BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 011605-EI

In the Matter of

REVIEW OF INVESTOR-OWNED ELECTRIC UTILITIES RISK MANAGEMENT POLICIES AND PROCEDURES.
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PROCEEDINGS:	WORKSHOP
BEFORE:	CHAIRMAN LILA A. JABER COMMISSIONER J. TERRY DEASON COMMISSIONER BRAULIO L. BAEZ COMMISSIONER MICHAEL A. PALECKI COMMISSIONER RUDOLPH "RUDY" BRADLEY
DATE:	Monday, June 17, 2002
TIME:	Commenced at 9:30 a.m. Concluded at 12:45 p.m.
PLACE:	Betty Easley Conference Center Room 148 4075 Esplanade Way Tallahassee, Florida
REPORTED BY:	LINDA BOLES, RPR Official FPSC Reporter (850) 413-6734

IN ATTENDANCE:

JENNIFER BRUBAKER, FPSC General Counsel's Office, representing the Commission Staff.

MATT BRINKLEY and BILL McNULTY, FPSC, Division of Economic Regulation.

ROB VANDIVER, Office of Public Counsel, representing the Citizens of the State of Florida.

RUSSELL A. BADDERS and NORRIE McKENZIE, representing Gulf Power Company.

JAMES D. BEASLEY, JOANN WEHLE and LYNN BROWN, representing Tampa Electric Company.

JAMES A. McGEE, JAVIER PORTUONDO and PAM MURPHY, representing Florida Power Corporation.

JOHN D. BUTLER, JOE STEPANOVITCH and KORY DUBIN, representing Florida Power Corporation.

JOHN McWHIRTER, representing Florida Industrial Power Users Group.

P R O C E E D I N G S

CHAIRMAN JABER: Good morning. We'll go ahead and get started. Ms. Brubaker, you want to read the notice?

MS. BRUBAKER: Pursuant to notice, the Florida Public Service Commission has set this time and place for the purpose of conducting a public workshop in Docket Number 011605-EI, Review of Investor-Owned Electric Utilities Risk Management Policies and Procedures. The purpose of the workshop is set out more fully in the notice.

CHAIRMAN JABER: Thank you, Ms. Brubaker. Now it's my understanding that the purpose of this workshop is to address one issue in the fuel adjustment proceeding, which is what incentives, if any, should the Commission establish to encourage investor-owned electric utilities to optimally manage the risks to ratepayers associated with price volatility. We need to stay focused on that issue. We have limited the presentations today to 20 minutes each entity. We plan on conducting the workshop only for the morning, and I think the parties have been briefed on that.

And there is an order, a suggested order of presentations. I have Florida Power Corporation will go first, Florida Power & Light next, Gulf Power Company, Tampa Electric, Florida Industrial Power Users Group, the Office of Public Counsel and other parties or interested persons as the situation arises. And then, Staff, I've set aside some time for you all, if you have questions, at the tail end of the workshop.

I think with respect to appearances, let's take appearances as the presentations are made. All right. So I'll turn it over to you.

MS. BRUBAKER: Go ahead and enter appearances for --

CHAIRMAN JABER: Do you have any opening comments or do you want --

MS. BRUBAKER: Staff doesn't have any opening comments. Thank you.

CHAIRMAN JABER: Okay. Then, Florida Power Corporation, who do you have to speak today?

MR. McGEE: Madam Chairman, my name is Jim McGee on behalf of Florida Power Corporation. With me I have Mr. Javier Portuondo, who is the Manager of Florida Power's Regulatory Services, and he will make the presentation. We also have with us Ms. Pam Murphy, who's the Director of Gas and Oil Trading, who will be available to respond to questions if they should arise.

CHAIRMAN JABER: Thank you.

MR. PORTUONDO: Good morning, Commissioners.

CHAIRMAN JABER: Good morning. Spell your last name for me.

MR. PORTUONDO: P-O-R-T-U-O-N-D-O.

CHAIRMAN JABER: O-N?

MR. PORTUONDO: O-N-D-O.

CHAIRMAN JABER: Thank you.

MR. PORTUONDO: As Florida Power was reviewing the issue in this proceeding, the key factor that we were focusing on was the price stability aspects and how we would be able to achieve that for the customers of Florida Power. Our proposal provides for the hedging of natural gas and Number 6 oil, two of the commodities that we've seen the most volatility in.

The plan would call for fixing the price for a predetermined annual volume of both of these commodities. The recommended annual volume committed will be established early in the year and included in the company's projection filing annually.

We also are recommending a change to the current incentive program for power sales to fund a portion of the incremental costs associated with implementation of this hedging program that the shareholders would have to pick up and to include the savings on purchased power also to fund the incremental cost of implementing the program.

The hedging program itself will fix the price of the annual predetermined forecast volume based on a methodology presented under confidentiality for review by the Staff and the Intervenors in this proceeding. This methodology, once approved, will be implemented and executed and the price will be fixed for the entire year without true-up to actual costs incurred, thereby providing price stability.

The balance of the oil and gas not covered under this plan would be recovered based on actual cost as it is today. Our proposal to share in the savings and the profits from wholesale power purchases and sales is based on a two-thirds/one-third basis from the first dollar between customers and shareholders. The existing mechanism is the 80/20 based on a three-year rolling average and that would be suspended going forward.

Shareholder risks assumed by this plan: Timing, execution of purchasing the exchange, traded futures, contracts on natural gas, the financial derivatives that we would need to execute to achieve the fixed price component of the plan, counterparty and credit risk. If gas is hedged through physical bilateral contracts, the shareholder would pick up the risk on the predetermined volume proposed in this plan, the volume risk as it relates to the hedged quantities, timing execution risk for over-the-counter trades for Number 6 oil and as well as the counterparty credit risk for financial trading houses that provide liquidity for the fixed price on residual oil. These risks would be assumed by the shareholder and not be passed on to the customer.

The implementation of this plan would call for incremental costs to be incurred for staffing experienced individuals capable of executing effective financial trades;

the staffing of mid and back office personnel to both monitor the risk, evaluate the effectiveness, monitor controls and implement the necessary accounting and credit pursuits with the counterparties.

In addition to the human aspect, there's systems that need to be implemented to effectively monitor and execute in the financial markets as well as in the physical to the degree that they're more creative contracts or instruments.

The customers' benefit is price stability for that predetermined volume, the potential for lower fuel costs through executing financial instruments or guaranteeing a price based on the expected market price, elimination of the supplier credit risk and delivery risk, elimination of the execution, timing and volume risks on the predetermined quantity.

Our plan, of course, calls for force majeure elements, which most of these types of plans would call for, events beyond the control of the company; acts of God, acts of government, in our world today, acts of war and terrorism and extended unscheduled baseload plant outages.

Exclusions from the plan would be noncommodity costs. Our plan focuses to fix the price of the commodity. The demand charges, taxes, transportation, et cetera, would continue to be recovered. Purchases for reliability or emergency needs would continue to be recovered as they are today. And, of course, all other costs associated with the fuel clause will remain under the status quo methodology.

In implementing the hedging program there are new costs that come along with this plan. There's basis differential, there's broker commissions, there are fees, cost of margin requirements with the NYMEX exchanges or other exchanges, and there's a risk premium that needs to be assessed.

The plan, as we envision it, is a pilot for us. We want to proceed slowly, gain the experience in financial trading to assure that we are effectively entering into the market, executing wise trades and trying to use the tools of the market to project the best price for the customer.

We propose a two-year initial plan starting with the '03 period. We would have the Commission approve the plan each year not for the coming year but the year after that. The reason for that is that we need to be able to enter the market in the year preceding the forecasted period. So it's -- the timing to wait to hearings is too late. We need to be able to execute as soon as the price is calculated for the customer; make sure that we minimize as much of the timing risk and volatility.

If the plan were to be terminated, the parties would all agree that we would revert to the status quo we have today and we would go on.

That is our plan. There are the calculation of the fixed price component which we would be requesting approval in this proceeding. Unfortunately, due to the sensitivity of the information, we're unable to discuss it openly. But we are willing to discuss it with the Staff and the appropriate intervenors to get them to the level of understanding that they require. Thank you, Commissioners.

CHAIRMAN JABER: Commissioners, do you have any questions before we move on?

Go ahead, Commissioner Palecki.

COMMISSIONER PALECKI: I have one question. What is the connection between the incentive itself, which is an increase in the sharing of profits from wholesale power sales, and the objective of managing risk to the ratepayers?

MR. PORTUONDO: Commissioner, the implementation of a dynamic hedging program comes with a cost, an incremental cost that is not currently being recovered. The objective of providing stability to the customer through financial trading requires extensive systems implementation and qualified individuals to assure that the calculation, that the methodologies we're applying try to, with the best knowledge that we have at the time, to provide that potential of lower cost to the customer along with the stability, they'll have the stability, but we want the infrastructure in place to, to help us also provide that component of lower cost.

The inclusion of sharing in the wholesale power was our way of trying to offset some of those costs that would be incurred by implementing this particular hedging program, knowing that the systems that would be implemented and the expertise that would be brought to the organization would potentially also contribute to possibly more effective wholesale power sales which the customer would benefit from. There isn't a direct correlation between the oil and gas and the power, but as a package it accomplishes the end goal.

COMMISSIONER PALECKI: Thank you.

CHAIRMAN JABER: I guess as a follow-up I had a similar question with respect to the different, understanding the purpose of the different programs. And I'm still not sure I understand based on what you just said to Commissioner Palecki.

The hedging program administrative expenses, one might assume that those administrative expenses would be incorporated into your final rates and that that would be included in the fuel adjustment hearing proposals that you submit.

With respect to the wholesale sharing mechanism, to the degree you have excess generation and the company wants to sell that power as opposed to keeping it, I thought that was the purpose of the sharing mechanism with respect to the wholesale sales, that, you know, to the degree the company is, is assisted by the fact that you've been able to unload the extra capacity, then, you know, there should be a sharing. And to the degree the general body of ratepayers benefit from the sale, then there should be a credit to the rates.

MR. PORTUONDO: Uh-huh. Commissioner, the -- we were proposing this so not to push the costs of implementing the hedging program through the fuel adjustment clause. We saw it as if, if we could take a portion of the savings as an offset, we would keep that on the shareholder side and it wouldn't muddy up the fuel adjustment clause by pushing the implementation costs through the clause, the O&M costs.

CHAIRMAN JABER: Well, how much are we talking about? What is your estimated cost of administrating the administration of the hedging program?

MR. PORTUONDO: It's not solely the administration. One of the biggest costs is the system's implementation. And early indications, they would run, I was told, about $10 million to implement a system.

We don't currently trade in the financial markets. Our systems are mostly to track the physical aspects of the transactions. So there's, there's a significant cost associated with entering this if you want to make sure you establish the protections and the controls necessary to have a good risk management program.

CHAIRMAN JABER: And do you have an amount for the credits to customers associated with your wholesale energy sales?

MR. PORTUONDO: As, as we've experienced in the past few years, because of the three-year rolling average, we've been unable to share. And if and when we do, the hurdle is set higher and higher and higher, so the company's really never benefiting from its efforts in the wholesale market. And that is why we felt that if we started to share from dollar one, it would help contribute as an offset to these costs.

CHAIRMAN JABER: Okay. Let me understand what you just said. The company has been unable to retain any of the benefits of the program, but you have been able to --

MR. PORTUONDO: Give the benefits to the customer. Yes, ma'am.

CHAIRMAN JABER: How much?

MR. PORTUONDO: I want to say that it was about $10 million in '01 and maybe $8 million in 2000. We were, we were below our three-year rolling average baseline.

CHAIRMAN JABER: It is not -- it would not be incorrect to flow through the costs, whether they're system implementation costs or administration costs of the hedging program into the fuel adjustment hearing.

MR. PORTUONDO: No, Madam Chair. If the Commission so wishes, that can be done.

CHAIRMAN JABER: Commissioners, any other questions? Thank you.

COMMISSIONER DEASON: No, I have --

CHAIRMAN JABER: Commissioner Deason.

COMMISSIONER DEASON: -- just kind of a follow-up.

You indicated that you've not been able to share because you've not met the three-year rolling average.

MR. PORTUONDO: Yes, sir.

COMMISSIONER DEASON: You would agree though that to the extent you've not been able to meet it, that means that on a going-forward basis your average is going to be lower and then that the target is lower and the likelihood in the future of you sharing is increased.

MR. PORTUONDO: To, to a degree, yes, sir, it would be.

COMMISSIONER DEASON: Okay. I have a question about the -- I'm looking at Page 4 of your handout and the shareholder risk.

Could you -- the first item there, the timing and execution of purchasing exchange traded futures contracts, and you're indicating that that is the shareholder risk. Can you explain further how that is a shareholder risk?

MR. PORTUONDO: I think I will defer to Ms. Murphy on that.

MS. MURPHY: The timing and the execution, what we actually proposed and sent under confidentiality would be a market on close on certain days. Well, if we don't get all of our contracts off for that market on close, then the next day we're in the market trying to capture that purchase contract. So it's a difference of -- let's say you're looking at May 15th and, you know, that's one of the days that, that the rates are established to fix the price of the forward contract year. So if we don't get -- you know, once the market is closed, then once it reopens again, gas starts trading at a different level. So you may see a swing of 10 to 15 cents associated with the market on closed for the prior day. So based on that, that's where the risk premium comes in to say if we have to execute at a higher rate or a lower rate, we're taking on that timing and execution.

CHAIRMAN JABER: Commissioner Bradley.

COMMISSIONER BRADLEY: Yes, thank you. Have you all done a, and I don't know if this is even possible, but have you all done a side-by-side of the current market situation and maybe what the situation was a couple of years ago to try and allow us to maybe prognosticate based on percentages what the change might be without factoring in some of the unpredictable scenarios such as acts of God and acts of government and war and terrorism? I mean, it would be helpful.

MS. MURPHY: We've not done an actual side-by-side comparison. However, we have looked at 10 to 15 cent differences every day based on where the NYMEX closes at, and that on days it could be even higher than that. We've seen dollar swings during the day due to the volatility of natural gas prices. So based on -- we're looking at always trying to give a very easy mark for the Commission to, to track what it is that the ratepayers will be charged the forward contract year. You know, those swings come based on the, based on the close of NYMEX, and then we're in the market either the day after or trying to get our contracts off that evening just before the market closes in order to protect ourself from a hedging standpoint. But, I mean, to say that it's been a 20 percent -- we've seen, based on December of 2000 to 2001, we've seen 200 percent swings in a day. I mean, they have just been enormous. And the price volatility of natural gas doesn't appear to be going away.

So to the extent that we're locking in, let's say, for that day a $3.50 price for the ratepayers, then tomorrow -- or if we don't get all of our contracts off, then the next day we may be looking at a $3.60 rate instead or a $3.40 rate, depending on where the market is going. So we're trying to get in there, you know, at the end of the day to hedge Florida Power Corporation's risk associated with it, but we may not get all our contracts off in time. We may be in access trading or in the next day. So that's the timing and execution risk that the shareholders would be taking with this program.

COMMISSIONER BRADLEY: One other question. So, therefore -- how is this going to affect your relationship with, with the producers? Are you going to purchase directly from the producers or are you going to continue to use the commodities market? I'm trying to figure out how you're going to lock in.

MS. MURPHY: We could do either. We're looking right now at using exchange traded futures contracts to avoid any price risk association with -- the producer is going to deliver to us at index, but as the prompt month comes close, we will exchange that over and close out at a fixed price. So, you know, we always have delivery risk because we're expected to have the natural gas and fuel oil there available to start the generation, but the price risk is what we're taking on the most. But we feel like we can lay that off with the exchange traded futures market to lay off that risk associated with the price.

The NYMEX requires a margin account for all of its customers. So, therefore, that margin account gives them a buffer to any price risk or somebody actually not -- if credit becomes an issue with a counterparty, they will immediately close them out. Their margin account will be used to pay off any deficit based on what their positions are.

COMMISSIONER BRADLEY: Well, the figures that you've been able to put together with the factors, does your spreadsheet indicate that you would be able to actually purchase gas and oil at a reduced price under this incentive plan or is it still somewhat unpredictable?

MS. MURPHY: No. All it does is create a snapshot to give a bigger window for what the price would be in the forward contract year versus setting it at one day or two day during the year. We're looking at a bigger snapshot to give a much more reasonable approach to setting the price for the ratepayers.

COMMISSIONER BRADLEY: And what happens if, if you have one of the unpredictable factors enter into the picture such as war or terrorism, acts of God or acts of a foreign government? I'm just trying to figure out --

MS. MURPHY: To the extent those occur, the offset, the differential would be passed through the fuel clause because it's beyond our control if something should happen, let's say a pipeline gets blown up or something like that, it's beyond our control if gas prices go north versus south during that time period. So to the extent that it affects our hedging program, we would pass that on through the fuel clause to the extent that there are damages.

COMMISSIONER BRADLEY: Basically what I'm trying to figure out is if we go to the new system, if we're going to, if you all will be able to, the bottom line is purchase gas and oil at a reduced price and as a result have less expense be borne by the ratepayer or if we're just speculating that this might be a better system than the current one. I'm just --

MR. PORTUONDO: Commissioner, the goal is, first and foremost, to try and provide some stability in the price to the customer. You won't always necessarily achieve a lower cost to try and accomplish that.

What we're proposing is to try and use a verifiable third-party mechanism that tracks the market that forecasts the price, try and eliminate through our methodology some of the forecasting inconsistencies to provide a view of where the market thinks the price will be in the coming year.

Any time you lock into a price, you're not assured it will be the lowest price. We don't want to be speculating whether the price is going, going to go south, going to go north. You want to use your best judgment based on information before you, as we do today in the spot market. We do ratio how much we go fixed versus spot. And any of our fixed contracts are subject to an opportunity loss or an opportunity gain because of the swings in the market.

What we're proposing is to go to the next step and enter financial derivatives to see if we can increase the stability in that price, always keeping in mind that we're trying to continue to bring the price down to the customer. But it's not necessarily guaranteed.

CHAIRMAN JABER: Commissioner Deason?

COMMISSIONER DEASON: Let me follow-up on that. I'm trying to understand the big picture in the mechanics involved as to how this would work.

Are you proposing that when we go forward into a projected fuel period and we're trying to establish the fuel adjustment factors for the coming year, for that portion of the commodity price of natural gas and Number 6 fuel oil, that you would come in and you would present to the Commission a case that says we believe that we can, through our hedging efforts and our market efforts, marketing efforts, we can lock that in at $3.50, let's just say, pick a number out of the air. And if we think that is reasonable, well, then we've pretty much locked in that price for the customers for the year at $3.50. Now if the market goes down and we look in hindsight and say, well, we could have bought it at $3, I mean, that's just -- the fact is we locked in at $3.50 because we wanted stability and we decided that was a good deal and that was fine. And then obviously if the price goes up to $4, we really feel good at that point because we locked in at $3.50 and we achieved our goal of price stability and it looks even better because the price of getting natural gas escalated up during the projected period. That's the way it would work; is that correct?

MR. PORTUONDO: That is correct.

COMMISSIONER DEASON: Okay. Now I'm trying to understand what risk you're taking, you're taking on. You're taking on the risk that you may not be actually able to engage in those transactions to lock it in at $3.50?

MR. PORTUONDO: Yes, sir. Yes.

COMMISSIONER DEASON: And you may actually lock in at $3.60 but, since you presented to the Commission $3.50, you're obligated to meet the $3.50.

MR. PORTUONDO: Yes, sir.

COMMISSIONER DEASON: Now if you're able to actually lock in some way through your efforts at $3.40, well, then you keep that difference; is that correct?

MR. PORTUONDO: Yes, sir. That's the incentive aspect of it.

COMMISSIONER DEASON: Okay.

MR. PORTUONDO: So it's all on the company to achieve the effectiveness of this program.

COMMISSIONER DEASON: Madam Chairman, I'm not really sure what the next step will be, but let me, let me suggest that it may be helpful to get at some point some scenarios, not using confidential information, just hypothetically, you know, this is what would happen under this set of facts and this would be the end result and this is what would happen under this set of facts so we can just kind of see hypothetically, you know, what would happen in a rising gas market, what would happen in a declining gas market, how the price stability would work. Is that something that you could put together?

MR. PORTUONDO: I think you illustrated it very well though. We can put something together for you, but it's exactly that. We're coming into the forecast period guaranteeing $3.50 for that predetermined volume, and it's up to the company to enter the markets quickly enough to execute at $3.50 to guarantee. If we're able to go in and hedge immediately and guarantee the $3.50, we, it's kind of breakeven at that point. The customer would pay $3.50 through the recovery clause and the company would pay the physical delivery at $3.50.

If we're able to, if we're unable to enter the market timely enough and the market increases, then the company and its shareholders would record a loss for the commodity portion on its books and records.

If, if the volatility is favorable and it goes down, well, then the shareholder is able to capture a small margin by locking in those contracts at the lower amount. But, again, it's all in the effectiveness of the program and the skills of the individuals entering that market and executing.

CHAIRMAN JABER: Commissioner Deason, to answer your question, it's my understanding that the prehearing officer and Staff set this workshop up -- Commissioner Palecki, let me know if I'm wrong -- to give the Commissioners an additional opportunity to ask questions about the hedging proposals by the various companies. So I don't think it was contemplated that we would have post-workshop comments because their testimony is due, correct me if I'm wrong, on June 24th. So I think by virtue of our questions, we're giving them some direction to include information in the testimony.

COMMISSIONER PALECKI: We'd be glad to.

CHAIRMAN JABER: But saying all of that, Commissioner, if you want, there's nothing that would prohibit us from asking for post-workshop comments.

COMMISSIONER DEASON: No, I -- that's fine. I guess the matter will be addressed in testimony and I guess the ultimate burden is going to be on Staff to explain it to the Commission. And so they may want to engage in some discussions with the companies and make sure they thoroughly understand the procedures so that they can explain it to us at the appropriate time.

But this is very helpful, this question and answer, I mean, this has been very helpful and I appreciate the efforts that have been put into it thus far.

CHAIRMAN JABER: I think Commissioner Palecki had a very good idea in establishing the workshop.

To build on what Commissioner Deason just said with respect to the risk you foresee in locking into a price and, of course, if the gas prices go up, you're locked in. But you still suggest that as a further compensation for the risk you have to suspend the wholesale energy sales sharing mechanism.

MR. PORTUONDO: To modify it in order to offset the incremental costs that we know we will have to incur in order to establish this program.

CHAIRMAN JABER: How would it be modified? I guess in everything that you've given us to read --

MR. PORTUONDO: Well, the wholesale we're modifying to be a two-thirds/one-third sharing rather than an 80/20 and eliminate the rolling average. So the customers would continue to benefit from the predominant share of that activity, but it would allow the shareholders to retain a portion of those benefits that we are not able to retain today as an offset to those costs. And one can envision that as the traders get more skilled in the financial, some day we may be here before you suggesting other ways to transact in the wholesale side. Right now we're just not prepared to, to take on that much.

But the new systems, I would imagine, would help us track better on the physical side and the wholesale power side to achieve even lower savings because we're bringing in the wholesale purchases, not solely the sales. So to the degree that we can purchase more economic than generating continues to provide lower fuel cost to the customer even with the sharing.

CHAIRMAN JABER: Okay. Thank you.

Staff, let me ask you a question procedurally. If, as a result of our consideration of the hedging program, we do find it appropriate to modify the wholesale sales incentive program, do we need a separate issue in this proceeding on that or -- yeah, is it worth separating the two issues out?

MR. McNULTY: I would assume that that would be a separate issue because of the fact that we have orders that are existing out there that are based upon rolling average.

CHAIRMAN JABER: Right. Commissioner Palecki, I don't think it's certainly something we have to work out today, but would you meet with Staff and see if it needs to be identified separately in time for testimony --

COMMISSIONER PALECKI: Yes, I'll do that.

CHAIRMAN JABER: -- to be filed? Thank you.

Commissioner Baez, you had a question or comment?

COMMISSIONER BAEZ: Just one quick question. On the fixed or the predetermined portions of the requirement that are applicable or to which the hedging is applicable, did you envision us having, this Commission having to set what that percentage is? I notice here you have at least 20 percent, so you're requesting that minimum. But is this a yearly -- at the time we review your proposed prices, et cetera, we also would, you would envision us deciding what percentage is available for hedging on a yearly basis?

MR. PORTUONDO: Commissioner, we envisioned the company making that decision. Over time, as we become more comfortable with our abilities in this market, we would try and ratchet that up to continue to provide more stability for a larger portion of the volume. But we, we did not envision the Commission having to rule on that. We envisioned going to the

Staff and informing them that this was the, the increase year over year when we filed our forecasted fixed price. And should they have some discomfort, I think we could work that out with them and maybe get them comfortable as to why we thought we could increase it if they thought it shouldn't be as high. Or, vice versa, if we didn't go up as high as they would like, I think we could talk about the reasons why we didn't do that.

COMMISSIONER BAEZ: Well, but it would all be subject -- I mean, I guess we would, the Commission would accept an increased percentage just like it would accept a $3.50 price. I mean, essentially --

MR. PORTUONDO: Yes. The fixed component would be a predetermined methodology that we would be approving in this proceeding. That would not change, the methodology. The number would change, but the methodology would not change, thereby not requiring annual Commission approval. It could just be executed, and the Staff would audit to make sure there's no mathematical error.

COMMISSIONER BAEZ: Thank you.

CHAIRMAN JABER: Commissioner Deason.

COMMISSIONER DEASON: Yes. Back to the, the mechanics of the way and the process, the procedure we will follow. What happens if you make your filing and, here again, just picking numbers out of the air, say that you want to, you want to hedge 50 percent of your natural gas purchases for the coming year and you come forward and say we want to lock, we think that we can manage this such that we guarantee a $3.50 price for the coming year, and what if the Commission is uncomfortable with that and we say, we think you can do a lot better than that, we reject that, and then what happens? We just fall back to where there's no hedging and it's 100 percent, whatever the market is is what you pay, is what the customers pay? How does that work?

MR. PORTUONDO: Well, the proposal would work in that if, if you approve our methodology, we would set the price for the customer almost concurrently with entering the market in order to try and minimize the risk. So we would need preapproval that you're comfortable with the methodology, preapproval that you're comfortable with the company making the decision on how much volume each year they think they're ready to transact in, and then after that point it's more of an audit function that the Staff would have to do.

COMMISSIONER DEASON: No. I think you're missing the point of the question. The question is -- it's a question of what is the fair price? Okay. If you come in and you say we can take 50 percent of these commodity purchases and we can lock it in at $3.50 and we say, you know, we think you can do a lot better than that, we reject it, does that mean then all bets are off and it's just 100 percent pass-through or whatever you buy for the coming year?

MR. PORTUONDO: It would already be executed under our plan. So that's why we have that timing issue that your decision to terminate the plan in the -- you would be deciding in 2003 -- let's say that we're going into the 2004 hearings and you think, well, maybe the methodology is no longer accomplishing what you would like, due to the timing we would already be in the market hedging for '05. So you would be terminating it for '06. And then at that point, I agree, everything would revert to what we have today.

COMMISSIONER DEASON: Okay. Well, then does the methodology that we would approve -- and I know that there has to be a time differential if we make a decision to get out because you're already in the market.

MR. PORTUONDO: Yes.

COMMISSIONER DEASON: But does the methodology itself that we would approve, does it by its operation end up with the price that's going to be fixed for the coming year?

MR. PORTUONDO: Yes. The methodology will determine it, will determine the price. And there's, there's -- I mean, we're using third-party published information easily verified by all involved.

COMMISSIONER DEASON: Okay. So it's not --

MR. PORTUONDO: It would set the price.

COMMISSIONER DEASON: Okay. I needed to understand that. Thank you.

MR. PORTUONDO: Okay.

CHAIRMAN JABER: Commissioner Palecki and then Commissioner Bradley.

COMMISSIONER PALECKI: This isn't a hedging question. It's really a question regarding incentives to maximize sales of wholesale power.

You stated earlier that in 2001 the ratepayers saw a $10 million savings due to your sale of wholesale power and in 2000 it was $8 million.

With the change that you've suggested to a two-third/one-third sharing without the rolling average, would you expect those numbers to go up or to go down, the savings to the ratepayers?

MR. PORTUONDO: The savings to the ratepayer would go down, yes, sir.

COMMISSIONER PALECKI: So you don't believe that the incentive of a two-thirds/one-third sharing would actually cause the company to increase the number of wholesale power sales?

MR. PORTUONDO: Oh, I guess I -- I answered it in the, in the context of just those numbers. Literally if we were looking at those numbers and had the one-third/two-thirds, their savings would go down.

I mean, the company is always attempting to maximize the benefits to the customer through the wholesale power activity and that would not cease to occur. And to the degree that we could continue through the new systems, through more skilled individuals that are focusing on the financial but could possibly bring their expertise to the company and to the other physical traders, the wholesale side, I mean, I see those as benefits. You know, kind of unexpected to some degree because you're bringing them in to do the oil and gas, but they may bring outside knowledge that we currently do not have that would increase those savings and profits from the wholesale jurisdiction. So it's, it's hard to have a crystal ball, but we would never lose sight of trying to increase those benefits for the customer.

COMMISSIONER PALECKI: So you don't believe that the company has actually maxed out on the amount of wholesale power that can be sold; that there might be additional volumes or additional sales that could be made if there are greater incentives put in place?

MR. PORTUONDO: Maybe not from the, necessarily from the volume aspect. But a lot of the transaction is are you finding the counterparties that need it and are willing to compensate you the most for it? So, again, it's in the skills of finding the right counterparties and depending on how the markets are acting and the demand and supply for power. So, again, it's the expertise, the kind of on-the-job training, the number, the longevity of the trader and how he's performed in the past. But to the degree that there is volume, because we're able, it's a mild time in Florida and we do have capacity, we will try and maximize the benefits of that in the marketplace. So it's very dynamic.

COMMISSIONER PALECKI: Thank you.

CHAIRMAN JABER: Commissioner Bradley, you had a question?

COMMISSIONER BRADLEY: Yes. It's pretty apparent to me that Florida Power has spent a lot of time going through the intricacies of this plan. My question is this though. Is this an original plan that you all put together from start to finish or is this a plan using your science and creativity or is this a plan that is in effect someplace else in the country or --

MR. PORTUONDO: No, sir. We came up with this. I don't think we were able to find other utilities that were in the -- that had published before their commissions hedging programs.

COMMISSIONER BRADLEY: So if we adopt this plan, then Florida would be in the forefront of, of using such a plan to deal with the cost of gas and oil?

MR. PORTUONDO: That could be true.

COMMISSIONER BRADLEY: Okay. Thank you.

CHAIRMAN JABER: Okay. Commissioners, any other questions? Thank you.

MR. PORTUONDO: You're welcome.

CHAIRMAN JABER: Florida Power & Light.

Oh, Mr. McNulty, do you want to ask a question before we move on or --

MR. McNULTY: I just wondered if we were going to ask our questions at the end or at this time?

CHAIRMAN JABER: I think -- let's go through the presentations, and then we'll ask, we'll have you ask questions at the very end of everyone.

MR. McNULTY: Okay.

MR. BUTLER: Good morning, Commissioners. My name is John Butler, Steel, Hector & Davis, on behalf of Florida Power & Light Company. And I have here to present FPL's proposed risk sharing program Joe Stepanovitch, the Director of Energy Marketing and Trading for FPL, and Kory Dubin, the Manager of Regulatory Issues for FPL. Their comments are going to be based on the program summary that FPL filed, and I just wanted to be sure that all of you have a copy of that. Okay. Thank you.

MR. STEPANOVITCH: Good morning, Commissioners. It's a pleasure to be here today on behalf of FPL and its customers. As John just said, my name is Joe Stepanovitch, and I'm employed by FPL as the Manager or Director of Energy Marketing and Trading.

FPL is here today to propose a hedging plan that offers dampened volatility in fuel prices for FPL's customers.

Also, the plan gives the FPSC the chance to offer customers a new service which gives the opportunity for stable rates while providing fuel at market prices. And, finally, the plan gives FPL an opportunity to increase shareholder value.

This plan has important changes. The plan transfers certain risks to FPL's shareholders that have previously been borne by the customers of FPL. Let me start with a brief summary before we move into the actual proposed plan.

Our objective, of course, is to reduce fuel cost volatility to FPL customers with an effective fuel procurement and fuel hedging plan.

In summary, number one, Bullet Item 1, this plan should start as soon as practical. If given ample time, January 2003 is achievable.

Bullet Item 2, this plan only applies to the commodity portion of the delivered price of oil and natural gas. All other fuels and noncommodity portions remain as is.

Customers will no longer pay actual fuel costs, but will pay current market prices at the time of purchase.

Bullet Item 4, customers will pay an average cost based on an agreed percentage of the volume at a fixed price and the remainder of the volume at spot index price. Certain risks will be transferred to the utility and removed from the customer.

Bullet Item 6, there will be a risk premium for the service provided. If I can give an example, if you were to go to the market for the type of service FPL is offering, you would expect to be, limiting risk would be a component of the service.

Think of it as your car or house insurance. If and when an accident occurred, your premium is simply a hedge against replacement costs. As you will see, FPL is offering this service by covering those certain risks.

Item 7, there is a need for a force majeure provision to cover unpredictable events.

And, lastly, the plan also calls for sharing of the savings associated with purchased power and sales transactions.

Moving into the proposed plan, number one, FPL's proposed plan only applies to the commodity portion, that is gas and oil. All the other fuels and noncommodity costs, i.e., transportation, will remain as is.

A major change from how it's done today is FPL will no longer recover actual oil and natural gas costs. Instead, FPL will recover the commodity cost on an average fixed price and spot index price basis.

Whereas, each year prior to FPL's fuel cost recovery projection filing FPL will seek Commission approval of the percentage of volume to be purchased and the methodology to determine the fixed prices to be used for that upcoming year. And, also, the balance will be based on an agreed upon spot price index within that methodology.

As you can see by moving to this procurement methodology, this assures market prices for both fixed and spot prices.

And, lastly, FPL will assume risks inherent to the hedging process. And to compensate FPL for those risks, the plan assumes the Commission will allow it to recover a risk premium.

A few of those risks are execution risk, timing risk, counterparty risk and volume risk. The first three are manageable through the implementation process. The volume risk will be managed by the utility, and let me give an example.

Today as the customer load varies, FPL's customers cover those variances from the market; i.e., we go out and buy more power, we buy more gas, we buy more oil, we buy more transport on a daily, hourly basis. Our proposal eliminates a portion of this variance. During the implementation process, as always, we will project load and generation along with our view of the forward market. Then we will agree on a set percentage of fuel requirement on a predetermined price set forth by the proposed methodology.

Once set, the price and volume percent for that fixed component will not change. For example, if load increases by one percent above the agreed upon percentage, the first 20 percent of the variance will be charged out to the customer at the agreed upon predetermined fixed price. The actual replacement of this variance, as you know, is done in the spot market. That variance will be transferred to FPL to manage.

So how does this help the customer? It takes the load variance away from the customer and assures market pricing, all the while dampening the volatility for the pre, from the predetermined fixed prices.

Also, the over-and underrecoveries will have a lessening effect during true-up because of the recalculation to actual volumes toward the fixed price component.

And, lastly, the biggest benefit is there is no chance of being over- or underhedged. The utility assumes that risk.

Number 3 is asking for certain costs to be recovered for transaction and hedging. A few of these costs are developing and implementing the risk management system, incremental costs of operating the trading floor and, of course, as stated before, the noncommodity related costs; i.e., transportation costs.

FPL's proposed plan assumes that a force majeure event will revert to the existing actual cost recovery mechanism. A force majeure event is defined as an unpredictable event that results in generation variance from a given month of at least 45 percent above the projected levels or 30 percent below the projected levels. Examples of the force majeure events are extended unscheduled nuclear outages and acts of God and government and war.

Number 5, FPL's proposed plan will not change the format of the fuel cost recovery filing.

Number 6, also, FPL's proposed plan allows for an 80/20 share from the wholesale power transactions. This share provides the assurance and incentive to the customer and to the FPSC that no stone will be left unturned.

FPL's proposed plan is a true-up mechanism that will work in the same manner that it currently does. The only change that will -- the only change will be that the actual costs will be replaced by the agreed upon indices.

All other components of the fuel and purchased power cost recovery factor will remain unchanged from current regulatory treatment.

Lastly, the implementation process. In July of each year FPL will file a proposed stipulation containing the percentage of fuel volume that will be recovered on a fixed basis, the methodology to determine those fixed prices, the spot price indices and the percent risk premium to be used for the upcoming year.

As you are aware, to have an effective procurement process, confidentiality is of the utmost importance. In order to ensure the maximum benefit to FPL customers, FPL will request confidential treatment for this information. That will be provided to Staff, Office of Public Counsel, Florida Industrial Power Users Group, and other directly related parties with legitimate interests to FPL customers.

FPL will request that the proposed stipulation be addressed at the next available agenda conference.

The company will implement this stipulation only if all parties agree to the stipulation and the Commission approves the stipulation.

If the condition listed in Item Number 3 does not occur, then a July proposed stipulation will not become the basis for the fuel cost recovery charge in that upcoming year. In that event, FPL will submit a second revised proposed stipulation, again on a confidential basis, approximately two weeks before the November fuel hearing.

If approved by the Commission, the company will implement the stipulation effective in April.

And, lastly, because of the market fluctuation, of course, prompt resolution of FPL's proposed stipulation is essential to the working of this proposed plan. Thank you.

CHAIRMAN JABER: Thank you. Commissioners, do you have any questions?

COMMISSIONER DEASON: Yeah, I have just a few.

Your -- the last point that you just made about the approval process, that if it can be done by stipulation, then that would be done early on in the process. And then if that cannot be achieved, that you would make a filing for the November hearing. And that actually would go to hearing and the Commission would determine if we would go forward from that point or how would that work?

MR. STEPANOVITCH: I'm going to ask -- you know, since Ms. Dubin with Regulatory Affairs is sitting right next to me -- not to -- that she could just cover that for me.

COMMISSIONER DEASON: Surely.

MS. DUBIN: Well, we've got it in two steps. Should the proposed stipulation that we file in July is not approved, we figured that we would try, go back to the drawing board and try again, and then we would file it with our filing or right after that so that we would look at it at the November hearing.

The only thing different there would be, would be some timing. If it's delayed that way, instead of being able to implement that fixed price position in January, it may be delayed a bit and, instead of being in January, it would be more like April.

COMMISSIONER DEASON: Okay.

CHAIRMAN JABER: Hang on a second, Commissioner Bradley.

COMMISSIONER DEASON: One further question. The -- I'm trying to understand the differences between your proposal and the proposal which was just presented by Florida Power.

You're seeking dollar-for-dollar recovery of the additional costs associated with implementing an effective hedging program; is that correct?

MR. STEPANOVITCH: That's correct.

COMMISSIONER DEASON: Okay. And that would be part of your fuel adjustment filing or would that be done in a separate proceeding?

MR. STEPANOVITCH: That would be part of the fuel adjustment filing.

COMMISSIONER DEASON: And as far as the sharing mechanisms which we currently have, you're, you're proposing that we retain the 80/20 split but that we do away with the three-year averaging, or what are you proposing?

MR. STEPANOVITCH: That's correct, sir. The -- we are asking for 80/20 of all power transactions and that the rolling average does go away.

COMMISSIONER DEASON: Okay.

CHAIRMAN JABER: Commissioner Bradley.

COMMISSIONER BRADLEY: Yes. Your plan applies only to the commodity portion of your oil and natural gas; is that correct?

MR. STEPANOVITCH: Oil and natural gas. That's correct.

COMMISSIONER BRADLEY: Only to the commodity portion and not the noncommodity portion?

MR. STEPANOVITCH: That's correct. All noncommodity costs; i.e., transportation, fees. That will go through as it always has, that cost.

COMMISSIONER BRADLEY: Okay. Could you elaborate a little bit on the concept of having a small risk premium?

MR. STEPANOVITCH: Sure. Risk, the risk premium is, again, based on those risks that I listed; i.e., the execution, the timing and the volume risk. As has been discussed quite a bit here already this morning, execution and timing risk is of the utmost importance to do it within a time frame that allows us to initiate the transactions before the markets move.

Volume risk is, again, of the utmost importance, and that is the, as in our plan versus forecast versus actual. When you look at the volume risk as stated in that example, the utility is picking up that volume risk. So basically when we go out and forecast that number, okay, forecast the number, we're going to actually move toward -- the forecast and the actual, and the utility is picking up the difference between, if you look at that price where we talked about the one percent above our forecast, the volume risk is in the pricing methodology. Where that 20 percent is set at the predetermined price, we go out and have to replace that volume at spot market. So the utility is taking on that part of the volume risk. That's where the risk premium comes in.

CHAIRMAN JABER: Any other --

COMMISSIONER DEASON: But that's for 20 percent, up to 20 percent of the, of the difference between the forecasted demand and actual?

MR. STEPANOVITCH: That's a good question. Our plan really can go from zero to 100 percent. There's -- it'll be, it'll be an agreement -- as we put forth the stipulation and we come here and agree, we'll give you our view of what our, what our overhaul schedules are, what our load projections are, what the forward markets are doing. And I can -- the way I see it is that we will advise on how much should be fixed and how much should be left up to spot. And it could be anywhere within zero to 100 percent.

COMMISSIONER DEASON: So that would be part of the initial filing?

MR. STEPANOVITCH: That would be part of the filing, that's correct, under the stipulation.

COMMISSIONER DEASON: Now if the actual demand is greater than forecasted, you have the obligation to go to the spot market and obtain that and that's your risk.

MR. STEPANOVITCH: We will go out and obtain it for the fixed -- we will go out and obtain it, all of it. The way it's recalculated or readjusted, if you have 100 MMBtus and it actually came in at 110, then 20 percent of that ten will revert to the fixed price. But we are buying 100 percent of it at spot. That piece of it, that volume, we will be taking on that risk.

COMMISSIONER DEASON: And what happens in the situation where actual demand is less than forecast?

MR. STEPANOVITCH: The same thing. We go back in and recalculate. If it's 90, you know, we'll go back in and recalculate it with that in mind. The same percentages; the percentages do not change.

COMMISSIONER DEASON: Okay. Thank you.

CHAIRMAN JABER: The -- with respect to the initial proposed stipulation, you anticipate filing something in July. Is that because you want six months' worth of market information? Are you wed to the July date?

MR. STEPANOVITCH: When you say six months' worth of market information --

CHAIRMAN JABER: I'm wondering why you picked July.

MS. DUBIN: More from a regulatory standpoint in order -- we figure that by the time we file and there's a Staff rec and agenda conference, at the minimum it would take three weeks. So to be able to do that -- and then also then once we have all that information we would incorporate it in our September filing for our projected factor. So we were just backing up from the September 20th filing date and taking into account the minimum would be three weeks for that to occur.

CHAIRMAN JABER: Uh-huh. But in terms, in terms of the information you would need to make your proposed settlement filing, is there any significance to July?

MR. STEPANOVITCH: We're going to give you -- now I understand exactly what you're asking for. We're going to give you the information for the upcoming year just like we would any other time of the year, only we're going to project out again what our, what our load patent is for that upcoming time period, generation patent, overhaul schedules and any forward market information at that point in time to make that decision. It could be September or it could be July. It's just going to be different market information.

CHAIRMAN JABER: Ms. Dubin, I'll tell you why I'm asking those questions, and obviously I don't know what the Commission will do with any of these proposals, but let's assume for a moment that we accept FP&L's proposal. I'm thinking ahead about the possibility of separating the, the hedging filings and having them resolved well in advance of the November hearing. Sort of like there are issues every year that we take to agenda, vote them and we just include the factor into the November proceeding, we don't file, you all don't file testimony, we don't resolve the specific issue in the fuel hearing, it's already resolved, and we just implement the factor into the final vote.

To that end, is it possible to have a proposed stipulation every January that could be resolved completely by July?

MS. DUBIN: I believe so, Commissioner. We were strictly backing up, like I said before, from the September filing date.

CHAIRMAN JABER: Okay. Commissioners, did you have any other questions?

COMMISSIONER BRADLEY: Yes, I have.

CHAIRMAN JABER: Commissioner Bradley.

COMMISSIONER BRADLEY: Under Number 3, it says that, "Florida Power and Light's proposed plan assumes that the Commission will allow recovery of all prudent transaction/hedging costs; for example, broker commissions, fees, cost of margin requirements, cost of developing and implementing the risk management system, the incremental cost of maintaining and operating the trading floor associated with the risk management plan, and natural gas and residual," and it goes on.

Under the current system these costs, as compared to what you're doing currently administratively, how do those two line up on a side-by-side basis? And I don't expect you to get to the point, I mean, down to the, down to the penny. But is this, is the system of administering this new system going to be, cost more administratively or less or the same?

MR. STEPANOVITCH: It should be -- it will be more simply because of the management of the information. There's more information to manage, more transactions to manage. The transportation costs, we do those today, we'll do those, we'll do those tomorrow. The incremental costs of the trading floor, and we already have a system in place that we manage all our risks with, this is just an enhancement to that. At this point I really don't know the cost of that. I would say it's probably a few million dollars. I'm not really positive. But those are the type of costs that are not, not there today. And there will probably be some additional personnel.

CHAIRMAN JABER: You have incentives today to hedge and, as a matter of fact, Florida Power & Light does hedge now. Can you walk me through what it is you do now to mitigate the risk with respect to price volatility and specifically how your proposal would enhance what you do?

MR. STEPANOVITCH: Well, basically today what we do is we physically hedge. We do not really go into the financial market to do what we do today.

Tomorrow, if this is approved, there will, we'll still do quite a bit of physical hedges. In fact, most of it will probably be physically hedged. To go into the financial market, we will use some of that depending -- we'll use some -- excuse me. We will use some financial instruments simply because you -- depending on size. And if you implement 20 percent of our portfolio, we can probably physically hedge that, depending on the situation.

If you go up to 40 or 50 percent, you're probably not going to have -- you're going to have to use both the financial market and physical market. So that's one difference.

The way we do it today is basically we don't go out much further than one or two months. The further you go out in the forward markets, you see -- there's two things in the forward markets: One is stability; two is usually you get a discount, there's a discount for further out you go.

The shorter time periods as in today's market depending on if you were to buy gas tomorrow or power tomorrow -- if a nuclear unit goes off, what's going to happen? The prices go up. So on a short-term basis you're subjected to more volatility, and that's where we are today.

If this plan is approved, we will -- the forward market is not subjected to those short-term opportunities, happenings. So, again, basically I'm repeating myself, it's basically a discount the further you go out and, again, more stability. So those are the big, two major differences.

CHAIRMAN JABER: Are there administrative costs associated with physical hedging?

MR. STEPANOVITCH: Depending on the type of transaction that you do, if you go out and buy maybe a call option or a put option, there is premiums for that. If you just go out regular and buy gas at a discount for a month period, sometimes, no.

CHAIRMAN JABER: To the degree there are some costs, if you exercise the call option, are those costs recovered through the fuel adjustment hearing, Ms. Dubin?

MS. DUBIN: Yes, they are.

CHAIRMAN JABER: You include them there? What would you say your current incentive is to do the physical hedging? What's your incentive now?

MR. STEPANOVITCH: To do the short-term physical hedging the way it is now? To achieve the lowest possible cost for the customer. That's our, that's our incentive right now.

CHAIRMAN JABER: Okay. And to the degree we don't approve at the end of the day your hedging proposal, you don't anticipate changing your, your, your goal of meeting that incentive, meeting that goal and certainly you wouldn't discontinue the physical short-term hedging that you, the company performs.

MR. STEPANOVITCH: We would definitely not discontinue that. The only thing that you would not be achieving is the stability in rates. You'd be, you know, fluctuating between the highest cost and the lowest cost and the stability would not be there if you did not accept this plan.

CHAIRMAN JABER: Commissioners, any other questions?

COMMISSIONER BRADLEY: Yeah. One other question.

CHAIRMAN JABER: Go ahead, Commissioner Bradley.

COMMISSIONER BRADLEY: Same as I asked Florida Power. Is this plan the result of your scientific and creative actions within Florida Power & Light or is this a plan that currently exists elsewhere in the country and that's in effect, in force?

MR. STEPANOVITCH: There are other plans out there that we have seen; i.e., Georgia in Savannah, out in California, there are some plans out there, some sharing plans.

I will say that this is completely different than those plans. Those are more of a sharing plan, where this plan here is to provide the stable rates with the risk premium. So I would say that it's completely ours and it would be the one of its kind in the country.

COMMISSIONER BRADLEY: Thank you.

CHAIRMAN JABER: Commissioners, are you ready to move to the next presenter? Do you need a break? How about we take a ten-minute break, and then we'll come back with Gulf Power's presentation.

(Recess taken.)

CHAIRMAN JABER: Let's go ahead and get started. Gulf Power.

MR. BADDERS: Good morning. I'm Russell Badders here on behalf of Gulf Power Company, and with me is Norrie McKenzie to give a brief presentation.

MR. McWHIRTER: Thank you. My name is Norrie McKenzie. I'm General Manager of Gas Procurement for Southern Company Services. Southern Company Services is Gulf's agent for fuel procurement. It's also the fuel procurement agent for

Georgia Power, Alabama Power, Mississippi Power and Savannah Electric.

As part of that, we manage the gas and oil procurement physically. And we also manage three PSC-approved financial derivative hedging programs: One at Savannah, one at Mississippi and one at Alabama. As far as my knowledge, these are three of the only four in the country that are publicly-approved hedging programs for electric utilities.

As our operating companies have added gas-fired generation we have approached our commissions about hedging, and this is a timely workshop in that Gulf Power's combined cycle plant went into effect, went into operation just a few weeks ago.

I have two questions that I'd like to ask and answer prior to getting into our proposal or the proposal that Gulf is contemplating filing.

One is why hedge? Buying at market is arguably the lowest cost long-term range price mechanism. However, if you buy into that and you decide to buy all your physical at market, you must be willing to pay high prices when the market's tight and you must also be willing not to hedge when the market squeezes.

I think California is a prime example of what not to do. They chose to buy at spot and then they chose to hedge long-term when the market peaked.

The second question I want to ask is why should we seek PSC approval for hedging? If we do anything that puts our ratepayers at risk of paying above market, I want to make sure that we have your approval.

Now I'd like to briefly review the five slides that you have in front of you which outline the objectives and a plan that Gulf is contemplating filing.

If you look at the first page, the hedging program objectives, Bullet Number 1, reduce fuel price volatility to customers. It's pretty self-explanatory.

The second bullet I would like to address a little. One, provide protection against natural gas price spikes. And the second part of that bullet, which is not commonly addressed, is to protect against unacceptable above market fuel prices. You can reduce volatility; however, you can lock in prices that result in above market for your customers.

And Bullet 3, procure the physical fuel at market and hedge with financial derivatives. Procuring the physical fuel at market allows us to optimize our system. Gulf Power is part of an integrated system with the other utilities and the plants are dispatched economically. If we were to tie a physical fuel at a fixed price, then we'd have to ensure that that fuel was burned at Gulf and it wouldn't allow us to operationally benefit from lower cost alternatives for the ratepayer, which the system does allow us to do now.

The second point in procuring the physical at market and hedging with financial derivatives is it helps mitigate what I term "supplier price majeure." If you lock in a physical hedge and a price results in a below market price to the supplier, he's tempted not to deliver, and we call that price majeure. It means you have to go out in the market and replace the gas. And the supplier may be claiming force majeure that you can't prove is not force majeure, so it puts you at a risk. And it only happens when you think that hedge is in place. In other words, he always delivers if that price is above the market, but is tempted to deliver when it's not -- tempted not to deliver when the price is below market.

If you'd turn to Page 2, I'll walk through briefly the proposal that we're contemplating filing. One, which I've already addressed, is all physical purchases at market at time of delivery. All hedging will be done with financial instruments. And it addresses -- the hedge is for the commodity portion of the risk. For gas at our combined cycle plant we have hedged the transportation in that we have firm transportation under a long-term contract at a fixed price. So it's the commodity portion of the gas for that plant that is at risk. For plants that burn gas as a peaking fuel, the transportation or delivered component of that would still be subject to the market value of that transportation at the time.

The fixed price volume that we could go out and hedge would be limited to 100 percent of the projected annual volume or future budget volume as appropriate.

Then the next bullet actually would allow us to hedge or have insurance against a hot summer, high-priced environment; i.e., we could buy options for ten percent over that. Now we could not hedge fixed price for anything greater than, quote, the budget, but we could purchase call options to protect against higher prices in a high demand summer.

The last bullet on this page addresses the time limit, and we propose to limit the hedging to 42 months out. There's nothing magical about that; it's 3-1/2 years. But if you look at the gas market over the last 10 to 12 years, it is cyclical and the cycles tend to be 3-1/2 years in length. We would like to take advantage of those cycles and be able to hedge up to three summers out from any point in time in a given year.

The last part of the 42-month-out limit is that long-term we don't want to be out of the market, long-term being 5 to 10 years out. We do not want to be locked into a price that could be resulted in an above market cost to ratepayers.

If you'll turn to Slide 3, I'd like to address the customer protection and the proposed company incentive parts of this plan.

Gulf will aggressively manage an above market cap for natural gas and oil in order to limit, to limit the risk of the customer paying above market prices. The annual above market cap in this proposal is 10 percent of the current year protection for delivered natural gas and oil.

For example, if Gulf's budget for gas and oil is $100 million in a year, then we would guarantee that the customer would not pay more than 10 percent above market. And that protects if the market starts declining and our hedge goes out of the money. We guarantee how far out of the money that hedge will go, and we take the risk that it goes more out of the money than that 10 percent limit.

Another limit that keeps us from aggressively hedging in a down market is a forward limit based on the 42 months. You take 5 percent of the budget and projection and we would not allow the mark-to-market value of the forward positions go negative more than 5 percent of that 42-month budget. That will require us to actively manage a hedging program, and it also puts risk on the company to manage it within those limits.

In exchange for managing that risk and guaranteeing those limits, Gulf is contemplating proposing an incentive program where, in exchange for managing those limits, Gulf would retain 25 percent of any savings that are achieved through its hedging activity. Gulf would not earn any incentive if the hedging activities did not generate customer savings.

Now I'd like to go ahead and answer a question that I'm sure you have. If we get to retain 25 percent of gains, why shouldn't we retain 25 percent of any losses?

The first answer to that is we would be incented to be inactive. If every time we entered a hedge we knew that there was a high probability of losing money, we would be incented to be inactive and the program would be ineffective.

The second part of that is you want your financial hedges to be negative. Unless you've hedged up to 100 percent of your volume, unless you hedged 100 percent of your volume requirement, you want your financial position to be negative. That means all the rest of your gas is going to cost less. So if we hedged at $3.50, what we really want to happen is the market go to $3, not $4.

These limits and incentives are designed to provide goals such that we would be incented to be a cautious hedger in a down market and an aggressive hedger in an up market.

Now if you'll turn to Page 4, what are the benefits for the customer? One is better rate stability through reducing the volatility of the fuel.

The second bullet is an opportunity for protection against natural gas price run-ups.

And the third, which is a real protection to the customer in a declining gas market, is that the company guarantees a limit on the above market exposure that the company, that the customer has.

And the fourth bullet, there's the potential for and, I would argue, the incentive for below market savings.

What are the benefits and risks to the company? One is that we would have PSC authorization to use financial derivatives to manage our fuel clause. Gulf to date has not used financial derivatives.

The second is the opportunity for incentive. It aligns our goals to minimize fuel cost for the customer. The risk to the company, we have to manage it within these limits or the stockholder loses money.

In closing, I want to thank you for the opportunity to discuss this timely proposal, and, as you can see, it's entirely different than other proposals. Gulf does not believe that one size fits all, but it believes that a program with these parameters will help Gulf maintain its goal of minimizing fuel cost. It not only has the potential to reduce the volatility, but has the possibility and incents Gulf to achieve below market savings, but it does protect the customer against above market risk. Thank you.

CHAIRMAN JABER: Thank you, Mr. McKenzie. Commissioners, do you have any questions? Commissioner Deason.

COMMISSIONER DEASON: I have a question on Page 3 of your handout.

MR. McKENZIE: Yes, sir.

COMMISSIONER DEASON: The 10 percent guarantee, you would use financial instruments to ensure that the customer would not have to pay more than 10 percent of what you project during a projection period to be the price of natural gas and oil?

MR. McKENZIE: Once the budget is set for a year, let's say, for example, if the budget were $100 million for gas and oil in 2003, then that number is fixed, it's $10 million. Then all of our hedging activity, the guarantee is that there will not be losses greater than $10 million due to hedging activity. All physical purchases would be at market.

COMMISSIONER DEASON: Well, I guess my question is what does the customer pay?

MR. McKENZIE: The customer pays the physical market price at time of delivery, and then he also gets the benefit of savings achieved through hedging of 75 percent netted at the end of the year or he incurs the cost up to that 10 percent limit.

COMMISSIONER DEASON: Okay. And the terminology you used, forward mark-to-market negative limit, can you define what mark-to-market negative limit is?

MR. McKENZIE: Yes, sir. Each day we look at the mark-to-market position of financial hedges. In other words, if we hedge next year at $3.50 and the price has gone to $4 on a certain day prior to the day of delivery, that position has a

50 cent positive mark-to-market. If it were to go to $3, it has a 50 cent negative mark-to-market. You take that 50 cents times the volume you've hedged and that's your mark-to-market position on that day of close.

We would manage it so that over the 42-month forward period we would not let the negative position of all of our hedges get above 5 percent of that budget. So if you had the $100 million a year assumed for 3-1/2 years, you would have a limit that would be 3-1/2 times $5 million, or about 17.5 million bucks. That keeps you from aggressively hedging forward in a down market.

COMMISSIONER DEASON: What, what protection does that give to the customer?

MR. McKENZIE: The protection the customer gets from that is it limits how much we would hedge in a market that is trending down. In other words, what you're really trying to protect is how much above market the customer will pay ultimately.

COMMISSIONER DEASON: Okay.

CHAIRMAN JABER: Commissioner Palecki.

COMMISSIONER PALECKI: In the past five years we've seen times where there's been tremendous fuel volatility and we've also seen some times where there's been relatively stable fuel prices. Would it be possible, and this is a company of all of the utilities, not just Gulf Power, but would it be possible for Gulf Power to go back and give us an example of what the customer would have, what the result to the customers would have been if you had implemented this plan over the last five years or so?

MR. McKENZIE: We can do that. The hedging -- hedging in the past is very easy to do. We can point to times when we would have or should have hedged and would that have cost the customer money or saved the customer money, we can give you examples of that. However, that example would not or may not be indicative of the activity that happens in the future. In other words, looking back, I would always assume I bought at the dips.

COMMISSIONER PALECKI: And I guess I'd be especially interested in seeing what happened during the time of very, very great fuel volatility. You know, about a year ago we saw that tremendous spike.

MR. McKENZIE: Right. Unfortunately our programs, even though we were talking with the Georgia Commission because Savannah's rate was very affected by gas, we were in the processes of getting a hedging program approved. It was not approved until May of 2001, so we did not have a hedging program in place when you saw the gas prices of $10.

COMMISSIONER PALECKI: So your timing was off just by a couple of months in that case, I guess.

MR. McKENZIE: Well, fortunately we didn't hedge when it was $6 and lock it in for a long term.

COMMISSIONER PALECKI: Thank you.

MR. McKENZIE: Yes, sir.

CHAIRMAN JABER: Commissioner Bradley.

COMMISSIONER BRADLEY: Yes. Thank you. In your first sentence it says that any hedging program will put the customer at risk of paying above market prices for fuel. I can appreciate your honesty.

And my question is this -- two things. If you, if you go to hedging, what might the reaction be to, of your investors in terms of, well, because of the fact that this might create some volatility within your company itself and financial volatility or uncertainty, do you have any idea about how your investors might react?

MR. McKENZIE: I believe my management and our investors will hold me to manage this program within the limits. If I lose money, you'll find somebody else sitting here.

COMMISSIONER BRADLEY: Beg your pardon?

MR. McKENZIE: If I lose money in these hedging programs for the company, you will find somebody else sitting here next year.

COMMISSIONER BRADLEY: Okay. But I don't want to find someone else sitting there. I want --

MR. McKENZIE: I don't either. I like my job. But my management will hold me accountable to manage these programs such that with your preapproved limits we don't plan on losing money for the company. And we only would earn any incentive if we saved the customer money.

COMMISSIONER BRADLEY: The reason why I said I can appreciate your honesty as it relates to the customer having to pay, putting the customer at risk of paying above market prices for fuel is because I don't know if we give, if we have given our proper due to what your relationship is going to be with the producers because, you know, the cost of production can go up, the cost of business can go up, in other words, for the producer actually to deliver to you. And if you've locked that producer in at a, at a price that's not advantageous to them and their investors, then they may decide that, in this competitive market to sell fuel not to you but to someone else who is willing, who doesn't have a hedging program.

MR. McKENZIE: Right. That's exactly why I like this proposal. We keep all of our physical contracts with producers at the current market at time of delivery and handle all hedging through financial instruments that are over-the-counter swaps, call options, et cetera, with banks. We currently use three banks: CIBC, which is Canadian Imperial Bank of Commerce; Bank of America and J.P. Morgan Chase. All of our contracts with Exxon, Dynergy, any producer or marketer who represents a producer or at market, as long as our contracts with that producer are at market, then he can't get a better price from somebody else. At the same time, neither can I.

So we like having our physical contracts at market. That way the producer is not incented to sell that gas to anyone else at a higher price. Did that answer your question?

COMMISSIONER BRADLEY: Yeah. But I'm trying to figure out if you lock in at --

MR. McKENZIE: We don't lock in long-term prices with a physical counterparty.

COMMISSIONER BRADLEY: Okay. Okay. That answered my question then.

MR. McKENZIE: Okay.

CHAIRMAN JABER: I have just a couple. You're the first one that talked about how the hedging programs aren't, do not have to be a one size fits all.

What are some of the company characteristics that would require, that we should look at in terms of justifying different hedging programs for different companies?

MR. McKENZIE: Well, and this may be particular to Gulf in that we do want to keep all of our physical contracts at market is because Gulf is part of an integrated system. Gulf's plants are not dispatched if it can buy from another sister company at a lower price. Therefore, it's very hard to determine what volume of fuel is required. We may line up gas for a power plant at Gulf and, if that plant doesn't dispatch at the market value of gas on that day, Gulf can buy power from a sister company at a lower price. If we had that physical gas tied to a fixed price, then we'd have to make sure that whatever happened to that gas, that fixed price position stayed with Gulf. That's probably one characteristic of Gulf that's different than the other utilities in your state in that we are an integrated system and it has that benefit of buying from its sister companies.

CHAIRMAN JABER: Based on the two proposals you've heard thus far, and this is truly putting you on the spot, is there an aspect of the Power Corp proposal or the Power & Light proposal that you just cannot live with, that you cannot adjust to?

MR. McKENZIE: I haven't quite asked my question, asked that question, but I do not want the volume risks that are in those proposals. I think Florida Power & Light and Florida Corp have put forth a proposal where they do take some volume risk. We don't want that.

At the same time, we don't want the execution risk. In other words, when we hedge, if we hedge at $3.50, $3.40, $3.60, that's the price that it's hedged at. I don't want to come in here and say I can get $3.50 and end up paying $3.70 and eat the 20 cent difference. At the same time, we will pass whatever price is hedged on. So those two risks we really don't want.

CHAIRMAN JABER: Okay. You said the Georgia Commission approved your hedging proposal in May 2001. You've had it implemented now, I guess, for a year.

MR. McKENZIE: Right.

CHAIRMAN JABER: Have you seen the effect of that or is it too early to --

MR. McKENZIE: Well, we've been in it for about a year. And I don't know how familiar you are with the gas market, but in January of 2001 summer prices for 2001 were $6. In May prices were $5.50 and they were dropping as we were speaking with the Commission. In June 1 the program was implemented, prices of gas dropped down to $4, and that looked like a pretty considerable bargain.

So we did hedge, we hedged, and I want to stay away from specifics, but let me just say a small amount of their requirement at $4. Well, the price immediately went to $3 three weeks thereafter. We, we had a strategy that protected against that above market cap. Prices went down past $2 eventually. We guaranteed a limit and we did not bust that limit. That's what you expect in a down market, and that was a significant down market. This year has been an up market. And without, again, citing specifics, the program is saving the customer money.

We have also -- I will say in Alabama the timing was much better in that their program was just approved earlier this year, and there's been significant savings achieved through that hedging program, which you would expect if you're hedging in an up market.

CHAIRMAN JABER: Is this proposal completely consistent with what you've implemented in Georgia and Alabama or have you adjusted it?

MR. McKENZIE: It is adjusted a little bit.

CHAIRMAN JABER: Where?

MR. McKENZIE: Okay. The adjustment between this one and Savannah is in the, the option limit. They are similar, but the percent that can be hedged above the fixed price percent, in other words, above the 100 percent, the calculation is a little different.

Here we are just proposing to take the budget and say that we can hedge with options, not fixed price, an extra 10 percent. And the reason you don't want to hedge with a fixed price is that quantity is really to protect against a very high demand, high-priced summer. If you burn less than that, we don't want the customer with that fixed price exposure.

CHAIRMAN JABER: So is that an adjustment you made based on just watching what's happened in Georgia?

MR. McKENZIE: It was -- in Savannah's case, their demand is much more peaking. And instead of having a 10 percent calculation, we actually run a high demand scenario by increasing the load out three years and it's more of a model calculation. The difference between Savannah and Gulf is that 50 percent of Savannah's capacity is gas-fired and the majority of that gas-fired capacity is peaking, not baseload.

CHAIRMAN JABER: Okay. That's the only place you've made an adjustment to the proposal?

MR. McKENZIE: That's how this proposal is very similar to the Savannah hedging program. The Mississippi and Alabama programs are different. You know, unfortunately I have to deal with five different managements and four different commissions, so each plan has evolved differently.

The proposals in Mississippi and Alabama do not have incentives and they also limit the hedging percent of budget to 75 percent. In other words, it's a given that at least 25 percent of their volume will be at market prices. And then the Alabama proposal has the 42-month time limit; the Mississippi proposal does not.

CHAIRMAN JABER: Okay. You reminded me, with respect to the 42-month time limitation, how do you envision we would approve that cycle? Is it that we would look at your proposal once?

MR. McKENZIE: You look at our proposal once when it is ordered or stipulated, and then we enter hedging activity at our discretion and file periodic reports with you to monitor the activity of that hedging activity. And you could shut it down at any time. And if you were to say, okay, I don't like this anymore, you've lost too much money, we close those positions out, they go into the fuel clause, and then all fuel is bought at market thereafter.

CHAIRMAN JABER: But in our approval process it would need to make clear that the time limitation before the next approval would be for 42 months?

MR. McKENZIE: Well, once you approve a program like this, there's no further approval required.

CHAIRMAN JABER: Okay.

MR. McKENZIE: We can only hedge up to 42 months out. In other words, I can't hedge 2010 today. I can only hedge 42 months out from today.

CHAIRMAN JABER: I see. Okay. Thank you.

Commissioner Bradley.

COMMISSIONER BRADLEY: Yes. Let's talk a little bit about approval at market price. And I noted you said that there's some differences between the regulatory, well, some differences between your hedging programs in Georgia, Alabama and Mississippi.

But the approval of a market price, is that, is that a regulatory function or is that something that's preapproved and you are allowed to determine that on your own without having to come back into the regulatory process for approval?

MR. McKENZIE: Our physical contracts, whether they're long-term or short-term, are tied to market indices so that the gas when it's delivered is at a market price or, if we buy gas for tomorrow, that's at tomorrow's spot price. So by definition, when physical contracts are like that, the physical procurement is at market.

I am an avid proponent of keeping physical contracts at market. I've been in the gas business for 21 years. And when suppliers have contract sales prices that are below market, it is amazing how much opportunities they take to claim force majeure. Or even if there's just a list of contracts they have to supply, they're tempted to cut the ones that have a lower price. So I like to keep all of our physical contracts at market at time of delivery. We do that by tying the sales price to a market index.

COMMISSIONER BRADLEY: Okay.

MR. McKENZIE: That does haven't to be Commission approved. However, I think the understanding in the hedging program, if all physical contracts are at market, then the Commission should understand that they are at market and at market at time of delivery.

COMMISSIONER BRADLEY: Okay. You said it doesn't have to be Commission approved. But I'm just wondering is it commission approved? Because I think that the Commission itself has an obligation to be accountable to the public and should be involved in this process, I think the public expects us to be, and that's why I'm asking. Because if it goes down, then that means that there's a savings; if it goes up, that means that the costs increase. And I'm just wondering how you get approval for those spikes.

MR. McKENZIE: Well, that's where you net the financial gains and losses with the physical contract.

In other words, if I'm buying gas for next year, next summer, and let's say the current price for next summer is $3.75. Okay. We might like that price, so we lock in a financial instrument at $3.75.

Assume the gas price goes to $4.50 next year. I pay $4.50 to my gas supplier, but I will receive 75 cents from my bank counterparty. So the net price to the customer is $3.75. You have to net the financial and the physical together to get the ultimate price.

So if the price goes up and you've hedged, you are protected from that uprise in price. The same is true if it goes down. If it goes to $3.25, then you'll pay $3.25 to the physical producer and you also pay the bank 50 cents. So net you'll be paying $3.75 for the fuel.

COMMISSIONER BRADLEY: One other question. What is the incentive to you or to Gulf Power to, to hedge?

MR. McKENZIE: Well, Gulf Power's incentive, is incented to minimize its fuel cost. I think it always has been incented to do that so that the ratepayers are paying as low a cost as they possibly can.

What we are proposing here actually guarantees how much above market they might pay for gas and oil. And then for taking on that risk I think it's an appropriate incentive that they retain 25 percent of any gains achieved, any savings achieved. If the hedging activity doesn't achieve any savings, they get no incentive or Gulf gets no incentive.

COMMISSIONER BRADLEY: Okay.

CHAIRMAN JABER: Commissioners, any other questions? Commissioner Deason.

COMMISSIONER DEASON: Yes. I'm trying to understand the mechanics of how you would go about -- if your proposal is approved, would you at the beginning, at the projection period, the November hearing when we're projecting what we're going to include in customers' bills as their, as their factor, at that point would you project what you think would be the market price for natural gas in your, in your projection as to what the demand and price is going to be for that entire year?

MR. McKENZIE: I may have to rely on Gulf's regulatory people to talk about actual mechanics of their filing. But the way I understand it, if I can briefly make a statement, Gulf would file projected costs and set its rates based on that. We would not come in and say, okay, this is what we're going to hedge at. Any hedging activity will be done to help mitigate that rate going up. But we wouldn't come in and say, okay, the price is $3.75, we're going to hedge at that price. And I would like to defer to the regulatory personnel here.

COMMISSIONER DEASON: Okay. Let me just throw out a very general hypothetical. If you believe that in the next projection period that you're going to have to pay $100 million for natural gas and that's the market, you would base your projection upon that, we would set the customers' factors at that. And if you are engaged in financial derivatives or whatever such that with physical delivery and the exercising of those derivatives that you actually, you actually had to pay $105 million, then, then what happens at that point?

MR. McKENZIE: Okay. Assume we did no hedging and the actual market ended up being $105 million, then that is the price that would go into the fuel clause. Assume in this case that we did hedge and that we were able to save four of that five additional cost, they would get 75 percent of the four. In other words, $3 million of the four would go to net the $105 million. So in this example they would pay $102 million.

COMMISSIONER DEASON: Thank you.

CHAIRMAN JABER: And procedurally that would happen in the true-up part of the fuel adjustment hearing?

MR. McKENZIE: That's where I definitely need to defer.

MR. BADDERS: That is correct.

CHAIRMAN JABER: Commissioners, any other questions? All right. We have TECO next. Thank you, Mr. McKenzie.

MR. McKENZIE: Thank you.

MR. BEASLEY: Commissioners, I'm Jim Beasley representing Tampa Electric Company. With me today is Ms. JoAnn Wehle, Director of Fuels for Tampa Electric. Also present is Ms. Denice Jordan, Tampa Electric's Director of Rates and Planning. Ms. Wehle will present a summary of Tampa Electric's position on Issue 7.

MS. WEHLE: Thank you, Jim, and thank you, Commissioners, for the opportunity to provide you with Tampa Electric's risk management activities to date and what we see going into the future.

Just as a backdrop, on our first slide there, a definition of hedging or several definitions. Hedging is an activity protecting the value of an investment from the risk of loss in case the price fluctuates. Or another way of saying this is it's a way of offsetting the risk of a position in the marketplace. Simply stated, it really is a form of insurance. And usually with a form of insurance there are costs associated with that.

Tampa Electric's risk management strategies to date have been through physical hedging programs, and that has been through a variety of contract mix and optionality that has been embedded in our contracts. We hold a portfolio of a variety of different contracts both in, that are short-term, medium-term and long-term which provide us opportunities for price and supply stability, as well as the opportunity to take advantage of any significant spot market flexibility that is available.

Likewise, we have embedded in several of these contracts volume flexibility. That gives us the opportunity to either increase or decrease the volumes that we take from particular producers given different market conditions and prices that are present at the time.

The current fuel clause methodology allows for full recovery of prudently managed costs of fuel and purchased power and nothing more than that. And also as part of that methodology costs are reviewed through the audits that are done on an annual and ongoing basis. And that's at the point at which these costs are determined whether they are prudent or not, and we feel that this incents the utilities to procure fuel and purchased power that are in the best interests of the ratepayers.

As you may or may not know, Tampa Electric has been predominantly a coal fuel user, and coal has been a commodity with very stable pricing in the past. We have not seen the need to use financial hedges associated with our coal because, again, they have been, the coal market has been very stable and it's not a very liquid market where you can actually go and provide a variety or procure a variety of instruments. There is a coal contract that is traded on the NYMEX. It is not representative of a type or a delivery point at which Tampa Electric takes fuel at this point. However -- and we feel as though any costs associated with buying this type of a derivative instrument outweigh any benefits derived.

As you can see on the next slide from our ten-year site plan which was recently filed, coal has been a predominant fuel source for our generating facilities. As recent as 2000 we've used over 95 percent for our generating stations. But as you can see going forward, natural gas will become a greater part of our mix. This is due to the repowering of our Gannon Station to our Bayside facility where natural gas will be used. And in the next two years we will be facing quite a transition period as it relates to fuel, going from anywhere from 2 percent of natural gas use, as you can see, up to between 30 and 40 percent of natural gas use.

Again, as I said, over the next two years we will be transitioning into this whole new arena. We will be developing experience not only in how to operate this new plant, but also in developing the appropriate fuel procurement, risk management and hedging strategies based on this new arena that we're facing. And, therefore, at this time we feel that an incentive to hedge is not appropriate for Tampa Electric.

We will continue, however, to evaluate opportunities that compliment this fuel mix and operational changes that will benefit ratepayers going into the future. Likewise, we feel that wholesale energy should not be hedged until a liquid published market exists in the State of Florida.

Lastly, I'd like to say that, again, I agree that there is not a one size fits all and any incentive that's put forth should allow the IOUs to develop their own unique plans. We are all on different ends of this spectrum. And as I've read and attended various seminars, the common theme that I've learned is that you need to have a slow-as-you-go approach or else you can actually get yourself burned fairly dramatically in this new hedging arena, especially as natural gas is concerned.

And so we'd like to take a more conservative approach. And as opportunities present themselves in the future, we would like to revisit the possibility of putting forth an incentive program, but at this time we feel that it's too premature for us to put one forth.

CHAIRMAN JABER: Is that it?

MS. WEHLE: That is the end of my comments. I'd be happy to answer any questions.

CHAIRMAN JABER: Thank you. Commissioners, do you have questions?

Commissioner Bradley.

COMMISSIONER BRADLEY: Just a statement. As I, as I've listened to your presentation, I do have to agree that the

Commission shouldn't approve a plan that would put anyone at a disadvantage, and we do need to give consideration to the fact that different companies are at different places in terms of their development as it relates to hedging.

And, you know, one of the things, until you mentioned it in presentations, that I hadn't considered is the fact -- well, I knew about it but I hadn't thought about it for the sake of this discussion, is the fact that we do need to give consideration to that end transition in terms of the types of fuel that they currently are using. And you said, what, 95 percent of your fuel right now currently is coal?

MS. WEHLE: That's correct.

COMMISSIONER BRADLEY: Hedging wouldn't apply to coal, would it?

MS. WEHLE: The types of hedging that we do are physical hedges and that is directly with the producer where we will lock in a price for a certain volume for a certain term and you can consider that hedging. What we do not do is financial hedging, which is where we would go and procure a derivative on an exchange in order to lock in prices.

As I mentioned, there is a coal contract on the NYMEX, but it is, it's very inactive and it's very illiquid and we feel as though it does not serve the needs of our ratepayers well at all.

COMMISSIONER BRADLEY: And I don't know where we, where we're going with this, and I strongly support the concept that, you know, one size doesn't fit all, as I said earlier. And I don't know if the end result, if we approved this, would be that companies would have the option to opt in or opt out as it relates to hedging. That sounds like what you're suggesting.

MS. WEHLE: That's what we're proposing at this point.

COMMISSIONER BRADLEY: Okay. Thank you.

CHAIRMAN JABER: Okay. Commissioner Bradley, just to give you some additional information, the beauty of this workshop is it's an indication of this PSC's willingness to take a cautious approach.

As I said before, Commissioner Palecki had the good idea of having this workshop to give the Commissioners even an additional opportunity to ask questions. But we will be deciding this issue at the fuel adjustment hearing, which is November.

COMMISSIONER PALECKI: That's correct. And I'm not sure it was my idea. I believe it may have been the Staff's idea, so we should give Staff thanks for that.

CHAIRMAN JABER: It doesn't matter whose it was. It was a great idea. So if it's Staff, that's even better.

But, Commissioner Bradley, to answer your question, we don't know where we're going with this. We don't have to decide anything today other than ask all the questions you're comfortable asking.

Do you have any -- Commissioners, saying that, are there questions for TECO?

Okay. Next on my list, FIPUG.

MR. McWHIRTER: Thank you, Madam Chairman. My name is John McWhirter representing the Florida Industrial Power Users Group.

And when this matter first came up, I've got to admit to you that I only had a broad general knowledge of hedging and now I still only have a broad general knowledge of hedging. But I've spent some time on it, as I know each of you have, because it's such an important issue. It was brought to my attention by the Public Counsel when he expressed concern about this issue in last year's fuel proceeding, and it was ironic that that happened almost simultaneous with the Enron debacle.

And as you know, the Enron debacle was an energy trading company deeply involved in derivative transactions and it got into trouble. So since last November there's been an awful lot in the newspaper about the Enron debacle and the things, the problems that can arise.

There's been -- I took the liberty of going out to Houston to take a course in energy trading to see what it was all about, and I found that to be a fascinating endeavor. And I went on vacation and I took along Florida, a financial accounting standard accounting book on Financial Standard 133, which deals with derivatives and the new concept of having to account for marking your derivative contracts to market, and that's most interesting.

From that limited study that I've done I've concluded what this case is not about. And what this case is not about, it's not about a utility locking in a price for fuel today for delivery at a future time. It's not about the physical contracts that Tampa Electric enters into, that Florida Power & Light said today that it now enters into to guarantee a price for the commodity it's going to buy. Those actions, those activities are permitted by the Commission's procedures today. Those actions are permitted by FAS 133. And you don't have to mark the transactions to market it and take them into account into your earnings.

It's not about -- the second thing this docket is not about is it's not about allowing utilities to recover the actual cost of fuel that they purchase. It's about collecting from customers something other than the actual cost that they pay for fuel. And the reason for that is to create a new earnings opportunity for utilities. And I think earnings opportunities for utilities and their holding companies are good and should be promoted and we should accept them. To the extent to which these earnings opportunities are passed along to consumers, however, is something that needs to be handled with great care.

I recall back in 1972 when I first appeared before this Commission and earlier when I worked for the Commission in the '60s the utilities assumed all the risk on fuel costs. They were included in base rates and the base rates were set and that was it and the utilities could hedge and they could do anything else they wanted to. And if they made profit on it, they kept the profit. If they didn't, then they would accept the loss. In 1972 fuel costs were separated and you started allowing the customers to pay for the actual fuel cost 60 days after the fact. In 1980 that was upgraded so that you go to a projected year with subsequent true-ups. And today utilities are guaranteed all of their costs.

In 1998 you concluded that fuel costs were too volatile because utilities were changing them four times a year and you removed the volatility from customers, and now the fuel costs are set on an annual basis. So if you're worried about customer volatility, that's not a real problem for customers today because fuel costs are set on an annual basis and trued-up.

And the bad year we had in 2000, you will recall that you trued that up over a couple of years and you gave the utilities commercial paper rates on their late recovery and everybody came out pretty well happily and the fuel cost remained substantially the same, except in February of

2000 everybody raised their fuel cost because the forecast they made three months earlier in November was off. For Florida Power & Light it was off by a half a billion dollars. So those costs were passed on. We had some volatility in that year, but we hadn't really had any volatility for a period of years before that.

So that's the three things that this case is not about: It's not about locking in a price in the future, it's not about allowing utilities to cover their actual out-of-pocket expense, and it's not about protecting customers from price volatility.

Well, if that's what it's not about, what is it about? What it is about is allowing utilities to enter into financial derivatives, and each person has explained that. And I gleaned from the questions that maybe we're not all really comfortable with exactly what's going on.

And as you recall, what we've read in the newspaper, financial derivatives are not regulated. Financial derivatives or the value of derivatives traded each year is around 100 times the total value of the stock traded on the American stock exchanges. Derivative contracts are contracts that deal with a promise to trade money.

And it came about in this way. In a pleading we filed earlier in this case, I briefly addressed what derivatives were, and I think it might be helpful to read that because I can read it quicker than I can recapitulate it.

Historically, as you know, hedging started with farmers; a guy needed to get money for his fertilizer in April and his crop wouldn't come in until October, so he would find somebody that would buy his crop and pay him so much a bushel in April for delivery in October. That's what the utilities do now with their fuel purchase. That's called a physical contract.

And what happened was this would enable the farmer to have the security of a known price for his commodity and he was able to buy the fertilizer and make a reasonable profit or a reasonable loss and then go forward with his transaction.

It happened earlier than that with insurance for the shipping industry; a well-known, well-tried-and-true mechanism for protecting yourself against risk. The problem arose with hedging, however, in that the farmer couldn't always find somebody to buy his crops in April because they may think that the price is going to go up or down and they wouldn't be willing to make a deal. So what happened was other people came into the transaction, gamblers and middlemen and speculators. And what we -- the risks that are to be avoided by these utilities and by farmers, also, were price risk, weather risk, delivery risk, machine failure risk, war risk, credit risk, basis risk, among others. There are people that are willing to gamble for these risks. Risks are based upon whether delivery of commodity comes soon or is postponed, and that's a very important thing that I will come back to in a minute.

As commodity markets matured, it quickly became apparent that buyers and sellers have difficulty in arriving at a fair price and this difficulty is resolved by the entry of middlemen who are willing to speculate. And these are wholesale traders, retail traders, basis traders, banks, brokers, market makers, power merchants, marketers and numerous others.

Now what our utilities want to do, today they are purchasers of fuel and they are sellers of electricity and buyers of electricity in the wholesale market. What they want to do is move out of that realm and into the realm of these middlemen speculators. And one of the most intriguing things in the presentations that have been made today is that they want customers to pick up the price for the risk premiums, they want the customers to pick up the cost of setting up their internal programs so that they can hire people and so forth to do this on the hypothesis that it's principally for the consumers' advantage, and the most important thing is they want customers to be responsible for margin risk.

I don't know if you know precisely what margin risk is, but most derivative transactions take place in bilateral transactions between individuals and they're not traded in an open exchange such as a NYMEX. The NYMEX has a gas exchange and they have oil commodities.

But if you deal in an exchange like that, the deal is that you buy gas at $3.50 and the price -- well, you sell gas, say, at $3.50 and the price goes up to $4. Then you have to post margin risk and you've got to post in cash the difference between your contract price and the current market price.

Same thing with fuel purchase. If you've guaranteed to buy fuel and the price goes down, you're in the money and you're in pretty good shape. But if you're having to make up your margin risk, then you're tracking the actual market price. So if that cost is passed along to consumers, consumers are not going to be saved, saving anything in the event that there is a transaction in which the costs have gone up. So this needs a little more careful evaluation as we go into the specific programs, and I won't go into it any further at this juncture.

The benefit to the consumers is that if we put up, we consumers put up all the chips, that is money to help them create the department, and we pay the premiums on the options and we pay the margin risk rate and if we pay the other costs that go along with the hedging, then the utilities will engage in this. But the customers are paying basically the cost of the utilities getting into the business.

Now each of these utilities presently has a trading company, they're engaged in the business. Florida Power & Light's current annual report shows that its energy trading company lost $34 million last year. This year the utility side is going to get into energy trading, so that is going to be an interesting phenomenon.

The customers will benefit if the utility estimate is, of fuel cost turns out to be less than actual cost, if the customers will pay the premium. Customers benefit then. If the price turns out to be higher with certain qualifications that Gulf has given us, the actual fuel costs will be borne by the utility companies. That's their margin of risk. However, if there's a significant unpredictable event, then customers will be asked to pick up that.

Now I happen to recall, since it isn't too long ago, in November of 2000 we had a fuel adjustment proceeding. Florida Power & Light came in and said our fuel cost for the Year 2000, I guess this was in '99, our fuel cost for the Year 2000 is going to be $2.5 billion. In February, which is three months after the hearing in which they said the fuel cost was going to be $2.5 billion, they came back and said the fuel cost, we find now because of increases, is going to be $3 billion. So we weren't able to predict that the fuel cost was going to go up higher.

One of the questions that we will ask, I guess, as this proceeding goes on, was that undiscovered half billion dollar deficiency, was that a significant unpredictable event because of something that went on in the world or was it something that the utility would bear the cost of?

The way it works now is customers to a large degree avoided the volatility because the price was imposed over a period of two years rather than imposed all at once. Later in the year Florida Power & Light recommended, recognized that it was a little bit high on its estimate and it had cut the cost back and it's pushed that forward. So customers really didn't suffer any significant volatility. And so --

CHAIRMAN JABER: Mr. McWhirter?

MR. McWHIRTER: Yes, ma'am.

CHAIRMAN JABER: Is it that they avoided the volatility or is it that we spread the expense of the volatility over time? I mean, I'm trying to understand your argument with respect to the customers.

MR. McWHIRTER: Well, all I was saying is that customers under this hedging program will benefit if costs go beyond what the projected budget is. But customers won't receive that benefit if that cost is an unpredictable event. So if the price in 2000 was an unpredictable event, then the customers will still bear it.

CHAIRMAN JABER: Uh-huh. Well, help me understand the position of your clients as we look at this issue going forward.

The two-year proceeding you were talking about, the result of our, I guess it was the Year 2000 fuel proceeding where we chose to spread the true-up amount over a two-year period.

MR. McWHIRTER: Uh-huh.

CHAIRMAN JABER: From your client's standpoint in particular, the industrial users, would they not prefer to have that amount closer to the time of when the expenses are incurred even if it means they may pay a higher price throughout the year, but at least they're paying it during the time the expenses are incurred as opposed to carrying, you know, for a two-year period not only the cost of the expenses incurred in that year but also from a year past?

MR. McWHIRTER: Well, what the utility said when we went to the annual thing is that the industrial customers didn't want that to happen. They said they wanted -- what industrial companies do is they set their budgets on an annual basis and they didn't want to have price volatility and that's why you went to the annual factor.

My clients at the time told me that, really most of them said we'd like to pay it, as you suggest, when it happens, we would like to have real-time pricing. And when prices go down, we'd like to get the benefit of that, and when they go up, we'd like to see that. And we think that those give good price signals to consumers, as they didn't do in California, you recall, because consumers would have cut back if their bills had gone up. Now they're frozen and when the costs go up you don't see that. But that's another case and another day and I won't --

CHAIRMAN JABER: I guess my request of you is to, if you could philosophically address that in your testimony, I'd really appreciate it. Because I guess I've approached the hedging issues in terms of benefits to the consumer. And I could be, you know, I stand to be corrected, I hope you take advantage of that in your testimony. But from an industrial user perspective where your own businesses hinge on the price of electricity in certain areas and how you engage in your market risks based on the expenses you have, I guess I thought, I guess I mistakenly thought that hedging might benefit the industrial users.

MR. McWHIRTER: The consumer would like to be able to hedge. And you may recall just two weeks ago we were here for IMC, and IMC said our generator has gone down and we're facing volatile electrical costs because of the circumstances within the utility that serves us. We'd like to be able to lock in a fixed price.

CHAIRMAN JABER: Uh-huh. Right.

MR. McWHIRTER: And they would like to engage in the hedging. Whether they want you to be their representatives on gambling with the utilities in a speculative market is another question.

The -- I told you that derivative transactions are sometimes 100 times what the actual market is. So look at the risk premium that customers may be asked to pay. If you're dealing with $5 billion in fuel costs in Florida and that's what the actual cost of the contracts are going to be, each month you get into financial transactions. And say we did 100 times that $5 billion, it would be 50 -- well, it just did ten times, it would be $50 billion in financial transactions backing up $5 billion in fuel costs. And if you have, you pay commissions and brokers' fees on $50 billion, that could be a fairly significant amount and that might offset to a great degree whatever the costs are and whatever the savings are in the fuel cost.

When you've got natural gas, which is now a pretty active competitive market, generally you do better to just follow the market, even though there may be price spikes from time to time. You've protected the consumers against these price spikes and you've protected the utilities by giving them the interest factor on the monies they had to put out already. The question is do you want to have the utilities come in and give you what their guess as to the next year's fuel cost is and then you gamble with them as to whether that is right or not? That's the issue before us.

And it may be something you want to do. But I would suggest to you that there's certain guidelines that you might want to follow. As we found out, there's a pretty good indicator of natural gas futures. We know what those prices are and you've got a pretty good indicator when somebody comes in with a budget for a natural gas price in the fall of the year, you can look at the NYMEX and you can see what gas prices are delivered at Henry Hub in Louisiana and you know what the transportation costs are from that point to the Florida delivery points and you can pretty well figure out what that is. Almost the same is true with oil; there's a good commodity market.

With coal, as the lady from Tampa Electric has just told you, there's no meaningful commodity market for fuel costs. So engaging in derivatives and bilateral confidential transactions on coal prices isn't going to give you the kind of benchmarks you need to look at to determine if the coal price is right.

And electricity hedging in Florida at this time, in my opinion, would be absolute folly. We have no real competitive market. The RTO, the independent system operator has not been set up, out-of-state electricity can't really get into Florida, so what we have is intrastate trading and without any open exchanges. It's all done in bilateral secret transactions.

So for you to monitor that and determine whether those hedged electric prices are good is going to be a Herculean task that I don't think you'd want to have happen.

Now one of the early articles after Enron, a very astute columnist with the Wall Street Journal said what happened with Enron is that it had better knowledge of the market than other people and it could go in and make transactions in this market, people weren't informed as to what the real market prices were, and they were able to do very well.

As the market opened up and as PMJ came along and the different ISOs around the United States and there was an electric power market going, then the prices became apparent and the margins went down. So I think instead of having secrecy in your transactions, you ought to have open, public record of what these transactions are. And as you know with respect to electricity, FERC has already started a rulemaking on this subject.

One of the things that you should guard against with all of your efforts is that if you're going to let people engage in financial transactions and pass the costs along to consumers, certainly you don't want that to be between related companies. You don't want Florida Power & Light Electric Company dealing with Florida Power & Light Trading Company in a secret transaction and then tell the consumers how that came out. That just may not be something you want to do. And I can assure you at our last workshop on this subject Florida Power & Light said it would not do that, that there was a Chinese wall between its trading company and the utility. But I think as you implement this program, if you implement it, you want to be extremely careful that there are no transactions between affiliated companies.

Oh, yeah. I think one of the other things that's important to you is the way this is setting up is a utility will come in in July and tell you what its prices are going to be, say July of this year, 2002, and it's going to tell you what its fuel cost prices are between January 1 of 2003 and December 31 of 2003.

Now what I learned at the little seminar I went to is that the market is pretty solid for about six months out. People have a pretty good idea of how much natural gas is in inventory and what the availability are and the weather projections. So for six months out these risk-takers, these middlemen don't charge much for the risks they take. The risk premium for shorter periods is less. So if you're going out 18 months, the risk premium is very high.

People that are taking the risk, just like insurance companies, if you're, if you have a teen-ager with a DUI conviction, his insurance rates are going to be higher. Well, people that are -- these banks and merchanters and marketers, they're not going to take this long-term risk that the gas will stay at $3 MMBtu for 18 months unless they charge a pretty good premium for it. So if they're going to charge you a 50-cent premium for $3 gas, you're going to be paying that premium. And as I understood the proposals we heard today, that 50 cents would be charged to the consumer. So it might be nice to have a price locked in for a long period of time, but it might not be nice if the premium is going to offset any potential savings that you might have.

So my final recommendation would be to you that we all recognize that our good friends with the utilities are interested in benefiting their shareholders and making propositions that are going to make them money in a field where they previously only had cost recovery. You're going to be on the other side of that and you're going to have to evaluate whether the budget they give you for their purchase prices are rational and reasonable because no longer will customers be paying the actual price that you can audit and determine that that was the price paid. What they're going to be paying is for a forecast price that's forecasted 18 months in advance.

Now what you need at a minimum is an independent expert who will come in and evaluate the reports and tell you whether the forecasts that are given to you by the utility are rational forecasts based on the circumstances. And I would suggest that you can put that in the public record.

My first reaction to this proposal was to do your evaluation after the fact. And if the utilities came in and beat the market for a year, then they should share in that benefit. But on further reflection, I don't think that's necessarily fair because you can make a projection and it's based on all known facts at the time and they're reasonable and rational facts, but if you know you're going to be blindsided in the rear when the real facts come out, you might not be willing to take that risk. So if we're going to deal with what the cost will be in the future, a forecast in the future, you don't take testimony only from the sophisticated electric utilities who stand to gain. You have to have some independent presentation.

My clients can't afford the kind of presentation that's needed; the Public Counsel may and they may do it. Your Staff is very well versed and very intelligent people, but it puts a great burden on them, especially when they're dealing with secret confidential transactions. So why not, if you have a budget and the utility says my price for gas is going to be $4 next year, have somebody from NYMEX or somebody that knows what the market is come in and say here's what the price is, these people have said that they want to charge a commission and fee to the customers based upon what they have budgeted for the gas price, these fees are in keeping with the customary trade practices in our industry, and then you can evaluate whether the fees that are going to be paid and the risk margin premiums that are going to be paid are comparable to the kind of price you want to place on the customer's back. And I thank you very much.

CHAIRMAN JABER: Thank you.

MR. McWHIRTER: This has been a great learning experience for all of us, and I'm sure it will be for you as we go forward.

CHAIRMAN JABER: Absolutely. Absolutely. Commissioners, do you have any questions of Mr. McWhirter?

Okay. Mr. Vandiver, OPC.

MR. VANDIVER: Just very briefly. Rob Vandiver from the Office of Public Counsel. We're trying to get educated in this complex process as well. And the presenters talked about price stability. And our query on that is at what price does price stability come? And, of course, that's the ultimate issue in this docket.

And for the -- and back to the insurance analogy, which several of the presenters raised, and our question on that is what's the premium for the insurance and what's the coverage of the insurance policy basically? And I don't think that's been fleshed out to date. And I think -- and so we're looking forward to the prefiled testimony to get down to some of the specifics of this. And as some of the Commissioners asked for perhaps some examples and to get to really the meat of this and perhaps see where this is going on a, to get some examples and to see where this thing shakes out because there's an awful lot at stake here, and just see how all this goes forward and look at the prefiled testimony and get some examples. Because I don't think there's enough here for any of us to make a decision on at this stage. I don't think there's enough specifics. And so we'll reserve judgment and see what goes forward.

CHAIRMAN JABER: Thank you. Commissioners, do you have any questions of Public Counsel?

All right. Next on my list I've got that other parties or interested persons may want to address the Commission. Is there anyone in the audience that hasn't made a presentation that would like to make a presentation?

All right. Staff, I promised you some time to ask questions of all the presenters. Let's do that now.

MR. McNULTY: Okay. I have questions for specific presenters.

And I guess my first question is to Florida Power Corporation. If the utility predetermines that prices will be fixed for, say, 20 percent of forecasted natural gas requirements, that's in terms of total volume, 20 percent, say that is the amount that is determined through the process, but then it purchases maybe 50 percent of its forecasted natural gas requirements through fixed price contracts, how does the utility determine which of these contracts will become part of the fixed volume for the cost recovery purposes?

MR. PORTUONDO: Well, Florida Power would be charging based on the execution of the hedge. So if the hedge was, would be executed for only the 20 percent of that volume, we would only be using financial derivatives for the predetermined volume.

MR. McNULTY: Right. But, I mean, you're going to have a large number of contracts. Some are going to be at higher prices, some at lower prices, and some of those are going to flow through the, the fixed price mechanism; whereas, the remainder is going to be through, I would assume, spot market pricing.

MR. PORTUONDO: Correct.

MR. McNULTY: So being able to differentiate which qualify to go into that bucket is, I guess, a question I have as to how that would be determined.

MR. PORTUONDO: That would be part of the tracking mechanism that correlates the hedge to the physical purchase. We would identify when the, when the transaction is entered into that this is for the predetermined fixed volume that we're entering into a hedge, and that would be the transaction that would be captured and priced out at the fixed component.

MR. McNULTY: I'm not sure I'm understanding or communicating very well the concern that I have is that you may do, you may have, you might close the positions out through a physical taking of the volume of fuel, you may do that for a number of contracts above the agreed upon volume that is, you know, anticipated and filed in the fuel filing.

CHAIRMAN JABER: Bill, let me interrupt you for just a second. Get right into the microphone. We're having trouble hearing you.

MR. McNULTY: Oh, I'm sorry. Okay. So I guess, I guess my question there is that, again, if you're taking physical volume, say you close out and get these physical delivery of purchases of 50 percent instead of the 20 percent that were forecasted, don't you have a problem with saying which of these are going to be used for purposes of the, of calculating what your fixed volume cost would be versus your, those which would spill over into the remaining recovery, which I assume would be, you know, running through the fuel clause, through the true-up mechanism for all remaining purchases?

MR. PORTUONDO: I guess it goes again back to, it would be correlated to the month in which the hedge is executed. So if I'm -- those, that volume being taken in the month of march, let's say, where I have my hedge are all going to be priced at the same amount. So it doesn't matter if it's the first 20 or 30, it's all going to come in at the same amount. And that's, that's what would be assigned, that the first 20 percent, let's say, is what we hedged, 20 percent, so that 20 percent would be at the fixed price component that we guaranteed to the customer and the remainder would be at the spot price which we bought it. Is that clear or --

MR. McNULTY: I think maybe that's something we could pursue through discovery. And I'm not 100 percent sure, but I'm sure we can work on that.

MR. BRINKLEY: I have a follow-up question on that. Based on what you just said, if you came to us and agreed upon fixing 30 percent of your gas, for instance, and recovery based on that volume, are you anticipating that that 30 percent will be entirely covered through financial derivatives or bilateral physical contracts as well?

MR. PORTUONDO: At this point it could be either one. It depends on -- you would be designating whatever contract, if it was a bilateral contract that was hedging that fixed price guarantee or a financial instrument, you would be designating it as such. But right now we're leaning towards, I think, financial instruments is what we're focusing on because I think that's what this whole docket is about.

MR. BRINKLEY: So are you -- and in answering his question, are you saying that if you say you're going to hedge 30 percent of your fuel, at no time would you ever accumulate fixed contracts either through hedging physically or financially in excess of the 30 percent?

MR. PORTUONDO: If -- I don't believe so.

MR. BRINKLEY: We're just trying to understand if you say you want 30 percent of your gas to be recovered through the plan but you anticipate you actually may fix the price of

40 percent, that 30 percent you want through the incentive plan and the other 10 percent you want recovery for either at 100 percent of recovery, of actually cost.

MR. PORTUONDO: Well, we have fixed price contracts today that are being recovered through the, through the clause like most utilities.

I guess what we're saying is if we enter into the hedging plan that we're proposing is that those derivatives would be part of the plan, those -- we would -- the month in which we execute the derivative would be priced out to the customer based on the fixed price guarantee.

MR. BRINKLEY: Okay. I think, I think what you're saying is that if you come to us and say you want 30 percent of your fuel fixed through the incentive plan, that you wouldn't have more than 30 percent fixed so that it wouldn't be a question of picking and choosing which contract --

MR. PORTUONDO: From the derivative perspective, correct.

MR. BRINKLEY: Okay.

CHAIRMAN JABER: Mr. McNulty.

MR. McNULTY: Yes, I have an additional question for Florida Power Corporation.

You spoke earlier of, I think there was an approximate $10 million system cost associated with implementing this hedging program and engaging in the financial derivatives market. Were you speaking of an annualized expense or is that a one-time expense?

MR. PORTUONDO: I think that was the systems expense to implement, so that would be amortized over five years.

MR. McNULTY: Okay. And --

MR. PORTUONDO: But I don't have the numbers on the ongoing maintenance and payroll costs.

MR. McNULTY: Okay. So if we were to start to compare, say, what we were talking about with the expansion of the shareholder incentive mechanism, which I think you indicated last year $10 million would have been made if there hadn't been an average rolling number for that and $8 million the year before, would we be comparing, if we wanted to say, you know, are you going to be getting your cost recovery for these additional expenses, would we be comparing the $10 million amortized plus some other types of expenses against the $10 million that would have been gained as gains for Florida Power Corp?

MR. PORTUONDO: Yes.

MR. McNULTY: Okay. Now what would those other expenses have been besides -- you said something about administrative costs.

MR. PORTUONDO: Sure. You have employees that need to be hired, very skilled employees, so that comes at a, it's very high priced. There's ongoing maintenance costs associated with the system and the vendor that supports that system. There's, both from the personnel, both from the front office making the trades to the risk managers making sure that the controls are in place to the back office actually accounting for the trades, there would be costs associated to make sure that those individuals are up to speed on current events, current techniques, market conditions. I mean, there's --

MR. McNULTY: Okay. And finally, has FPC attempted to measure in any way the value of managed price volatility to its customers?

MR. PORTUONDO: I don't believe there's any survey that Florida Power has performed that actually asks that of the customers.

MR. McNULTY: Okay. Thank you.

MR. PORTUONDO: You're welcome.

MR. McNULTY: My next question is for Florida Power & Light. On Page 2 of your submitted comments it appears as though it stated that the incremental costs of maintaining and operating the trading floor associated with risk management would be recovered on a dollar-for-dollar basis; is that correct?

MR. STEPANOVITCH: That's correct.

MR. McNULTY: Okay. Does this mean that these costs would be credited to the fuel clause?

MR. STEPANOVITCH: Yes.

MR. McNULTY: How are those -- those are O&M, basically O&M costs. How are those costs currently recovered at this time?

MR. STEPANOVITCH: Well, we're just talking incremental costs compared for this program?

MR. McNULTY: Right.

MR. STEPANOVITCH: And not being -- because it's not being done.

MR. McNULTY: Right. But say, for instance, costs that may be somewhat similar to that, say maybe related to bilateral transactions and things like that, all O&M costs at this time that you know of are being recovered through base rates; is that correct?

MR. STEPANOVITCH: If you're talking about our existing procurement process, yes, that's through base rates.

MR. McNULTY: Yes. Okay. The proposal that FPL has does not propose to change the format of the fuel cost recovery filing requirements, including the E and the A schedules. In order to, you know, gauge the effectiveness of a financial hedging program such as this, which is obviously very large, would it be necessary to report certain additional information such as the total volumes of fuels hedged, the total cost of the various types of hedging, the underlying commodity costs by month and the associated gains and losses?

MS. DUBIN: That would be part of the filing that we make to begin with. And then we would, we could, we would report on that, also, so that whatever, whatever hedge position we took or fixed price and spot index position we took we would come back to you, here's what we've done.

MR. McNULTY: I guess I'm just wondering, like I say, maybe it would be difficult, given the program that was described, to do it on the E schedules. But maybe the A schedules as an after-the-fact item could be, could it be included there?

MS. DUBIN: Well, some of the information will be included in that, included in the actual basis on the A schedules. But some of the information would also be confidential and be filed separately and then also, of course, in audit.

MR. McNULTY: Okay. All right. And just a few more questions for FPL.

Considering your definition for a force majeure event, does this definition presume that only those events that are outside of management control qualify as a force majeure event?

MR. STEPANOVITCH: Yes. I mean, it's everything -- if you're talking about unscheduled outages for nuclear units, you're talking about hurricanes, it's something that's out of, that's unpredictable and out of our control.

MR. McNULTY: Okay. And finally, how does allowing

FPL to keep 20 percent of all economy energy sales incent the utility to reduce fuel price volatility?

MR. STEPANOVITCH: Well, it's all, it's all part -- first of all, it's all part of a balanced portfolio. It's a, it's a part of your procurement program. And it's not only a balanced portfolio procurement program, but it provides for an economic dispatch for FPL. So it's, again, it's the whole ball of wax, if you want to put it that way.

MR. McNULTY: Okay. And I'll ask one last question. This is similar to what I asked Florida Power Corporation, which is has FPL attempted to measure the value of managed price volatility to its customers?

MR. STEPANOVITCH: No. I mean, when you say "managed volatility," you know, from what we've done thus far -- let me make sure I understand the question.

MR. McNULTY: Basically putting any program in place that would limit the fluctuations in the, in the price that is charged to the customer. Any -- you know, have they looked at it -- obviously there's a number of things that the utility does today. It's anticipating doing more with this establishment of this program. I'm just wondering as you engage in this, that you're looking at incurring additional costs that are going to be borne by ratepayers if we went this way, and obviously a cost and benefit analysis is something that, you know, we would want to look at. And I was just wondering if you have at this point any preliminary idea of the benefits?

MR. STEPANOVITCH: I don't think so.

MS. DUBIN: Yeah. No. Just in terms of do customers -- I thought your question was going towards the customers, do we know customers want to minimize their volatility? And I was just going to add to that that, you know, we have right now about 250,000 customers on budget billing, so you know that it is of an importance to customers to minimize the volatility in bills.

MR. McNULTY: Okay.

MR. BRINKLEY: I have one question. Does resolution of the other issues in the docket as far as approval of gains, actual gains and losses, transactions costs and premiums offer an incentive to use financial derivatives even in the absence of an approval of a specific incentive plan?

MR. STEPANOVITCH: I'm not sure I followed your question completely, but let me see if I interpreted it right.

You're saying that if, if we don't do the financial incentives?

MR. BRINKLEY: No. If we were to approve actual gains and losses, transaction costs and premiums paid for financial hedging, would that offer an incentive for you to go out there and do more of it, even without a specific filed strategic incentive plan that we approve?

MR. STEPANOVITCH: It really all depends on what, you know, what type of risks you're taking on.

I think, you know, again, it all depends on if you're taking on any risks, you know. The, the incentive that you have -- or I should say it actually removes that incentive.

MR. BRINKLEY: Well, what risk would you take on for financial derivatives if you knew you were going to get 100 percent of actual costs, gains and losses, transaction costs and premiums, what risk would you take on?

MR. STEPANOVITCH: Well, again, you're not -- if you're just going to go out and put on a hedge and just leave it there, you're not taking on any risks. I mean, you're the one that's saying go ahead and do that, go ahead and do 20 percent; right? I think this is your example. I'm going to pay you to put on, I'm going to pay for your costs to put on the hedge; right? And it could be 20, 25 percent. And what you're saying is just leave it there.

MR. BRINKLEY: Well, I'm saying you will manage it however way you feel is appropriate.

MR. STEPANOVITCH: That's what I'm saying. Managing it adds the risk. That's where the risks come from.

MR. BRINKLEY: But isn't the risk that you're concerned about is not recovering your costs?

MR. STEPANOVITCH: The risks -- no. We've already decided and we've already agreed on that the costs would be covered.

I'm talking about what risks you're taking on, whether they be the execution risk, whether they be the timing risk, the volume risk, that's the risk that's being taken up by the premium. I think that's what you're getting to.

MR. BRINKLEY: But even with your plan you would ask for a premium for execution, timing and volume risk because the price that you have to go out there and pay may not equal what you would get recovery for. But assuming you were in a scenario where your actual costs were recovered through the fuel clause, would that be an incentive for you to engage in that or is there some concern that the Commission may not let you recover a loss on a contract at some future date?

MR. STEPANOVITCH: That's what I was saying before, that's a disincentive to not do anything. I mean, you're -- what you're saying is you're really back to the beginning the way we are today.

CHAIRMAN JABER: No. I think the question goes to understanding the risk that the company will be, will have in terms of your proposal. And Mr. Brinkley's question is this: If the customer will always bear the expense associated with your risk, then what exactly is FP&L's risk? It's the customers' risk. It's not your risk.

MR. STEPANOVITCH: I think we're both saying the same thing. What I'm saying is that your -- if we're not taking on any risk, then the consumer is taking on the risk, so there's no difference in what it is today. It's only a fixed cost versus a spot market cost.

CHAIRMAN JABER: But isn't that the result of your proposal? I guess we're trying to get to the heart of where the risk belongs to the company.

MR. STEPANOVITCH: The risk belongs to the company, and I'll just talk to one of them, the volume risk. That's where the risk belongs to the company simply because if you take -- I hope I'm not repeating myself. Let's go back to the 100 MMBtus.

CHAIRMAN JABER: Uh-huh.

MR. STEPANOVITCH: We're going to come in, we're going to forecast 100 MMBtus and we're going to forecast a price. We're going to say whatever the percentage is, and I'll just use this as an example, at 20 percent we say you should hedge 20 percent of that 100 MMBtus. It actually comes in at 110. Two percent or, excuse me, 20 percent of that extra 10 will be priced at the fixed, predetermined fixed price.

CHAIRMAN JABER: Uh-huh.

MR. STEPANOVITCH: But all 10 will be purchased at spot market. The company is picking up the piece or taking on the risk and managing that 20 percent of that 10. It's being priced out at fixed but being bought at spot. That's the risk that I'm talking about.

MR. BRINKLEY: I guess what I'm trying to get down to --

CHAIRMAN JABER: Mr. Brinkley, to the degree those questions are more detailed, you guys probably need to pursue them in discovery.

MR. BRINKLEY: Okay.

CHAIRMAN JABER: I want to give you all an opportunity though to ask conceptual questions so that we're benefited from the discussion.

So, Mr. McNulty, do you have any other questions? I'm not looking for the specifics.

MR. McNULTY: I don't have any other questions for Florida Power & Light. Thank you.

CHAIRMAN JABER: Okay.

MR. McNULTY: Let's see. For Tampa Electric Company, I just wondered in the comments that were provided whether or not TECO has considered any ways in which it could hedge its price risk today for, for purchased power that may be indexed to natural gas prices? I understand somewhat of the reluctance to engage currently in the explanation that you're mostly coal-fired generation today; however, there's a significant volume of purchased power. Some of that may be indexed to natural gas. Is there a way to hedge that, those purchases?

MS. WEHLE: I'm not the, the person who deals with purchased power, and so I don't feel comfortable answering that question.

MR. BRINKLEY: I have a question about --

CHAIRMAN JABER: Let's get the response to this question, first.

MR. BROWN: I think you were referring to purchased power contracts where the resource is a gas-fired resource and the contract contains simply a fuel pass-through.

MR. McNULTY: Yes. Exactly.

MR. BROWN: Okay. Currently all of our purchased power contracts of that nature do not include hedging. In other words, we do not require a guaranteed energy price.

It was not -- well, since we're not proposing a hedging incentive plan, we had not addressed that issue yet. But should we propose a plan in the future, which we, we indicated we might, we would possibly consider those as well included in the, in the hedging plan.

MR. McNULTY: Thank you very much.

MR. BEASLEY: For the record, that was Mr. Lynn Brown, Director of Wholesale Power for Tampa Electric.

CHAIRMAN JABER: Thank you.

Mr. Brinkley, you had a question?

MR. BRINKLEY: Yes. I had a clarification on a comment you made, Commissioner Bradley.

By your proposal, which is not to enter into a specific incentive plan like the others, you're saying that you're not opting out of hedging, but you're just not -- you're opting out of financial hedging.

MS. WEHLE: Currently we do actually do hedging. We do physical hedging --

MR. BRINKLEY: Physical.

MS. WEHLE: -- on our bilateral coal contracts. When you enter into a position in the marketplace, you are taking a position and you are hedging.

MR. BRINKLEY: Okay.

MS. WEHLE: And what we're saying is at this point it would be premature for us to put an incentive plan proposal forth for natural gas, given the fact that we are in a transitional period, not understanding yet all of the nuances of how our natural gas generating units will operate, dispatch, what volumes will be needed, how those will fit into our fuel mix, what risk management strategies need to be developed. It's just premature for us. So at this point we feel as though we would, we would like to take a position where we're not ready to do that. However, we would potentially in the future like to participate in that, probably seeing how things go with the other utilities as well in understanding how these other proposals are being implemented and learning from them and how well the objectives are achieved.

MR. BRINKLEY: Thank you.

CHAIRMAN JABER: Okay. Staff, that concludes your questions?

MR. McNULTY: That concludes our questions. Thank you.

CHAIRMAN JABER: Okay. Let me tell you, Commissioners, my cheat sheet here indicates that the utilities' direct testimony is due June 24th. I would expect that to the degree you all can include in your testimony additional examples, responses to the questions that you've been presented with today, that you would want to take advantage of that.

Staff, I've got that the intervenor's direct testimony is due July 10th and Staff's direct testimony, if any, would be due July 17th. I anticipate a lot of discovery on this issue and I would encourage the parties to work with Staff on answering the questions as expeditiously as possible.

And, Commissioner Palecki, I am sure that you would pursue with Staff that additional issue that I requested.

COMMISSIONER PALECKI: Yes, I will.

CHAIRMAN JABER: Okay. And please do not read into my request. I just don't want to get to the November hearing and find ourselves without an issue when we need an issue.

There are no messages to be sent with the identification of that issue, Commissioner Palecki, and I'm sure you'll reinforce it when the time comes.

This concludes our workshop. Thank you all for participating.

(Workshop concluded at 12:45 p.m.)

STATE OF FLORIDA)

: CERTIFICATE OF REPORTER

COUNTY OF LEON)

I, LINDA BOLES, RPR, Official Commission Reporter, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

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

DATED THIS 21st DAY OF JUNE, 2002.

Linda Boles

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