peabody/S to Rvr Eagle				0.00		
BB	KMay/S to KCT Dock				0.00 *		
C	DMay/S to KCT				0.00 *		
CC	Sandy Rvr(Pen) to Cyrus Dock				0.00	0.00	0.00
D	Pen to Pen Dock				0.00		
E	Pen to Placer Dock				0.00		
E	Coal Net/S to WhiteCreek				0.00	0.00	0.00
F	Massey to Ceredo				0.00		
G	Mapco/S to Ceredo				0.00		
G	Franklin to Ceredo				0.00		
G	Quaker to Ceredo				0.00		
H	BlackHawk/S to Ceredo	#6			0.00 *		
I	DMay/S to Ceredo				0.00 *	0.00	0.00
J	KRT/Eagle to KRT/Quincy		37,701.16				
J	Marmet/Eagle to KRT/Quincy						
K	BlackHawk/Spot to Quincy		42,503.34				
K	Black Hawk/S to KRT/Quincy	#5	3,586.85				
K	Black Hawk/S to KRT/Quincy	#6	5,151.15				
L	New River/S to KRT/Quincy		64,453.80			153,390.50	
S	Guasare/S to IMT		58,753.60				
S	Guasare/S to IMT					58,753.60	
T	InterAmer/S to IMT					0.00	
			212,144.10			212,144.10	
				Average Rate			

	RIVER TERMINAL	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
M	CBT/S to KCT			0.00		
M	KMay/S to KCT			0.00		
M	Sandy River/S to Cyrus Dock			0.00		
M	KMay/S to KCT Dock			0.00		
M	DMay/S to KCT			0.00		
M	Sandy Rvr(Pen) to Cyrus Dock			0.00	0.00	0.00
N	Pen to Pen Dock			0.00		
N	Pen to Placer Dock			0.00	0.00	0.00
N	Massey to Ceredo			0.00		
O	Mapco/S to Ceredo			0.00		
O	Frklin to Ceredo			0.00		
O	Quaker to Ceredo			0.00		
O	BlackHawk/S to Ceredo			0.00		
[illegible]	y/S to Ceredo			0.00	0.00	0.00
I	I-Marmet/Eagle to Quincy	37,701.16		0.00		
P	BlackHawk/Spot to Quincy	42,503.34		0.00		
P	Black Hawk/S to KRT/Quincy	8,732.20		0.00		
P	New River/S to KRT/Quincy	64,453.80		0.00	153,390.50	0.00
		153,390.50	0.00	0.00	153,390.50	0.00
			Average Rate			

	RIVER FREIGHT	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
M	From KCT/Cyrus Memco			0.00		
M	From KCT/Rvr Eagle ACBL/S			0.00		
M	From KCT/Rvr Eagle OHRV/S			0.00	0.00	0.00
N	From Pen/Whitark on ACBL/S			0.00		
N	From Pen/Placer on Memco			0.00		
N	From Pen/Whitark on OHRV/S			0.00	0.00	0.00
O	From Ceredo on Memco			0.00		
O	From Ceredo on OHRV/S			0.00		
O	From Ceredo on ACBL/S			0.00	0.00	0.00
P	From KRT/Quincy on OHRV/S			0.00		
P	From KRT/Quincy on Memco	153,390.50		0.00		
P	From Kanawha on ACBL/S			0.00	153,390.50	0.00
		153,390.50	0.00	0.00	153,390.50	0.00
			Average Rate			

	GULF TERMINAL - IMT	Tons	Cost/Ton	Dollars
]	From KCT DK/Cyrus Dock			0.00
]	From Pen Dock/Placer Dk			0.00
]	From Ceredo/Ohio Rvr Dk			
]	From Kanawha/Quincy	133,175.35		
]	From Guasare/S	58,753.60		
]	From InterAmer/S			
		191,928.95		
			Average Rate	

	GULF TERM-ECT&OTHER	Tons	Cost/Ton	Dollars
R	From KCT Dock			0.00
R	From Pen Dock			0.00
R	From Ceredo/Ohio Rvr Dk			0.00
R	From Kanawha/Quincy			0.00
R	From Guasare/S			0.00
R	From InterAmer/S			0.00
		0.00		0.00

	GULF FREIGHT	Tons	Cost/Ton	Dollars
	From IMT	178,663.81	0.00	0.00
	From Electro-Coal & Other		0.00	0.00
				0.00
				0.00
		178,663.81	0.00	0.00
			Average Rate	

	F FREIGHT	Tons	Cost/Ton	Dollars
	.ns delivered-IMT	179,167.23		
	Tons delivered-Electro & Other			
		179,167.23		
			Average Rate	

PBC

PEF Pg. 54

PSC Staff W/P No. 45-1, Pg. 5 of 12

Electric Fuels Corporation
Regulated (FPC) Business
Inventory Accrual
June 2002

02-Jul-02
10:53 AM

CRYSTAL RIVER 4 AND 5

* denotes I/C

	COST OF COAL		Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
A	CBT/S to KCT				0.00 *		
A	CBT/Replace to KCT				0.00 *		
A	CBT/S to KCT				0.00 *		
A	KMay/S to KCT				0.00 *		
I	Sandy River/S to Cyrus Dock				0.00		
L	Allbody/S to Rvr Eagle				0.00		
BB	KMay/S to KCT Dock				0.00 *		
C	OMay/S to KCT				0.00 *		
CC	Sandy Rvr(Pen) to Cyrus Dock				0.00	0.00	0.00
O	Pen to Pen Dock				0.00		
E	Pen to Placer Dock				0.00		
E	Coal Net/S to WhiteCreek				0.00	0.00	0.00
F	Massey to Ceredo				0.00		
G	Mapco/S to Ceredo				0.00		
G	Franklin to Ceredo				0.00		
G	Quaker to Ceredo				0.00		
H	BlackHawk to Ceredo	#6			0.00 *		
I	OMay/S to Ceredo				0.00 *	0.00	0.00
J	KRT to KRT/Quincy		40,131.97				
J	Marmet/Eagle to KRT/Quincy		33,238.08				
K	BlackHawk/Spot to Quincy		42,515.54				
K	Black Hawk to KRT/Quincy	#5	3,395.70				
K	Black Hawk to KRT/Quincy	#6	5,100.56				
L	New River to KRT/Quincy		24,742.63			149,124.58	
S	Guasare/S to IMT						
S	Guasare/S to IMT					0.00	0.00
T	InterAmer/S to IMT					0.00	0.00
			149,124.58			149,124.58	
				Average Rate			

	RIVER TERMINAL	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
M	CBT/S to KCT			0.00		
M	KMay/S to KCT			0.00		
M	Sandy River/S to Cyrus Dock			0.00		
M	KMay/S to KCT Dock			0.00		
M	OMay/S to KCT			0.00		
M	Sandy Rvr(Pen) to Cyrus Dock			0.00	0.00	0.00
N	Pen to Pen Dock			0.00		
N	Pen to Placer Dock			0.00	0.00	0.00
N	Massey to Ceredo			0.00		
O	Mapco/S to Ceredo			0.00		
O	Frkln to Ceredo			0.00		
O	Quaker to Ceredo			0.00		
O	BlackHawk to Ceredo			0.00		
O	OMay/S to Ceredo			0.00	0.00	0.00
	T-Marmet/Eagle to Quincy	73,370.05		0.00		
	BlackHawk/Spot to Quincy	42,515.54		0.00		
P	Black Hawk to KRT/Quincy	8,496.36		0.00		
P	New River to KRT/Quincy	24,742.63		0.00	149,124.58	0.00
		149,124.58	0.00	0.00	149,124.58	0.00
			Average Rate			

	RIVER FREIGHT	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
M	From KCT/Cyrus Memco			0.00		
M	From KCT/Rvr Eagle ACBL/S			0.00		
M	From KCT/Rvr Eagle OHRV/S			0.00	0.00	0.00
N	From Pen/Whitcrk on ACBL/S			0.00		
N	From Pen/Placer on Memco			0.00		
N	From Pen/Whitcrk on OHRV/S			0.00	0.00	0.00
O	From Ceredo on Memco			0.00		
O	From Ceredo on OHRV/S			0.00		
O	From Ceredo on ACBL/S			0.00	0.00	0.00
P	From KRT/Quincy on OHRV/S			0.00		
P	From KRT/Quincy on Memco	149,124.58		0.00		
P	From Kanawha on ACBL/S			0.00	149,124.58	0.00
		149,124.58	0.00	0.00	149,124.58	0.00
			Average Rate			

	GULF TERMINAL - IMT	Tons	Cost/Ton	Dollars
I	From KCT Dk/Cyrus Dock			0.00
I	From Pen Dock/Placer Dk			0.00
I	From Ceredo/Ohio Rvr Dk			
I	From KRT/Quincy,Marmet	127,057.81		
	From Guasare/S			
	From InterAmer/S			
		127,057.81		
			Average Rate	

	GULF TERM-ECT&OTHER	Tons	Cost/Ton	Dollars
R	From KCT Dock			0.00
R	From Pen Dock			0.00
R	From Ceredo/Ohio Rvr Dk			0.00
R	From KRT/Quincy,Marmet			0.00
R	From Guasare/S			0.00
R	From InterAmer/S			0.00
		0.00		0.00
			Average Rate	

GULF FREIGHT	Tons	Cost/Ton	Dollars
From IMT	98,432.79	0.00	0.00
From Electro-Coal & Other		0.00	0.00
			0.00
			0.00
	98,432.79	0.00	0.00
		Average Rate	

LF FREIGHT	Tons	Cost/Ton	Dollars
is delivered-IMT	131,223.91		
ons delivered-Electro & Other			
	131,223.91		
		Average Rate	

PBC

PEF Pg. 55

PSC Staff W/P No. 45-1, Pg. 6 of 12

Electric Fuels Corporation
Regulated (FPC) Business
Inventory Accrual
July 2002

02-Aug-02
02:18 PM

CRYSTAL RIVER 4 AND 5

* denotes I/C

	COST OF COAL		Tons	Cost/Ton	Dollars		Total Tons	Total Dollars
A	CBT/S to KCT			[redacted]	0.00	*		
A	CBT/Replace to KCT				0.00	*		
A	CBT/S to KCT				0.00	*		
/	·yy/S to KCT				0.00	*		
:	dy River/S to Cyrus Dock				0.00			
B	..eabody/S to Rvr Eagle				0.00			
BB	KMay/S to KCT Dock				0.00	*		
C	DMay/S to KCT				0.00	*		
CC	Sandy Rvr(Pen) to Cyrus Dock				0.00		0.00	0.00
D	Pen to Pen Dock				0.00			
E	Pen to Placer Dock				0.00			
E	Coal Net/S to WhiteCreek				0.00		0.00	0.00
F	Massey to Ceredo				0.00			
G	Mapco/S to Ceredo				0.00			
G	Franklin to Ceredo				0.00			
G	Quaker to Ceredo				0.00			
H	BlackHawk to Ceredo	#6			0.00	*		
I	DMay/S to Ceredo				0.00	*	0.00	0.00
J	KRT to KRT/Quincy		56,128.20					
J	Marmet/Eagle to KRT/Quincy		26,127.11					
K	BlackHawk/Spot to Quincy		41,562.75					
K	Black Hawk to KRT/Quincy	#5	3,534.02					
K	Black Hawk to KRT/Quincy	#6	5,296.82					
L	New River to KRT/Quincy						132,645.10	[redacted]
S	Guasare/S to IMT		52,021.33					
S	Guasare/S to IMT						52,021.33	
T	InterAmer/S to IMT						0.00	
			184,866.43	[redacted]			184,866.43	

Average Rate

	RIVER TERMINAL	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
M	CBT/S to KCT			0.00		
M	KMay/S to KCT			0.00		
M	Sandy River/S to Cyrus Dock			0.00		
M	KMay/S to KCT Dock			0.00		
M	DMay/S to KCT			0.00		
M	Sandy Rvr(Pen) to Cyrus Dock			0.00	0.00	0.00
N	Pen to Pen Dock			0.00		
N	Pen to Placer Dock			0.00	0.00	0.00
N	Massey to Ceredo			0.00		
O	Mapco/S to Ceredo			0.00		
O	Frkln to Ceredo			0.00		
O	Quaker to Ceredo			0.00		
O	BlackHawk to Ceredo			0.00		
?	·lay/S to Ceredo			0.00	0.00	0.00
	·f-Marmet/Eagle to Quincy	82,252.31		0.00		
	·ackHawk/Spot to Quincy	41,562.75		0.00		
P	Black Hawk to KRT/Quincy	8,830.04		0.00		
P	New River to KRT/Quincy			0.00		
		132,645.10	0.00	0.00	132,645.10	0.00
			Average Rate		132,645.10	0.00

	RIVER FREIGHT	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
I	From KCT/Cyrus Memco			0.00		
I	From KCT/Rvr Eagle ACBL/S			0.00		
I	From KCT/Rvr Eagle OHRV/S			0.00	0.00	0.00
	From Pen/Whitark on ACBL/S			0.00		
	From Pen/Placer on Memco			0.00		
	From Pen/Whitark on OHRV/S			0.00	0.00	0.00
	From Ceredo on Memco			0.00		
	From Ceredo on OHRV/S			0.00		
	From Ceredo on ACBL/S			0.00	0.00	0.00
	From KRT/Quincy on OHRV/S			0.00		
	From KRT/Quincy on Memco	132,645.10		0.00		
	From Kanawha on ACBL/S			0.00	132,645.10	0.00
		132,645.10	0.00	0.00	132,645.10	0.00
			Average Rate			

GULF TERMINAL - IMT	Tons	Cost/Ton	Dollars		GULF TERM-ECT&OTHER	Tons	Cost/Ton	Dollars
From KCT OK/Cyrus Dock		[redacted]	0.00	R	From KCT Dock		[redacted]	0.00
From Pen Dock/Placer Dk			0.00	R	From Pen Dock			0.00
From Ceredo/Ohio Rvr Dk				R	From Ceredo/Ohio Rvr Dk			0.00
From KRT/Quincy,Marmet	150,231.57			R	From KRT/Quincy,Marmet			0.00
From Guasare/S	52,021.33			R	From Guasare/S			0.00
From InterAmer/S				R	From InterAmer/S			0.00
	202,252.90					0.00		0.00
		Average Rate					Average Rate	

GULF FREIGHT	Tons	Cost/Ton	Dollars
From IMT	211,915.53	0.00	0.00
From Electro-Coal & Other		0.00	0.00
			0.00
			0.00
	211,915.53	0.00	0.00
		Average Rate	

F FREIGHT	Tons	Cost/Ton	Dollars
·s delivered-IMT	195,415.53		
Tons delivered-Electro & Other		[redacted]	
	195,415.53		
		Average Rate	

PBC

PEF Pg. 56
PSC Staff W/P No. 45-1, Pg. 7 of 12

Electric Fuels Corporation
Regulated (FPC) Business
Inventory Accrual
August 2002

04-Sep-02
11:43 AM

CRYSTAL RIVER 4 AND 5

* denotes I/C

	COST OF COAL		Tons	Cost/Ton	Dollars		Total Tons	Total Dollars
A	CBT/S to KCT			[redacted]	0.00	*		
A	CBT/Replace to KCT				0.00	*		
A	CBT/S to KCT				0.00	*		
A	KMay/S to KCT				0.00	*		
[illegible]	[illegible]dy River/S to Cyrus Dock				0.00			
b	[illegible]abody/S to Rvr Eagle				0.00			
BB	KMay/S to KCT Dock				0.00	*		
C	OMay/S to KCT				0.00	*		
CC	Sandy Rvr(Pen) to Cyrus Dock				0.00		0.00	0.00
D	Pen to Pen Dock				0.00			
E	Pen to Placer Dock				0.00			
E	Coal Net/S to WhiteCreek				0.00		0.00	0.00
F	Massey to Caredo				0.00			
G	Mapco/S to Caredo				0.00			
G	Franklin to Caredo				0.00			
G	Quaker to Caredo				0.00			
H	BlackHawk to Caredo	#6			0.00	*		
I	OMay/S to Caredo				0.00	*	0.00	0.00
J	KRT to KRT/Quincy		53,816.34					
J	Marmet/Eagle to KRT/Quincy		37,816.53					
K	BlackHawk/Spot to Quincy		36,222.06					
K	Black Hawk to KRT/Quincy	#5	1,765.75					
K	Black Hawk to KRT/Quincy	#6	5,224.40					
L	New River to KRT/Quincy						134,839.08	[redacted]
S	Guasare/S to IMT							
S	Guasare/S to IMT						0.00	
T	InterAmer/S to IMT						0.00	
			134,839.08				134,839.08	
				Average Rate				

	RIVER TERMINAL	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
M	CBT/S to KCT			0.00		
M	KMay/S to KCT			0.00		
M	Sandy River/S to Cyrus Dock			0.00		
M	KMay/S to KCT Dock			0.00		
M	OMay/S to KCT			0.00		
M	Sandy Rvr(Pen) to Cyrus Dock			0.00	0.00	0.00
N	Pen to Pen Dock			0.00		
N	Pen to Placer Dock			0.00	0.00	0.00
N	Massey to Caredo			0.00		
O	Mapco/S to Caredo			0.00		
O	Fridn to Caredo			0.00		
O	Quaker to Caredo			0.00		
O	BlackHawk to Caredo			0.00		
O	OMay/S to Caredo			0.00	0.00	0.00
I	T-Marmet/Eagle to Quincy	91,628.87		0.00		
I	ckHawk/Spot to Quincy	36,222.06		0.00		
P	Black Hawk to KRT/Quincy	6,990.15		0.00		
P	New River to KRT/Quincy			0.00	134,839.08	0.00
		134,839.08	0.00	0.00	134,839.08	0.00
			Average Rate			

	RIVER FREIGHT	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
M	From KCT/Cyrus Memco			0.00		
M	From KCT/Rvr Eagle ACBL/S			0.00		
M	From KCT/Rvr Eagle OHRV/S			0.00	0.00	0.00
N	From PenWhitcrk on ACBL/S			0.00		
N	From Pen/Placer on Memco			0.00		
N	From PenWhitcrk on OHRV/S			0.00	0.00	0.00
O	From Caredo on Memco			0.00		
O	From Caredo on OHRV/S			0.00		
O	From Caredo on ACBL/S			0.00	0.00	0.00
P	From KRT/Quincy on OHRV/S			0.00		
P	From KRT/Quincy on Memco	134,839.08		0.00		
P	From Kanawha on ACBL/S			0.00	134,839.08	0.00
		134,839.08	0.00	0.00	134,839.08	0.00
			Average Rate			

	GULF TERMINAL - IMT	Tons	Cost/Ton	Dollars		GULF TERM-ECT&OTHER	Tons	Cost/Ton	Dollars
I	From KCT Dk/Cyrus Dock		[redacted]	0.00	R	From KCT Dock		[redacted]	0.00
I	From Pen Dock/Placer Dk			0.00	R	From Pen Dock			0.00
I	From Caredo/Ohio Rvr Dk			0.00	R	From Caredo/Ohio Rvr Dk			0.00
I	From KRT/Quincy,Marmet	140,192.20			R	From KRT/Quincy,Marmet			0.00
I	From Guasare/S				R	From Guasare/S			0.00
I	From InterAmer/S				R	From InterAmer/S			0.00
		140,192.20					0.00		0.00
			Average Rate					Average Rate	

	GULF FREIGHT	Tons	Cost/Ton	Dollars
	From IMT	231,312.41	0.00	0.00
	From Electro-Coal & Other		0.00	0.00
				0.00
				0.00
		231,312.41	0.00	0.00
			Average Rate	

	F FREIGHT	Tons	Cost/Ton	Dollars
	is delivered-IMT	214,460.62	[redacted]	
	ons delivered-Electro & Other			
		214,460.62		
			Average Rate	

PBC

PEF Pg. 57

PSC Staff W/P No. 45-1, Pg. 8 of 12

Electric Fuels Corporation
Regulated (FPC) Business
Inventory Accrual
September 2002

02-Oct-02
01:59 PM

CRYSTAL RIVER 4 AND 5

* denotes I/C

	COST OF COAL		Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
A	CBT/S to KCT				0.00 *		
A	CBT/Replace to KCT				0.00 *		
A	CBT/S to KCT				0.00 *		
	KMay/S to KCT				0.00 *		
	ndy River/S to Cyrus Dock				0.00		
	abody/S to Rvr Eagle				0.00		
BB	KMay/S to KCT Dock				0.00 *		
C	DMay/S to KCT				0.00 *		
CC	Sandy Rvr(Pen) to Cyrus Dock				0.00	0.00	0.00
D	Pen to Pen Dock				0.00		
E	Pen to Placer Dock				0.00		
E	Coal Nat/S to WhiteCreek				0.00	0.00	0.00
F	Massey to Ceredo				0.00		
G	Mapco/S to Ceredo				0.00		
G	Franklin to Ceredo				0.00		
G	Quaker to Ceredo				0.00		
H	BlackHawk to Ceredo	#6			0.00 *		
I	DMay/S to Ceredo				0.00 *	0.00	0.00
J	Marmet(KRT) to Marmet		68,634.49				
J	Marmet/Eagle to Marmet		35,475.13				
K	BlackHawk/Spot to Quincy		35,068.75				
K	Black Hawk to KRT/Quincy	#5	1,552.76				
K	Black Hawk to KRT/Quincy	#6	5,061.53				
K	BlackHawk(KRT) to Quincy		88.73				
L	New River to KRT/Quincy					143,880.39	
S	Guasare/S to IMT		50,981.66				
S	Guasare/S to IMT					50,981.66	
T	InterAmer/S to IMT					0.00	
			204,862.05			204,862.05	
				Average Rate			

	RIVER TERMINAL	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
A	CBT/S to KCT			0.00		
A	KMay/S to KCT			0.00		
A	Sandy River/S to Cyrus Dock			0.00		
B	KMay/S to KCT Dock			0.00		
C	DMay/S to KCT			0.00		
CC	Sandy Rvr(Pen) to Cyrus Dock			0.00	0.00	0.00
D	Pen to Pen Dock			0.00		
E	Pen to Placer Dock			0.00	0.00	0.00
F	Massey to Ceredo			0.00		
G	Mapco/S to Ceredo			0.00		
G	Frklin to Ceredo			0.00		
G	Quaker to Ceredo			0.00		
H	BlackHawk to Ceredo			0.00		
I	DMay/S to Ceredo			0.00	0.00	0.00
J	Marmet/Eagle to KRT/Marmet	102,110.82		0.00		
K	BlackHawk/Spot to KRT/Quincy	35,068.75		0.00		
K	Black Hawk to KRT/Quincy	6,703.02		0.00		
L	New River to KRT/Quincy			0.00	143,880.39	0.00
		143,880.39	0.00	0.00	143,880.39	0.00
			Average Rate			

	RIVER FREIGHT	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
	From KCT/Cyrus Memco			0.00		
	From KCT/Rvr Eagle ACBL/S			0.00		
	From KCT/Rvr Eagle OHRV/S			0.00	0.00	0.00
	From Pen/Whitcrk on ACBL/S			0.00		
	From Pen/Placer on Memco			0.00		
	From Pen/Whitcrk on OHRV/S			0.00	0.00	0.00
	From Ceredo on Memco			0.00		
	From Ceredo on OHRV/S			0.00		
	From Ceredo on ACBL/S			0.00	0.00	0.00
	From KRT/Quincy on OHRV/S			0.00		
	Frm KRT/Quincy,Marmet on Memco	143,880.39		0.00		
	From Kanawha on ACBL/S			0.00	143,880.39	0.00
		143,880.39	0.00	0.00	143,880.39	0.00
			Average Rate			

	GULF TERMINAL - IMT	Tons	Cost/Ton	Dollars		GULF TERM-ECT&OTHER	Tons	Cost/Ton	Dollars
	From KCT DK/Cyrus Dock			0.00	R	From KCT Dock			0.00
	From Pen Dock/Placer Dk			0.00	R	From Pen Dock			0.00
	From Ceredo/Ohio Rvr Dk			0.00	R	From Ceredo/Ohio Rvr Dk			0.00
	From KRT/Quincy,Marmet	106,923.39			R	From KRT/Quincy,Marmet			0.00
	From Guasare/S	50,981.66			R	From Guasare/S			0.00
	From InterAmer/S				R	From InterAmer/S			0.00
		157,905.05					0.00		0.00
			Average Rate					Average Rate	

	GULF FREIGHT	Tons	Cost/Ton	Dollars
	From IMT	130,941.04	0.00	0.00
	From Electro-Coal & Other		0.00	0.00
				0.00
				0.00
		130,941.04	0.00	0.00
			Average Rate	

	FREIGHT	Tons	Cost/Ton	Dollars
	ons delivered-IMT	131,741.47		
	ons delivered-Electro & Other			
		131,741.47		
			Average Rate	

PBC

PEF Pg. 58

PSC Staff W/P No. 45-1, Pg. 9 of 12

Electric Fuels Corporation
Regulated (FPC) Business
Inventory Accrual
October 2002

04-Nov-02
02:22 PM

CRYSTAL RIVER 4 AND 5

* denotes I/C

	COST OF COAL		Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
A	CBT/S to KCT				0.00 *		
A	CBT/Replace to KCT				0.00 *		
A	CBT/S to KCT				0.00 *		
	ry/S to KCT				0.00 *		
	ly River/S to Cyrus Dock				0.00		
B	..bbody/S to Rvr Eagle				0.00		
BB	KMay/S to KCT Dock				0.00 *		
C	OMay/S to KCT				0.00 *		
CC	Sandy Rvr(Pen) to Cyrus Dock				0.00	0.00	0.00
D	Pen to Pen Dock				0.00		
E	Pen to Placer Dock				0.00		
E	Coal Nat/S to WhiteCreek				0.00	0.00	0.00
F	Massey to Caredo				0.00		
G	Mapco/S to Caredo				0.00		
G	Franklin to Caredo				0.00		
G	Quaker to Caredo				0.00		
H	BlackHawk to Caredo	#6			0.00 *		
I	DMay/S to Caredo				0.00 *	0.00	0.00
J	Marmet(KRT) to Marmet		31,059.49				
J	Marmet/Eagle to Marmet		29,415.04				
K	BlackHawk/Spot to Quincy		42,528.10				
K	Black Hawk to KRT/Quincy	#5	1,583.22				
K	Black Hawk to KRT/Quincy	#6	5,115.22				
K	BlackHawk(KRT) to Quincy		16,548.09				
L	New River to KRT/Quincy					126,329.16	
S	Guasare/S to IMT		58,766.98				
S	Guasare/S to IMT					58,766.98	
T	InterAmer/S to IMT					0.00	
			185,096.12			185,096.12	
				Average Rate			

	RIVER TERMINAL	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
M	CBT/S to KCT			0.00		
M	KMay/S to KCT			0.00		
M	Sandy River/S to Cyrus Dock			0.00		
M	KMay/S to KCT Dock			0.00		
M	OMay/S to KCT			0.00		
M	Sandy Rvr(Pen) to Cyrus Dock			0.00	0.00	0.00
N	Pen to Pen Dock			0.00		
N	Pen to Placer Dock			0.00	0.00	0.00
N	Massey to Caredo			0.00		
O	Mapco/S to Caredo			0.00		
O	Frkln to Caredo			0.00		
O	Quaker to Caredo			0.00		
O	...ckHawk to Caredo			0.00		
	...y/S to Caredo			0.00		
	...met/Eagle to KRT/Marmet	80,474.53		0.00	0.00	0.00
	BlackHawk/Spot to KRT/Quincy	42,528.10		0.00		
	Black Hawk to KRT/Quincy	23,326.53		0.00		
	New River to KRT/Quincy			0.00		
		126,329.16	0.00	0.00	126,329.16	0.00
			Average Rate		126,329.16	0.00

	RIVER FREIGHT	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
	From KCT/Cyrus Memco			0.00		
	From KCT/Rvr Eagle ACBL/S			0.00		
	From KCT/Rvr Eagle OHRV/S			0.00	0.00	0.00
	From Pen/Whitark on ACBL/S			0.00		
	From Pen/Placer on Memco			0.00		
	From Pen/Whitark on OHRV/S			0.00	0.00	0.00
	From Caredo on Memco			0.00		
	From Caredo on OHRV/S			0.00		
	From Caredo on ACBL/S			0.00	0.00	0.00
	From KRT/Quincy on OHRV/S			0.00		
	Frm KRT/Quincy,Marmet on Memco	126,329.16		0.00		
	From Kanawha on ACBL/S			0.00	126,329.16	0.00
		126,329.16	0.00	0.00	126,329.16	0.00
			Average Rate			

	GULF TERMINAL - IMT	Tons	Cost/Ton	Dollars
	From KCT Dk/Cyrus Dock			0.00
	From Pen Dock/Placer Dk			0.00
	From Caredo/Ohio Rvr Dk			0.00
	From KRT/Quincy,Marmet	162,590.90		
	From Guasare/S	58,766.98		
	From InterAmer/S			
		221,357.88		
			Average Rate	

	GULF TERM-ECT&OTHER	Tons	Cost/Ton	Dollars
R	From KCT Dock			0.00
R	From Pen Dock			0.00
R	From Caredo/Ohio Rvr Dk			0.00
R	From KRT/Quincy,Marmet			0.00
R	From Guasare/S			0.00
R	From InterAmer/S			0.00
		0.00		0.00

GULF FREIGHT	Tons	Cost/Ton	Dollars
From IMT	164,778.91	0.00	0.00
From Electro-Coal & Other		0.00	0.00
			0.00
			0.00
	164,778.91	0.00	0.00
		Average Rate	

...F FREIGHT	Tons	Cost/Ton	Dollars
...ons delivered-IMT	181,104.33		
Tons delivered-Electro & Other			
	181,104.33		

PBC

PEF Pg. 59
PSC Staff W/P No. 45-1, Pg. 10 of 12

Electric Fuels Corporation
Regulated (FPC) Business
Inventory Accrual
November 2002

03-Dec-02
02:53 PM

CRYSTAL RIVER 4 AND 5

* denotes I/C

	COST OF COAL		Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
A	CBT/S to KCT				0.00 *		
A	CBT/Replace to KCT				0.00 *		
A	CBT/S to KCT				0.00 *		
A	[illegible]y/S to KCT				0.00 *		
E	[illegible]y River/S to Cyrus Dock				0.00		
B	[illegible]eabody/S to Rvr Eagle				0.00		
BB	KMay/S to KCT Dock				0.00 *		
C	OMay/S to KCT				0.00 *		
CC	Sandy Rvr(Pen) to Cyrus Dock				0.00	0.00	0.00
D	Pen to Pen Dock				0.00		
E	Pen to Placer Dock				0.00		
E	Coal Net/S to WhiteCreek				0.00	0.00	0.00
F	Massey to Ceredo				0.00		
G	Mapco/S to Ceredo				0.00		
G	Franklin to Ceredo				0.00		
G	Quaker to Ceredo				0.00		
H	BlackHawk to Ceredo	#6			0.00 *		
I	OMay/S to Ceredo				0.00 *	0.00	0.00
J	Marmet(KRT) to Marmet		38,165.89				
J	Marmet/Eagle to Marmet		29,464.06				
K	BlackHawk/Spot to Quincy		48,396.19				
K	Black Hawk to KRT/Quincy	#5	1,876.96				
K	Black Hawk to KRT/Quincy	#6	8,819.67				
K	BlackHawk(KRT) to Quincy						
L	New River to KRT/Quincy					126,722.59	[redacted]
S	Guasare/S to IMT						
S	Guasare/S to IMT					0.00	
T	InterAmer/S to IMT					0.00	
			126,722.59			126,722.59	

	RIVER TERMINAL	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
M	CBT/S to KCT			0.00		
M	KMay/S to KCT			0.00		
M	Sandy River/S to Cyrus Dock			0.00		
M	KMay/S to KCT Dock			0.00		
M	OMay/S to KCT			0.00		
M	Sandy Rvr(Pen) to Cyrus Dock			0.00	0.00	0.00
M	Pen to Pen Dock			0.00		
M	Pen to Placer Dock			0.00	0.00	0.00
M	Massey to Ceredo			0.00		
M	Mapco/S to Ceredo			0.00		
M	Frklin to Ceredo			0.00		
M	Quaker to Ceredo			0.00		
M	[illegible]kHawk to Ceredo			0.00		
M	[illegible]y/S to Ceredo			0.00	0.00	0.00
M	[illegible]rmet/Eagle to KRT/Marmet	67,829.77		0.00		
M	BlackHawk/Spot to KRT/Quincy	48,396.19		0.00		
M	Black Hawk to KRT/Quincy	10,696.63		0.00		
M	New River to KRT/Quincy			0.00		
		126,722.59	0.00	0.00	126,722.59	0.00
			Average Rate		126,722.59	0.00

RIVER FREIGHT	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
From KCT/Cyrus Memco			0.00		
From KCT/Rvr Eagle ACBL/S			0.00		
From KCT/Rvr Eagle OHRV/S			0.00	0.00	0.00
From Pen/Whitcrk on ACBL/S			0.00		
From Pen/Placer on Memco			0.00		
From Pen/Whitcrk on OHRV/S			0.00	0.00	0.00
From Ceredo on Memco			0.00		
From Ceredo on OHRV/S			0.00		
From Ceredo on ACBL/S			0.00	0.00	0.00
From KRT/Quincy on OHRV/S			0.00		
Frm KRT/Quincy,Marmet on Memco	126,722.59		0.00		
From Kanawha on ACBL/S			0.00	126,722.59	0.00
	126,722.59	0.00	0.00	126,722.59	0.00
		Average Rate			

GULF TERMINAL - IMT	Tons	Cost/Ton	Dollars
From KCT OK/Cyrus Dock		[redacted]	0.00
From Pen Dock/Placer Dk			0.00
From Ceredo/Ohio Rvr Dk			0.00
From KRT/Quincy,Marmet	118,573.02		
From Guasare/S			
From InterAmer/S			
	118,573.02		

GULF TERM-ECT&OTHER		Tons	Cost/Ton	Dollars
R	From KCT Dock		[redacted]	0.00
R	From Pen Dock			0.00
R	From Ceredo/Ohio Rvr Dk			0.00
R	From KRT/Quincy,Marmet			0.00
R	From Guasare/S			0.00
R	From InterAmer/S			0.00
		0.00	#DIV/0!	0.00
			Average Rate	

GULF FREIGHT	Tons	Cost/Ton	Dollars
From IMT	155,917.25	0.00	0.00
From Electro-Coal & Other		0.00	0.00
			0.00
			0.00
	155,917.25	0.00	0.00
		Average Rate	

GULF FREIGHT	Tons	Cost/Ton	Dollars
Tons delivered-IMT	110,063.55		
Tons delivered-Electro & Other			
	110,063.55	[redacted]	

PEF Pg. 60
PSC Staff W/P No. 45-1, Pg. 11 of 12

PROGRESS FUELS CORPORATION
WATERBORNE TRANSPORTATION AUDIT
INVENTORY ACCRUAL
12 MONTHS ENDED 12/31/02

Electric Fuels Corporation
Regulated (FPC) Business
Inventory Accrual
December 2002

03-Jan-03
12:18 PM

CRYSTAL RIVER 4 AND 5

* denotes I/C

COST OF COAL		Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
CBT/S to KCT				0.00 *		
CBT/Replace to KCT				0.00 *		
CBT/S to KCT				0.00 *		
ty/S to KCT				0.00 *		
Jy River/S to Cyrus Dock				0.00 *		
eabody/S to Rvr Eagle				0.00		
KMay/S to KCT Dock				0.00		
DMay/S to KCT				0.00 *		
Sandy Rvr(Pen) to Cyrus Dock				0.00 *		
Pen to Pen Dock				0.00	0.00	0.00
Pen to Placer Dock				0.00		
Coal Net/S to WhiteCreek				0.00		
Massey to Canada				0.00	0.00	0.00
Mapco/S to Canada				0.00		
Franklin to Canada				0.00		
Quaker to Canada				0.00		
BlackHawk to Canada	#6			0.00		
DMay/S to Canada				0.00 *		
BlackHawk/Spot to Marmet		9,869.13		0.00 *	0.00	0.00
Marmet/Eagle to Marmet		29,098.48				
BlackHawk/Spot to Quincy		36,572.12				
Black Hawk to KRT/Quincy	#5					
Black Hawk to KRT/Quincy	#6					
BlackHawk(KRT) to Quincy		58,346.01				
New River to KRT/Quincy					133,887.74	
Dussare/S to IMT						
Dussare/S to IMT					0.00	
Emerald/S to IMT		1,400.70			1,400.70	
		135,288.44			135,288.44	
			Average Rate			

RIVER TERMINAL	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
BT/S to KCT			0.00		
May/S to KCT			0.00		
andy River/S to Cyrus Dock			0.00		
May/S to KCT Dock			0.00		
May/S to KCT			0.00		
andy Rvr(Pen) to Cyrus Dock			0.00		
n to Pen Dock			0.00	0.00	0.00
n to Placer Dock			0.00		
assay to Canada			0.00	0.00	0.00
apco/S to Canada			0.00		
lin to Canada			0.00		
aker to Canada			0.00		
ckHawk to Canada			0.00		
n/S to Canada			0.00		
rmet/BHS to KRT/Marmet	37,967.61		0.00	0.00	0.00
ackHawk/Spot to KRT/Quincy	36,572.12		0.00		
ack Hawk to KRT/Quincy	58,346.01		0.00		
w River to KRT/Quincy			0.00		
	133,887.74	0.00	0.00	133,887.74	0.00
		Average Rate		133,887.74	0.00

VER FREIGHT	Tons	Cost/Ton	Dollars	Total Tons	Total Dollars
m KCT/Cyrus Memco			0.00		
m KCT/Rvr Eagle ACBL/S			0.00		
m KCT/Rvr Eagle OHRV/S			0.00	0.00	0.00
m Pen/Whitork on ACBL/S			0.00		
m Pen/Placer on Memco			0.00		
m Pen/Whitork on OHRV/S			0.00	0.00	0.00
m Canada on Memco			0.00		
m Canada on OHRV/S			0.00		
m Canada on ACBL/S			0.00	0.00	0.00
m KRT/Quincy on OHRV/S			0.00		
KRT/Quincy,Marmet on Memco	132,058.02		0.00		
m Kanawha on ACBL/S			0.00		
	132,058.02	0.00	0.00	132,058.02	0.00
		Average Rate		132,058.02	0.00

F TERMINAL - IMT	Tons	Cost/Ton	Dollars
n KCT Dk/Cyrus Dock			
n Pen Dock/Placer Dk			
n Canada/Ohio Rvr Dk			
n KRT/Quincy,Marmet	124,556.26		
n Gussares/S			
n Emerald/S	1,400.70		
	125,956.96		
		Average Rate	

GULF TERM-ECT&OTHER	Tons	Cost/Ton	Dollars
R From KCT Dock			0.00
R From Pen Dock			0.00
R From Canada/Ohio Rvr Dk			0.00
R From KRT/Quincy,Marmet			0.00
R From Gussares/S			0.00
R From InterAmer/S			0.00
	0.00		0.00

F FREIGHT	Tons	Cost/Ton	Dollars
n IMT	170,538.81	0.00	0.00
n Electro-Coal & Other		0.00	0.00
			0.00
			0.00
	170,538.81	0.00	0.00
		Average Rate	

F FREIGHT	Tons	Cost/Ton	Dollars
delivered-IMT	186,408.07		
delivered-Electro & Other			
	186,408.07		

Dixie Freight - Gulf

PBC

SOURCE: Workpapers showing number of tons and cost for each transportation company

PEF Pg. 61

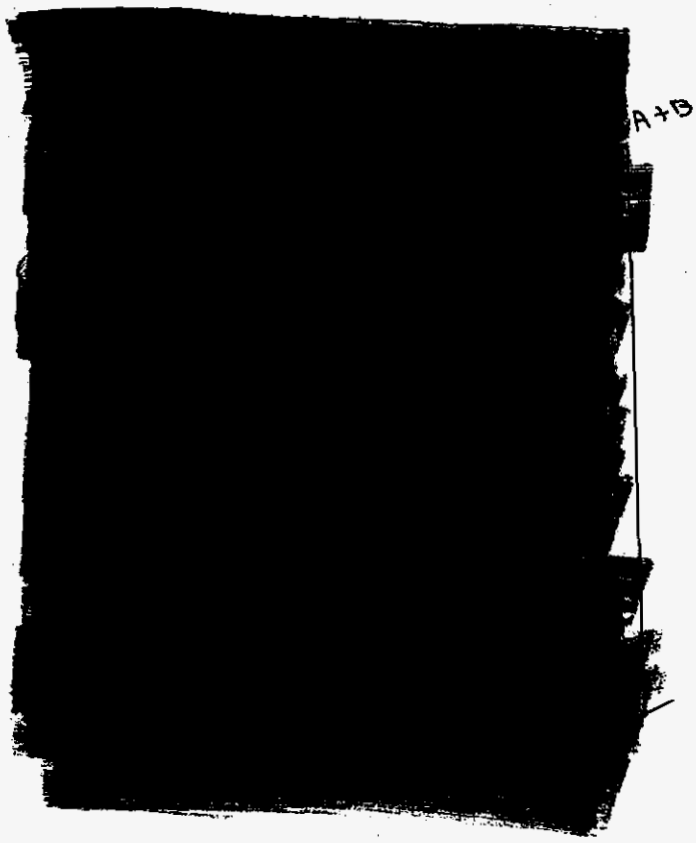
PSC Staff W/P No. 45-1, Pg. 12 of 12

INTEGRITY BUSINESS FORMS, INC. (847) 696-2626 FAX (847) 696-4606

COMPANY: PROGRESS FUELS CORPORTAION
SUBJECT: AVERAGE TRANSPORTATION COSTS
PERIOD: 12 MONTHS ENDED DECEMBER 31, 2002
AUDITOR: J. W. ROHRBACHER

AUDIT: WATERBORNE TRANSPORTATION
FILENAME: A-5 TO GL RECON.123
SHEET: PFC TRANSPORTATION

Month	Tons to CR From IMT
Jan-02	160,132
CR 1 & 2	7,579
Feb-02	190,208
Mar-02	159,646
Apr-02	178,833
May-02	179,167
Jun-02	131,224
Jul-02	195,418
Aug-02	214,461
Sep-02	131,741
Oct-02	181,104
Nov-02	110,064
Dec-02	186,405
	2,025,980



Avg Gulf Freight
Avg Other Transp

Avg Water Transp



SOURCE: Acct 5380-010, JE02E (From IMT inventory accrua

Docket No. 030001-EI
Exhibit JWR-5 (Page 35 of 39)
Selected Audit Work Papers

ELECTRIC FUELS CORPORATION
ONE PROGRESS PLAZA, P.O. BOX 15208, ST. PETERSBURG, FLORIDA 33733, (727) 824-6600

January 2, 2002

Mr. Michael Gatens
Vice President
Kanawha River Terminals, Inc.
150 Dairy Lane
Belle, West Virginia 25015

Dear Mr. Gatens:

[redacted]

If you are in agreement with the above, please sign both originals, return one original to me, and retain one original for your files.

Sincerely,

PROGRESS FUELS CORPORATION

F. Michael Lelak
Manager, CSX/Barge Transportation

FML/ro

Agreed to and accepted this the 5 day of Jan 2002.

KANAWHA RIVER TERMINALS, INC.

By: _____
Michael Gatens, Vice President

DRC

SOURCE: PBC

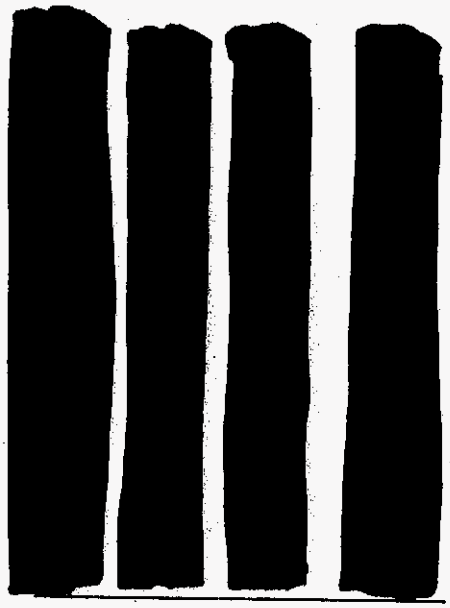
EGRITY BUSINESS FORMS, INC. (847) 956-2626 FAX (847) 956-4606

COMPANY: PROGRESS FUELS CORPORTAION
SUBJECT: AVERAGE COAL & TRANSPORTATION CHARGES TO PEF
PERIOD: 12 MONTHS ENDED DECEMBER 31, 2002
AUDITOR: J. W. ROHRBACHER Sep 03

AUDIT: WATERBORNE TRANSPORTATION
FILENAME: A-5 TO GL RECON.123
SHEET: ~~REC TRANSPORTATION~~ Avg Cost

Month	Tons to CR From IMT	Average Coal Cost Per Ton	Total Coal Cost
Jan-02	160,132		
CR 1 & 2	7,579		
Feb-02	190,206		
Mar-02	159,646		
Apr-02	176,833		
May-02	179,167		
Jun-02	131,224		
Jul-02	195,416		
Aug-02	214,461		
Sep-02	131,741		
Oct-02	181,104		
Nov-02	110,064		
Dec-02	186,405		
	2,025,980		

Avg Coal Cost
Avg Transp
Avg Total Cost to PEF



SOURCE: Acct 5380-010, JE02E (From IMT Inventory accrual)

W/P 47-1

COMPANY: PROGRESS ENERGY FLORIDA
SUBJECT: COAL SOLICITATION PROPOSELS
PERIOD: 12 MONTHS ENDED DECEMBER 31, 2002
AUDITOR: J. W. ROHRBACHER

AUDIT: WATERBORNE TRANSPORTATION
FILENAME: COAL PURCHASE.123
SHEET: BID RESPONSE

Response to PFC coal purchase bid packages

Company	FOB Mine Bid 2002	Transp Cost	Total Bid Price	Term of Contract	Submitted Bid	Accepted By PFC	Used in 2002
Black Hawk Synfuel LLC					Yes	Yes	Yes
Massey Utility Sales Company		0.00 0.00			Yes	Yes	Yes
ENRON (Panther Coal)		0.00			Yes	Yes	Yes
Alliance Coal, LLC		0.00			Yes	Yes	Yes
AEI Coal Sales Co.					No		
Clinchfield Coal Company		0.00			Yes	No	
Appalachian Fuels, LLC		0.00			Yes	No	
Arch Coal Sales		0.00 0.00 0.00			Yes		No
Cardigan Coal & Coke Corporation					No		
Coal Energy Resources, Inc.					No		
Commonwealth Coal services, Inc.		0.00			Yes	No	
Electric Fuels Corporation ? Cincinnati, Ohio					No		
Guasare Coal America, Inc.		0.00			Yes	Yes	Yes
James River Coal Sales					No		
Kentucky-Cumberland Coal Company					No		
Pen Coal Corporation					No		
PS Energy Group					No		
RAG Coal Sales of America					No		
Smoky Mountain Coal Corporation					No		
Solar Services, Inc.		0.00			Yes	No	
Triton Coal Company, LLC					Yes	No	

SOURCE: Bid Proposals

W/P 47-2

PEF Pg. 80
PSC Staff W/P No. 47-2

CONFIDENTIAL

Company: Florida Power Corporation
Subject: Analysis of the Escalation of the Costs of Waterborne Coal Transportation
Period: Year Ended 12/31/02.

Filename: Waterborne Coal Transportation
Range: A37_Y115
Auditor: Tom Stambaugh 04/02/03

Purpose: Verify that the escalation of the benchmark price for waterborne coal transportation has been calculated accurately and with the use of the proper factors and weighting of factors.

Verification of Calculation of Basic Components of Benchmark Price and Escalation:

Escalation of Total Benchmark Price by Total Change

			(CY 1993) Base Year		(CY 1994) Escalated Year		(CY 1995) Escalated Year		(CY 1996) Escalated Year		(CY 1997) Escalated Year		(CY 1998) Escalated Year		(CY 1999) Escalated Year		(CY 2000) Escalated Year		(CY 2001) Escalated Year		(CY 2002) Escalated Year
Benchmark price as recalculated by auditor	$23.00	1.342%	$23.31	-0.830%	$23.30	2.465%	$23.87	6.235%	$25.36	-0.436%	$25.25	-5.216%	$23.93	5.460%	$25.24	15.780%					
Benchmark price as recalculated by Utility	$23.00	1.340%	$23.31	-0.830%	$23.30	2.460%	$23.87	6.240%	$25.36	-0.440%	$25.25	-5.220%	$23.93	5.460%	$25.24	15.780%					
Unaccounted Difference	$0.00		$0.00		$0.00		($0.00)		($0.00)		($0.00)		$0.00		$0.00						

48-2

Verification of Weighted Percentage Change:

Component	Weights	Factors By year	(CY 1993) Base Year	Factors By year	(CY 1994) Escalated Year	Factors By year	(CY 1995) Escalated Year	Factors By year	(CY 1996) Escalated Year	Factors By year	(CY 1997) Escalated Year	Factors By year	(CY 1998) Escalated Year	Factors By year	(CY 1999) Escalated Year	Factors By year	(CY 2000) Escalated Year	Factors By year	(CY 2001) Escalated Year	Factors By year	(CY 2002) Escalated Year
Fixed																					
Consumer Price Index-U																					
Rail Cost Adjustment Factor-Unadjusted																					
Producer Price Index-All Commodities																					
Average Hourly Earnings Index																					
Producer Price Index-#2 Diesel Fuel																					
Calculation of Weighted Factors																					
Calculations by Utility																					
Unaccounted Difference																					

Conclusion: The Utility has apparently used the weighted average of the factors to calculate the annual escalation of the benchmark price. Accept the Utility calculation of the benchmark price.

Source: FAC Audit

PROGRESS FUELS CORPORATION
WATERBORNE TRANSPORTATION AUDIT
UTILITY CALCULATION OF TRANSPORTATION RATE
12 MONTHS ENDED 12/31/02

PROGRESS FUELS CORPORATION
Average Indices - FPC Waterborne Rate
2002 Rate

CONFIDENTIAL

Waterborne rate estimated based upon YTD average indices.

	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	AVERAGE 2001	AVERAGE 2000	% CHG	WATER RATE 2001	WATER RATE 2002	Variance
FIXED																		
CPI-U																		
RCAF-U																		
rebased PPI-ALL COMMODITIES																		
AHE-TOTAL PRIVATE																		
PPI-#2 DIESEL FUEL																		
100%													TOTAL WEIGHTED AVERAGE PERCENT CHANGE					
													Waterway User Tax.					
													Total Waterborne rate					
													Offshore rate - 50.2%					

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PEF Pg. 82

PSC Staff W/P No. 48-1

Comparison of Average Annual Growth Rates of PEFI DWCTS Market Price Proxy versus Multi-mode Coal Transportation Market
Years 1993-1997

A Year	B* PEFI's Market Price Proxy ($/ton	C** Mileage Adjustment	D CPI-U Average Annual Growth Rate	E PEFI's Market Price Proxy Growth Rate (adjusted for mileage and CPI-U)	F*** Avg. Rate Per Ton-Mile Multi-mode (mills in1996 $)	G Avg. Rate Per Ton-Mile Multi-mode Growth Rate
1992	$23.00				13.7	
1993	[redacted]	0.8%	2.99%	[redacted]%	13.1	-4.38%
1994	[redacted]	0.8%	2.56%	[redacted]%	13.2	0.76%
1995	[redacted]	0.8%	2.83%	[redacted]%	12.0	-9.09%
1996	[redacted]	0.8%	2.96%	[redacted]%	11.1	-7.50%
1997	[redacted]	0.8%	2.29%	[redacted]%	11.4	2.70%
Average Growth Rate, 1993 to 1997				[redacted]%		-3.50%

* Source: Staff Audit WP-81
** Source: Florida 423 Forms, 1992 and 1997 (tons, counties); coal industry transportation maps (various)
*** Source: Energy Information Administration, "Average Utility Contract Coal Transportation Rate per Ton-Mile by Transportation Mode, 1979-1997 (Mills in 1996 Dollars); http://www.eia.doe.gov/cneaf/ctrdb/tab37.html, printed 10/10/2003

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 35
COMPANY/ FPSC Staff
WITNESS: WBM-1 thru WBM-3
DATE: 11-12-03

PFC'S 2002 DOMESTIC AND FOREIGN WCTS MARGINS
(FOR COAL TRANSPORT ON BEHALF OF PEFI)

Domestic WCTS Margin

A	B	C
	Per Unit Analysis ($/ton)	Total Revenue and Cost Analysis (B x 2002 domestic tons) (4)
Market Price Proxy (1)	[redacted]	[redacted]
Direct Costs (2)	[redacted]	[redacted]
Indirect Costs (3)	$0.37	$656,608
Total Costs	[redacted]	[redacted]
Margin	[redacted]	[redacted]
Margin Percentage	[redacted]	[redacted]

(1) Source: Staff Audit Workpaper WP-82
(2) Source: PEFI Response to Staff Interrogatory No. 16. See also 10/10/03 deposition of PEFI Witness Javier Portuondo - specifically, his estimated correction (midpoint) to the interrogatory response:
[redacted] Direct Costs less ($2.00 + $3.00)/2 Correction = [redacted]
(3) Source: Indirect Costs based on deposition of PEFI Witness Javier Portuondo and Interpretation of Order No. PSC-93-1331-FOF-EI. Estimate doesn't recognize Dixie Fuel Lines O&M costs but does recognize PFC's G&A costs;
($.75M G&A x [redacted]%total tons)[redacted] domestic tons = $0.37/ton
(4) Tonnage per PEFI response to Staff Interrogatory No. 15.

Foreign WCTS Margin

A	B	C
	Per Unit Analysis	Revenue and Cost Analysis (B x 2002 foreign tons) (4)
Market Price Proxy (1)	[redacted]	[redacted]
Direct Costs (2)	[redacted]	[redacted]
Indirect Costs (3)	$0.37	$103,525
Total Costs	[redacted]	[redacted]
Margin	[redacted]	[redacted]
Margin Percentage	[redacted]	[redacted]

(1) Source: Staff Audit Workpaper WP-82
(2) Source: PEFI Response to Staff Interrogatory No. 16. See also 10/10/03 deposition of PEFI Witness Javier Portuondo.
(3) Source: Indirect Costs based on deposition of PEFI Witness Javier Portuondo and Interpretation of Order No. PSC-93-1331-FOF-EI. Estimate doesn't recognize Dixie Fuel Lines O&M costs but does recognize PFC's G&A costs;
(($.75M G&A x [redacted]% total tons)[redacted] tons =$0.37/ton
(4) Tonnage per PEFI response to Staff Interrogatory No. 15.

Comparison of PEFI Market Price Proxy Escalators to Barge Industry Cost Profile

Row		PEFI's Escalators, WCTS (1)	PEFI's Weightings, WCTS (1)	REEBIE BCAM Cost Percent (2)	REEBIE BCAM Cost Descriptors
1	Fixed Costs		10%	58%	Towboat and Barge
2		Sum of Fixed Costs	10%	58%	
3					
4	Variable Costs				
5		Average Hourly Earnings	[redacted]%	11%	Wages
6		Consume Price Index-U	[redacted]%	9%	Overhead
7		Produce Price Index	[redacted]%	1%	Fleeting
8		Rail Cost Adj. Factor-U	[redacted]%	NA	
9		No. 2 Diesel	[redacted]%	16%	Fuel
10			NA	5%	Profit
11		Sum of Variable Costs (Rows 5-10)	90%	42%	
12					
13	Total, Fixed and Variable Costs		100%	100%	

(1) 'Source: Staff Audit WP-81
(2) Source: REEBIE Barge Transportation Cost Model Webpage
http://www.reebie.com/images/BCAM.htm

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 001148-EI

AUGUST 15, 2001

DOCUMENT NUMBER-DATE
10016 AUG 15 01
FPSC-COMMISSION CLERK

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 36
COMPANY/ FPSC Staff
WITNESS: MGB-1 thru MGB-3
DATE: 11-12-03

Adjustment for Transmission Costs in Base Rates

In order to ensure that there is no double recovery, FPL's proposed methodology calls for the GridFlorida costs to be adjusted for Transmission Costs in Base Rates. Each year the amount of transmission costs currently in base rates is to be adjusted for sales as described below. This amount would then be subtracted from the GridFlorida costs before inclusion in the Capacity Cost Recovery Factor calculation. For illustrative purposes, we have used the preliminary 2000 Cost of Service. (See KMD-1, Page 5 of 6). This shows that the imbedded cost of retail transmission service in 2000 is $265 million. However, this amount will be updated to reflect the results of the 2002 cost of service. This $265 million would be divided by actual 2000 MWh sales of 87,959,341 which results in 0.3013 cents per kWh. This 0.3013 cents per kWh multiplied by the projected 2003 MWh sales of 98,415,270 results in $296.5 million transmission costs included in base rates adjusted for sales. This results in the transmission cost in base rates escalated to 2003 to reflect the increase in sales in 2003. (See KMD-1, Page 2 of 6, Note 1). This $296.5 million (KMD-1, Page 2 of 6, Line 6) is then subtracted from the total payment to GridFlorida of $366 million (KMD-1, Page 2 of 6, Line 5) resulting in a difference of $69.5 million (KMD-1, Page 2 of 6, Line 7).

Adjustment for Oil Backout

One other adjustment FPL proposes is to reflect an Oil Back-out flow back to

A. FPL believes it is appropriate for the Commission to expressly approve the methodology to recover the GridFlorida transmission costs, to the extent they exceed the amount reflected in base rates, through the Capacity Cost Recovery Clause. Such approval would; 1) avoid double recovery, 2) avoid under/over recovery of costs, 3) would be administratively efficient and would greatly facilitate review of the level and basis for transmission costs in the future, and 4) appear to be the type of costs the Commission acknowledged would be appropriate in establishing the Capacity Cost Recovery Clause.

First, FPL's proposed methodology, whereby the GridFlorida transmission costs recovered through the Capacity Cost Recovery Clause are adjusted for the amount included in base rates, avoids double recovery of these costs.

Second, these incremental transmission costs are volatile and as such are more appropriately reflected in a clause to avoid over/under recovery of costs. As described in the Joint Panel Testimony regarding the GridFlorida proposal, the Joint Applicants currently have pending requests for interconnection of 53 plants representing 26,468 MW of non-utility owned generation to come on line between 2001 and 2005. The speed with which future interconnections are made is uncertain and will result in unpredictable fluctuations in GridFlorida's System Charge. There is also fluctuation in costs due to the various transition proposals of the pricing plan. As described in GridFlorida Witness William Ashburn's prepared Direct Testimony, the cost shifting

Example Gross-up Calculation

MGB-2

		Base Year 1984		Current Yr 2001	Actual 2001		Gross-up Without	Gross-up With
RATE BASE (AVERAGE)		$1,000		$1,653				
RATE OF RETURN	X	7.00%	X	7.00%				
REQUIRED NOI		$70		$116				
Operating Revenues		$300		$496				
Adj. for Excess Revenues								
Operating Expenses:								
Operation & Maintenance		$127		$210				
Sample Expense		23		38	34		$34	$34
(On cents per KWH basis:		0.767		0.767	0.686	)	($23)	($38)
							$11	($4)
Depreciation		60		99				
Taxes		20		33				
Total Operating Expenses		$230		$380				
PROJECTED NOI		$70		$116				
KWH experienced		3000		4,959				
Base Rate		$0.10		$0.10				

Growth in energy sold 3% per year

Conclusion: Without grossing up, although base recovery of .767 cents/KWH is more than sufficient to recover the sample expense, $11 (or .081 cents/KWH) too much is recovered through a clause. This extra amount is double recovered.

With grossing up in this example, it is recognized that base rates are sufficient to recover growth-related increases in the sample expense.

Example Gross-up Calculation with Refund

MGB-3

		MFR 1984		Proj. Before Cap 2001	Adjustments		Proj. After Cap 2001	Actual 2001
RATE BASE (AVERAGE)		$1,000		$1,653			$1,653	
RATE OF RETURN	X	7.00%	X	7.00%		X	7.00%	
REQUIRED NOI		$70		$116			$116	
Operating Revenues		$300		$496	(1% refund) ($5)		$491	
Adj. for Excess Revenues								
Operating Expenses:								
Operation & Maintenance		$127		$210	($2.74)		$207	
Sample Expense		23		38	(0.50)		37.52	34
On cents per KWH t		0.767		0.767			0.764	
Depreciation		60		99	(1.29)		97.88	
Taxes		20		33	(0.43)		32.63	
Total Operating Expenses		$230		$380	($5)		$375	
PROJECTED NOI		$70		$116	$0		$116	
KWH		3000		4,959	Less: 1%		4,909	
Base Rate		$0.10		$0.10			$0.10	

Growth in energy sold 3% per year

Conclusion: A refund of revenues if allocated across expenses pro rata to adjust the gross-up results in a higher increment (lower base) keeping NOI constant. This shows that reducing the gross-up gives back the refund to the utility which wasn't the intent of the rate case settlements.

Florida Power & Light Company, P.O. Box 029100, Miami, FL 33102

FPL

July 25, 2003

Blanca S. Bayo
Division of the Commission Clerk
and Administrative Services
Florida Public Service Commission
Betty Easley Conference Center
Room 110
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Re: Order No. PSC-02-0501-AS-EI
Revenue Refund

Dear Ms. Bayo:

Enclosed is Florida Power & Light Company's Revenue Refund 90 day Report for the 8 1/2-month period of April 15, 2002 through December 31, 2002 per the Florida Public Service Commission Order No. PSC-02-0501-AS-EI. This report was prepared in accordance with Rule 25-6.109, F. A. C. The refunds were completed April 28, 2003.

Please advise if you need additional information.

Sincerely,

Steve Romig
Director
Rates and Tariffs Department

SR/eam
Enclosure

cc:

Tim Devlin – Director, Division of Economic Regulation
Connie Kummer – Chief, Economics, Rates & Forecasting
Ronald C. LaFace, Esq.-The Coalition for Equitable Rates
John W. McWhirter, Jr., Esq.-Florida Industrial Power Users Group
Charley Beck – Office of Public Counsel
Bob Trapp – Assistant Director, Division of Policy Analysis and
Intergovernmental Liaison

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 37
COMPANY/ WITNESS: FP+L / 7-25-03 letter from Steve Romig
DATE: 11-12-03
37

FLORIDA POWER & LIGHT COMPANY
Revenue Refund
90 Day Report

This report is being filed in accordance with Commission Rule 25-6.109, F. A. C.

7(a) FPL was required to refund certain retail base rate revenues above $3.580 billion for the calendar year of 2002 that relate to the 8 1/2-month period of April 15, 2002 to December 31, 2002, in accordance with the terms approved by the Commission in Order No. PSC-02-0501-AS-EI.

Specifically, for the calendar year 2002, FPL's retail base rate revenues in excess of $3.580 billion and below $3.740 billion are to be shared between FPL and its customers on a one-third/two-thirds basis, one-third to be retained by FPL and two-thirds to be refunded to its customers. However, for 2002 only, the refund will be limited to 71.5% (April 15 through December 31) of the two-thirds customer share.

Accordingly, 71.5% of two-thirds of the retail base rate revenues above $3.580 billion and below $3.740 billion have been refunded to FPL's customers.

	Revenue	Revenues to Be Refunded	Interest
Total Revenues	$3,603,189,570		
Less: Refund Threshold	3,580,000,000		
	23,189,570		
Amount to be Refunded (2/3 to Customers)	15,459,713		
2002 Limited per Agreement (71.5% to Customers)	$11,053,695	$11,053,695	
Plus Interest through 4/28/03			102,130
Amount of Refund		$11,053,695	$102,130

FLORIDA POWER & LIGHT COMPANY
Revenue Refund
90 Day Report

(b) The amounts actually refunded are as follows:

	Refund	Interest
Amount Refunded through 4/28/03	$11,041,382	$100,517
Refund Amount per 7(a)	11,053,695	102,130
Over/(Under) Refund 4/28/03	$ (12,313)	$ (1,613)

The difference between the amount to be refunded and the amount actually refunded will be reflected in the next 12-month refund period.

(c & d) Unclaimed Refunds as of July 10, 2003

Revenue refund checks that have been cancelled	3,146	$ 93,496
Revenue refund checks that have not been cashed or cancelled	16,390	55,869
Revenue refund checks were not issued for excess credits less than $1.00 per FAC 25-6.109(5)	61,668	27,038
TOTAL	81,204	$ 176,403

EXHIBIT NO. 38
TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
(WTW-2)
FILED: 10/16/03

INDEX

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 38
COMPANY/ TECO / WTW-2
WITNESS:
DATE: 11-18-03

EXHIBIT TO THE REBUTTAL TESTIMONY OF

WILLIAM T. WHALE

DOCUMENT NO. 1

2000 - 2003 SAFETY BUDGET

EXHIBIT NO. _____
TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
(WTW-2)
DOCUMENT NO. 1
PAGE 1 OF 3
FILED: 10/16/03

Tampa Electric Company
Docket No. 030001-EI
Late Filed Deposition
Exhibit of Buddy Maye
No. 2
Page 1 of 3

2000-2003 Safety Budget

Q. Provide the Gannon Station safety budget for each year since 2000, as shown for 2003 on page 1,535 of Tampa Electric's response to OPC's 1st Request for POD.

A. The Gannon Station safety budget for each year is shown in the following tables.

2000 Gannon Station Safety Budget

Budget ($)	Description
15,000	Safety Eye Glasses
5,000	Safety Supplies
1,200	S.E.A.L. Program
65,000	Care Team Nurse
86,200	Total

2001 Gannon Station Safety Budget

Budget ($)	Description
18,000	Safety Eye Glasses
270,160	Safety Budget Operations
2,000	S.E.A.L. Program
65,000	Care Team Nurse
355,160	Total

EXHIBIT NO. _____
TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
(WTW-2)
DOCUMENT NO. 1
PAGE 2 OF 3
FILED: 10/16/03

Tampa Electric Company
Docket No. 030001-EI
Late Filed Deposition
Exhibit of Buddy Maye
No. 2
Page 2 of 3

2002 Gannon Station Safety Budget

Budget ($)	Description
103,200	IH consultants, doctor charges, ergonomics, drug testing, PFT interpretations, noise monitoring, audiometric test follow-ups, chest x-rays
72,000	PPE, spirometry supply, audiometric, supplies, fit testing supplies
72,420	Luminometer, safety rewards, prescriptions, safety glasses, 4-gas monitors, pager, cell phone, thermometers for heat stress, confined space rescue equipment
5,500	Travel expense
4,100	Miscellaneous expense
13,200	Meals expense
900	Personal auto reimbursement
65,000	Care Team Nurse
336,320	Total

2003 Gannon Station Safety Budget

Budget ($)	Description
75,000	IH consultants, doctor charges, ergonomics, drug testing, PFT interpretations, noise monitoring, audiometric test follow-ups, chest x-rays
24,000	PPE, spirometry supply, audiometric, supplies, fit testing supplies
57,000	Luminometer, safety rewards, prescriptions, safety glasses, 4-gas air monitors, pager, cell phone, thermometers for heat stress, confined space rescue equipment
2,000	Travel expense
1,000	Miscellaneous expense
10,000	Meals expense
1,000	Personal auto reimbursement
70,000	Care Team Nurse
240,000	Total

Based on actual spending in 2001 and 2002, the 2003 budget was refined to more accurately reflect an appropriate budget level.

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
FILED: 10/16/03

EXHIBIT TO THE REBUTTAL TESTIMONY OF

WILLIAM T. WHALE

DOCUMENT NO. 2

RESPONSE TO INTERROGATORY NO. 37

EXHIBIT NO. _____
TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
(WTW-2)
DOCUMENT NO. 2
PAGE 1 OF 3
FILED: 10/16/03

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
STAFF'S 4th SET OF INTERROGATORIES
INTERROGATORY NO. 37
PAGE 1 OF 3
FILED: SEPTEMBER 9, 2003

37. Please list, describe, and indicate the cost for all maintenance tasks required to keep Gannon Units 1 - 4 in operation until December 2004.

A. The great number of years that these units have been in service has resulted in their operations being difficult to predict. Therefore, there is much more uncertainty than is typically associated with Tampa Electric's estimates of both the work required and the cost for the maintenance tasks required to keep Gannon Units 1 – 4 in operation until December 2004. Tampa Electric provides its best estimates of the information requested in the attached table. The total estimated maintenance cost to keep Gannon Units 1 - 4 in operation until December 2004 with expected reliability near historical levels is approximately $57.4 million. This total includes costs for major activities required to restart or keep the units operating as well as for planned maintenance activities. The attached table also includes a brief description of the activities required.

EXHIBIT NO. _____
TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
(WTW-2)
DOCUMENT NO. 2
PAGE 2 OF 3
FILED: 10/16/03

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
STAFF'S 4th SET OF INTERROGATORIES
INTERROGATORY NO. 37
PAGE 2 OF 3
FILED: SEPTEMBER 9, 2003

Gannon Units 1-4
Costs for Operating Through December 31, 2004
($000)

Major Repair or Replacement Activities	Unit 1	Unit 2	Unit 3	Unit 4	Other	Total
Cyclone Replacements (49 day outage)	4,500	4,500	6,000	6,000	-	21,000
Furnace Tube Work: Unit 4 East&West Wall Repair; Header Flush and Clean; Unit 2 Rear Wall Replacement	-	2,300	-	500	-	2,800
Replace Expansion Joints	60	60	60	60	-	240
Replace Insulation and Lagging	300	300	200	200	-	1,000
Slag Tanks: Unit 1 Top of Slag Tank; Unit 3 Slag Tank Neck	60	-	150	-	-	210
Coal Field Equipment: Bulldozer Maintenance; Crusher Maintenance (Hammer Change); Belt Replacement; Dock Maintenance	-	-	-	-	500	500
Structural Repairs to Unit 3 Stack	-	-	70	-	-	70
Transmission: New Lines Required for Bayside 2C/2D if Gannon Unit 4 Generator Lead Line is Not Available	-	-	-	950	-	950
Pond Dredge	-	-	-	-	600	600
Water Treatment: Reverse Osmosis Rental; Clarifier Rental; Portable Demineralization Trailers	-	-	-	-	1,000	1,000
Replace Control Room Annunciators	-	-	30	30	-	60
Total Major Activities Costs	**4,920**	**7,160**	**6,510**	**7,740**	**2,100**	**28,430**

EXHIBIT NO. _____
TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
(WTW-2)
DOCUMENT NO. 2
PAGE 3 OF 3
FILED: 10/16/03

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
STAFF'S 4th SET OF INTERROGATORIES
INTERROGATORY NO. 37
PAGE 3 OF 3
FILED: SEPTEMBER 9, 2003

Gannon Units 1-4
Costs for Operating Through December 31, 2004, Continued
($000)

2003 Maintenance Costs						
2003 45-day Planned Outage	400	400	-	-	-	800
2003 28-day Planned Outage	-	-	500	500	-	1,000
2003 Additional Staff and Benefits Costs	-	-	-	-	3,200	3,200
Stevedoring	-	-	-	-	400	400
Additional Costs for Water, Chemicals, Environmental Fees, Equipment Repairs and Inspections, Stores; Other Required Preventive Maintenance Activities; etc.	-	-	-	-	1,600	1,600
Total 2003 Maintenance Costs	**400**	**400**	**500**	**500**	**5,200**	**7,000**
2004 Maintenance Costs						
2004 10-day Planned Outage	250	250	-	-	-	500
2004 28-day Planned Outage	-	-	500	500	-	1,000
2004 Staff and Benefits Cost	-	-	-	-	12,200	12,200
Stevedoring	-	-	-	-	1,200	1,200
Additional Costs for Water, Chemicals, Environmental Fees, Equipment Repairs and Inspections, Stores; Other Required Preventive Maintenance Activities; etc.	-	-	-	-	7,100	7,100
Total 2004 Maintenance Costs	**250**	**250**	**500**	**500**	**20,500**	**22,000**
Total 2003-2004 Major Activity and Maintenance Costs	**5,570**	**7,810**	**7,510**	**8,740**	**27,800**	**57,430**

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 030003-EI EXHIBIT NO 39
COMPANY/
WITNESS: TECO Responce to DPC P0020
DATE: 11-12-03
(Conf.)

TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
FILED: 10/16/03
REVISED: 11/07/03

EXHIBIT TO THE REBUTTAL TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 1

HARDEE POWER PARTNERS TRANSFER OF OWNERSHIP

SEPTEMBER 2003

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 030001-EI EXHIBIT NO. 40
COMPANY/ WITNESS: TECO/JDJ-4
DATE: 11-12-03
EX 40

EXHIBIT NO. _____
TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
(JDJ-4)
DOCUMENT NO. 1
PAGE 1 OF 1
FILED: 10/16/03

TAMPA ELECTRIC

September 12, 2003

Dr. Mary Andrews Bane
Executive Director
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Dr. Bane:

I wanted to advise you that two of Tampa Electric Company's affiliates, Hardee Power I, Inc. and Hardee Power II, Inc., have agreed to sell their partnership interests in the Hardee Power Station in Florida to GTCR Golder Rauner LLC and partner, Chicago-based Invenergy. The transaction is expected to close by the end of September. This transaction will further strengthen TECO Energy's financial position. In April of this year, TECO Energy identified a number of potential assets that could be sold to improve the company's financial condition and Hardee Power Station was one of them. With this agreement, Tampa Electric's parent has demonstrated its commitment to the plan and its continued refocus on its regulated utility operations.

Under this transaction, the power purchase agreements will not be amended, changed or assigned. Accordingly, Hardee Power Partners will not be applying to the Federal Energy Regulatory Commission for approval of any amendment, change or assignment of the purchased power agreements. This transaction will be transparent to Tampa Electric and its customers. The Hardee Power Station, a 370 MW generating facility, will continue to serve both Seminole Electric Cooperative, Inc., and Tampa Electric under established long-term contracts. A TECO Power Services subsidiary will continue to operate the facility after the change in ownership. The net effect of the transaction will be an improvement to the financial condition of Tampa Electric's parent corporation.

Chicago-based Invenergy is a developer, owner and operator of power generation and energy delivery assets. Partnered with GTCR Golder Rauner LLC, a leading private equity firm, Invenergy is pursuing acquisitions of large-scale power plants currently being divested by utilities, IPPs and financial institutions. GTCR Golder Rauner is a leading private equity investment firm currently managing more than $6 billion of equity capital invested in a wide range of companies and industries.

We are not requesting any action by the Florida Public Service Commission relative to this matter, but simply wanted to keep you informed about the status of the transaction.

Sincerely,

Deirdre A. Brown

Deirdre A. Brown
Vice President – Regulatory Affairs

cc: Tim Devlin

TAMPA ELECTRIC COMPANY
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TAMPA ELECTRIC COMPANY
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FILED: 10/16/03
REVISED: 11/07/03

EXHIBIT TO THE REBUTTAL TESTIMONY OF

J. DENISE JORDAN

DOCUMENT NO. 2

GANNON REPLACEMENT FUEL COSTS FOR 2003 AND 2004

EXHIBIT NO. _____
TAMPA ELECTRIC COMPANY
DOCKET NO. 030001-EI
(JDJ-4)
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I. Correction of Gannon Unit 5 generation math error:

Month	Gannon 1	Gannon 2	Gannon 3	Gannon 4	Gannon 5	Gannon 6	Total
Jan	0	0	0	0	0	0	0
Feb	0	0	0	0	34,488	0	34,488
Mar	0	0	0	0	0	0	0
Apr	48,902	43,565	0	0	573	0	93,040
May	45,994	45,722	0	0	99,739	0	191,455
Jun	42,306	41,350	0	0	110,417	0	194,073
Jul	53,279	48,092	0	0	94,688	0	196,059
Aug	44,015	44,471	0	0	122,031	0	210,517
Sep	40,940	39,108	0	0	89,300	0	169,348
Oct	51,079	52,415	28,021	29,449	83,099	39,227	283,290
Nov	36,494	37,407	23,448	55,035	102,728	0	255,112
Dec	27,043	24,678	39,051	51,249	99,138	57,508	298,667
Annual Total	**390,052**	**376,808**	**90,520**	**135,733**	**836,201**	**96,735**	**1,926,049**

II. Recalculation of Gannon generation given correction of incorrect assumptions which results in reduction of 1,068,669 MWH:

Month	Gannon 1	Gannon 2	Gannon 3	Gannon 4	Gannon 5	Gannon 6	Total
Jan	0	0	0	0	0	0	0
Feb	0	0	0	0	0	0	0
Mar	0	0	0	0	0	0	0
Apr	48,902	43,565	0	0	0	0	92,467
May	45,994	45,722	0	0	0	0	91,716
Jun	42,306	41,350	0	0	0	0	83,656
Jul	53,279	48,092	0	0	0	0	101,371
Aug	44,015	44,471	0	0	0	0	88,486
Sep	40,940	39,108	0	0	0	0	80,048
Oct	51,079	52,415	28,021	0	0	0	131,515
Nov	36,494	37,407	23,448	0	0	0	97,349
Dec	27,043	24,678	39,051	0	0	0	90,772
Annual Total	**390,052**	**376,808**	**90,520**	**0**	**0**	**0**	**857,380**

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III. Correct calculation of costs for Gannon generation:

	2002 Total Generation (MWH)	2002 Fuel Cost ($)	2002 Fuel Cost ($/kWh)
Gannon 1	511,532	10,655,009	0.0208
Gannon 2	457,756	10,038,103	0.0219
Gannon 3	677,783	17,667,860	0.0261
Total	1,647,071	38,360,972	**0.0233**

IV. Revised analysis using Ms. Brown's methodology:

Estimated impact = {Lost Gannon generation *x* (Bayside gen. cost - Gannon gen. cost)/1000} + Coal Contract Penalties + Dead Freight

A. Ms. Brown's original calculation:

Estimated impact = {1,926,049 *x* (.046 - .0214)/1000} + 6.555 + 7.67

Estimated impact = $61.6 million

B. Tampa Electric's corrected calculation:

Estimated impact = {857,380 *x* (.0328 - .0233)/1000} + 0 + 0

Estimated impact = $8.2 million