BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

In the Matter of

REGIONAL TRANSMISSION ORGANIZATION WORKSHOP.

DOCKET NO. UNDOCKETED

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PROCEEDINGS: WORKSHOP

BEFORE: CHAIRMAN J. TERRY DEASON
COMMISSIONER E. LEON JACOBS., JR.
COMMISSIONER LILA A. JABER

DATE: Thursday, August 10, 2000

TIME: Commenced at 9:40 a.m.
Concluded at 12:35 p.m.

PLACE: Betty Easley Conference Center
Room 148
4075 Esplanade Way
Tallahassee, Florida 32399-0850

REPORTED BY: KORETTA E. STANFORD, RPR
Official FPSC Reporter

IN ATTENDANCE:

ROBERT ELIAS, FPSC Division of Legal Services.

BOB TRAPP, Division of Safety & Electric System Reliability.

MICHAEL NAEVE, Skadden, Arps, Slate, Maagher & Flom LLP, representing Florida Power & Light and Chairman of the Governance Committee.

MARTY MENNES, Florida Power & Light, Chairman of the Operations and Planing Committee.

GAIL McKAIG, Tampa Electric Company, Chairwoman of the Tariff and Pricing Working Group.

GREG RAMON, Chairman of the Market Design Working Group.

PROCEEDINGS

CHAIRMAN DEASON: If I could have everyone's attention. We'll go ahead and we'll call the workshop to order. We do have an agenda here that we're going to follow, and I see that the first item is opening remarks.

Let me ask, first, do we need to have a notice read?

MR. ELIAS: I can do it. Notice issued by the clerk's office on July 21st, 2000, advises that this time and place have been reserved for a workshop concerning Regional Transmission Organization for Florida.

The purpose of this workshop is to allow presentations to the Commission by the Florida Regional Transmission Organization working groups regarding the status of their efforts supporting the formation of a Regional Transmission Organization for Florida.

The notice further provides that any interested person may present information regarding these efforts.

CHAIRMAN DEASON: Okay, thank you.

I really don't have any opening remarks, per se, other than to say thank you for coming, welcome. We, as the Commission, appreciate all of the hard work that has gone into this process. We eagerly await the presentations today.

We hope that it will be an opportunity for there to be some, not only presentation, but for there to be some dialogue and some discussion, question and answer, that sort of thing.

Also on today's agenda, there will be an opportunity for interested persons to also address the Commission, and we will get to that at that time.

I've been asked to remind everyone that there is a sign-up sheet in the back of the room. It's not mandatory that you sign up, but I think if you've expressed interest in this matter, you may wish to put your name on that list.

And without -- any other Commissioners have any opening remarks or thoughts? If not, then, I'm going to turn it over to Bob Trapp, who, then, I think, will turn it over to the presenters.

MR. TRAPP: Thank you, Chairman Deason. I don't have a whole lot of remarks to say. I just want to thank the parties for being here. Thank you in advance for the wonderful presentations you're going to make.

Commissioners, as you know, the Staff has been trying to be party to this process and has attended most of these meetings. We're happy that the utility and stakeholders are coming up here to bring you to the level of confusion that we're at in our review of this process.

I think, as we go along, we need to keep in mind the critical issues that are important to us with respect to our jurisdiction; those of, basically, costs and benefits to the rate payers of Florida and then, more specifically, the rate payer impacts on the regulated investor-owned utilities.

And while a lot has been accomplished in these meetings, a lot remains to be accomplished. There's still a lot of questions that need to be answered. Staff has issued about 115 of them in an informal questionnaire to the parties. We've received one response from Florida Power & Light on a preliminary basis which, again, a lot of their responses are, "Well, we're still working on that." So, a lot of work still has to be done to bring this to fruition.

I understand, as will probably be discussed here, that plans are, however, to make a filing with FERC on the governance of the RTO asking for clarification from FERC as to whether or not it complies with what they're looking for in their Order 2000. I believe that has been postponed, we heard, at least to September 1st, Mike?

MR. NAEVE: That's correct.

MR. TRAPP: One of the things that we did pass out was kind of a rough drawing of the structure of the RTO that I hope that Mike Naeve will cover in his presentation on governance. I think, there was some questions from the Commissioners to try to understand this. And, I guess, with that, I'll turn it over to the RTO stakeholders.

CHAIRMAN DEASON: Mike, I believe, it's yours now.

MR. NAEVE: Okay. I'm Mike Naeve. I'm with the law firm of Skadden, Arps, Slate, Maagher & Flom. I'm representing Florida Power & Light. And in addition to that, I've been chairing the governance committee of the RTO working group.

I'm also filling in today for Vinny Dolan, who is chair of the steering committee, who is going to act as moderator on behalf of the working group, but Vinny was on vacation and wasn't able to attend today, and he asked if I would fill in on behalf of him. So, I'm going to function in both capacities.

Let me begin by talking about the governance committee and the working we're doing and where we think we are going.

As you know, there are four committees working on various aspects of the formation of the RTO. The governance committee is the committee responsible for satisfying the -- or developing a structure that satisfies the FERC independence criteria.

We are working on preparing a petition to file with FERC, a petition for declaratory order, seeking FERC's advice and, hopefully, consent as to the approach that we hope to have developed by -- originally, it was August 15th, now we're shooting for September 1st. We'll file that petition and ask FERC to respond to it as quickly as possible.

The petition will deal with a variety of governance issues, but most important, it will deal with the method by which the board of directors and the officers of the new corporation will be selected.

It will deal with other issues as well; the criteria for being chosen to the board, various factors dealing with independence to assure that the RTO functions in a way that's independent of market participants. It will establish an advisory board that will be composed of market participants to give advice to the RTO management and so forth.

It's important to get FERC sign-off on this structure as early as possible, if there's any hope of trying to meet the deadlines established by FERC for the implementation of RTOs. As you're probably aware, in Order 2000, FERC asked investor-owned utilities to implement and participate in RTOs by December 15th, 2001, to have them up and running by that date.

And when we stepped back and looked at the various steps that had to be implemented to achieve that deadline, it became quite clear that we needed to have in place some officers and directors who could make decisions and who can begin staffing up and getting ready for that date, and we had to have them fairly soon.

So we also, then, realized that if we wanted to select those officers and directors, we wanted to do so in a way that assured they were selected in a form that guaranteed independence and satisfied the requirements of Order 2000.

That's the purpose of this -- the primary purpose of this petition is to file it early, get the FERC blessing on the proposed steps that we intend to take to select the board and officers so that we can be in the process, as soon as possible, in anticipation of meeting the December 15th, 2001, deadline.

I was just asked by Bob to address this chart, which is the structure that has been proposed for the RTO. And before I go through this, let me, just briefly, describe the broader approach that's being proposed and then go into this particular chart.

As a broad approach, the Florida Power & Light has proposed, and the various participants in Florida, are working towards a structure in which the Regional Transmission Organization is an independent transmission company.

This is a company that actually owns transmission assets. It's an investor-owned company, who will hopefully have shareholders. And it will, not only own and operate its own transmission assets and try to purchase and acquire transmission assets from the various transmission owners in Florida, but to the extent, for whatever reason, current transmission owners believe or have believed they should not transfer ownership to this company or for tax reasons or constitutional reasons or other reasons find that they're limited in their ability to transfer ownership, this same entity that has its own assets will also provide ISO type services for the other transmission owners.

In other words, it'll enter into contracts with other transmission owners to operate their systems in an independent fashion to satisfy the RTO requirements with respect to their systems. So, it'll be both a transmission owner and operator with respect to its own facilities and an independent operator with respect to the facilities of other transmission owners.

CHAIRMAN DEASON: Let me ask the question.

MR. NAEVE: Yes.

CHAIRMAN DEASON: Will the RTO manager be leasing assets?

MR. NAEVE: It is conceivable that it will, but it's not anticipated. We've not ruled it out, but for various financial reasons we concluded that you may not be prudent for them to lease, certainly too many assets. If a large segment of the assets that it controlled were leased, it would affect its ability to raise capital, we concluded. So, we didn't want to lease too many assets.

A lot of the financial markets might treat lease as a long-term debt, and then looking at how much equity they might contribute to this company, they'd treat those assets as the functionally equivalent of debt.

CHAIRMAN DEASON: The way you envision it, it will be a combination of owning assets and then having agreements with others to be, basically, an ISO for those other entities.

MR. NAEVE: That's correct.

COMMISSIONER JABER: In response to Chairman Deason's question, though, it's not the RTO manager. You're at the RTO LLC level.

MR. NAEVE: That's correct. The RTO LLC will -- going to this chart to try to clarify things -- and by the way, I apologize for the names, RTO, LLC, and RTO manager. We're going to try to come up with some better names for purposes of our final organization, but I think for the time being, these are the names we've been using. So, you know, just bear with us on these until we can think of something more creative.

COMMISSIONER JABER: Okay.

MR. NAEVE: The RTO LLC will actually be the entity that files at FERC to become the RTO. It'll have to show to FERC that it's independent. It'll have to satisfy the various other criteria set forth by FERC to qualify as an RTO.

It will be a limited liability corporation. And limited liability corporations, as you know, are very similar to limited partnerships. They, typically, have one managing member, like the general partner in a limited liability partnership. And then, they have other members that are not managing members. They're just members of the LLC, and they're functionally equivalent to limited liability partners.

They have financial investment, but they don't have a management role. So, in this case, the RTO manager will be the so-called managing member. And any utility that contributes assets to the RTO, in exchange for an interest in the RTO, a membership interest, will become a member of the RTO LLC. There will be --

CHAIRMAN DEASON: Now, let me -- will the RTO manager, will that be a corporation?

MR. NAEVE: It will be a corporation. It will be a "C" corporation, which is your standard form of corporation. FP&L, for example, and Florida Power, are "C" corps. This will be a "C" corp for publicly-traded shareholders.

CHAIRMAN DEASON: It's anticipated that the stock of that corporation will be traded on the market?

MR. NAEVE: Yes, it is.

COMMISSIONER JACOBS: But the majority of that stock will be held by the contributing companies, isn't it?

MR. NAEVE: Well, the majority of the ownership interest of the RTO of the LLC, this big score at the bottom, the majority of that interest will be held by the parties that contribute assets in exchange for an ownership interest. In this case, the ownership interest is not in the form of stock, it's in the form of a membership interest, but basically, that's correct.

That will be true for the RTO LLC. As for the RTO manager, they're going to do an initial public offering, offering shares of stock for the public to purchase. And, hopefully, on day one, all of their shares will be owned by the public at large. And, initially, none of their shares will be owned by utilities that contributed assets.

COMMISSIONER JABER: That confused me. The RTO

LLC will be owned by the stockholders, who are the utilities, right?

MR. NAEVE: Well, it'll be owned by -- yeah. Let's call them stockholders. Actually, they're -- since this isn't a stock corporation, they won't have a stock interest. This is an LLC. They'll have a membership interest. So, the terminology is they'll have a membership interest as opposed to a stock interest. It's just a terminology difference, but they will have a membership interest in the RTO LLC.

So, hypothetically, in this drawing, we have two utilities contributing assets. They will contribute those, and the payment they get for those assets, the consideration they receive, will be a membership interest in the LLC.

COMMISSIONER JABER: Okay. The utilities will have a membership interest in the LLC.

MR. NAEVE: That's right.

COMMISSIONER JABER: And the only reason you call them membership interest is because it's an LLC.

MR. NAEVE: That's correct. If this were a "C" corp, we'd call it a stock ownership.

COMMISSIONER JACOBS: Now, let's make sure I understand this, because it was my understanding previously that the contributing companies would get these

Class-B shares in RTO manager, and that would be their interest. But what I'm hearing you say is that the contributing company will get a direct membership interest in the LLC.

MR. NAEVE: That's right. The Class-B shares -- this is, I realize, it's complicated structural confusing, but we've provided for the ability for companies that have a membership interest in the LLC, if you look -- the first utility box, it'll have a membership interest in the LLC.

The problem with having a membership interest in the LLC, especially one that has restricted voting rights and so forth, is that it's not liquid, it's not fungible. You can't sell it to other people easily. It's not a publicly-traded type of security.

And to enable the utilities to be able to liquidate their investment, if they want at some point to get out of this investment, to sell it to the public or whatever, by holding the membership interest, that's hard to get out of.

So, we have a provision that allows them to convert that membership interest in the LLC into Class-B shares of the RTO manager. And there'll be a formula by which they can convert their membership interest into stock interest in the RTO manager.

One of the problems we have, though, is that the

RTO manager, because it is the managing member of the RTO, it has all the control. And it has to be independent of market participants. These utilities will be market participants, so they're not permitted to have voting stock in the RTO manager. So, we've created a Class-B type of stock that is nonvoting. It's equivalent to Class-A stock, except that it's nonvoting.

COMMISSIONER JACOBS: And the IPO will only do Class A, right?

MR. NAEVE: That's right. We'll do the IPO to the public at large. They'll get Class-A stock. And if -- let's say, hypothetically, three years from now, utility "A" decides they want to sell their interest in the RTO. No one would buy this membership interest, because there's not a public market for it.

There is a public market for Class-A shares. So, what they will do is they'll convert their membership interest into Class-B shares, which are identical to Class-A shares, except they can't vote. And the Class-B shares will have a feature in them that allows them to be converted to Class-A shares anytime they're owned by an entity that's not a market participant. So, if you sell your Class-B shares to somebody, they automatically become Class-A shares, if that purchaser is not a market participant.

So, that's how -- this is the feature that was designed to enable the passive owners, we call them, the utilities that have exchanged transmission assets for a membership interest. This is a way for them to ultimately divest their passive ownership interest for cash.

COMMISSIONER JACOBS: Mike, one of the questions that comes to my mind is these membership interests, then, have to have some value attached. And I assume that it would be derived from some value attached to the assets that have contributed.

MR. NAEVE: That's right.

COMMISSIONER JACOBS: How then, do you make that fit into the whole pie here, the LLC? In other words --

MR. NAEVE: Sure. I'm going to step back just a second and kind of answer that indirectly, and then more directly.

COMMISSIONER JACOBS: Okay.

MR. NAEVE: The LLC wants to acquire transmission assets. It's going to have a limited amount of cash. The RTO LLC is going to have a limited amount of cash. And where that cash will come from is when the RTO manager does an initial public offering, it will sell its shares to the public, and it will receive cash.

It will contribute that cash down to the RTO LLC in exchange for a membership interest. And we think they'll own, roughly, 20% of the RTO LLC, at least initially. So, they'll raise cash, they'll contribute that cash downward into the RTO LLC, and they will, in exchange for that, get their membership interest, that 20% interest.

The utilities will contribute their assets into this. And instead of getting cash from the RTO LLC, some of them will get membership interest. You know, it's conceivable that other utilities will want to transfer their assets into this for cash. We're giving them the option to do it either way.

But if you are -- let's call this actually, if you want, call it utility one and utility two. And let's say, utility one is an investor-owned utility and utility two, theoretically, might be a utility that's not investor owned, but it doesn't pay taxes.

Utility two may decide that rather than getting a membership interest in the LLC, they may rather just have cash. And they would sell their assets to the LLC and in exchange for that get cash. And the LLC, in effect, would buy them for cash.

And utility two, because they don't pay taxes, they probably wouldn't have to pay capital gains tax on that transaction. So, that would be a tax-efficient transaction for them and probably would be a smart way to go.

Utility one, let's say it's an investor-owned utility, and they have a rate base for these assets, but also have a tax basis for these assets. And let's say, they sell these assets -- if they were to sell these assets to the RTO LLC, and let's say they were to sell them at regulatory book value, they would get a cash payment equal to their regulatory book value. But if the regulatory book value is greater than the tax basis, they'd have to pay a capital gains tax on the difference.

And for FP&L, we've look at that, and it's several hundred million dollars. So, we'd have to pay a significant capital gains tax, if we were to do that. So, that wouldn't be a very tax-efficient transaction. We can though, under the tax laws, contribute our assets down for a membership interest, and that would initially be tax-free.

So, we'd get the membership interest tax-free. If we ever later sell that membership interest, we have to pay taxes at that time, but that would be -- at least if we wait five years and sell the membership interest, we will have deferred for five years paying tax. We may decide in five years, it's not worth paying that tax either, and hold on to it longer than that, but at least there's a substantial tax deferral, but not a tax avoidance, if you ever liquidate your interest.

MR. ELIAS: Mike, if I can ask -- I'm over here, Bob Elias -- is the exchange in the scenario you just described, is the exchange of the membership interest for Class-B stock a realization event? Is that something where the tax liability accrues?

MR. NAEVE: Yes.

MR. TRAPP: And Mike, if I might -- Bob Trapp -- is it my understanding that Power & Light, along with a lot of other companies, are trying to get favorable legislation in Congress relief from this capital gains tax?

MR. NAEVE: Yes is the answer. I think, the prognosis is not very good at all, but the answer is yes.

There is proposed legislation. I'm not certain how seriously it's being considered by the recipients of the proposal by Congress, but as electric institute and others have proposed legislation. I know Commissioner Kurt Herberte at FERC is also working on proposed legislation that would allow utility "A" to sell its assets to the RTO and not pay capital gains taxes on that transfer, because it would be doing so pursuant to FERC Order 2000.

You know, the likelihood of -- it's anybody's guess as to what's the likelihood of Congress enacting that change. What makes it complicated a little bit is it doesn't go to the energy committee, which is considering the bulk of the energy legislation. It would have to go to the Ways & Means Committee and the finance committee, and they haven't been as involved in this legislation. It does reduce somewhat the likelihood of that happening.

COMMISSIONER JABER: Mr. Naeve, if utility one is an IOU, and it has chosen to contribute its assets for a membership interest to avoid the capital gains tax --

MR. NAEVE: Right.

COMMISSIONER JABER: -- how is the membership interest reported on your books for regulatory purposes? And how is the tax deferral reported on your books for regulatory purposes?

MR. NAEVE: I must say, for purposes of Florida Public Service Commission recordkeeping, I'm not an expert in that matter and probably couldn't answer it. I don't know if anybody here -- Anne says that's a take-home question. We'll have to get back to you.

COMMISSIONER JABER: Sounds like a plan.

CHAIRMAN DEASON: I thought Bill Walker would have the answer just like that.

MR. WALKER: I don't think you want to hear it.

COMMISSIONER JABER: I didn't ask.

MR. TRAPP: Commissioners, if I might, at this point, we've asked the same question of the company, and they've given us the same answer, but we --

COMMISSIONER JABER: Did you ask Bill? Did you ask Bill Walker? Is that why?

MR. TRAPP: Well, he was at the meeting we asked, but they have committed to come back at the next staff meeting with us. We've been holding some individual staff meetings with the utilities. They have committed to come back to us with a trace-through of the regulatory impact structure. And I asked them if they were going to be able to discuss that today, and they said they weren't ready yet. So, we're looking to schedule with Anne pretty quickly a meeting to try to trace through those regulatory effects.

MR. NAEVE: The intent -- the RTO LLC acquires assets. It could -- whether it pays cash or whether it pays for these interest in the form of a membership interest, it could acquire assets at greater than book, at book. You know, theoretically, it could pay any price it wants for them.

However, FERC precedent has been to not recognize acquisition adjustments and allow rates to be based on anything above book. So, our expectation is that the RTO LLC, in acquiring assets, will pay regulatory book, because that's what it can earn on. If it pays more than that, they're paying an amount which they cannot earn on. So prudence, on the point of the RTO LLC, I would say, as a general rule, they will pay book.

Now, that's not to say in the future they will always pay book, but they may at some point work out some rate arrangement with FERC where, theoretically, they might be permitted to pay above book for certain key assets or something, I'm not sure.

But it's an initial matter that FERC precedent, historically, has been rates have to be based on book value. And if rates are based on assets that were previously owned by another company, and they're now transferred to you, they're based on the book value in the hands of the previous owner.

So, our expectation is that in FP&L's case, we will transfer them in and we will receive a membership interest value based on the book value of the assets transferred in.

CHAIRMAN DEASON: Let me ask a question. Utility two, let's just say it's a municipal, and they wish to sell assets to the RTO LLC. The municipal system doesn't have a rate base, per se. So, is that a concern? And would that transfer, since there's not a rate base, not a book value, would it be at an appraised value or a replacement cost, less depreciation value?

MR. NAEVE: Well, my guess is it would be at a value based on some sort of reconstructed book value, had they used something like the FERC uniform system of accounts.

All this hasn't been worked out precisely yet, but my guess is it'll be a value based something on that, because in other proceedings in which -- involving ISOs in which the ISO incurs costs for operating systems of various utilities, some of them FERC regulated, some of them not FERC regulated, and they want to pass through those costs. FERC has indicated that passing through the cost for transmission owners that are not FERC regulated, the amount of costs passed have to be based on a system roughly approximate in their uniform system of accounts.

So, I presume, the same type of principles will largely apply to the RTO. Bill reminded me that there may be people in the audience from the muni's or co-ops or others that may want to say something about this point. So, I would be happy to let anybody else address this issue, if they choose to.

CHAIRMAN DEASON: Any volunteers?

MR. WOODBURY: Good morning, Commissioners. My name is Tim Woodbury. I'm with Seminole Electric Cooperative.

As far as Seminole goes, we have on the books a net book value for our transmission assets that would be -- is easily shown and demonstrated to anyone that we would be willing to sell those assets to.

CHAIRMAN DEASON: You're saying you're willing to sell it at book value or that's a totally different question?

MR. WOODBURY: We may, in fact, be selling some of those assets at some point after the organization gets up and running.

CHAIRMAN DEASON: Okay. Thank you.

While we've interrupted, let me back up for just a second. I believe, in response to a question from Mr. Elias, if I understand it correctly, and I may not understand but, I believe, you indicated that when the membership interest in the LLC is converted to Class-B stock, that that is a taxable event or is not a taxable event?

MR. NAEVE: That is.

CHAIRMAN DEASON: That is a taxable event.

MR. NAEVE: That's right.

CHAIRMAN DEASON: Okay.

MR. NAEVE: Now, one of the things worth pointing out is that in this particular situation, the RTO is this LLC, the institution at the bottom. But it's actually under the control of this other organization called the RTO manager, because it is the managing member. And as the managing member it has, essentially, all of the control.

Because it controls the RTO it, too, has to satisfy the FERC independence criteria. So, we have, in the petition we'll be filing with FERC, a variety of criteria to ensure that it, too, is free of influence of market participants and that its board is selected in an independent way and so forth.

So, in some ways the RTO, technically, is the bottom entity, but in other ways, because the RTO manager will control the policies and practices of the RTO LLC as the managing member, you almost need to draw a dotted line around both of them and think of them as the RTO.

I mentioned that we originally hoped to file by August 15th so that we can, as soon as possible, commence the process of trying to select a management search firm to begin the search for directors. And then, once we pick the first eight directors, we would ask them to go out and pick the CEO.

Based on the meeting of the governance committee yesterday, we concluded that there is still opportunity to reach a more broad consensus on some of the key issues that we've delayed for a couple of weeks, until September 1 filing of that petition.

I think, we probably can't go beyond September 1, if we would have any hope at all of meeting the December 15th, 2001, deadline. But we're going to have additional meetings, unfortunately, maybe three more meetings between now and September 1, to see if we can't get a broader consensus for what we file.

CHAIRMAN DEASON: Any questions?

COMMISSIONER JABER: Yes. Mr. Naeve, my previous notes from attending some of the meetings, if I'm not mistaken, you said the RTO LLC will have a revenue requirement?

MR. NAEVE: I'm sorry, will have a what?

COMMISSIONER JABER: Revenue requirement?

MR. NAEVE: Yes.

COMMISSIONER JABER: Walk me through who else -- what entity, what other entity will have a revenue requirement. Is it just RTO LLC or do you envision the RTO manager also having rate-based revenue requirements?

MR. NAEVE: No, the RTO manager won't. We will -- at one point -- we've actually changed this ever so slightly. At one point, we were planning on putting, basically, all of the staff up at the RTO manager level. And we would have a contract for management services down at the LLC level.

And I'm sure FERC, and this Commission, probably would have insisted that be a cost-based contract, so they would have, in effect, had a revenue requirement. We, subsequently, decided that the cleaner way to go would be to put all the employees down here at the LLC level to avoid those sort of affiliate contracts.

Now, the RTO LLC, its revenue requirement will have essentially, two components. The first component will be its own cost of service. It will have employees, it will have assets, it'll look just like a transmission company that owns assets and has depreciation and earnings and so forth on those assets.

And when it files rates at FERC for transmission service, it will seek to recover those costs and a return and so forth. But in addition to that, the RTO LLC will function as the manager of other transmission assets owned by different transmission owners.

And those other transmission owners will enter into a contract with the RTO LLC under which the RTO LLC will operate their assets. And they will recover from the RTO LLC their revenue requirement.

COMMISSIONER JABER: Okay. Back up. So, for the sake of simplicity, the RTO LLC has become, and I use it loosely, but has become a new IOU.

MR. NAEVE: Yes. It's a new IOU that is both a transmission owner, but also a transmission operator for both companies. So, part of its revenue requirement will come from the assets it owns, and part of it will come from the revenue requirements sent to it by the other transmission owners.

So, hypothetically, let's say utility three hasn't contributed its assets here but, instead, enters into a contract with the RTO LLC to operate its transmission system. Utility three will file -- they will enter into a contract, as I described with the RTO LLC. That contract will be a FERC jurisdictional contract. The rates that it sets forth, its revenue requirement, will be reviewed by FERC and established by FERC, and it will be sent up to the RTO LLC. It will then bundle that revenue requirement with its own revenue requirement to develop statewide rates.

COMMISSIONER JABER: Wait a second. Who will file with FERC, the RTO LLC or the RTO manager for rate approval?

MR. NAEVE: The RTO LLC.

COMMISSIONER JABER: Okay.

MR. NAEVE: But also, in this case, utility three will enter into a contract with the RTO LLC to operate its system. And utility three will recover its wholesale revenue requirement from the RTO LLC, not from customers.

The RTO LLC will be the own entity that interacts with transmission customers. So, the RTO LLC will have a tariff. Transmission customers will pay their rates to the RTO LLC, and then the RTO LLC will, in turn, make payments to the utility three to cover its revenue requirement.

And that contract it has with utility three will be FERC jurisdictional contract, and the revenue requirement, the wholesale revenue requirement for utility three, will be set by FERC.

MR. TRAPP: Mike, Bob Trapp over here again.

Since the scope of the RTO is going down all the way to the distribution substations, that wholesale revenue requirement that you're talking about really is what we would call now the wholesale revenue requirements that exist now, plus the retail transmission revenue requirements. There would be a transference, as I understand it, of that jurisdiction of those revenue requirements from the state of Florida to FERC.

MR. NAEVE: That is true for the assets that are contributed to the RTO LLC. The organizations that sell their assets to the RTO LLC are the organizations that contribute their assets in exchange for a membership interest.

They will be out of the transmission business.

They won't own transmission assets anymore. They will be owned by the RTO LLC. So, to the extent that those utilities need transmission service to serve their retail load, they'll now have to go to the RTO LLC for that service. So, that's correct.

MR. TRAPP: Explain to me the other side of the coin, the Florida Power Corporation side of the coin, where they're going to take operational services from you. From a jurisdictional rate-making standpoint, how would you see that handled?

MR. NAEVE: That looks more like a traditional ISO operation. Well, let's back up. Today, investor-owned utilities that provide transmission service at wholesale, they have an Order 888 tariff. And they recover that portion of their transmission costs associated with wholesale service from FERC under their 888 tariff.

In establishing ISOs, FERC has, up to this point at least, permitted an arrangement in which the owner of the transmission system will not take service from the ISO directly for its retail load but, instead, will take service from the ISO only for wholesale transmission service.

So, to the extent that, let's say in California, PG&E is entered into a contract with the ISO to manage

PG&E's transmission system, to the extent PG&E uses the transmission system for purposes of serving its own native load, they'd still recover those costs from the retail customers, and they don't take that service from the ISO.

To the extent that a customer, a wholesale transmission customer, approaches PG&E and says we want transmission service, that service isn't provided by PG&E anymore, it's provided by the ISO using PG&E system. And PG&E recovers those rates or the ISO recovers those wholesale rates, and then PG&E recovers them in turn from the ISO.

MR. TRAPP: What kind of additional regulatory mechanisms, in terms of cost recovery, do you envision being needed with respect to the retail side of the business? Are you going to recover all your costs from FERC?

MR. NAEVE: Transmission costs?

MR. TRAPP: Yes.

MR. NAEVE: Florida Power & Light won't own transmission assets anymore. But with respect to the assets that it previously owned that are now owned by the RTO, it will recover its rates through FERC. But Florida Power & Light, then, will pay the RTO for service. And those costs, they will attempt to recover through its retail rates.

MR. TRAPP: But there is already a body of those costs that are in retail rates -- excuse me, base rates. You've got the transmission rate basis in base rates.

MR. NAEVE: Right.

MR. TRAPP: You're recovering revenue requirement, including a return, at the state level for that. Now, those are being transferred out --

MR. NAEVE: And in exchange, what we're getting is a --

MR. TRAPP: Exchange for a charge from the RTO. So, there's --

MR. NAEVE: But in effect, you're substituting a revenue requirement in retail rates, which you have today, for a different revenue requirement, which is the charge you pay the RTO for transmission service.

MR. TRAPP: And how do you expect to treat the difference?

MR. NAEVE: Well, first, we're trying to figure out what the difference is. But, you know, I think the -- in the long run -- you know, in the short run, the issue is will there be need for filing an additional -- and I should let the Florida Power & Light people speak to this issue, but there will be a question of is there sufficient difference between those two charges that we need to file a new retail rate case to make up the difference?

If they're sufficiently close together that it's kind of exchanging dollar for dollar, something close to dollar for dollar, then there may be no need for a retail rate case. And what we're trying to do is ascertain, you know, what are the various factors that would contribute to that being higher or lower.

MR. TRAPP: Have you contemplated leaving the rate base alone and requesting a separate cost recovery clause?

MR. NAEVE: Anne says, yes.

MR. TRAPP: So, no rate case, but separate cost recovery clause.

MR. WALKER: Bob, we're not going to double count, if that's what you're getting at the question of trying to collect it twice; once through the clause and once through the base rate, no, we will not do that. We may ask for a recovery of incremental cost through some mechanism. Again, we don't know how much money it will be or whether or not it's even necessary. We won't know that, until we know what the transmission rates are.

MR. TRAPP: And when will you know that?

CHAIRMAN DEASON: Excuse me, just a second. Bill, you probably need to identify yourself. That's Bill Walker from Florida Power & Light.

MR. TRAPP: Under this current development timetable, when do you anticipate knowing what those revenue requirements are?

MS. GREALY: I think, we're pretty close to identifying --

CHAIRMAN DEASON: Ms. Grealy, you need to identify yourself.

MS. GREALY: Anne Grealy, Florida Power & Light.

We're pretty close to identifying what's in our retail rates. And a lot of this is what will probably be covered by the pricing committee report later, but we're in that process of identifying what's in our retail rates. And at this point, you know, we don't know what the charges of the RTO are going to be.

I mean, everyone's identifying the revenue requirements associated with what they'll either be contributing or divesting or leasing. But frankly, I think there'll be a settlement process as to what those rates are going to be. And hopefully, we can reach agreement on what we're going to file with FERC for those rates.

So, I think, we have a requirement of, you know, no more than 60 days for the actual prices to file with FERC, but the committee is working, and we hope to identify that sooner rather than later. I think, the next time that we meet with the FERC staff -- with the PSC staff, we'll be in a position to say here is what is currently in our retail rates associated with the services that we'll now be paying the RTO for.

MR. TRAPP: 60 days from when, Anne? Bob Trapp over here.

MS. GREALY: Okay. I'm going to let Gail address that or even Mike. It's my understanding that we would have to file prices 60 days before December 15th, 2001.

COMMISSIONER JACOBS: Before we move on, I kind of want to walk through that analysis. From a rate perspective, you're just simply not looking to avoid double recovery. From a perspective of separations, do I understand you to say that you'll know what retail rates are being used now to recover costs associated with your wholesale transmissions?

MS. GREALY: Wholesale and retail.

COMMISSIONER JACOBS: And retail. So that when you look to allocate some cost recovery to the LLC, you'll look to back out from your retail rates that portion of the costs that are now -- for wholesale? You'll back that out, whatever that is?

MS. GREALY: Right. Let's look at it in pieces. We have, in our retail rates, what we're using to serve our retail customers and the costs associated with that, let's say, that's $260 million revenue requirement. And now we're going to have to pay something, you know, higher or lower to the RTO. And that's the issue that we're going to be addressing with you. And, you know, frankly, realistically, it's going to be higher.

COMMISSIONER JACOBS: You'll pay them for doing your wholesale transmissions.

MS. GREALY: Right. So, what I want to be able to do is to demonstrate to you and the staff that we have in our retail rates $260 million. We're now having to pay this RTO $270 million or $265 million, whatever that is. And, you know, through other cost-cutting measures, maybe we can absorb a part of that. But to the extent that there --

COMMISSIONER JABER: Or all of it?

MS. GREALY: Or all of it. I mean, I think, that's our goal. You know, no one wants to raise their rates any less than we do, so that will certainly be our goal. But if we come to you and say we've been able to absorb all of it but one million or two million, we would want to seek recovery of that through, either the existing recovery clause or a new clause. And, I think, we'll be able to utilize the existing capacity cost recovery clause. But, you know, Staff has made it very clear that that is going to be a rigorous examination, and we're going to have to demonstrate, you know, what is in retail rates and what we've done to absorb the increase.

CHAIRMAN DEASON: I have a fundamental question. When the RTO becomes functional -- I think, Bob's already asked this question earlier -- basically, the rates are going to be set by FERC.

MS. GREALY: Right.

CHAIRMAN DEASON: So, they have jurisdiction to set those rates. But there's a portion, and probably the vast majority of that though is going to have to be recovered somehow in retail rates.

MS. GREALY: Correct.

CHAIRMAN DEASON: Okay. So, the question is, how do we split out the portion, even though FERC's got jurisdiction to set the rates over at all, how do we separate out that portion of those costs that are going to be recovered wholesale and the portion that is going to be recovered retail?

MR. NAEVE: I actually think on that issue, it'll be easier than it is today, because today FP&L has a revenue requirement that's associated with their entire transmission system, that portion which is providing wholesale service, and that portion which is providing retail service.

Once they've transferred all of that asset to the RTO, the entities taking wholesale service will take that from the RTO and will pay for that service. They won't pay FP&L. FP&L won't be in the business anymore providing wholesale service. FP&L will be purchasing service just for the retail load. And that's the portion they'll come to you and seek recovery of.

CHAIRMAN DEASON: Okay. That's fine. Then, the question becomes -- let me put it bluntly.

I don't want to be in a situation of retail customers subsidizing wholesale customers. If the RTO feels like they're not getting enough revenue requirement recovery from the wholesale side, and they're an entity, is there going to be the possibility of shifting cost to the retail side, because maybe we have a higher rate of return in state or whatever?

How do we ensure that there's not a subsidy, one way or the other?

MR. NAEVE: I think, by the way rates are set at FERC, hopefully, there won't be a subsidy. The RTO won't have a retail rate and a wholesale rate, they'll just have a wholesale rate. And we will be paying the same rate that the wholesale customers are paying, because we will be a wholesale customer.

CHAIRMAN DEASON: There'll be one rate.

MR. NAEVE: There'll be one rate. So, everybody pays the same rate. So, I think, on that basis, there shouldn't be a subsidy, one group versus the other, because they all pay the same rate.

CHAIRMAN DEASON: Okay.

MR. TRAPP: I guess, my last remaining question is wouldn't it just be easier to make a clean cut of all this and just take it all out of retail rate base and let it all be FERC jurisdictional and let you recover your money from FERC?

MR. NAEVE: I'm not -- Bob, actually, I'm not sure I understand the question.

MR. TRAPP: Well, I'm sure Commissioner Deason's concerned about overlaps between -- you know, we got retail rate base now, but part of it is being transferred to FERC. Shouldn't we just make a clean split of all of that?

MR. ELIAS: In other words, I think what Mr. Trapp was contemplating is resetting base rates to reflect the reduction in assets associated with the delivery of service.

MS. GREALY: We would then have to turn right around and set revenue requirements for the increase in expenses that we're going to have to pay the RTO. So, while rate base is decreasing, expenses are going to go up. It'll be an expense that we'll have to pay the RTO for these services.

MR. ELIAS: And, I think, you previously mentioned that, you know, you saw recovery of these costs through the capacity cost recovery clause, and I think the thinking implicit. And the question was that we would look at all the expenses associated with transmission the way we do with capacity and purchase power and fuel now.

MS. GREALY: Yeah. I think, it's six to one half a dozen on the other. I think, you're going to want to look at the impact of this on our revenue requirements and how our current retail rates cover those revenue requirements.

And based on the numbers that we're seeing so far, it'll be close to a wash or a higher expense than we see today that's included in our retail rates. What you're describing is one option. I don't think it's the most efficient or expeditious option, but it's one approach. I mean, obviously, we would want to show you that you don't have to have a retail rate case. I mean, that's not something that we would look forward to doing or want to do, but it's an approach.

COMMISSIONER JABER: Ms. Grealy, you said we will have to pay the RTO for expenses. Are you, in your FP&L capacity, you're saying we, FP&L, have to pay which RTO for expenses?

MS. GREALY: We're going to have to buy transmission services from the RTO.

COMMISSIONER JABER: LLC.

MR. NAEVE: That's correct, RTO LLC.

CHAIRMAN DEASON: Okay. Let me back up for just a second and kind of take the concern that I have, maybe from a little bit different angle. FP&L is going to have to be buying transmission services from the RTO LLC. And the rate it pays is going to be one tariff rate, and regardless of whether it's wholesale or retail type of a transaction or utilization, it's going to be one rate.

MR. NAEVE: In effect, it's a wholesale rate.

CHAIRMAN DEASON: Everything is wholesale.

MR. NAEVE: We will be a wholesale customer of the LLC.

CHAIRMAN DEASON: Okay. Then, that's my point. How, then, do you determine, if you're just a wholesale customer and you utilize -- right now you utilize -- there's some wholesale use of your system right now, and that's allocated to FERC, and it's not in retail rates, correct?

MR. NAEVE: Well, yes, that's correct.

CHAIRMAN DEASON: And, I guess, my question is this: How do we -- how do you know, as a customer of the RTO, what you pay them, how do you know how much of that needs to be recovered in retail rates?

MR. NAEVE: All right. Let me take another crack at this.

Today, we have a wholesale use system and a retail use. The wholesale use is largely revenues that we earn from providing wholesale transmission service. So, to the extent that wholesale customers come to FP&L and ask for transmission service, that's largely the wholesale component of their wholesale use.

In the future, those customers won't come to FP&L. They'll go to the RTO for transmission service. So, that piece of the FP&L wholesale use will disappear. So, in effect, in the future, the RTO will be allocating those costs between FP&L and the wholesale customers -- not allocating, but they'll all be paying the same rate, and the costs will be divided up.

CHAIRMAN DEASON: FP&L is not going to be entering into wholesale transactions?

MR. NAEVE: That's the second piece I was about to get to.

CHAIRMAN DEASON: Okay, I'm sorry.

MR. NAEVE: The second piece is the extent to which FP&L makes off-system sales. They also, in effect, are required to pay themselves for wholesale service today. In the future, they will be paying the RTO for that service. So, that will be a payment they make to the RTO for transmission service.

So, if you step back and ask yourself what will FP&L be purchasing when they buy transmission service in the future from the RTO, they will buy service largely to service their retail customers. They will also be required to buy service, if they're making off-system sales. And, you know, that would be relatively easy.

CHAIRMAN DEASON: Is that something that's clearly identifiable on its face and something that can be audited?

MR. NAEVE: Yes.

CHAIRMAN DEASON: Because my concern is that, while I'm not accusing anybody of anything, there would be a tendency to minimize cost on the wholesale side, because it's more of a competitive environment, and to shift costs to the retail side, because there's more of a guaranteed return there.

MR. NAEVE: Right. No, actually, that will be very easily audited and tracked. It'll be a lot more precise than it is today. We're trying to estimate and allocate. It'll be a very precise cost incurred by them for their, quote, network native load and for their off-system sales.

CHAIRMAN DEASON: Staff, have any of our

auditing folks been involved in this process or is it too early yet? We want to make sure that we're able to track these transactions and make everything is as it's represented.

MR. TRAPP: We have some of the people from Tim Dublin's group on economic regulations that have been following along. But, like I say, so far attending these meetings, they're still way up here.

CHAIRMAN DEASON: But we have a commitment that -- I mean, it's your representation it's going to be easier to track these under the new system than it is now.

MR. NAEVE: I think, much easier.

CHAIRMAN DEASON: Okay. And this type of information would be made available to our auditors to review?

MR. NAEVE: I'm sure it'll be available.

CHAIRMAN DEASON: Okay.

MR. ELIAS: This is Bob Elias, I've got a related question concerning the transfer of rate-making, and the transfer of the transmission assets.

A lot of the studies that I've read over the last few years that talk about the business risk associated with the three functions that a typical bundled retail monopoly utility electric provider has; i.e., generation, transmission and distribution have ascribed the lowest business risk to transmission suggesting that distribution and generation are the two riskier activities, in terms of competition, the likelihood of competition.

And my question is doesn't this divestiture of the transmission assets, all other things being equal, increase FP&L's, the utility's, business risk which would require a higher stated return than would otherwise be applicable?

MR. NAEVE: I don't know the answer to that. I believe that it depends, in part, on regulatory risk, as well as business risk. And to the extent that there is reduced regulatory risk, then, perhaps there is reduced business risk as well. But I must say, you know, I'm not sure any of us know whether, once companies divest transmission assets, investors will feel they need lower returns or higher returns to invest in those companies.

I think, FP&L will still largely be a distribution company and a generation company. And I would expect it wouldn't have much effect, but you know, I think there's still a lot to be learned. I think, the jury is really out on how investors are going to treat these companies.

COMMISSIONER JACOBS: It would be anticipated that the price that the LLC charges would be calibrated to recover the, whatever the revenue requirement would be. What happens if that doesn't -- if the price doesn't wind up doing the recovery?

MR. NAEVE: Is the question what would happen if the rates approved by FERC would not allow the RTO to recover its revenues?

COMMISSIONER JACOBS: Right.

MR. NAEVE: Well, they'll lose money and potentially, I guess, if that happened over a long period of time, they would go out of business.

COMMISSIONER JACOBS: But nothing --

MR. NAEVE: I don't think FERC would set revenues that don't allow them to recover their fair revenue requirement. Certainly, FERC doesn't have a history of driving companies out of business for that reason anymore than any competent regulator would.

COMMISSIONER JABER: Did you craft this RTO proposal after any other state?

MR. NAEVE: You mean, RTO proposals in other areas? It is very similar to Transco proposals being developed in various different regions.

The alliance Transco proposal has a structure somewhat similar to this. I happen to be involved working with some of the companies. The pacific northwest, they're looking at a Transco proposal very similar to this.

The interesting thing is, in each of those cases, different economic advisors were involved, different accounting firms and banking firms were involved in advising the companies, and they all came up with very similar structures, because what that tells me is there aren't a lot of options here.

COMMISSIONER JABER: Are you -- well, have you used the California ISO at all?

MR. NAEVE: Well, no. That's an ISO as opposed to a transmission company. And this is a structure that is designed to permit the creation of a transmission company while avoiding adverse tax effects -- adverse tax effects and accounting effects.

COMMISSIONER JABER: Are you also watching, though, some of the problems that have occurred with the pacific?

MR. NAEVE: Oh, yes, yeah. The problems out there can be attributed to a lot of things, maybe moving, you know, unfortunately, being -- the expression somebody's pioneers get the arrows in the back, and they were certainly a pioneer.

I also think that the ISO structure itself has some inherent flaws. And, I think, in small part, maybe, not large part, but in small part, they're attributable to what's happening in California. And the market design in California, I think, could be improved upon. And we're working on market design now.

And hopefully, we can avoid some of the flaws that they have in California, but there are a lot of factors that are resulting in -- they're the cause of the problem in California; in part, just not having built enough generation over the last several years, too, because of clean-air restrictions and so forth in California has caused very high prices.

COMMISSIONER JABER: Who would determine, in your plan, if additional transmission is necessary? Is that the RTO LLC?

MR. NAEVE: Well, the RTO LLC, certainly in the first instance, has the responsibility to plan for transmission. And we're going to have a report of the planning committee. Marty Mennes chairs that, and he can talk about how those decisions are made and planned for.

But yes, in the first instance, they're going to have the responsibility to develop plans for providing fair and reliable transmission service. There's going to be a process through which we involve all the stakeholders of the state and integrate with reliability councils in doing that.

CHAIRMAN DEASON: The RTO LLC, will it be a utility under Florida law?

MR. NAEVE: On that issue, not being a Florida lawyer, I cannot offer to cop an opinion, but I can defer to any Florida lawyer in the audience, who would like to try it.

MR. LITCHFIELD: Well, you might ask a few Florida lawyers in the audience and get different answers.

CHAIRMAN DEASON: You need to identify yourself for the record.

MR. LITCHFIELD: Wade Litchfield for FPL.

It's a difficult question and one that we're looking at. You're well aware of the Supreme Court case involving Duke and Smyrna in that merchant plant, which is yet to be finally resolved. And, I think, we're watching that closely to see how that ultimate disposition might affect our views on the subject, but it's a tough question.

And ultimately, you also have to consider whether FERC is going to federally preempt some aspects of this Commission's jurisdiction, regardless of whether the Transco is considered an electric utility or a public utility under Chapter 366.

So, we're awaiting the outcome of the Supreme Court case before we finalize our views, but a few things are clear. I mean, Mike has described for its jurisdiction over the rates that the Transco would charge. We think that, nonetheless, this Commission would retain jurisdiction over transmission siting, safety, and some aspects of reliability, but the jury is still out.

CHAIRMAN DEASON: Well, I guess, that really is kind of the purpose of the question. It's not so much rate-setting. I think it's pretty much understood that it's going to be a FERC jurisdiction, as far as rate-setting.

The question is as siting transmission facilities and having some oversight of reliability purposes within the state and so, I guess, just for the sake of argument, if the Supreme Court decision is -- stands, does this entity have standing to come to the Commission and initiate a transmission siting request?

MR. LITCHFIELD: Well, that's a good question.

There may be some avenue under which we could come as Transco, as an applicant under the transmission siting act. But if we're wrong about that, we would; A, either seek an amendment to the legislature or B, have the utility come and make that application on behalf of the Transco, the retail utility, on an interim basis.

We think we can cross that bridge, one way or the other, and that Transco's business would not be impeded, regardless of the interpretation.

CHAIRMAN DEASON: So, you're saying that if it's necessary, then, it would be a matter of just having the law amended in Florida to make it clear that there is standing to initiate a transmission siting?

MR. LITCHFIELD: That's correct. We don't think the jurisdiction would slide over to FERC, if that's what your concern is, no. The jurisdiction would be here. It would just be a question of whether, you know, we had the right mechanics in place for the Transco to actually come before this Commission and get siting authority.

COMMISSIONER JABER: You said, "or," or you'd have the utilities apply to the PSC for siting. And the utilities, if they contribute their assets to the RTO LLC, won't have transmission?

MR. LITCHFIELD: No, they won't. And it's not clear how it would work, but if transmission had to be sited in FP&L service territory, it may be that FP&L would be the applicant under the siting act and then contract for the construction of that line through the Transco and give that asset to the Transco upon completion, something along those lines.

COMMISSIONER JABER: Well, with reliability being critical, the critical factor, shouldn't you all have the answer to that question before you do the preliminary filing at FERC on September 1st?

MR. LITCHFIELD: Well, I'm not sure that we see any critical lines on the eminent horizon that would be necessary to be constructed. So, I think our view is we've got some time in order to get that situation or that question resolved definitively. We do have an interim approach. I'm sorry, Mike.

MR. NAEVE: I was just going to say that the September 1st approach deals more with how we pick a board and let's us get started. It's a nonbinding filing. It's a petition for a declaratory order. Obviously, there are a lot of other various serious issues that we have to work through before we can actually implement the RTO and get it started.

I might suggest we allow the chair of the other -- chairs of the other committees to make their reports, if that's acceptable to you. I know they came prepared to do that. I don't want to take up the whole agenda time.

CHAIRMAN DEASON: That's agreeable.

MR. NAEVE: Why don't we start with market design. Greg Ramon from TECO is the chair of that committee. Greg?

CHAIRMAN DEASON: Perhaps now is a good time to take a short recess.

MR. NAEVE: Okay.

CHAIRMAN DEASON: And we'll try to reconvene as close to 11:00 as possible.

(Recess taken.)

CHAIRMAN DEASON: If I could have everyone's attention, please, ask you to take your places.

I think, the next -- according to my agenda, there's a report from Planning and Operations; is that correct?

MR. NAEVE: That's fine. We can do it in any sequence.

MR. MENNES: Marty Mennes, Florida Power & Light. And I've been facilitating or chairing the Operations and Planning. And just to hit a couple of highlights, and reflecting back on some of the questions that were asked, We'll start first with the operation side of it.

We are looking at -- basically, we'll have a tariff. The LLC will have a tariff to tell the customers how to do business, transmission business, transmission request, and scheduling.

The operating committee is, I think, you know, basically, if you look at the per forma tariff that's out there now, we'll have a few odds and ends to that, but we're in real good shape, as far as how we're going to coordinate with each other.

We see the Transco operating as the security coordinator, having the reliability function. It will be completely independent. We have a group, reflecting back on your questions about reliability, that we think is very important.

Looking at the standards right now, addressing all the way to what we do as the IOUs right now and coming up with such things as service unavailability, safety, frequency type of things, and taking various standards and giving these standards to the RTO, if you would, or to Transco to operate.

I think, a good example would be such things as we're talking about, if we would only expect the transmission or the standard would be no more than three outages of a minute or more per year, having to do with transmission. And we would expect that Transco to go in and clean up those things, fix those things. So, we are looking at having reliability measures that we would ask the Transco to do.

And when I get into planning, we'll talk a little bit how some of those things would be implemented once -- if they're not meeting a standard, you have to go ahead and get the planning folks together to go ahead and implement the various criteria.

So, that's pretty much it from the reliability standpoint. Maybe the only other existing thing would be the relationship in the standards and how they're set. Right now we look at the security coordination function and what would be required in the operation as getting its standards and policies and how it works from the FRCC, as it now exists, and later on as NERC, or whatever else may change into some kind of regional reliability organization. The Transco would be part of that organization, and we'd be accountable to any standards that the FRCC would have.

These standards would, basically, be set on a national level by NERC, and we would have some Florida-specific type of procedures, just like we do right now that would be voted on, and the Transco would be required to operate under these various standards and guidelines. So, that's pretty much from an operating standpoint.

The planning, we do have a document that talks about planning and, basically, the protocols that will be necessary. The planning, basically, has a load forecast, which will be the responsibility of the purchasing selling entities. They will be responsible.

If you would, the distribution company left behind by Florida Power & Light and the others will be responsible for load forecasting and coming up with a need. And then, these needs will be brought to kind of a committee structure, if you would, to go ahead and address these in a planning environment.

The Transco will have the responsibility to come up and address these plans for the needs of load growth, as well as integrating the degeneration and making sure that the various requests for transmission from either wholesale or from native loaders and network customers go ahead and specify generation and specify load, the Transco will have the obligation to go ahead and build these. There will be a process that you'll look at various alternatives and ways to do things and integrate the transmission requirements and requests of all the various members.

COMMISSIONER JACOBS: I assume that the security coordinator will have a primary responsibility for system control functions?

Let me give you a hypothetical where there is a line that's at risk of overloading, and there's a transaction that goes over it. I assume, the security coordinator would step in and exercise some control in that instance?

MR. MENNES: That is correct, Commissioner. Maybe a good example would be such things that we experience, every now and then, during dry weather. If we have fires in particular areas where lines do become at risk, the security coordinator will have, at his disposal, ways to go ahead and make sure if that line goes out or actually to take the line out and make sure that whatever's going on, he can still serve the load.

And that will be taken care of, various contingency things the market design folks will come up with. But he will have, on his authority, which really exists today, with all the entities in the state, they will have the obligation to go ahead and perform and operate as dictated by the security coordinator.

COMMISSIONER JACOBS: And so, Transco will be really at the control of the coordinator, in that instance?

MR. MENNES: Yes.

COMMISSIONER JACOBS: Now, your responsibility to the recipient of the load -- no, actually, it would be to the utility that's entered the transaction to provide the load.

In other words, if, pursuant to some action by the security coordinator, this transaction wasn't completed in a timely fashion, what qualifications would there be to Transco?

Normally, and I understand that in a normal environment, those kinds of circumstances would be worked out, but here, what arguably is a poor party involved between the serving company and the actual customer --

MR. MENNES: Right. There will be protocols and methods in place that, I think, what the question is, is if, okay, you'll come in and request a required transmission services from the Transco, and the security coordinator's going to be overseeing all these requests, and they'll have the obligation to make the transmission available to put the various generation and loads together.

So, whether it's on an hourly basis, a request that comes in that the security coordinator would then approve or whether it's on -- and when I say security coordinator, it would be the process in the Transco that it would approve, or whether it's a longer-term obligation, the security coordinator will have the obligation to make sure that transmission is there.

There'll be built into that various market ways and protocols that we'll handle. And maybe, I don't know whether -- we haven't got down to those details yet of how the markets will actually work with the security coordinator, but the security coordinator is really in charge of the pipes and makes sure the pipes are there and working.

COMMISSIONER JACOBS: My concern is would there be exposure to Transco for them? And what you're telling me that there are protocols in place that will remove that exposure.

MR. MENNES: Would there be exposure -- I don't know if I understand the question, quite frankly.

COMMISSIONER JACOBS: I would expect that Transco is ultimately the one who has fiduciary responsibility for those transactions that -- for the transmission services that are requested.

MR. MENNES: The Transco will have the responsibility to make sure the pipes are there. As far as implementing the transactions, the way it is right now, we envision that what we call right now our control areas, the various entities in the state would still stay as their own control areas.

So, the control areas will still have the -- let's just say, one control area wants to sell to Florida Power & Light, they would still have the responsibility of making sure those generations goes up and down.

Now, where the security coordinator and the Transco will be, come into play, they can also monitor that. And if that is not happening and causing problems somewhere, the security coordinator will be able to go out and dictate, if you would, back to those control areas or those generators to move their units or to discontinue the sale that there's such things going on. Or there'll be a balancing mechanism in place that maybe Greg will talk about a little bit later on that will kind of be part of market design when some of these things don't happen appropriately.

COMMISSIONER JACOBS: Okay.

CHAIRMAN DEASON: The question I have is you mentioned standards, operating standards and reliability, which are all very important. I take it that the decision to construct additional transmission or not, that decision rests with the RTO LLC; is that correct?

MR. MENNES: The way it is envisioned right now, that is correct. There's also a mechanism in there, if an entity comes and it's brought to this forum and, basically, the RTO goes back and comes back with a plan, and there's still an entity that does not like it, they have a certain way they can go to dispute. There may also be a way that they can go in and build it themselves or something.

So, we're still addressing some of that. But right now we're hoping, you know, theoretically, the way it is that the RTO would say, yeah, it's needed and necessary and, if you would, the advisory committee to the planning process will work together.

CHAIRMAN DEASON: And the determination as to whether it is needed, is that based upon both reliability and economics or is there -- how does it play into that concern?

MR. MENNES: There is a play-in. What happens there is, basically -- I think, a good example is the right way to serve a particular load. You go ahead and run a transmission line close to it so that you can build a substation and then serve it from the distribution or do you have distribution facilities around it already, then you have to run a longer distribution line.

So, the cost and the right economic decisions are something that the Transco will work out with the various members. And the objective there is definitely to make sure that we choose the most economic reliability solution to load growth or incorporating generation.

And again, this will be done with the Transco overseeing it. But the existing members and entities that are purchasing, selling or the IPPs or generators will all be there participating in this plan, if you would, that Transco will always have to come up with a transmission plan for the next years.

CHAIRMAN DEASON: Let me express what my concern is.

Under the current scenario where you've got an integrated system, generation transmission and distribution, while there may be some faults with that mechanism, I think, one of the benefits of that mechanism over the years has been that that entity has been able to look at various alternatives, whether it's locating generation in a certain place or building more transmission or extending distribution, or whatever.

They look at all those scenarios and, hopefully, they come up with the most economic, least cost, most reliable way of providing that. Now, some of that vertical integration is going to be taken away, and you're going to have a retail-serving utility that's going to be a customer of the RTO.

And my concern is that are we still going to have a planning process which, hopefully, results in the least cost, most reliable system? Or is there going to be friction between competing interests and some of that assurance that we've had in the past going to disappear?

MR. MENNES: Okay. Hopefully, we'll always do the right, reliable thing, most economic thing. And I think the process is what we're working towards just to make sure we do that.

There's a couple of areas that we're -- that are maybe a little bit difficult to address is to make sure that you send, for example, price signals to the various generators who were to site their generation.

So, we're looking at the various ways to do all that from our committee. When it gets down to the other thing, like you said, whether you do generation or transmission, we're hoping that this process will bring that out; that the load-serving entities -- and there are load-serving entities that are part of this type of process today.

Right now, quite frankly, the Florida Power & Light runs that are wholesale customers of ours that we'd like to think we do this process correctly and everything else. So, there may be a little bit something to be gained there, that now you've got more of this independent organization doing this for the state, for all the purchasing, selling entities.

So, I think, right now the way the process has been very well received by the stakeholders, I just as soon not speak for any, but we've worked real well together as a group addressing these type of issues. We understand these -- where they are. And, I think, it'll work. We know it'll work.

CHAIRMAN DEASON: If there is a dispute, is there some type of a dispute resolution process anticipated? And if that doesn't work, is there some ultimate decision that FERC would have to make? Does it get elevated up to FERC?

MR. MENNES: We will have a dispute process coming out of the planning committee. And how it goes through the rest of anything that's disputed with the Transco, I'm not sure that that's agreed to right now. I know, of course, the FERC would be the last thing, but when it comes to reliability matters and other things like that, it may be different. I really don't know.

CHAIRMAN DEASON: Okay. Further questions? Thank you.

MR. MENNES: Sure.

CHAIRMAN DEASON: Pricing.

MS. McKAIG: I'm Gail McKaig, and I work for Tampa Electric Company, and I'm currently chairing the Tariff and Pricing Working Group. And I'm going to give an update of where the group is at this time. I'll be referring to the Tariff and Pricing Working Group as the TPWG.

We are charged with bringing a consensus pricing proposal to the RTO steering committee by their September 21st meeting. I am here today to do two things, describe the pricing issues and report on the status of negotiations.

While there are many issues, we are wrestling with five key issues. I have scheduled a full-day meeting for August 24th for final negotiations by the Tampa Electric Company to reach consensus on these key issues.

If consensus is not achieved on the five key issues on August 24th, parties obligated to file on October 16 will begin drafting their own proposals, and I will turn over the negotiations to the steering committee.

In order to give our negotiations the best possible chance of success, I have asked the Florida conflict resolution consortium, specifically, Analee Moore, to help facilitate the negotiations. I worked with Analee prior to Tuesday's meeting. She attended the meeting, and I will work with her to prepare for the August 24th meeting. I trust that the consortium and Analee will add the necessary ingredients for successful negotiations.

Before I list each of the five key issues, I will provide a little bit of background on the pricing issue. With an RTO, assuming everyone joins, the entire peninsula of Florida transmission system could be priced as a single system under a single tariff. All owners of transmission would receive approved revenue requirement, and all users would pay their fair share of the cost of the system.

But you may ask, if transmission owners will continue to receive their revenue requirements as today, why are these owners having problems reaching consensus? The issue stems from the fact that each transmission owner also has a set of retail customers from whom they collect the majority of their transmission revenue requirements.

To the extent that their retail loads share of the costs of the new RTO system rate would be higher than the amount they currently collect from their retail customers, the owner is faced with a shortfall and would have to increase its cost of service.

Let me give you an example. If city "A" has a current transmission revenue requirement of $10 million per year and its load share of the RTO cost is $12 million per year, it would collect the $10 million from the RTO for its transmission revenue requirement, but it would have to pay the RTO $12 million a year for its load, resulting in a shortfall of $2 million a year. The issue is what happens with the $2 million shortfall?

Now, some owners may see their retail load share of costs increase, while others may see a decrease. We have referred to this as winners and losers. And, obviously, any potential loser is not inclined to agree to move forward in light of its loss. And a potential winner is anxious for the change.

In other regional RTO developments, parties have negotiated various ways to mitigate cost shifts, such as the $2 million shortfall in my example. The TPWG, has explored such methods in its negotiating, and I'll describe this work later.

The dollar impacts to the parties was the first thing that TPWG attempted to identify. A lot of data was gathered, and a lot of work has been done. I brought the latest version of this work with me, including a summary sheet as a handout for people to take with them today.

This latest version was updated Tuesday with some changes in it. Now, let me offer a caveat to these numbers. The purpose of gathering these numbers was to get a handle on the magnitude of potential dollar impacts on the parties, if the system is priced as a single system with all users in the region paying their load share of the cost based on their peak load. However, please understand that these are only estimates and there are many inconsistencies in the numbers.

The real numbers will not be available, perhaps until some time next year. This is because the transmission owners plan to develop new transmission revenue requirements closer to the time that the RTO rates would go into effect, which would not be until close to the end of next year.

In other regions where RTOs are being developed, transmission owners have used their current FERC file transmission rates, such that clear numbers are available during the negotiations.

With this background, let me frame the key issues under negotiation. The first key issue is whether the initial RTO rate should be based, either on zones or on a single postage stamp rate. There is consensus that the end state rate should be a single postage stamp rate, but there is no agreement on the initial state.

Although all can agree the end state should be realized, at least in 10 years, several parties prefer a much shorter transition with some degree of phasing within the transition period.

COMMISSIONER JABER: Gail, I'm sorry to interrupt you. You said the first issue is whether the initial RTO rate should be based on zones or what?

MS. McKAIG: Or a single postage stamp rate average over the whole state.

Regardless, whether the initial rate is zonal or postage stamp, there are mechanisms by which cost shifts among parties could transition. Zonal rates would have RTO users continue to pay their load share of the costs of the transmission owner where they happen to reside.

This solution would seem simple and could help mitigate cost shifts, but the parties cannot agree on zonal boundaries. This is because some retail customers of cooperatives and municipals reside in pancaked zones.

For example, some of Seminole's co-op customers reside in FPC's zone, but they also own transmission lines. So, would Seminole's load and transmission costs be included in FPC's zones such that each user would pay a load share of the average of the costs of the combined systems? Or would Seminole be in a separate zone and pay only the costs of their own transmission? The parties have not been able to agree on either scenario.

The other proposal is a single postage stamp rate, the average rate, where the parties would move immediately to the end state and mitigate cost shifts through time. Again, this solution seems simple, but the parties have not agreed on the mechanism for mitigation of cost shifts.

One method would be through distribution of revenues to the transmission owners. For example, if it is agreed that a party would be harmed by "X" dollars, the parties could agree that when the RTO makes its payment to the transmission owners for their revenue requirement, they could pay "X" dollars less to the other parties and "X" dollars more to the harmed party, but there is no agreement amongst the parties that FERC would allow such a proposal.

Another method that has been proposed is for a loser to carve out its retail load and associated revenue requirements from the RTO to sort of self-mitigate the cost shift. This proposal comes with many questions as to the treatment of such carved out retail load on other RTO functions, such as expansion and congestion costs and rights to access for the -- access to the RTO for reserves and et cetera. The parties have not agreed on this issue.

The second, but very much related key issue, is the treatment of existing transmission contracts. All existing contracts that involve transmission services would have to be administered by the RTO.

The rates, terms and conditions of transmission service within each contract will have to be either converted to RTO rates, terms and conditions, or grandfathered. The issue here is this --

COMMISSIONER JABER: Which RTO are you referring to when you say that the existing transmission contracts would need to be administered, the LLC or the manager?

MR. NAEVE: That would be the LLC. In all instances, it'll be the LLC that runs the system and that is the RTO.

COMMISSIONER JABER: Okay.

MS. McKAIG: The issue here is this: Transmission owners, who have sold long-term firm transmission services, have reflected the revenues those services provide in their cost of service to retail customers. Many such revenues would be lost in the move to an RTO because of the removal of pancaked charges.

For example, if Tampa Electric had a firm power sale to Jacksonville to be wheeled through Florida Power & Light's transmission system, FPL has counted on receiving the wheeling revenues from such a sale.

Under an RTO, if Jacksonville was a participant and took network service for its retail customers from the RTO, Jacksonville would pay its share of the costs of the RTO transmission system and could buy power from any generator in the RTO with no additional transmission charges.

Thus, FPL would no longer receive revenues linked to such transactions. Keep in mind, though, that all owners will continue to receive their approved revenue requirement from the RTO. Thus, no revenue is really lost. It's just that there's a difference as to how the system is paid for and by whom.

This issue is linked to the first issue I discussed, because the treatment of existing contracts is one of the factors in the calculation and mitigation of cost shifts. The TPWG must resolve how such contracts will be transitioned into the RTO, both from a rate standpoint and from a terms and conditions standpoint.

The grandfathering task force of the TPWG, led by Pat McGovern of FPC, has an assignment, a huge undertaking, really, to present a detailed grandfathering proposal to the TPWG at the August 24th meeting.

For your information, the pricing handout includes a one-page draft prepared by Pat McGovern, which was handed out at Tuesday's meeting, and this is in the handout. The paper describes other grandfathering issues upon which a consensus has been reached, such as the cut-off date of April 1996, which was the FERC Order 888 date, and that only long-term firm contracts would be eligible for grandfathering.

The third key issue relates to the RTO's base transmission access charge. The current TPWG strawman proposes a two-part rate. The first part would be a stated rate to recover the costs of the initial divested assets with the rate being frozen for a number of years. The second part would be an adjustment rate to recover various costs that are outside the control of the RTO, such as the revenue --

COMMISSIONER JABER: Gail, tell me again what that third issue is. You said it relates to RTO-based -- and when you hit the issues, I'm actually writing them down, so go slow for me.

MS. McKAIG: Okay. The third issue is the design of the RTO's base transmission access charge. This is the RTO's rate now, okay. It's a two-part rate. The first part would be a stated rate to recover the costs of the initial divested assets with the rate being frozen for a number of years.

The second part would be an adjustment rate to recover those costs that are outside the control of the RTO, such as the revenue requirements of nondivesting owners, assets divested after the start-up, upgrade costs, and settlements for cost-shift mitigation.

COMMISSIONER JACOBS: Why do you have the need to recover those in separate charges?

MS. McKAIG: The proposal for a first-part frozen rate has to do with the financial community's view that that will add viability to the stock of the company, it will give rate stability so that they can see a stream of revenues that they feel is really going to be there.

Did I capture that?

MR. RAMON: Yes.

MS. McKAIG: Okay. Some parties have expressed concern over the automatic pass through some of these costs in the adjusted rate, the second-part rate, particularly upgrade costs. Discussions continue as to whether a rate freeze or adoption of a formula rate or a hybrid approach should be adopted. Each rate design brings with it a different meaning to the financial community, as to the viability of the stock, which is of primary concern to the divesting transmission owners.

The fourth key issue concerns the degree of consistency required for the calculation of transmission owner's revenue requirements. If the ultimate goal is a single postage stamp rate for all users, this will entail the averaging of each transmission owner's revenue requirements. It would not make sense, then, for one owner to throw in a different set of facilities than another owner into the pot.

Therefore, there has to be some level of consistency, a formula or methodology, if you will, for how each owner calculates its revenue requirement and what is contained within it. The group has not agreed to the level of such consistency. The rates task force, led by Renae Deaton of FPL, has been asked to bring a detailed proposal on the revenue requirement assumptions to the August 24th meeting.

The fifth and last key issue is whether or not the RTO should offer network contract demand service. It would probably take me another 10 minutes to explain what that is and why that's an issue, but let us just suffice to say that network contract demand service is not one of the services offered in FERC's pro forma open access transmission tariff, but FPC currently offers this service in their tariff.

So, the parties are discussing whether the RTO should offer this service or simply grandfather any existing contracts that take this service. There was productive discussion at this issue at Tuesday's meeting and it will, hopefully, be resolved at the August 24th meeting.

This concludes my report on the status of the pricing issues in the RTO discussions. I'll be glad to answer any questions you may have. And there's plenty of people here on the committee, I'm sure, who can also help answer the questions.

CHAIRMAN DEASON: Did you provide us this handout?

MS. McKAIG: Yes.

CHAIRMAN DEASON: Okay. The first page, passed the cover page, this indicates shortfalls and -- is this cost shifts or shortfalls? Exactly what is this?

MS. McKAIG: Yes. Based on the numbers that we looked at, as a task force in making assumptions about, you know, assuming everybody in Florida joins this thing and what their revenue requirements are and what their load is, these numbers indicate the shortfalls. And they're all shortfalls when you average all that information.

CHAIRMAN DEASON: So, and, of course, there's a significant shift, depending upon whether Florida Power Corporation is included or excluded?

MS. McKAIG: If the retail load pays the RTO rate and is part of the RTO, yes. And this is just one scenario. I mean, if you took various parties out, in and out, the numbers would change, but this is a summary of the information for the IOUs that we've looked at as a task force or as a committee.

CHAIRMAN DEASON: And these numbers are still being refined? These numbers are pretty much in the ballpark as to what is anticipated?

MS. McKAIG: We're not refining the numbers, because the exercise was really to get a handle on the potential. And we looked at old data. We made a lot of assumptions about who's in and who's out. We won't really know the numbers, but the idea was that this would give us at least an idea of who might be a winner and a loser.

CHAIRMAN DEASON: You have five issues; for example, zonal rates versus postage stamp rates. Would the determination of those issues have impact on these numbers?

MS. McKAIG: Yes.

CHAIRMAN DEASON: Okay. So, that's what, I guess, I wanted --

MS. McKAIG: This analysis was assuming an average single rate what the cost shift would be.

CHAIRMAN DEASON: Okay.

MR. ELIAS: Gail, this is Bob Elias over here. Do these numbers just include -- I mean, there was a lot of discussion about 1998 numbers. Is this, basically, just taking the 1998 revenue requirement and playing with that?

MS. McKAIG: Right. It would be different when we would look at -- if we looked at 1999 data and probably what will ultimately be filed as year 2000 data, and we don't have that data yet.

MR. ELIAS: And, you know, the start-up costs and the other incremental costs associated with the operation of the RTO are not reflected in these numbers either.

MS. McKAIG: That's correct.

CHAIRMAN DEASON: Further questions?

COMMISSIONER JABER: I've got a couple. And I'm not sure really where they would go.

For the companies that will let the LLC operate the assets versus the, you know, the companies that will contribute the assets, how will that service be priced?

MS. McKAIG: The companies that allow the LLC to operate their assets will contract with the LLC for their revenue requirement. So, those companies will get their revenue requirements approved at FERC, and then contract to collect those revenue requirements from the RTO. The RTO will take those revenue requirements, add them up, and its own revenue requirements, add them all up, and then, develop a rate to recover all of it.

COMMISSIONER JABER: I don't understand that. If they're not contributing their assets, they maintain their revenue requirement.

Florida Power Corporation, as I understand it, is not contributing their assets to the LLC. They're allowing the LLC -- will allow the LLC to manage and operate the transmission, correct?

MR. NAEVE: That's correct.

COMMISSIONER JABER: How will you assess a charge -- how will the LLC assess a charge for Florida Power Corporation?

MS. McKAIG: Do you want to answer?

This is not a question about whether they carve out part of their revenue requirements. This is for a company that submits its entire revenue requirement to the RTO and then takes service from the RTO.

That company would receive its revenue requirements from the RTO, and then would pay the RTO for whatever service it takes from it for its retail load. Those two numbers may not match.

COMMISSIONER JABER: So, even though they're not contributing the assets, you envision that they would contribute their revenue requirements.

MS. McKAIG: Yes.

COMMISSIONER JABER: But there are other things in the revenue requirements.

MR. NAEVE: Well, in the case of an entity like Florida Power that does not contribute its assets, the revenue requirement that it would recover from the LLC would be the revenue requirement in associate with wholesale service. They wouldn't recover the revenue requirement associated with all of their transmission costs, just that portion of it allocated to wholesale service.

COMMISSIONER JABER: But the cost associated with managing and operating the asset for Florida Power Corporation, I'm assuming, will be included in the revenue requirement used for retail purposes.

MR. NAEVE: No.

COMMISSIONER JABER: Why not?

MR. NAEVE: Well, that is an interesting question, because they will be getting management services with respect to the assets they're operating.

MS. McKAIG: And to answer that, a fellow from Florida Power Corp. reminded me that they will be assessed a grid management fee, which is separate from the revenue requirement charge. And that fee will be assessed to all load, including retail.

COMMISSIONER JABER: So, then, the question becomes for those companies that have not contributed their assets, how can you assure that costs will not be shifted such that the retail rate payer pays that burden?

See, you can assure us, and you need to correct me if I'm wrong, but I think you can give us assurances to the degree that companies have agreed to contribute their assets in their entirety to the LLC that you will take the cost shifting into account.

But for the companies that are going to allow the LLC to manage and operate the assets, the LLC will assess charges for that. That's operating a business. You are operating a service and conducting a business. FPC, another business, will want to assess or recover those costs from the retail rate payer. At that point, the LLC can't give us assurances, right?

MR. SLUSHER: May I jump in?

COMMISSIONER JABER: Be my guess.

MR. SLUSHER: I'm Bill Slusher with Florida Power Corporation.

And, as you said, Florida Power does not have any immediate plans to sell off its facilities. It does, of course, support an RTO for the purpose of a wholesale grid on a depancaked rate. But we see, at least initially, that our retail business, which our existing transmission system was predominantly designed for and has very little use of other systems, should not incur any additional cost that it's not receiving any benefits for.

Your question about the RTO doing operations and planning, we do think that is benefitting the retail business. It should be replacing some functions that the company's already doing. So, that cost they should share in. It's being dubbed a grid management cost.

But the transmission facilities cost, we feel like the traditional jurisdictional separation of what Florida Power has as transmission rate base and expenses, should continue. And in that jurisdictional separation, the wholesale portion is what the revenue requirement is that the RTO is to recover from Florida Power Corporation.

COMMISSIONER JABER: So, you're thinking there would be a wash. To the degree that your employees are now managing transmission, that service is no longer being --

MR. SLUSHER: There will be some, to some extent that, on the operation and planning cost.

COMMISSIONER JABER: To the degree that the LLC can provide that management, an operation of the asset at a lower cost than what your own employees or your own company could do it, will the benefits be passed on for the rate payer?

MR. SLUSHER: It'll show up in the cost of service.

COMMISSIONER JABER: Okay.

CHAIRMAN DEASON: Further questions? Okay. Thank you. Market structure.

MR. RAMON: Good morning. Greg Ramon, Tampa Electric Company and chairman of the market design working group.

Commissioner Deason, with your approval, after my presentation, I'd like to make some comments regarding the market dynamics and regions that are undergoing industry restructuring.

Commissioner Jaber, justifiably, raised some issues related to what's going on in California and the northeast and just some real fatal flaws in design that are out there. And, I think, it would be of interest to the Commission Staff and the Commission to hear what, at least, we have compiled and some reasons to think about in terms of looking at market design. So, but that's with your approval.

Moving into the presentation, which you all should have a copy of, just a three-point presentation. I want to share with you where we've been, where we are, and at a very high level, talk to you a little bit in terms of some basic one-on-one market design.

Real-time balancing, that's really the genesis of getting a market going. Real-time balancing is a moment-to-moment balancing of generation and load. And the way we set that up, the balancing market will also create the infrastructure in time for fully-competitive wholesale market.

Attached to this presentation is a matrix, which is a comparison of the Tampa Electric and the Florida Power & Light, Florida Power Corporation market design proposals. I suggest we don't go there into great detail. That matrix is a work in progress, and I'd be glad to talk about the matrix, if you want, but I think after the presentation, we can all decide how much you all want to get into the matrix or the Staff.

If we turn the page, let's talk about where we've been. You can see a picture of myself. I'm trying to keep control of the market design working group. It's kind of hard. But I would submit to you that you could say that that picture represents several other people of the market design working group.

I think, on April the 27th, you could say that's Bill Locke and Henry Southwick. And at other meetings you could say that was Tim Woodbury. And on August the 7th, you could say that was Leslie Paugh and John Orr from Reliant. So, we've been having some fun; a little bit of food fights, but we're moving along.

The thrust of what we've been moving along on is a phasing approach. Rome wasn't built in a day, which is where Florida Power & Light and Florida Power Corporation have especially been coming from. And Tampa Electric's phase two. We need to know our destination, an end state, an end state in the context of this filing with the FERC.

So, we were instructed, if you will, by the whole working group for the three of us to try to merge those two proposals. And we had six meetings and intents to do that, and we've had three meetings of the full working group. We've also had some education. On three separate days, we had some market design workshops where we invited speakers from the other markets in the country to share with us their market designs.

At the moment where we are is that what's been floated is a July 6th proposal by Tampa Electric. And it was our effort, after a lot of discussion, to merge both proposals. Florida Power & Light and Florida Power Corporation, on August the 3rd, submitted a mark-up of that July the 6th proposal. Also, we've had two stakeholders submit written comments.

Regarding the three companies, there's a narrowing of the gap between our two proposals, but significant differences still remain. And those are illustrated in the attached matrix, which I can cover after the presentation. But as I said, it's still a work in progress. We have a conference call on Monday afternoon for several hours on a mark-up that Tampa is going to do on the August 3rd Power Corp. and Power & Light proposal. So it, indeed, is still evolving.

One of the critical issues is the process past next Monday, August 14th. We've had six meetings between the three companies. And we've put enough meat on the bones that what I'm hearing from other stakeholders is a need to now, you know, get to full working group meetings and to start having the other stakeholders. It's not that they haven't waded in, but now that the three companies have really got some meat on the bones, and it's starting to get enough people's attention that we need to think about our process going forward.

I think, and I suggest, and I can do whatever the Commissioners want me to do, but I would like to spend some time on just the next few slides talking about a real-time balancing market, which is really the guts of creating a market in Florida. And it's a real high level. And, I think, it paints a picture of the kind of issues that we have as a working group going forward.

If we move to the next slide, talk about real-time balancing, the genesis of a market, it makes very much sense to create a regional real-time balancing market, notwithstanding that it also is a very absolute FERC requirement.

It represents, if you will, the necessary mechanism to reconcile the physics with the creation of the market. And what I'm talking about in past presentation before this Commission, you know, I have made the point, I hope, about the inseparability between reliability and markets in commercial practices. We have a very unique industry that's undergoing deregulation, and you have to reconcile whatever markets you're going to create with the reliability aspects of that.

And again, when we talk about balancing, we're talking about the moment-to-moment matching of load and generation on a systemwide basis. If you don't do that, I think, you all know you don't get 60 hertz in stability and all those sorts of power system issues and problems.

Moving to the next slide, let's talk about today. Today's world, there's no balancing market. It's an absolute must that you have to balance load and generation. So, the way it's being done today is you have control areas balancing, you know, for the NERC performance criteria as a control area, and you have individual grid users under the FERC per forma tariff under the energy and balance service with dead bands and penalties and those sorts of things.

And it's really two sets of rules in terms of pricing for imbalances of how control areas deal with it and individual grid users deal with it. And it's a very emotional and controversial subject. And we know all about that, because Tampa Electric recently submitted to FERC for a generation and balance schedule. And to put it politely, we really got hammered by the industry on trying to set that up. So, it's a real, real problem in terms of equity and equal access to pricing for imbalances.

If we move to the next page, the solution is to create a real-time balancing set-up. And sort of the principle underlying this is first and foremost, the physics. You have, from a system basis, regional basis, you have to be in a moment-to-moment balance on a regional basis.

But if you think about the principle of diversity, there doesn't have to be a requirement that there be a moment-to-moment balance between the individual loads and resources of bilateral trades and load-serving entities and the schedules and actual production of individual generators.

Also, there's some real economics there on that principle of diversity looking at that from a statewide basis. That's not to say that those individual loads and generators are off the hook for imbalances, but you are able to set up with its principle a market that creates a comparable way for all market participants to face the same pricing mechanism for imbalancing and settlements. And it is truly a way to bring convergence to this issue. I have talked about, on several occasions, bringing convergence to this reliability and commercial interest.

So, with that principle, we can set up a balancing market that is set through a spot market that creates a real-time energy price. And this is the fertile soil that gets us going. The creation of a real-time regional energy price, in turn, creates the market mechanisms for congestion management. And that's much of a religious debate going on between LMP and forward markets and flow gates and those sorts of things, and we're doing that.

Also, for ancillary services and most importantly, the clearing of imbalances by all market participants, the same market-clearing price or the same pricing mechanism. And it most certainly sets the stage for further market enhancements, forward markets and power exchanges.

You move from one set of problems to another. At least three companies and, I believe, most of the stakeholders, if not all, support creating a real-time balancing market, that the issue, the food fight issue, if you will, is how and when we go about putting that in place.

The last page aspect that I want to point out that's significant, in terms of attributes of creating this spot market, is price transparency and providing market information on the value of potential expansion of transmission and generation.

We need to think about, and some questions have arisen about market power and mitigating that market power. We didn't talk today about the creation of an independent market monitor, but that entity will need this kind of information to be able to look at the market in terms of design flaws and gaming and those sorts of things.

Also, regarding market power, regardless of whatever consensus market design that we come up with, before it's implemented on day one, we're committed to, as a working group, to address market power and how that has to play into the design, whether we're talking about bid caps and those sorts of things. That is the quickie presentation.

CHAIRMAN DEASON: Let me ask you a quick question.

You indicate other significant spot market attributes, second bullet there, provides market information on the value of potential expansion of transmission and generation. How does that work?

MR. RAMON: I should have said that it can provide. Now, you know, Tampa very much likes the idea of a real-time balancing market with locational pricing, namely LMP, but we're arguing about that. But that tells you -- and location of marginal pricing is a price that particular load or aggregated set of load pays related to congestion. And that congestion is, theoretically, the incremental cost of transmission.

So, you're able to put a value on the potential expansion for that congestion of a transmission or generation. In some cases, you'd be better to truck on with just paying the congestion cost, but it's a transparent way to provide that information.

MR. TRAPP: Greg, can I ask you -- I'm Bob Trapp over here. Sorry, we're to the side and out of view.

Can I ask you to try to clarify some clouds, in my mind, with respect to there's -- on the other hand, the pricing committee is struggling with setting a single statewide rate for transmission in Florida, postage stamp rate, one charge for all. But then, over here in marketing, you're talking about locational marginal pricing. Can you explain, briefly, the overlap between those two?

MR. RAMON: Well, it's still, in your own words, this is where we are on market design, okay? So, we haven't, you know, come to an agreement on congestion management method and locational pricing.

MR. TRAPP: But do I understand that if you set a statewide average rate over here, that would be kind of like the fixed rate that everybody would pay for transmission, fixed transmission cost, but then over here you've got an energy market that's working with generators, putting generation in through the transmission system.

And as long as there's no congestion, and there's plenty of flow available on the lines, all they're paying is this average cost over here. But it's only when lines begin to overload that you have to look at maybe putting an incremental cost on top of that for --

MR. RAMON: Right.

MR. TRAPP: And it's through that pricing mechanism that you hope to send price signals to the market to locate generators in the right place, to get the proper clearing of transmission lines. If that LMP price or that marginal price gets so high, maybe people just don't want to sell in the market, so you've got relief on transmission. And then, the third control, the ultimate control, is the security coordinator, who says, okay, we're just going to have to allocate that line.

MR. RAMON: Yes, that's Tampa's idea. But at the last meeting, what's evolving in this religious debate in the country, and it has a lot of appeal to Tampa Electric, is Van Prader from Dynergy gave us an update. I have been talking with him for some time on this hybrid model for congestion management that is under development at the midwest ISO and the southwest power pool. And it's a convergence over this debate on a real-time balancing market with LMP and more of a forward market with pricing certainty to be able to marry the best of both. And, so on the congestion management question, we're in the throes of, you know, trying to also look at both approaches.

COMMISSIONER JACOBS: So, if I understand you correctly, you want to seek some kind of a balance there, but that's a very interesting idea. How do we reach that balance? When you have a hot spot, essentially, where you're looking to get load into, and you're sitting there having to -- and what I hear you saying is that's one of the functions that the market designer's going to do is to figure out how to balance some of that.

MR. RAMON: Right.

COMMISSIONER JACOBS: Are there precisions of protocols that will be available to you within the LLC to reach that without potential agreements, some interest that one of the parties be a purchaser or a transmission owner?

Here's what I'm thinking. If one of the great features of this is supposedly is independence, and one of the great features of that independence is the ability for all parties who would seek to sell into a hot spot to get there at a reasonable price, and what I hear you saying is that there will be some balancing there as to how to -- in terms of market structure. And I want to make sure that in the event that everybody doesn't see eye to eye, whether or not they're right or not, there are ways to resolve those differences.

MR. RAMON: You're talking about just the market design to take into account congestion? I guess, I don't really understand the question.

MR. NAEVE: I think, I follow your point. There are two issues here. One issue is who makes the decisions? And are the decisions being made by a party that has a stake in the game or are the decisions being made by an independent party?

And the structure we're proposing creates an independent party to make those decisions so that when parties either benefit from those decisions or the party who doesn't benefit from the decision, at least they are assured the decision was made by a party who didn't have some hidden motive. So, we're trying to establish a structure where the decisions are implemented in a fair and neutral way.

The second part of the question is by what standards do they make that decision? And when there's a congested transmission facility and a number of people want access to that transmission facility, there are a lot of different ways you might go about deciding who gets access to the facility.

When FERC first started implementing transmission tariffs, first in the gas industry, and then in the electric industry, they decided who got access by merely first in time gets access, but that didn't always necessarily produce the most efficient result.

So, now they're trying to develop other mechanisms that allocate access to constrained transmission facilities in a more efficient way. And that's what Greg's committee is all about is trying to figure out what will be the rules that are utilized by this independent party for making those decisions.

COMMISSIONER JACOBS: I understand, and I expect that you'll arrive at a good result.

My concern is that is it going to be automatic that everybody's going to agree once you hit the road? And, I think, you can agree that it won't happen. And when it happens, how are we going to get beyond that? Sounds to me like we could be in front of FERC trying to figure out how to allocate a congested facility. That could be the most effective way to do this.

MR. NAEVE: I think, the decision authority will be left -- will be given to the LLC, the RTO LLC, to make these decisions and allocate capacity. There will be avenues available to parties who feel that they've been improperly treated.

If they feel that the LLC did not properly follow the protocols that they have in place, that they did in an improper way, there will be both dispute resolution protocols available and also the avenue of filing a complaint.

Today, though, most of those disputes arise, because people believe that the owner of the transmission made those decisions in a way to favor their own generation. And here, that won't happen, because the transmission owner won't have generation.

CHAIRMAN DEASON: Well, is there consensus -- there needs to be some type of market mechanism, which sends the correct pricing to optimize utilization of the constrained resource.

MR. NAEVE: I haven't been sitting in on Greg's meetings, so I'll let him address it.

MR. RAMON: Well, that's still under discussion. You know, Tampa supports that strongly, but the -- and I can't speak for the whole group, but it's an issue that we have to deal with.

CHAIRMAN DEASON: Well, what are your other alternatives, if you do not rely on some type of a market mechanism and a price which sends the signal? What are the other alternatives?

MR. RAMON: Well, in terms of reliability, you're into TLRs and cutting and those sort of things, which is not where we really need to be. I don't want to paint a negative picture on it. We just haven't dwelled on that. It's not that the group will not deal with it.

CHAIRMAN DEASON: Okay.

COMMISSIONER JACOBS: Again, because you've indicated that you haven't -- the chart is very premature, I don't want to dig too deeply in it, but there's a point that I've been seeing in the article. I've seen that probably one of the most highly-contested areas here would be ancillary services. There is some thought that that will be highly -- and what I see is that you're proposing a bid-based option for that.

MR. RAMON: Right.

COMMISSIONER JACOBS: Walk me through how that would work.

MR. RAMON: Okay. You know, the creation of the real-time balancing market, okay, will create the real-time energy price, you know, for the ancillary services, namely AGC or a regulation and operating reserves.

Now, underscoring that, we will need to come up with explicit, you know, standards probably using, you know, NERC policy which will have standards for certifying units that, for instance, once you bid in or participate in that particular ancillary service product, like regulation, they'll have to be certified and tested on a periodic basis to be able to do that.

There will be explicit metrics to be able to, you know, measure are they doing what they say they're doing and performance measures. And ancillary services are critical. That's what boosts up the system and keeps it running and those sorts of things. So, there has to be, when you're moving to a competitive market for ancillary services, you have to have the explicit standards to be able to certify and measure performance. So, assuming that all that has been done, you have this central bid-based bidding into this central market for energy and capacity.

Again, the protocols for all of that, you know, we have not done that yet. That's, if you look at the matrix, you can see that that's an area that needs a lot more work. So, what I've told you is just some principle at a high level.

COMMISSIONER JACOBS: Okay.

CHAIRMAN DEASON: You indicated you wanted a moment to educate us some on some of the difficulties the markets are experiencing.

MR. RAMON: Okay. And this has been so much in the news lately. We've been spending some time, Tampa Electric, putting down some real contributing factors as to what's going on. So, we'd just like to share what we've put together thus far.

In those regions, California, northeast, we feel those prices, high prices, are reflecting supply and demand fundamentals; in particular, the effects of serious capacity shortages and surging demand. And those fundamentals are what's largely responsible for those price spikes.

And also, decisions by load-serving entities, not to hedge their price risk that has exposed retail customers to the full brunt of price volatility, namely

San Diego Electric & Gas. I'll mention something about that real soon. This supply and demand --

CHAIRMAN DEASON: Just a second. You're talking about risk management and -- expand on that.

MR. RAMON: Well, what's happening -- I'll jump ahead here a little bit, but California tried to implement a statewide market, and one failed, including requiring all the California utilities to meet their loads through purchases in a statewide prior exchange. So, important flexibility is really lost. Now, they're considering implementing, you know, more localized pricing structure and encouraging utilities to meet their load obligation, in part, outside of this, statewide, PX.

COMMISSIONER JACOBS: As I understand it, they couldn't do long-term purchases outside of the --

MR. RAMON: A limited amount, only a limited amount.

CHAIRMAN DEASON: They were totally divested of all generating assets; is that right, the retail utility or not?

MR. RAMON: I don't know what percentage they're still in.

MR. NAEVE: PG&E has divested all of its fossil facilities. They still have their hydro facilities. They still have their nuclear facility. Edison, Southern

California Edison, has divested their fossil facilities. I'm not sure what else they have. I think, they still have nuclear. And, I think, San Diego has divested all of its facilities.

MR. RAMON: Mike mentions, and I want to emphasize this shortfall between capacity and demand, their reserves have dwindled in the past five years and on a whole they're dangerously operating at low levels. They do not have an installed capacity requirement. Demand, long term, is increasing much more rapidly. Load reflects the vibrant economy and particularly, the intensity of the telecommunications Internet revolution.

The weather, summer of 2000, is one of the hottest ever. And '99 in California was one of the coolest. And so, those price increases this year reflect that variation in temperature.

Fuel prices, in California and other regions, depending on natural gas, the fuel prices have doubled this year. And, of course, the age-old import situation in California is dependent on in the northwest and southwest and in both cases those imports are down.

CHAIRMAN DEASON: Sir, let me interrupt just a second. There's a gentleman who came forward, I think, in response to a question I asked.

MR. ORR: Right. I'm John Orr with Reliant

Energy, and we're involved in the California market pretty extensively. We're one of the purchasers of some of the generation out there as the utilities divested.

They were originally required under the restructuring that took place in California to sell. I believe, the number was 50% was the requirement. Most of the utilities out there chose to sell, except for the nuclear and some of the hydro, nearly 100% of what they had.

And so they, basically, got themselves out of the generation business, except for the things that are involved, things like nuclear and environmental concerns.

CHAIRMAN DEASON: Okay. Thank you for that clarification.

MR. RAMON: I mentioned load-serving entities have failed to hedge price risk exposing retail customers. Only in San Diego have retail customers been fully exposed to the competitive market. In other areas of the state, a rate-freeze remains in place until the stranded costs are recovered. And the San Diego utility made a choice not to hedge its price risk through forward contracts in the past on to its retail customers, the full increase in spot market prices. So, the San Diego customers are, therefore, being fully exposed to the price spikes and have been insufficiently protected by their load-serving entity.

But We can learn from this experience. As I mentioned, this insistence on the load-serving entities being required to meet their loads for purchases through statewide PX, that's changing, thankfully. Handling of stranded costs have contributed. As you know, utilities in California have linked the rate-freeze agreements in place.

So, there's little incentive for the utilities to implement demand-side management, this whole price elasticity thing. And so, they're now striving to create incentives to make -- that make load and load-serving entities more price sensitive. And there's a need for financial hedging capabilities.

And California embarked on restructuring without having in place adequate opportunities for customers to hedge financial exposure to price volatility. So, the utility and their customers have been too exposed to the spot market, and I've talked about that.

California is working on rectifying that problem. The hedging contracts will allow a splitting of the risk and, hopefully, should result in less market volatility. I think, it's sort of by a glimpse of the audience what poor market designs can do in terms of the kinds of price spikes and turbulence that it causes. But

I know it's a real complicated market design, but as you look at California, possibly one of the biggest solutions is pretty simple, and that's the need for more competition to get some generation built.

CHAIRMAN DEASON: Thank you. I think that concludes all of the formal presentations that were planned. I'm going to, unless there's -- unless some of the presenters need to make any concluding remarks, I'm going then to open it up to any other interested persons who are in attendance today, who wish to make any comment to the Commission, now is your opportunity. If you'll just raise your hand and come forward.

MR. WOODBURY: Tim Woodbury with Seminole Electric. As you know, Commissioners, Seminole has been kind of at the forefront of trying to promote a formation of an RTO, along with FMPA and Tampa Electric.

And I'm not going to shine any light that hasn't already been cast here today, but I did want to indicate to the Commission that Seminole is very pleased with the cooperation, the work that Florida Power & Light, Tampa Electric, and Florida Power Corporation have done in trying to move this thing forward.

We've got a lot of tough issues that are still in front of us. I'm not sure we're going to be able to resolve all of them in the next couple months. It may take a little longer to be able to do that, but I did want you to know, because you had heard us speak before on the subject, that we're very actively involved in it and that we're very supportive of the efforts that have gone on so far.

CHAIRMAN DEASON: Thank you for sharing that with us. Any other comments?

MR. WOODBURY: If I could add one other comment.

CHAIRMAN DEASON: Sure.

MR. WOODBURY: The work of your Staff has been very helpful. And it's very important for us to keep them involved in this process, as we move forward.

CHAIRMAN DEASON: It's our intent to have them actively involved.

Well, if there are no other comments to be made, we have a section for questions and discussion. I believe that the Commissioners have pretty much availed themselves of the opportunity to ask questions as we proceeded through the presentation, I think, is the most conducive and constructive way to engage, but if there are any remaining questions from either Commissioners or Staff, now is the opportunity.

Yes, sir.

MR. RAMON: Thinking back on some of the questions that were asked by Bob and yourself, Commissioner, about price signals, while this is a principle though, we need to be talking about, it's also explicit in the FERC Rule 2000 congestion of management that there be, you know, locational prices and the ways to look at doing tradable rights and being able to create, you know, the price information.

CHAIRMAN DEASON: Okay, thank you.

COMMISSIONER JACOBS: What's the -- I know this issue has been raised primarily with respect to ISOs, but as a point of interest, I think, we should look at with regard to Transcos or RTOs, what's the posture that you anticipate with regard to information that will be available, either to FERC or to the state commission on Transco operations?

One of the big issues that has come up in California is that they have not been able to ascertain real facts, because of the inability to obtain information from the ISO, both at the request of FERC and the request of the state commission.

MR. NAEVE: One of the issues, or one of the policies that we will be developing for the RTO, is an information policy. It's our intention that much of what the RTO does, in terms of planning and operations, be done so in a way that is transparent so that people know that it's carrying out its function responsibly, that they have information to monitor its behavior, that the regulators, both state and federal, will be able to follow it to be informed as to what's going on. And we have, you know, we will be developing a drafting and filing that information policy.

COMMISSIONER JACOBS: That would be formally, some formal response?

MR. NAEVE: Yes, it will. It will be a document filed as a rate schedule at FERC.

COMMISSIONER JACOBS: Okay.

CHAIRMAN DEASON: Okay. Any other --

MR. TRAPP: Could I just end by getting, again, the clarification on the schedule for any activities that remain.

As I understand it, you're going to file with FERC your governance proposal September 1st?

MR. NAEVE: That's correct.

MR. TRAPP: And then, you're expecting a response for that, independent of your October 15th filing?

MR. NAEVE: That's right. We would hope to get a response from FERC on the governance proposal much earlier than they would be able to respond to the October 15th filing.

MR. TRAPP: In getting that response you'll go out and hire directors for this?

MR. NAEVE: Yes, we'll start the process. It'll take a while, but yes.

COMMISSIONER JACOBS: That's going to be a national search? If I recall, you were going to get a national search firm to do that?

MR. NAEVE: Yes. We'll establish a board selection committee composed of stakeholders. The stakeholders will then interview and pick a search firm, and the search firm will help identify candidates for them, and then they'll select from the candidates the board.

MR. TRAPP: On October 15th, you plan to file another filing with FERC that at least will have a conceptual addressing of the planning operations, pricing and market design?

MR. NAEVE: That's correct.

MR. TRAPP: Then, the two filings will run concurrent. What comes after that? You're going to turn over to the RTO new directors this whole thing some time. Will that be before or after FERC rules on the principles that are put before them?

MR. NAEVE: Well, certainly they will rule on the governance principles before we can even start retaining those people. So, that will go first. The process of selecting and hiring a board and staff and so forth will take a long time. And FERC, I presume, will have ruled on the other filings or give it its guidance with respect to the other filings before we can have staff and board of directors up and running.

So, the work that would need to be done to refine our filings and to prepare the actual tariff filings, the rate filings, that will need to be made will have to commence before we have that -- any staff onboard to the RTOs. It'll be largely the same -- pardon me, largely the same working groups that are engaged today will continue to carry the bulk of that work.

At some point we will begin to have staff people onboard. A lot of what the staff will have to do is not just prepare regulatory filings, but actually begin the commercial work of getting in place the facilities and people and procedures to take over their responsibility.

MR. TRAPP: And all of that has a convergence date of December 15th, 2001?

MR. NAEVE: That's correct.

MR. TRAPP: Okay.

MR. NAEVE: Tight schedule.

MR. TRAPP: At what point and time does Florida Power & Light, the distribution and generation company, separate itself from the RTO formation company and begin to negotiate on behalf of its rate payers for terms, rates, and conditions from the FERC RTO?

MR. NAEVE: Well, there actually will have to be contracts negotiated between Florida Power & Light and, I presume, other utilities and the RTO staff. And that will probably -- we're going to have to have the staff in place first. And my guess is in, you know, mid 2000 to late -- I'm sorry, mid 2001. We have to be there by December 15th, 2001. And I'd like to say earlier than that, but realistically, I just don't know whether we'll be able to get the staff up and running before that.

So, obviously, on our own we'll be coming up with draft agreements that we'll be presenting to them.

MR. TRAPP: I think, that's all the questions I have.

CHAIRMAN DEASON: Okay, thank you.

Let me take this opportunity to thank everyone for your attendance, your presentations, all of the hard work that's gone on and the openness of this process.

There currently is scheduled another workshop on the 18th of September. I think, that's still on our calendars. You may want to make a note of that. And hearing nothing else to come before the Commission, this workshop is concluded. Thank you all.

COMMISSIONER JACOBS: Thank you.

(Workshop concluded at 12:35 p.m.)

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STATE OF FLORIDA)
: CERTIFICATE OF REPORTER
COUNTY OF LEON)

I, KORETTA E. STANFORD, RPR, Official Commission Reporter,

DO HEREBY CERTIFY that an undocketed workshop, regarding the Regional Transmission Organization, was conducted by the Florida Public Service Commission at the time and place herein stated.

IT IS FURTHER CERTIFIED that I stenographically reported the said proceedings; that the same has been transcribed by me; and that this transcript, consisting of 110 pages, constitutes a true transcription of my notes of said proceedings.

DATED this 17th day of August, 2000.

Koretta E. Stanford

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