BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 020233-EI

In the Matter of

REVIEW OF GRIDFLORIDA
REGIONAL TRANSMISSION
ORGANIZATION (RTO)
PROPOSAL.

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PROCEEDINGS: WORKSHOP

BEFORE: CHAIRMAN BRAULIO L. BAEZ
COMMISSIONER J. TERRY DEASON
COMMISSIONER RUDOLPH "RUDY" BRADLEY
COMMISSIONER LISA POLAK EDGAR

DATE: Monday, May 23, 2005

TIME: Commenced at 9:30 a.m.
Concluded at 2:50 p.m.

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

REPORTED BY: LINDA BOLES, RPR
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IN ATTENDANCE:

JUDAH ROSE, KOJO OFORI-ATTA and CHRISTIAN McCARTHY, appearing on behalf of ICF.

WILLIAM "BUD" MILLER and ROBERT DAVIS, appearing on behalf of Seminole Electric Cooperative.

ROBERT C. WILLIAMS, appearing on behalf of Florida Municipal Power Agency.

JOSEPH A. REGNERY, appearing on behalf of Calpine.

P. G. "BUD" PARA, appearing on behalf of JEA.

GARY BRINKWORTH, appearing on behalf of Florida Municipal Group.

JOHN W. MCWHIRTER, JR., ESQUIRE, appearing on behalf of Florida Industrial Power Users Group.

MIKE NAEVE, appearing on behalf of the GridFlorida Applicants.

GREG RAMON, appearing on behalf of Tampa Electric Company.

NINA McLAUREN, appearing on behalf of Progress Energy Florida.

BOB CROES, appearing on behalf of Florida Power & Light Company.

BOB MACHUGA, appearing on behalf of the Federal Energy Regulatory Commission.

JENNIFER BRUBAKER, ESQUIRE, appearing on behalf of the Commission Staff.

P R O C E E D I N G S

CHAIRMAN BAEZ: Good morning. We'll call the workshop to order. Counsel, will you read the notice.

MS. BRUBAKER: Pursuant to notice, this time and place has been set aside for the purpose of conducting a workshop in Docket 020233-EI. The purpose of the workshop is set forth more fully in the notice.

CHAIRMAN BAEZ: Once again, good morning all. It's, it's interesting to see an almost full room today. I wonder what that's about.

As most of you know, we, we organized the workshop or called the workshop in order to try and discuss and hear comments from stakeholders on at least the preliminary draft of the Cost Benefit Study on GridFlorida. We have a fairly lengthy agenda, and I'm going to be turning it over to Roberta Bass in a second.

I want to thank you all for coming. My understanding is that, you know, the stakeholder process and the discussion and issues offered have been fairly productive. I hope that that continues. And all of your participation, all of you who are going to be presenting today, we do appreciate that participation and your showing up today.

With that, Commissioners, if you, if you don't have any other comments, we can turn it over to Ms. Bass. And, Ms. Bass, you can handle the emcee job for the morning, if you would.

MS. BASS: Thank you, Chairman Baez.

I, too, would like to welcome everyone and to express my appreciation to all the stakeholders for their participation and their cooperation as we've gone through this very lengthy process. And this isn't the end yet.

If you'll note on the agenda, and I did place copies of it on the far side, there is -- I have one change to the agenda. We will be adding after Florida Power & Light a representative from the Florida Energy Regulatory Commission is here -- Federal. I'm stuck in Florida. And he was very quick to remind me it was federal.

CHAIRMAN BAEZ: For today they're all ours.

(Laughter.)

MS. BASS: Thank you. Bob Machuga is going to -- will be speaking afterwards.

And then under -- at 11:00 when FMPA is scheduled to present, the first speaker -- there's just a change in the order. The first speaker will be Bud Miller, the second speaker will be Bob Davis, and then Bob Williams will speak as the third speaker in place of Cindy Bogarod. Other than that, there aren't any changes.

I would like to -- if you notice on the agenda, it is a very, very tight agenda. We put a lot of information into a short period of time. So I would please ask the speakers to be mindful of the time as they are making their presentations. So without anything further, I am going to turn it over to a representative from ICF to start us off.

MR. ROSE: Roberta, thank you very much. Good morning. It's a pleasure on behalf of ICF to be back here in Florida.

My name is Judah Rose. That's spelled J-U-D-A-H. And I'm here with the project manager of the study, Kojo Ofori-Atta. Also here is Chris McCarthy, who, among other things, led up our cost analysis. I want to acknowledge our division leader Phil Mihlmester is here.

As you can see on Page 2 of our presentation, there are six parts to our presentation. We're going to review the objective and the scope, discuss the process. **As you can see,** we've broken out the cost and benefits to a quantitative benefit discussion, a qualitative benefit and cost discussion, an RTO cost discussion, which is quantitative, and then we'll have a summary of our results.

I wanted to emphasize that the stakeholder process has been very open. We've been -- we've had the pleasure and the honor to work with some very impressive people here in Florida, they've been very helpful to us, they've been very knowledgeable about the industry and from whom we've learned a lot. So it's been a very positive experience in that respect.

As you can see, the objective of our study is to estimate the cost and benefits of a GridFlorida greenfield RTO. And one of the key things that will be throughout our presentation is Day 1 versus Day 2 mode of operations.

The Day 1 is the operation mode that's most similar to the current situation in Florida, except that there'll be a single tariff and transmission provider. And, therefore, you'll eliminate a thing, which we'll talk about, called pancaking of transmission rates among other things.

The Day 2 is similar to Day 1, except for there's a pool wide market for energy. And I did want to introduce the first number for today, which is that the modeling of that involves something on the order of 20 million electrical energy prices per year, and the study is over a 12-year period. So it gives you a sense of the complexity of some of the analysis of that particular pool wide energy market.

When we look at the cost and benefits, we'll always be either explicitly or implicitly comparing them to a base case that's reflective of what's going on today in the industry projected out over more than, more than a dozen years.

We have broken out the cost and benefits into three categories. The first here is investment efficiency, which we are going to be describing qualitatively.

As the Commissioners are well aware, this is one of the fastest growing states in the country, and there's a lot of investments that will have to be made over the next 12 years.

And just so you understand how we're coming at this, the investments are fixed across the scenario. So the discussion will be qualitative, in large part reflect the fact that there's no established industry procedure to figure out how your investments in plants, et cetera, and power plants would change across the scenarios. So we'll be talking about investment efficiency.

We'll also be talking about operational efficiency. And everything -- and most of the presentation will actually cover operational efficiency, about which the procedures for analyzing that are more established. And so a lot of what we'll be talking about falls in the category of dispatch or power plant operations. We'll be using terms like unit dispatch and unit commitment, and this is all related to the quantitative assessment of those operations. And we'll also look at the costs of a greenfield RTO under the various different modes. These will be the direct costs that you'd see in sort of a budget for the entity.

And then lastly, the stakeholders will be providing estimates of costs and benefits of working with the RTO.

And so those are the categories, and I just, I'm sort of priming up the pump of some of the ideas and nomenclature we'll be using. And with that, I'll turn it over to our project manager, Kojo Ofori-Atta.

MR. OFORI-ATTA: Thank you, Judah.

Good morning. And picking up from where Judah left off, we -- and I'm on Slide Number 4, we examined three cases. We have a base case which is reflective of today's market. Now in this base case the characteristic features are the fact that we have company operation. Each company basically looks at its footprint. What I mean by that is they commit their units to meet their, to serve their load. And we also -- in the base case we have multiple transmission providers working with different, I mean, separate, you know, transmission, open access transmission tariffs, and we have pancaked transmission rates. So these are the three key features of the base case: One, company operation; two, pancaked transmission transactions and, three, some market inefficiency.

Now when we migrate from that to a Day 1 case, the features that remain again, company operation, which is also in the base case, but we eliminate the pancaked transmission transactions and we eliminate market inefficiencies associated with transactions. So let me take it again because this is very important; you'll be hearing it as we go through.

In the base case we have company operation, we have pancaked transmission charges, and we have market inefficiencies. These market inefficiencies are often associated with transactions. So these are the three features.

When we go to Day 1, two of them go away. The pancaked transmission transactions go away and the market inefficiencies, which we associated with, we associated with transactions, also go away. Then in Day 2 we eliminate the company operation.

Now in the industry there are standard ways of capturing these inefficiencies. For company operation we tried using commitment hurdles. Then for the other two inefficiencies, that's pancaked transmission transactions and market inefficiencies, collectively, that combined, we are capturing it using what we call dispatch hurdles. So I'll be talking about two types of hurdles: Commitment hurdle and a dispatch hurdle. Commitment hurdle capturing company operation and dispatch hurdle capturing transaction inefficiencies. And you can think about that as comprising two components: One, pancaked transactions and, two, other market inefficiencies associated with transactions.

So our three cases are the base case, the Day 1 case and the delayed Day 2 case. Let me explain that. The base case, we are looking at it over 13 years, 2004 through 2016. A Day 1 case is also being looked at over 13 years. In the delayed Day 2 case we have the first three years reflective of a Day 1 scenario, followed by ten years of a Day 2 scenario with pool wide markets.

Okay. With that I'll go over to Page Number 5. We also looked at two scenarios, and this is very important. These two scenarios have to deal with how resources, external firm resources are treated in the marketplace. There's some companies in Florida that own external resources in Georgia. Now in their daily operation they commit these units to meet their load. So in one of the scenarios, that's Scenario 2, we allow them to commit these units to meet their load resources in Florida. And in Scenario 1 we disallowed that. So we looked at these two scenarios.

Now just fast-forwarding, Scenario 2, where we allow them to commit these units to meet their resources in Florida, which is what they do today, was the one that provided the most benefits. And for brevity I'm trying -- I'm only going to focus on Scenario 2 in my presentation.

So summarizing that on Page 6, I show the two scenarios and the three cases that we looked at. And both of these scenarios, results from both of these scenarios was presented to stakeholders on April 27th. And just for the purposes of this presentation we will focus only on what we call the partial commitment and dispatch scenario.

This has been a stakeholder process. There has been significant stakeholder involvement and input into everything that we have done, and I'd like to just highlight some of the things we've done over the period.

We've had six cost benefit work group meetings covering various issues. The first was just a teleconference and we basically introduced ourselves, defined the project scope and laid down the communication and the data submission, you know, procedures.

In the second meeting, it was solely -- the sole purpose of the second meeting held in Tampa was to focus on the modeling assumptions. A lot of assumptions go into deriving these benefits like gas prices, like, you know, must-run, there's something we call, you know, the units that must always run to provide reliability, you know, and related assumptions, environmental assumptions, you know, what environmental allowance prices are we using. We provided this to stakeholders to get their input, we got a lot of good questions from that, and we had to revise some of these assumptions to incorporate stakeholder input. And all the documents that we produced, you know, as part of this process was posted on a stakeholder website so stakeholders can at any time access these documents.

The third cost benefit work group meeting was focused on the study approach. We wanted to lay down our, lay out our approach, how we're going to go about modeling details. There were lots of questions, you know, there were lots of inputs from stakeholders. And in some cases we had to reconsider some of the stakeholder, you know, inputs and make, you know, modifications to the study approach.

The fourth cost benefit work group meeting was held in October also in Tampa, and we presented our model calibration results. The key aspect of calibration results is it captures the inefficiencies of today's market. So we captured the company operation, and we also captured the market, the transactional inefficiencies. So we made -- we presented these results to stakeholders and it was very detailed. You know, you'll find a binder, Commissioners, you'll find a binder right by you. You know, and in that binder you'll find some of the results that we presented to stakeholders at that particular meeting, and you'll see that as Exhibit 7 in your binder.

Also the fourth stakeholder -- the fourth cost benefit work group meeting we walked stakeholders through the kind of RTO structure we were going to model, and we also talked about, you know, what would stakeholders -- talking about the roles -- you know, before you cost, you cost an organization, you want to first understand what are the roles and responsibilities, what are the functions of this organization, what is going to be its roles and responsibilities? So as we go through this presentation, we'll just show you some slides where -- the stakeholders are very familiar with these slides. We show the RTO structure. We also show the roles and responsibilities of the new RTO organization and how it will work with existing control areas today that will morph into what we call control zones. We will talk about that. But we worked with stakeholders through that.

Then from that point on we distilled that information into personnel, systems and facility requirements for Day 1 and Day 2 operation.

We followed that with a fifth cost benefit work group meeting in December where we presented preliminary RTO cost estimates. It was a conference, teleconference call, and it was heavily -- we got a lot of participation from stakeholders. Our process throughout this exercise is always to release our preliminary estimates, get stakeholder input, give concentration to stakeholder questions and release our final estimate incorporating these stakeholder comments. So at the fifth work group meeting we presented the preliminary cost estimates.

And at the sixth meeting what we did was we presented the final RTO cost estimates and at the same time presented what we called a preliminary RTO benefits estimates. And today we are going to be presenting the final RTO benefits estimate and the final RTO cost estimates.

I'm going to skip Slide Number 8 and go to Slide Number 9. This study has been a long study and, as you will agree with me, once you have an open process, there's going to be lots of questions, you know. And I think it's, it's been time well spent in my opinion. There are many stakeholders here today who have been involved in other studies and, in my opinion, I think this has been the most open, this has been the most detailed. And there are a few things I would like to talk about.

First of all, we modeled ten explicit years. I mean, we explicitly modeled ten years. Most analysis will model maybe just three representative years or will model maybe just about four. You know, there are many other studies that have been carried out. We were asked to look at ten years. So it usually -- what it means is we increased, you know, model run times.

Additionally, we modeled marginal transmission losses. And by doing that, basically we are pricing transmission losses on the margin especially in the Day 2 market. By doing that, in terms of time it increases your computer run time by a factor of four. So in some sense that is what it meant.

During our calibration exercise to pick up the company operation, you know, and market inefficiencies, what we did was we didn't calibrate to just coal resources. You know, there have been studies where they've just calibrated to coal resources. What we did was we said, look, coal resources will dispatch anyway regardless of your condition, especially when you don't have stringent environmental assumptions. So what we did was we put in a little more effort to calibrate to make sure that we're capturing other units, other mid merit units, you know, to make sure that whatever we're doing, we're trying to mimic what was going on in the market today. We calibrated to 2003, and what we did was we made sure that the mid merit units were dispatching at, you know, at or close to their 2003 levels. So that also took a little bit of effort, and we thought that it was, again, time well spent, you know, to try to get as accurate as we possibly could get.

I talked about two scenarios. Apart from looking at Day 1 and Day 2, we also looked at two scenarios in this process. And there were three explicit stakeholder comment periods. In your, in your, in your binder you will find that. We have responses to every single question. There were detailed questions. You know, typically you were getting about 37 questions that you had to respond to. But, again, it was all good.

So I'm going to move on to Slide Number 11 where we show the annual benefits for both Day 1 and Day 2. But generally this slide is supposed to show that RTO benefits are largely driven by pool wide markets, you know, which is basically the Day 2 operation where you have, you know, pool wide markets. So you can see from this slide where we show only 2007 to 2016 how the Day 2 benefits compare with Day 1.

Remember, Day 1, as Judah introduced it, is similar to a base case, today's market. The difference is that you eliminate pancaked transmission transactions and you have a single transmission tariff and a single transmission provider.

So the small -- the short box you see there, the blue are the Day 1 benefits, and the yellow box are the delayed Day 2 benefits.

So on an NPV basis for the entire period from 2004 through 2016 we realize about $70 million in Day 1 benefits and almost $1 billion in Day 2 benefits, specifically $968 million.

So moving on to Slide 13, we asked ourselves where are these benefits coming from? You know, which units are providing these benefits? And as you can see from just a sampling of, you know, units in the marketplace, you see that for the most part the benefits are being derived from the mid merit units and the peaking units. And consistent with our belief, coal plants and base load units will dispatch under any market scenario. They will dispatch to their full availability. So we shouldn't be expecting benefits from these units. And, again, if benefits are going to come from units of this kind, it's likely to be under stringent environmental assumptions, you know, where you have maybe a carbon policy and you have other policies.

So in our modeling we saw that these units were really not changing their capacity at dispatch. They were dispatching healthily in all the years, almost close to the availabilities.

But as you can see over here, the units that were providing benefits were either old combined cycle units or oil/gas/steam units and peaking facilities.

Now you can tell from this chart also that the dispatch between the Day 1 and the base case, you know, although there was some difference, it wasn't as large as the displacement between the base case and the delayed Day 2. So this basically explains why the Day 2 benefits were much, much larger than the Day 1 benefits.

I'll skip Slide Number 14. It's just another sampling of units that changed their dispatch as we went across the cases.

In the introduction Judah mentioned the fact that the three primary sources of benefits are investment efficiency, operational efficiency and also the costs and benefits of stakeholders or market participants working with the RTO.

Investment efficiency was something that we treated qualitatively. In performing the quantitative analysis, stakeholders gave us their resource additions going forward. And on Slide 15 what you see is that in Florida stakeholders said that they were planning, by 2007 they were planning to add about 5,800 megawatts of combined cycle capacity and a few cogeneration facilities and very few gas turbine facilities compared to the amount of combined cycle facilities that has been added.

Now this is significant. One is if you add in this amount of capacity, then it's likely going to -- if your demand is not growing as fast, you're likely to offset, likely to offset the imports that will be coming in from Georgia; some of the imports, not all of it. But if you look at this chart, you'll see that Southern is not adding as much capacity also. Southern was saying basically by 2007 Southern will be adding about a third of what Florida was going to be adding. But this is what stakeholders gave us that this is what they think they will be adding going forward and that's what we modeled.

Over the full period through 2016 basically we added 16,000 megawatts of combined cycle capacity, a few megawatts, about 450 megawatts of coal capacity and a few gas turbine facilities. Again, we added more capacity in the Florida area than in Southern.

If you look at Slide Number 17, what we tried to capture here was the general load growth that we expect, what we modeled, which is the line graph that you see over there and how it changes every year. Then from 2010 we looked at it on a two-year basis. So this is the incremental load growth in Florida expected from 2005 through 2016.

And the bars that you see on this chart is generation from only the new facilities that stakeholders asked us to model. What you can tell from this graph is that the new facilities were generating more than demand growth. So, again, what this means is that you are likely to offset generation from either your peaking units, your existing peaking units in

Florida, or you are likely to -- and/or you could offset imports coming from Georgia. And we saw this in our results.

If you look at the next slide, it shows you the imports from Georgia as we go through time from 2004 through 2016. Now two key points here: Apart from the fact that we added more capacity than demand growth naturally would depress their level of imports, we also were modeling marginal transmission losses and average transmission losses. Now this is a little different from what goes on today.

Today many of the utilities have what we call constant losses. Basically they have a loss factor of 3 percent and it changes from, you know, utility to utility. What we realized when we were doing this study was that every utility had a different way of treating losses and treating, you know, its transmission tariffs. So we had to come and harmonize some of these things.

So what we decided to do, you know, in consultation with stakeholders was we will model average losses, which is a little more punitive compared to what we call constant losses for the Day 1 and the base case scenarios. Then we will model what we call marginal losses for the Day 2 scenarios.

So what I mean by all this is that if we, if we actually had a flat constant loss structure, perhaps the imports will not decline as much. It would decline some, but probably not as -- I don't know whether the word is precipitously as we see on this graph. But the fact that in measuring benefits we are looking at all this against the base case, I don't think that affects the results by much.

With this we asked ourselves -- you know, after you perform such an exercise you ask yourself, how reasonable are these results? What we found was that almost $1 billion in Day 2 benefits, you know, sounds like reasonable in our opinion. So we decided to take a closer look at the Day 1 benefits, you know. The Day 1 benefits, we've got about $70 million. And we started asking ourselves some of the common sense questions. Why are these benefits reasonable, these Day 1 benefits? So I actually called up a few stakeholders to ask them their opinion, and basically I think we recognize that the majority of these benefits come from unit commitment, company operation. Once we pull apart -- I mean, once we stop company operation and we have pool wide unit commitment and pool wide dispatch, this is where the benefits are really going to come from.

And the Day 1 results basically reflect traditional -- I'm sorry. I take that back. First of all, there's very high connectivity, interconnectivity between control areas in Florida. Almost every control area is connected to the next control area. So there aren't that many transactions that are wheeled through multiple systems. So the effect of pancaked transmission charges is minimal. That is one.

Contrast this with a scenario where you would maybe -- if you have pancaked transmission charges in a market like, say, PJM and you are moving power from, say, Chicago to New Jersey, which is one market, then you're likely to cross about six systems. In such a scenario then the impact of pancaking is very, very significant.

Regardless, we saw that there's an impact, and we think that the fact that there's so much connectivity right now in today's market makes us believe that we shouldn't be expecting a whole lot.

The other point also is that in terms of transaction size it didn't appear, at least those who were paying pancaked transmission rates in any form were dealing with very large transaction sizes. So, again, that also gave us some amount of comfort that what perhaps we were seeing was about right.

Then the last and final point was that most transmission service providers in Florida or most of the transmission service provided today in Florida is network service. Many of the market participants pay a network service. There are very few of them that pay point to point. Network service -- you know, and basically most of these utilities are paying the embedded costs of the transmission service through the network service. So, again, the fact that there aren't that many paying point to point underscores the fact that, I mean, our belief that perhaps our Day 1 quantitative benefits are reasonable.

But we didn't just, you know, take it at that and say, look, this is it. We decided, you know, on our own nickel, on our own cost to try to look at sensitivities around that. Because we, we are independent, we don't want to -- you know, we know the positions of some of the stakeholders, you know, who really want, we really think they want -- RTO is what, you know, Florida should be looking at. So we said, look, let's try and be fair to everybody. Let's try and see whether really these Day 1 benefits, there are any variables that we modeled that are very -- I mean, where the Day 1 benefits are sensitive to.

So on Slide Number 21 we started performing sensitivities to these commitment and dispatch hurdles. And what we did was -- what you see on this slide is that we told ourselves that, okay, the dispatch hurdles that I talked about, which is basically the transaction inefficiencies, what if we almost doubled these dispatch hurdles? And basically let me give you an example by what I mean.

In our original case, let's say there was a $5 hurdle between, say, Progress Energy and Florida Power & Light. Then in this case what we did was we added about $2 to $3 saying that, okay, what if we increased this; instead of $5 we increase it to $7? And the numbers that you see on this chart are actually in 2003 dollars. So if you look at in nominal terms, you should be adding $1. So we are talking about increasing it to $6 and $8, you know. We don't think it's that high, but, you know, we still performed the sensitivity. And we saw that the Day 1 benefits double. So if we are forecasting in the extreme scenario where these hurdles really exist as much as $8, then we are seeing that the Day 1 benefits, you know, if we just make the rough, simple approximation, the Day 1 benefits are going to increase from about $70 million to about $150 million. So we looked at that.

Then we also tried to see whether these Day 1 benefits are sensitive to the commitment hurdle. That's on Slide Number 22. And, again, the commitment hurdle was supposed to capture company operation and, recall, that company operation still exists in Day 1. And if we have a base case with company operation and the Day 1 case with company operation, then we don't think that the benefits are going to be that sensitive. And our results showed that there's a slight -- you know, this graph doesn't do a lot of justice to it. There's a slight, just a slight difference, order of magnitude of about, I believe, about $100,000 difference. But it was very, very minimal over a 13-year period. So it is largely unaffected basically by the company operation.

We also looked at the impact of the commitment hurdle, company operation on the Day 2 benefits. We, in our calibration, said that we needed a hurdle of about $20 per megawatt hour. But we said, what if we cut that in half? What impact would it have on the Day 2 benefits? The Day 2 benefits declined somewhat, as you can see in this chart, you know. On an annual basis it was declining from, in this case, 2007 from $113 million to $106 million.

So with that, we satisfied ourselves that we believe that the commitment hurdles and the dispatch hurdles that we derived were reasonable. But, again, we want to be the first also to say -- to show, you know, which factors that drive, you know, these benefits, you know. And if the -- or what factors are sensitive to these Day 1 benefits and Day 2 benefits.

So with that, that concludes basically our quantitative RTO benefits estimates and the work that we did there.

But benefits don't end only with quantitative aspect. We also looked at the qualitative RTO factors. And we enumerate on Slide Number 25 the various categories of qualitative benefits and costs. And what we did over here was to try to, you know, put them in various categories. Basically under Day 1 we wanted to capture which ones would be a cost and which ones would be benefits. And similarly in Day 2 we captured those ones that we believe will be a benefit and those that will be costs.

Investment efficiency we think largely, would largely be a benefit in both Day 1 and Day 2; probably a little more in Day 2 because in Day 2 you have prices. So prices reflect information and, therefore, with prices we think there'll be a little more benefit in investments.

Our modeling reflects short-term transactions. We usually don't capture long-term bilateral transactions, you know, on an economic basis. So in some sense we think that if we eliminate pancaked transmission transactions, it may enable market participants to enter into long-term bilateral transactions, which our models don't capture. So it's possible that there could be additional Day 1 benefits, for instance, if we have long-term bilateral transactions. But this is something we are treating qualitatively. And, again, it will also reflect the benefits in Day 2. So we captured that benefit under the Day 1 column and also in the Day 2 column.

The next is elimination of contract path scheduling. Some of this we captured in the quantitative analysis. But we also believe that there are some other factors associated with the fact that you have to, you know, schedule based on contract path today. And we captured that also as a benefit in Day 1 and also in Day 2.

Transition risks, we think there may be transition risks whether we go to a Day 1 or a Day 2, so we tried to capture, you know, the costs associated with transitioning the market to Day 1, you know, under the Day 1 column and also to

Day 2. We think it will be slightly more in Day 2 because you have markets and you have all the hedging that has to be, you know, done in markets. So we captured the -- we think it will be a slightly more cost in Day 2 than Day 1. Regardless, you know, in both cases we will still have costs.

Market transparency, we think it will be a benefit in Day 1 and also Day 2, but we think it will be more in Day 2 than in Day 1 because Day 2 will have prices.

Scope of the RTO, you know, organizational, regulatory issues, we think RTOs may have some, sometimes have additional functionality, you know, after they've been set up. That was the evidence that we saw during this exercise. And we think that there are potential, there could be potential costs associated with that in Day 1 and Day 2 if that one is not checked.

There are other factors also. Return on equity, whether it's going to be a cost or a benefit depends on, you know, the entity you're looking at. For transmission owners, ***, if you form an RTO, you've got to have it over ten (phonetic), so maybe it may be a benefit for a transmission owner, but from a ratepayer perspective it probably may not. So it's more of an unknown for us right now.

Inter-regional tariffs, market efficiency and standards, you know, introduction of merchant power plants, we think that all these three will be benefits in both Day 1 and

Day 2. So these are the qualitative benefits and costs that we have captured so far.

With that, we will move over to RTO costing exercise. And when we were asked to perform this study, we looked around at all the previous studies that have been performed and asked ourselves how did these -- were these studies performed on -- how did these studies look at RTO costing. And what we found is that a lot of it was a top-down approach, you know. Roughly, you know, some just looked at some of the existing RTOs, you know, start-up costs. Some used some, you know, energy-dollar-per-megawatt-hour estimates, you know. Some just took what transmission owners provided them that what we think is going to be this amount of money, you know, for, to set up an RTO. So there were all kinds of top-down approaches.

So what we thought would be beneficial to all stakeholders and to the industry was to try a bottom-up approach where we itemize costs. So, again, this was a case where we tried to work with stakeholders to, you know, go through the procedures, and this is exactly what we did.

On Slide Number 28, the very first thing we started with was what structure are we looking at? And you can tell from this that, on Slide Number 29 that -- and stick with this. I'm very familiar with this slide. The existing -- today's control areas, and there are about 11 of them in Florida, will become control zones working under the GridFlorida, the new

GridFlorida RTO. And we were asked to look at a greenfield RTO, a wholly new RTO with wholly new facilities, you know, and buildings, et cetera. So we showed stakeholders this chart that this is the structure that we're going to be modeling.

So after that, then came the next level: What will be the roles and responsibilities of this new RTO? What responsibilities will be taken up by the control zones and what will be taken up by the new body?

So with that, as you see on Slide Number 30, we worked with stakeholders and identify who does what. In fact, those days it was more like the title -- that was the title of the slide, "Who does what between GridFlorida RTO and the control zones?" And what you see here is when we show the letter X, as in x-ray, it meant that that entity had exclusive responsibility. And where we show the letters A and B, A had the primary responsibility, with B providing supporting functions. So we went through this, and you see from the next slide, you know, that we identify each of these functions and who would be doing what.

So from this the natural thing that we did was we took this information and stakeholder input on this and went on to the next step to identify personnel requirements, systems requirements and facility requirements for both Day 1 and Day 2.

So as you see on Slide Number 35, we identify the personnel requirements, the system's requirements for Day 1 operation, which -- and all this was, you know, discussed as far back as October 2004 at the fourth cost benefit work group meeting. So we identified these systems, then also personnel facilities.

And as you can see on Slide Number 37, we showed the physical facility requirements that we will need, you know, for Day 1 and for Day 2. So Day 1, we show the requirements for, the facility requirements for Day 1 and also for Day 2.

But one thing that we also did, which I haven't talked about, is the architecture. We created what we call -- what would be the architecture of this new body, you know. So if you look on Slide Number 34, you see all the various operational functions that will be performed by this new RTO body, which we call the architecture of the GridFlorida RTO operation. This was, again, identified and delineated by Day 1 and Day 2 functions.

So after working with this, on Slide Number 38 we identified the number of employees that will be required for Day 1 operation by function. And I'm not enough expert in drawing of structures, but we tried to put what we believed, you know, was a reasonable org structure, you know, multi-level (phonetic) organizational structure for the RTO for a Day 1 organization, and identified under each of these divisions the number of FTEs, full-time equivalents that may be needed. This was shared with stakeholders in October, and it was also provided to stakeholders in December when we released the preliminary cost estimates and we opened it up for comments. And comments were submitted to us in January where there was some cases, you know, some stakeholders said, we think we have, we probably have too many, you know, employees, you know, for this function, and it should be, you know, this much. Or in some cases they called us and they say, we think we have fewer employees for this function and we think it should be more. So on the next slide -- this is for Day 1. And on the next slide, which is Slide 39, you see the number of FTEs for Day 2.

So having done this and going through this process, we were now equipped to start putting unit costs to each of these: The systems, the personnel -- I mean, the systems, the personnel and the facility requirements.

And with that, I'll turn it over to my colleague Christian McCarthy, who basically did all the work in assigning numbers to each of the line items.

MR. McCARTHY: Thank you. Good morning. What we'll do here for the next probably ten slides or so is walk you through an estimate of, or a summary of the RTO, the proposed GridFlorida RTO start-up and operating costs as we estimated. If you also look -- later on if you want to look at the detail, in Exhibit 9 is the line-by-line, in your binders is the line-by-line cost estimate that backs up these numbers. So there's quite a bit of detail provided there.

What we -- the way we approach this section, as Kojo described, we had a long process leading up to actually beginning the line-by-line estimate of the GridFlorida cost. We determined that we would estimate the cost in five broad categories: Three start-up cost categories, so we have our Day 0 cost category, which is the kind of simplest and most straightforward cost category. That will be all of the costs expended to date on, for example, the ICF study and all the things leading up to GridFlorida -- leading up to this point or December, let's see, I believe December 31st of last year, and all of the costs that are expected to be expended over the next couple of years before leading up to the point where the final decision to move forward or not with the GridFlorida RTO is made. So those are our costs to Day 0. So the cost of when the commitment to proceed with the RTO is made.

The second category is going to be Day 1 start-up costs. These will be incremental to the Day 0 start-up costs as we treat them, and these will include all of the major system and employees' cost for getting the Day 1 market up and operating. And similarly, we have an incremental set of costs for Day 2, which will be all of the market structure, additional employees, additional office space, et cetera, that's required for operation of the much more complicated

Day 2 markets.

Similarly, in the operating costs, the two broad categories there are Day 1 operating costs, which we look at for a period, in the Day 1 case, a period of 16 years, I think. And in the Day 2 case we have a ten-year period of -- I'm sorry. We have a ten-year period of Day 2 operating costs.

So if you turn to Slide 41, this is the summary of start-up costs that we developed. Overall we looked at a total cost of $223 million in start-up costs in 2004 dollars. All of the estimates you'll see going forward here are in real 2004 dollars for simplicity. We looked at a total cost of $223 million in start-up costs to get to full Day 2 operation. The largest piece of that is the, getting the organization off the ground to Day 1 operations, $110 million. And we'll go through on the following slides a little bit what makes that up. $33 million of that is Day 0 costs, and then the remainder is the Day 2 start-up costs.

So if we turn to Slide 42, the pie chart here, like I said, this was the simple cost category, just two numbers making this up. The current costs incurred, the $19 million, that estimate was provided to us by the applicants and stakeholders, costs expended through the end of 2003; and then a simple estimate of $14.4 million to get us -- incremental costs to get us to Day 0 from that point.

On Slide 43 we have a kind of high-level breakdown of our Day 1 start-up cost estimates. The two largest pieces here obviously are going to be the gray bar or the gray pie, the salary and benefits costs for all of the employees to staff the RTO during the 18-month ramp up period, as well as the $33.4 million, the blue bar, which is our systems cost. That represents a new EMS system, office equipment, office set-up, et cetera. During -- again, this is just for start-up costs.

If we turn to the Day 2 start-up cost estimates on Slide 44, much heavier weighting here towards systems costs in our estimate. So we were able to work with, we were able to work with vendors as well as existing RTOs to estimate what are the costs of getting up and running day-ahead markets, real-time markets, FTR markets, which we've included in the cost estimate, as well as backup control centers and emergency recovery systems for all the markets. So we were able to work with representatives of PJM and the other ISOs to develop these.

COMMISSIONER EDGAR: Excuse me. May I? What is corporate inception, the orange?

MR. McCARTHY: The corporate inception, I'd have to look back at my notes to see the exact line items included in there, but those would include legal requirements for getting the company set up. I'm sorry. I can turn to my binder in just a minute. Initial recruiting.

So included under what we call corporate inception for the Day 1 start-up costs, we had a total of $16 million, I believe. Those would include executive staff and board recruiting, recruiting of non-executive staff, relocation expenses, external legal fees, consultant fees, travel and business expenses during inception, as well as audits during the inception phase. And for the Day 2 cost estimate, that would -- it looks like a very similar list, as well as system procurement, contract management for the, for the new systems. And I think -- and the detail there should be included on the second and third or third and fourth sheet in Exhibit 9.

COMMISSIONER EDGAR: Thank you.

MR. McCARTHY: So once we completed our estimate of the start-up costs, we wanted to turn to the available literature, and the next few slides will show some of the benchmarking work we did in order to understand whether, again, this was a reasonable estimate.

The first piece of literature we had that was very well timed with when we were just completing our study was the FERC staff report on RTO costs. And so if you look at Slide 45, we've got some bar charts here representing how we, how our cost estimates compare with those. I think the key sets -- a lot of information here. The key numbers to focus on are going to be the third set of bars, the total cost to Day 1, as well as the fifth set of bars. If we look at the total cost to Day 1, we have in orange our estimate for the GridFlorida start-up cost of about $144 million. And then the following two numbers are the estimates from the FERC staff report, which are $38 to $117 million. That's the low and the high end of the estimates presented there.

So the first thing we thought as we turned to look at this was to -- obviously we're slightly higher than the FERC estimates. We wanted to make sure that was reasonable and we understood the difference there.

There's three or four factors driving that. The first, obviously, is going to be the far left bar, the Day 0 cost where we -- since this has been a relatively long process and is not complete yet, our costs to Day 0 are slightly higher than estimated in FERC for the RTOs that they had studied.

Similarly, our costs to Day 1 are slightly higher. We are modeling, again, a greenfield RTO, which is slightly different than the survey, than those surveyed in the, the FERC staff report. We also do include some additional market functions in Day 1 that are not included in the FERC staff report.

So once we were able to examine those specific line items, we felt our estimate was reasonable. And, again, looking to the far right at the Day 2 cost estimates, this gave us further evidence that our estimates were reasonable and that our total cost estimates to Day 2 were within the range, if slightly on the high end, of the FERC staff report estimates.

CHAIRMAN BAEZ: Mr. McCarthy, quick question. You mentioned -- you were pointing to the second group of bars, the incremental costs to Day 1.

MR. McCARTHY: Yes.

CHAIRMAN BAEZ: And you mentioned something about a greenfield. Is that implying that the FERC staff report was not using a greenfield?

MR. McCARTHY: The FERC staff report looked at several different RTOs. It was SPP, PJM and, I'm sorry, the third was -- I'm not remembering off the top of my head -- and New England. Each of those had some history of central dispatch and central coordination; whereas, our greenfield RTO is looking at a whole new system and a whole new structure. So that would imply some additional costs.

CHAIRMAN BAEZ: Okay. Thank you.

MR. McCARTHY: So turning to Slide 46, we have our, again, a pie chart representing the Day 2, I'm sorry, the Day 1 operating costs by category. So we spent some time on our start-up costs. We were able to look at the available literature as well as talk with the stakeholders and applicants and determined that we -- we felt they were reasonable and within the expected range.

On the Day 1 operating costs chart here, again, we see the largest category is going to be salary and benefit costs of $31 million on an annual basis for a representative year, first year of operation here, excuse me, of $30.9 million for 194 new employees of the RTO.

The remaining categories, a significant cat is going to be the $5.5 million for systems operation, as well as capital and interest expenses on an annual basis for recapitalization of initial investment, as well as ongoing investment needs in the green bar.

And on Slide 47 we have a similar chart for our Day 2 operation. Again, any of the Day 2 numbers you see here are going to be incremental to Day 1. So we have incremental operating costs of $50 million for Day 2 that is on top of the $61 million we have for Day 1 estimate you saw in the preceding chart. Again, a large portion of the estimates here is representative of salary and benefits cost for the incremental employees needed, I believe it's 160 incremental employees under Day 2 operation, to bring our total to 354, as well as capital and interest expense. So we have to maintain and replace existing capital throughout the life of the RTO.

And so, again, once we completed these estimates and -- again, in Exhibit 9 there's a detailed line-by-line estimate for the full 13-year study horizon of each of these. Those are just summary numbers. Once we completed this, we again wanted to analyze and understand whether these cost estimates were reasonable.

I'll skip over Slide 48, which presents the kind of price stream, the long-term stream over time of expected costs in real and nominal dollars, and move right to Slide 49. Again, we wanted to understand whether our cost estimates were reasonable. And through talking with the, I believe it was the fifth cost benefit work group meeting and the fourth cost benefit work group meeting we determined to look specifically at ISO New England and the New York ISO for detailed comparisons and understanding whether our cost estimates were reasonable because those are similar sized RTOs, if a little bit smaller. The New York RTO is representing a single state, which is similar to the GridFlorida. We felt those were the best comparisons as opposed to the larger PJM and Midwest ISO or the problematic California ISO. We didn't want to bias our study there.

So the first thing we looked at was annual operating costs for the three RTOs. And what we have here in orange on the far left is the estimate for the GridFlorida RTO. This is under Day 2 operation. So it's our first year of Day 2 operation, 2007; a cost estimate of $85 million in operating costs. That compares very well with the 2004 and 2005 for ISO New England, which was slightly below that at $78 and $82 million. The New York ISO at $114 to $108 were slightly above, so we felt, again, there's more detail provided in some of the further presentation material, but on a category breakdown we felt that our estimates were reasonable. I would just note that on the footnotes here, these exclude the capital expenses, debt service and kind of one-time costs that might have been reflected in any of these estimates, and the sources are provided at the bottom here.

If we turn to Slide 50, this is the other kind of benchmarking process we undertook or benchmarking exercise we undertook during this process. As you saw on the preceding pie charts, the largest single cost item in all of the, both the start-up and the operating costs were going to be the salary and benefits cost for the employees, the 354 through Day 2. We wanted to look at the history of RTOs and examine the available literature to understand whether, whether that estimate was reasonable. So you've got quite a bit of information here on Slide 50. You'll see the Day 1 and Day 2 estimates for the GridFlorida presented in the dash lines, and they're well within the range of history of employees at the existing RTOs.

We did have quite a few comments on our employee count. That was one of the, actually one of the updates we made to our cost model coming out of the cost benefit work group meeting. The fifth one, I believe, was to reanalyze that and make sure we had a good, a good estimate. We did look at the New York ISO and ISO New England in specific. If you look on Slide 50, you'll notice about towards the middle the 2005 estimate for the New York ISO is slightly above our estimate for the GridFlorida, as is, just to the right there, the ISO New England 2005. Those being similar RTOs, we wanted to make sure we understood why there was a difference there and make sure we weren't overestimating the costs or underestimating the costs for operations.

And, again, we had to return then to our first step of the RTO cost estimate was to look at the roles and responsibilities of each of the organizations to make sure we were comparing apples to apples. Spent quite a bit of time, we were able to get access to representatives of both ISOs through the help of FERC representatives, and spent quite a bit of time detailing the differences between the two. And what we found was once we trued up the two organizations, we took out, for example, past employees dealing with capacity markets in the northeastern RTOs, which we're not modeling in the GridFlorida RTO, we looked at special situations in the northeast versus what we expect in GridFlorida, as well as line items that we assumed as kind of outsource costs for simplicity's sake in the modeling exercise versus items like market monitoring that are done internally in some of the northeastern RTOs. We found that our cost estimates, our employees estimates compared very well.

If you turn to Slide 53, our estimate of 354 Day 2 employees for the GridFlorida RTO is right in between the comparative New York and ISO New England adjusted numbers. And the two preceding slides give the detail on how we kind of adjusted those FTE counts in order to build that estimate. So we did spend quite a bit of time benchmarking, looking at existing RTOs, and through help of the FERC, FERC contacts dealing with the existing RTOs to understand the comparison and make sure our estimates are reasonable.

Slide 54 is the kind of bottom line of our cost estimate. We're looking at -- the blue portion of the bars are going to be the start-up costs that we saw on the first set of pie charts. The orange piece is the net present value of the operating costs over the study horizon. So in Day 1 that gets you from 2004 to 2016. Day 2, that's the ten-year period we modeled for Day 2. We look at a total of $775 million for Day 1, $470 million for Day 2, for a $1.25 billion estimate for total net present value start-up operating costs for that time horizon.

MR. ROSE: Okay. We're at the summary comments and the conclusions. Before I get directly into the numbers, I just wanted to give some perspective on what we've been talking about and what we found. First of all, although we did not look at all issues quantitatively, we certainly looked, I think, at the biggest issues.

Over the period of time that we're examining Florida should be paying approximately $100 to $130 billion for variable costs, these operational costs. We're looking at a lot of money, $100 to $130 billion roughly over the ten, 12-year period. And we looked at this with a fine-tooth comb, I would sort of say. And I think Kojo didn't do justice to the level of detail we did and, therefore, I don't think we even had a chance to acknowledge the openness of the industry here in Florida to our looking over their shoulders. When we talk about a 2003 calibration, we're saying we have almost perfect information ex post; let's see how well they did in terms of their operations. That was necessary in order to do these hurdles and then pull away the hurdles to see what would happen if you could do better over time and how much money you would save.

And just, just roughly to get a sense of it, the dollars you'll see are large. We've talked about numbers that are large. But the level of efficiency is sort of something on the order of 95 percent plus or maybe even higher, closer to 98 percent plus. So as you go around the country, I think there are examples in which maybe the industry's operations don't do as well as Florida does. In this sort of, you know, 0 to 100 percent category where maybe there are coal plants that should be operating that are not or merchant combined cycles that are not, we haven't found that level of inefficiency in this area.

I think that what we can say is, is that when you do these type of look over your shoulders where you have sort of perfect knowledge, you're never going to achieve perfection, but I think we did see that and we do believe that there is significant money still nonetheless, given the size of the dollars that we're talking about, and to achieve the full efficiencies, whether it's a net beneficial or not that's an issue that's separate. It's -- you do have this issue of whether 11 entities, without all the information that would be available, could achieve all of the benefits. And then I think the issue is weighed against sort of what are the costs of achieving that.

So I think that's just to give some perspective again of really what we did. And if nothing else came out of it, I think the Commissioners can feel reassured that while there's room for improvement, it's not like we've uncovered some major, massive gross inefficiencies by way of perspective.

So turning to the last slide, we bring together -- as you can see, the orange are the costs. So this is expressed in net present value, so we've discounted all the dollars that Chris was describing on the costs, and both of these for Day 1 and Day 2 are greenfield facilities. And as Chris indicated, some of the RTOs that have been created were not greenfield because they had legacy assets that were deployed.

And the Day 2 is more expensive, it's about $1.3 billion, than the Day 1, which is around $.8 billion, and this is sort of the costs that you have.

The benefits that we have for the, that we've estimated are on Day 2 around $1 billion and in Day 1 about $71 million. So it's pretty clear that there's a large discrepancy between the costs and the benefits on Day 1. And in Day 2 that discrepancy is less, but still the costs are larger than the benefits as we've estimated them.

This, of course, is the quantitative summation of our analysis. It doesn't address some of the qualitative issues, and there are obviously significant benefits. But the costs are significant for the greenfield. And I think as laid out, to the extent that we were looking at within the scope of these issues, I think we did a lot of very detailed work together with getting a lot of information with an industry that no one likes to have them, have themselves looked over the shoulder, but we found people to be very professional and very committed to the process.

So with that, we would strongly encourage questions because we actually, I think, beat our time limit by 17 minutes, and any questions will be answered as best we can.

CHAIRMAN BAEZ: Commissioners, questions?

COMMISSIONER DEASON: Mr. Chairman, I have just a few.

CHAIRMAN BAEZ: Okay. Commissioner Deason.

COMMISSIONER DEASON: I'm looking at Page 25 of the presentation wherein the slide describes qualitative benefits and costs. The second item there is bilateral long-term contracting. I believe you touched upon this in your presentation.

I guess the question that I have, first of all, since this is under the category of qualitative, there was no attempt to put any type of, of dollar value associated with this in the analysis; is that correct?

MR. OFORI-ATTA: Yes. That's correct.

COMMISSIONER DEASON: Okay. Well, how did -- so at the very bottom, at the very last slide where we have the comparison of the total benefits versus total cost, that doesn't reflect any of the qualitative benefits such as bilateral long-term contracting; correct?

MR. OFORI-ATTA: That's correct, sir.

COMMISSIONER DEASON: That would be the same for investment efficiency as well?

MR. OFORI-ATTA: That's correct. All the items on this slide are not reflected in that summary. That summary actually reflects only the quantitative benefits and costs.

MR. ROSE: You know --

COMMISSIONER DEASON: So this is something this Commission, we should consider, and the stakeholders should consider what value we give to these qualitative benefits and costs?

MR. ROSE: Yes. And I think, just by way of perspective, in many cases there's no accepted procedure and that -- as there was for the dispatch and the plant operations to figure out how you would have a base case with inefficiencies going forward, for example, in the case of investment efficiency, or how would you, how would you address the bilateral, so there was no quantitative way. So that does require the decision-makers to give consideration to sort of the qualitative issues, and we're not in any way minimizing the qualitative issues.

To give you a sense of some of them, for example, in the case of investment efficiency, on generation alone Florida probably would have to invest over this period of time something on the order of $10 to $15 billion, and, and each year is spending something on the order of $7 to $10 billion in variable costs. So, as I said, there was 100 to 120, so the investment would be maybe something on the order of 10 percent of the dollars being spent during that period of time. And the question is can you approve the efficiency of that? And I wanted to give you a flavor, if that's useful to you, as to some of the issues there. Given the magnitude of that investment, on the one hand you might, for example, on Day 2, as I indicated in my opening remarks, have something on the order of arguably 35 million prices a year, and that information might help you site your facilities better because you would know in each location what the prices are. And so you'd end up with 350 million prices over that period of time. So there's a lot of information that you would have that might not only improve operations but also sort of investment. The question is how much would it improve it? That gets into issues of how good is the price information? How good are the market monitors in dealing with, for example, market power issues and getting the right signals in place? And also how good is the process today? How do we judge the process today? And I think it's difficult to, to answer the question of prices versus administrative efficiency, and, and so those are the type of issues that there's no easy answer for.

But I did want to say that we did look at most of the costs that the industry is going to be incurring on the wholesale side, you know, a factor of 10 to 1. On bilateral long-term contracting the idea is theoretically if the basic market, spot or cash market against which everything is derived including bilateral long-term contracts is as efficient as possible, they'll be as efficient and they'll be encouraged through de-pancaking, et cetera. But how much would they be encouraged? So, again, there's no easy methodology that we could throw into place that would make your, your decisions easier.

CHAIRMAN BAEZ: Commissioner Deason, can I interrupt a moment and ask -- and you may have answered this question already, Mr. Rose. But assuming for the moment that the, I guess the qualitative benefits as identified, for instance, in bilateral contracting would work to offset whatever, whatever deficiencies between benefits and costs that you've identified as, as part of the study, assuming that for the moment, is there a way to appreciate the kind of scale of bilateral contracting that would have to take place in order, in order to begin offsetting those, those differences? Or is that not -- I mean, I appreciate that quantifying it is nearly impossible. But, but is there a way to bring it back to a notion of scale to say, you know, in order to overcome what looks like about $300 million difference between the benefits that have been quantified and the costs that have been quantified, you'd have to have a market, a scale of market for bilateral contracts of a certain size? I mean, is that a fair --

MR. ROSE: I think that I'm partial to numbers, so let me -- there's two parameters that you'd have to look at. One would be the size of the bilateral market and then the efficiency improvement you'd have in the bilateral market. So, for example, if we're talking roughly $7 to $10 billion a year of this related to the variable costs and the power plant operations, let's just say that 10 percent of it was traded bilaterally, you'd be at $70 to $100 million. Let's say you improve that by 50 percent -- I'm just pulling this totally out of the air in response to your question -- you'd be looking at

$35 to $50 million of benefit. The net present value of that would be about $350 to $500 million.

CHAIRMAN BAEZ: And is the, is the 10 percent bilateral number a fair, you know, like an industry standard or is there a percentage -- is that a standard percentage or across the country? What would you base that, that percentage on?

MR. ROSE: Well, you know, I think, I did sort of pull that a little out of thin air. You know, the issue is who's participating in the bilateral market. Who is there to participate? To have a thick market you have to have buy and sell side players. So, for example, if you had a market that was, had retail access and merchant power plants, then you might have an even larger number of bilaterals. On the other hand, the state does have a fairly rich bilateral tradition because we're represented here by munis, municipals and cooperatives. The 11 control areas, I guess eight of them are non-IOUs. So that is a significant area where there is significant bilateral contracting even without the merchant and the retail.

Given -- nonetheless, I don't know if 10 percent is the right number. Where I really have the real trouble is how much more efficient are we making them?

CHAIRMAN BAEZ: Well, and I, and I think I got that implication. If, if whatever goes on in Florida today is efficient at a very high percentage, then you get into the questions of, well, how much, how much is a couple of points of efficiency worth? And I, I got that from, from the presentation or at least a suggestion of that.

I guess I'm trying to, I'm trying to simplify it in my mind. This is all very, this is all very complex, and I think you made a good point of, a good attempt to drive that home. But if what we're boiled down to is trying to -- you know, Commissioner Deason alluded to there's, there's qualitative benefits that we should be considering. In my mind I would be trying to say, well, okay, I can accept the fact that you can't put a price tag on these because information isn't available, it's not reliable and so on. But you fall back into that logic of, well, if it were reliable and if it were available. How, how -- you know, is there a, is there a point at which the, the available market in Florida is too small to make up a number even on, even on, even on a qualitative basis, given everything you know of our market?

MR. ROSE: Right. Well, first of all, it is a fairly large market, but it's not as huge. It's sort of in the mid, middle range there. That is, we have these two huge markets, PJM and MISO, and then everything else is sort of small. I notice you guys have a lot of electoral votes as well as electricity, so you're not that small. And, you know, I -- you know, some of these issues are, really would require sort of knowing everything about the Florida process. And we're still -- we've learned a lot, but it gets into the issue of how well and how comfortable are you with the process right now?

You know, we give you some flavor of that. That is, you know, if you have all these prices, there's a lot of transparency, a lot of information. And it -- but on the other hand, you know, how good are the prices going to be given the concentration in the market? Well, the market monitor may be doing a great job. I'm not sure how to judge how well you feel you're doing.

I would add one other point in this regard. In our analysis we didn't find huge price differences within the regions within Florida. So we didn't find a huge difference in these locational prices, that $35 million I described in Miami versus Sarasota where my parents live or Ocala where they used to live. And, you know, and so it wasn't like there was a huge lack of transmission that we noticed from the, from that narrow perspective of locational marginal prices. Perhaps even maybe there's too much transmission that got billed related to everyone having to connect to each other because of the pancaking.

But these are anecdotes. And, again, I think to really answer the question of, for example, some of these qualitative issues, I think, is a question of how comfortable you are with the processes that are already in place. And, again, that was sort of beyond the scope of, of our analysis.

CHAIRMAN BAEZ: Thank you. Commissioner Deason, I'm sorry I interrupted.

COMMISSIONER DEASON: That's quite all right.

Still looking at Page 25, I would notice that the majority of these qualitative items are in the benefit category. Two are in the cost category: One being transition risks and the other being scope, organizational and regulatory issues.

First of all, could you describe what you mean by transition risk and the second cost category of scope, organizational and regulatory?

MR. OFORI-ATTA: Usually when you change a market structure there's a lot of education that has to go on, and especially when you are introducing the whole idea of risks, I mean, like congestion, hedging congestion. You know, there are experiences in the marketplace where some entities didn't fully, you know, grasp these new concepts and these new issues. You know, one can think of it like, you know, maybe stock market trading. You know, you need to understand some of these things. If you have a locational marginal pricing market where you have, like Judah was saying, multiple, you know, thousands of prices and hedging congestion, those kinds of things, there's some risks that, you know, those who have been used and inured (phonetic) with the traditional processes of, you know, operating may face as the market transitions.

COMMISSIONER DEASON: Are those risks that the participants, individual participants would face, or is this some risk that gets transferred to the end use customer?

MR. OFORI-ATTA: It is conceivable that, yes, the market participants will be facing this risk. But I'm not -- I don't know if my colleagues, you know, are familiar with that. I don't know whether some of these risks are passed on to consumers, you know, directly by any one of the entities in Florida.

MR. ROSE: You know, to the extent that there's municipals or co-ops, you might not have the ability to, if you will, tag the shareholders for problems that occur. They may just directly go through.

You know, I think that some of these risks are mitigated by the control zone structure. We have sort of two layers: You have GridFlorida and then you have the control zones. And some of the risks on the operational side are being mitigated by that level of added protection, and that's more of an operational risk. There are things like, geez, maybe people don't want to work in the new system and they retire and you lose some talented people. This FTR thing where people are having to function in a complicated system may make mistakes. That happens and it's, you know, it's difficult to quantify mistakes. We certainly put a fair amount of money in for education and trying to bring people up to speed, and certainly this process itself has been an education. But, you know, change is, you know, risky as well as having opportunities, and we just wanted to identify that, recognizing that we really can't quantify that.

MR. OFORI-ATTA: Looking at your next question, you know, scope, organizational, regulatory issues, what we found when we released the preliminary RTO cost estimate in December was that, you know, stakeholders, you know, some stakeholders say that, you know, our estimates were too conservative. So with the help of FERC, like Chris mentioned, we managed to get access to the New England and the New York ISO. And what we found was that, you know, there are significant, you know, organizational functions that were being considered there that we hadn't looked at, you know. Perhaps based on analytic, you know, modeling of the costs, some of those functions -- in our thinking at the time, we didn't think they were necessary. But, you know, after looking at these organizations, we saw that it's some amount of scope expansion for these organizations. And that was the reason why we, we put on this chart that should there be scope expansion for the new RTO, you know, then --

COMMISSIONER DEASON: Do you mean that the, that the RTO could not function with the way, effectively function with, for example, the number of full-time equivalents that you're projecting, and that there's a risk that perhaps more people are needed, there's going to be more cost to actually fulfill the requirements of the RTO? I'm trying to understand what you mean by scope and organizational, regulatory issues.

MR. OFORI-ATTA: Right. If you look at this chart in Slide Number 50, if you look at this chart -- let's take New York ISO. It became an ISO in November of 2000 and they started operations and it was functional. But with time they added more functionality to the ISO, and you can see with an increasing number of employees as time went on. And that is basically what I'm referring to in the qualitative section that should it be a case, I'm not saying this is going to be representative of every single RTO out there, but should there be a case where there aren't strong checks on these RTOs on the cost side, there's the tendency to add additional functionality. And that's what basically we were referring to under scope issues.

COMMISSIONER DEASON: Thank you. That raises two questions then.

MR. ROSE: If I could just add, in fairness on that issue. There's certainly this, this tendency. The other reason is but there's also a platform and you have some optionality that, geez, maybe you want to deal with one entity or you do want to increase the scope, that the Commissioners want to increase the scope. So I did want to say that even though we have it listed under costs, you know, it might be easier to deal with one entity. And then if you have certain issues that you want them to deal with, you have some sort of more centralized functionality. But I think the reason why we put it a little bit on the left side of the costs there on net is the growth in FTEs.

COMMISSIONER DEASON: Well, the, the New York ISO, as an example, and apparently there was an increase in FTEs, was that because of added functionality or lack of efficiency on the part of the organization as a whole or just growth in the market?

MR. McCARTHY: We did look -- maybe I can't speak to the New York ISO, but I'll speak to the PJM example because we looked at that one in detail. That was the most significant increase. There were a number of things driving that, both expansion of geographic scope in the recent term for PJM, as well as the addition of, addition and expansion of markets, the addition of FTR markets, the addition of FTR options trading and different functions that were being offered by the RTO and what's exactly driving those new functions. We didn't analyze whether those were functions being requested by participants or regulatory bodies or offered by the RTO. So it was similar in the New York ISO in the addition of markets in the near term, but I didn't look at the specific time series there.

COMMISSIONER DEASON: There was reference in answer to previous questions about the need for a check to be in place to, I guess to, to make sure there's just not unbridled increase in RTO budget without there being a need to do so. Whose responsibility is that? Is that the board of directors, is it the participants within the market, is it FERC, is it this Commission, is it the Governor, the Legislature? Whose responsibility is that?

MR. McCARTHY: I'm not, I'm not sure. I think there's a growing -- there's been a growing body of literature talking about the rising costs and the rising employee numbers at various RTOs, and we've heard comments at -- I don't remember the date, but there was a FERC presentation on that. So FERC is taking notice of the budget expansion and looking for accounting, uniform accounting practices across the RTOs. So I don't know where the ultimate responsibility lies, but over the past year and a half just as we've been doing the study of the issue there's been a lot of, lot of literature and a lot of comments on the issue. So it is rising.

COMMISSIONER DEASON: Well, within the internal structure, I mean, you did a lot of detail work on the number of full-time equivalents and had it all, you know, categorized by function. There is a board of directors; correct?

MR. McCARTHY:

responsible for controlling costs. You know, as far as making decisions on additional functions, you know, in our opinion we didn't really look at the expansion of functions over time because we didn't know how it would evolve. **We went through** the process of determining what, what we thought the starting functions would be. Then anything incremental to that would have to be, I guess would have to be self-funded. So if you wanted to add FTR trading, you would need a tariff on the FTRs in order to fund that. If you wanted to -- or I'm sorry. If you wanted a capacity market, that would have to be a self-funded capacity market within our view.

MR. ROSE: I mean, we do have someone here from FERC. I mean, it's a legal issue in my mind as to whose role is what. It's just beyond my pay grade on that one.

But, you know, we did point out that there was this FERC study on the cost. So it is an issue that we know it's on their radar screen. And I would also sort of say that the RTOs that we have here are in the context of these, these type of modes of operation are relatively new, and I think that it's a report issue that's still to be shaken out.

COMMISSIONER DEASON: Well, that's a good segue into the next question I have. **You mentioned it being above your** pay grade. I did a simple analysis, and maybe I'm oversimplifying it, but the incremental cost of employee costs for Day 1 is $30.9 million, 194 full-time equivalents. It works out to about $160,000 per employee. Now I know that that probably includes a lot of loadings. That's just not average salary. That's, you know, a lot of costs associated with, you know, personnel and other, you know, things that get added in that an entity has to pay just in straight salary. But that strikes me as quite high. I just -- what is your reading on that?

MR. McCARTHY: Yeah. I think looking at it that way, it does seem quite high. There's a number of things included in there. That would include, you know, starting off salary as well as benefits for all of the employees. Payroll taxes are included in that category as well. So I believe --

COMMISSIONER DEASON: What is the average salary then, excluding all the loadings? What is the average salary of those incremental employees, 194? Do you have any --

MR. McCARTHY: I would need to check. I believe it's in the $60,000 to $70,000 --

COMMISSIONER DEASON: That leaves a loading factor or a factor of two and a half?

MR. McCARTHY: I can -- I'd be happy to pull the details. Actually I can turn on my computer and pull the exact details. I don't remember off the top of my head. I believe it's a factor of 60, and then the -- maybe -- let's take a step back and tell you how we developed the estimate, and then I can pull out the actual numbers in detail.

We started off with Bureau of Labor statistics estimates for utility employees within the southeast. So we were able to pull those on average over, I believe it was the past 10 to 15 years and look at the trajectory over time, how they've been rising or falling in real dollars, and determine on, I believe it was six different cost categories, you know, starting with director down to management, electrical engineers and computer programmers were the four categories I can think of. I believe there were six all together. Administrative was the fifth, and there was one other in there.

So we were able to look at the federally projected or Federal Bureau of Labor statistics estimates for the southeast region. We then also used Bureau of Labor statistics to determine the loading factor on top of that. And I want to say it was a ratio of 64 percent salary to 30 percent benefits on top of that. So that increased the number from there.

Again, that was based on Bureau of Labor statistics. And I -- it may actually be included in here. I'll take a look. We did distribute that to some folks previously exactly how we got --

COMMISSIONER DEASON: With that loading then you're roughly talking about an average salary of something in the neighborhood of $120,000; is that correct?

MR. McCARTHY: Well, we then layered on top of that payroll taxes and a couple of other categories.

COMMISSIONER DEASON: So that loading factor did not include payroll taxes?

MR. McCARTHY: No. I'm sorry. I just don't have the exact detail.

COMMISSIONER DEASON: Okay. Well, that -- I mean, we can go to a different area of a question that I have then, and I guess it's kind of related.

You made reference to the fact that, when you were making comparisons between some FERC estimates on the total cost, that the GridFlorida was a greenfield; whereas, under some of the FERC estimates that there were some, there were some carryover costs and legacy costs that were going to be, I guess, were going to be used in some of these, some of their estimates. Did I understand -- is that correct? Did I understand that, or is that an incorrect assumption?

MR. McCARTHY: I think the, the key difference between the, the RTO study -- I think of PJM and SPV specifically that were studied in the FERC report versus the GridFlorida RTO. The key difference is the kind of history of working together and having central dispatch and central, at least central coordination and central dispatch in the case of PJM where the entities within those organizations were more used to working together and had systems in place to work together and to coordinate, coordinate internally, which are not necessarily present within GridFlorida or within the current Florida operations.

So, for example, there's not a control center currently within Florida that's linked to each of the generators that covers the entire state. I believe in PJM that had always existed.

COMMISSIONER DEASON: But there is coordination within peninsular Florida, is there not?

MR. McCARTHY: Oh, Certainly. Certainly. But the dispatch coordination is handled on a company level rather than a group-wide level.

COMMISSIONER DEASON: Okay. Well, then I guess that leads to the next question. If, if this entire dispatch function is going to be carried out by a third entity, are there savings within the utilities that your study does not capture? In other words, we don't want to be duplicating work. And if it is captured, where is it captured? And if it's not captured, why was it not captured?

MR. OFORI-ATTA: Actually that would take me back to, I think, Slide Number 3, one of the very first things we talked about.

Generally with these studies there are three main categories of costs and benefits. We've talked about investment efficiency, then operational efficiency. And I think that what you're referring to is the third item, the third bullet item, which is, you know, some savings or costs from utility operations. This wasn't part of our work, and it's something that I think Roberta asked, you know, along the line, you know, and stakeholders are supposed to provide that.

COMMISSIONER DEASON: So that's not part of your study, but it's something we will be, we will be getting information on it.

MR. OFORI-ATTA: Right.

COMMISSIONER DEASON: I see Roberta nodding her head. Very good.

And I guess the last question I have concerns the Day 0 costs, which I, for lack of a better term, I just refer to as sunk costs. Those are costs that have been incurred or will be incurred before there is to be an RTO. Were those costs figured into your slide on Page 56 as part of the cost structure or were they ignored for that cost comparison?

MR. McCARTHY: Yes, they were included in the costs there.

COMMISSIONER DEASON: But to the extent they're already sunk, I know that they're quite small in comparison to these numbers. I think we're in the neighborhood of $33 million of Day 0 costs. But if we're doing -- since those costs are -- well, if you or any of your economists -- I've always heard that sunk costs are sunk costs. And if you're making a decision on doing something going forward, you don't really calculate that into a cost benefit analysis. But I may be wrong. I'd like your feedback on that.

MR. McCARTHY: I guess I'll retroactively wish I had given the same introduction on the, on the five categories as I had previously that the main reason we broke up those costs specifically, and I mentioned this at the previous stakeholder meetings, the main reason we separated the Day 0, the Day 1, the Day 2 costs were for individuals to include or exclude them from the, from the total as they see fit.

So currently included in the total are those Day 0 costs, as well as some IDC and some incremental carrying costs on those going forward. And they can be easily included or excluded by the reader, and we'll definitely point that out in the final report, I think.

MR. ROSE: We're not trying to minimize the economic principles on costs. It's just a question of what's going to happen to them and just being, everyone being aware of what they are. And they're clearly separated and easy to pull out and don't necessarily change the results in a major way.

COMMISSIONER DEASON: Yeah. Okay. Thank you.

That's all I have, Mr. Chairman.

CHAIRMAN BAEZ: Thank you, Commissioner.

Commissioner Bradley, you had questions?

COMMISSIONER BRADLEY: Just one question. On Page, going back to Page 25, and maybe you all have already -- maybe I just missed this.

Under "Other Factors" you don't have anything inserted for ROE. Can you -- is that return on equity?

MR. OFORI-ATTA: The main reason why we don't have anything for ROE was it was -- at the time of putting together this slide and thinking about this problem, we recognized that from a transmission owner's perspective it's a benefit because you're getting a higher ROE. But then if you look at it from a ratepayer's perspective as the source of all the dollars, then it probably isn't -- it probably is a cost from a ratepayer's perspective. So in the interim we said, you know, it's more of an unknown. It's something that we intend to pick up with stakeholders.

If we are looking at this whole study from a consumer perspective, then probably it's a cost. But as of now we are unsure, so we have just, you know, tagged it as unknown.

MR. ROSE: There is the issue of whether or not by being in the RTO you get a higher ROE, and whether or not that somehow is increasing the amount of investment in transmission or other type of facilities and whether that is necessary. That is, is there an inefficiency at the current ROE? And that gets back to sort of this issue of investment efficiency, which is -- again, we don't really have a procedure to measure the extent to which you've got -- which the current system is inefficient.

Again, we did not do a detailed study of whether or not you have exactly the right transmission equipment for reliability. We just noticed there wasn't any large, huge decreases in the nodal prices that the model was generating within GridFlorida, which would, if there were -- that is, if, again, Miami was $100 a megawatt hour and Ocala was $20, then that would sort of be a clue, not the only clue, but a clue that there's something where you need more incentives on the efficiency. But, again, we didn't, we didn't notice that.

COMMISSIONER BRADLEY: One follow-up. As it relates to -- which regulatory agency do you envision as having regulatory authority over the ROE? Is that FERC or would that be a state commission? And I guess that -- my question -- I'm dealing strictly with GridFlorida. I know that you have two scenarios here. But --

MR. ROSE: I think what we're referring to here is to the extent to which the Federal Energy Regulatory Commission would be in charge of setting the rates or the costs that the GridFlorida would have and the return on capital.

Again, that's a legal issue which is, again, not our area of expertise as to, well, if FERC sets the rates but the Commission doesn't allow it to get past the ratepayers, what happens or, you know, what trumps the commerce (phonetic) clause or, you know, some other, other legal issue.

CHAIRMAN BAEZ: Commissioner Edgar.

COMMISSIONER EDGAR: I don't want to slow us down too much, but very, very briefly.

CHAIRMAN BAEZ: No, not at all.

COMMISSIONER EDGAR: If you could turn for me back to Slide 13 -- yeah, 13 and 14. And when you were going over that earlier in the presentation, you talked about which facilities there were basically no benefits and then more benefits. Could you go over that for me again briefly?

MR. OFORI-ATTA: Usually when you have modeled, you have performed your modeling and you derive your benefits, you want to try to take a look at which facilities are really providing these benefits. And there's a more detailed example shown to stakeholders, and this is just a simplified version that we want to share with you.

We, we would have been concerned if coal plants, for instance, were providing any of the benefits or nuclear units, you know, and we didn't see any of that. So that gives us some comfort that what we're doing is about right. And we usually expect that the mid merit and the peaking units will be the ones where we'll see displacement in their capacity factors.

So as you can tell from this table, this is just a simplified table with some units showing, for instance, if you look at this John R. Kelly unit on Slide Number 13, in the base case it dispatches at 67 percent, you know, but -- and also in the Day 1 case. But perhaps if we go to a Day 2, it's going to be displaced by more efficient units, and its capacity factor will be, you know, much lower. You know, so that in itself tells us that we are getting some efficiency gains. And I don't, I don't, I don't want to pick on just that unit, but, you know, we showed all other units also that were shifting in terms of -- were being displaced, you know, in a more efficient Day 2 market.

COMMISSIONER EDGAR: Okay. Thank you.

MR. OFORI-ATTA: And just for the record also, we provided stakeholders, and you have a copy in your, your binder, with the capacity factors of all these units for each single year modeled and for the base case Day 1 and the Day 2 cases.

MR. ROSE: And just again to -- we're so involved in the modeling, you know, that -- picking on John R. Kelly, when it goes down, someone else's capacity factor is going up whose heat rate might be a little bit better or whose pressure on the transmission grid in terms of creating congestion is less or whose loss factor, we talked a lot about loss -- well, it's a long peninsula and you get losses as you go, as you try to move the power. There's what they call thermal heating losses, et cetera, on the transmission grid.

So, again, the way to read this is that there's another table that shows someone else is going up. And then if we looked at each of the 2000 locations, each of -- almost 9,000 hours a year, we could go back and try to figure out what was involved in each one of those, those inefficiencies that we identified. And it's, again, it's, it's not one where we found highly efficient IPP merchant plants using advanced combined cycle technology at 10 percent capacity factor when they should have been at 50 percent. What you do see -- and we believe if we did the similar study, and we could never do that type of study in those areas, we would see that type of thing. Or, again, if we would look in areas and we might find coal plants that should be operated but people are not, those are the ones where you start going from, you know, 95 to 98 percent efficiency down to much lower economic efficiency.

And the modeling that we did, we talked about that last time we were here and we'd love to talk about that, is taking into account not only the cost of operating the facilities, the fuel, the thermal efficiency of converting the fuel to electricity, but also its effects on the transmission grid, which is why it takes -- we have 32 computers running for you just so that we can do one day. One year requires us -- and we did, what, 13 years. One year requires the machine to operate for four days continuously. If you make a mistake, it's very painful because then you have to go back in that cycle. And what it's cranking through is for each unit what its effect is on both the transmission in terms of how it competes with the other units making sure you get the most efficient, least cost, taking into account all those factors.

COMMISSIONER EDGAR: Okay. Thank you. And then if we could just for a moment go back to those pie charts on 46 and 47. I want to make sure I understand what I'm looking at.

Commissioner Deason talked about the already expended or the sunk costs. But for this Day 1 operating period, I realize we're talking about 2004 dollars, but the $61.9 million is an annual budget for the RTO; is that what's displayed here projected?

MR. McCARTHY: Yes. That would be for -- on Slide 46, the 61.9, that would be the annual budget for the first year of operation in our modeling framework. That was 2004. So it would be one year.

COMMISSIONER EDGAR: So does that include start-up costs that would not be then in the following year?

MR. McCARTHY: That includes -- it does not include the start-up costs. It does include interest expense on the start-up costs. So we do have -- we assume that that -- what the number is. But the previous pie chart of start-up costs, we assume that's capitalized over a five-year period. Included in the operating costs are going to be capital expenses for that. But other than that, the two are not directly related.

COMMISSIONER EDGAR: Okay. And then the chart on Page 47 or Slide 47 is just for the Day 2 operating period annual budget that would be added to. So for those Day 2 years, annually it would be a budget of approximately $111 million; is that correct?

MR. McCARTHY: Correct. And if you -- on Slide 48 kind of the two are combined with a few other categories, are combined Day 1 and Day 2. So the modeling framework we did was 2004 through 2016. The yellow -- the first three sets of bars on the bottom represent the Day 1. The next three on top of that represent the Day 2 and how they play out over time.

So this stream of numbers is what we then took a net present value of to get the big orange bars you saw at the end of the presentation, the $775 and $1,253 million, I think.

COMMISSIONER EDGAR: Okay. Thank you.

CHAIRMAN BAEZ: Commissioner Bradley, you had a question?

COMMISSIONER BRADLEY: Yes. And I don't know if this is outside of the scope of your study, but it's a concern that comes to my mind.

Can you somewhat discuss restoration and maintenance as a part of the operation, the cost of operating the RTO? And I'm thinking about restoration and maintenance as it relates to extraordinary weather events. Was that a consideration of your study?

MR. OFORI-ATTA: No, it's not. Yes and no. I'm sorry. No in the sense that we don't have an explicit line item for that. But yes because we allowed sufficient staff, you know, FTEs to account for those kinds of events.

MR. McCARTHY: As far as the RTO operation, we did include cost estimate -- included in the cost estimate would be sufficient budget to allow for a fully functional backup facility both in Day 1 and Day 2. So there would be an operating EMS system similar to what all, to what the utilities would do today. You would have an off-site online backup system available that can take over immediately upon any sort of weather event or power loss or whatever the event might be for Day 1. So that means the EMS system as well as any of the data that's needed in Day 1 for billing and for, for balancing, and in Day 2 for all of the market operations. So we would include that. And we would assume that that would be a separate enough location that hopefully it won't be affected by the same weather event, and that's able to come online immediately. Yes. Both facilities would be treated as hardened. So we did, we worked with FPL on looking at their -- I guess it's not that recent -- but their most recent facility addition and making sure that they were, we had facilities sufficient enough to withstand Florida-specific weather events.

MR. OFORI-ATTA: And we'll say that we didn't only work with FPL on that. We toured the facilities of Progress as well to try to see, you know, just in case there was something that was peculiar with FPL. We also wanted to make sure that we didn't just drive those peculiarities into the study.

But like Chris said, you know, we have a fully functional backup control center which will help with restoration. In terms of lines being down, we think that we have sufficient FTEs to take care of that.

MS. BASS: Commissioner Bradley, if I could add something to that. I think that if you were asking about the control facilities and who would restore and maintain those, that would be by GridFlorida. If you're talking about the physical transmission lines, those would continue to be restored and maintained by the utilities themselves. They're not turning physical ownership of their transmission facilities over to GridFlorida. They're only turning operational control over. I just wanted to make sure that, that you understood what the distinction was, and that any maintenance and restoration will continue to be done by the individual utilities that own the transmission lines. So poles and lines stay with the company.

COMMISSIONER BRADLEY: Thank you.

CHAIRMAN BAEZ: Commissioners, if there's no other questions, why don't we -- let's take a five-minute break and we'll be back with further presentations.

(Recess taken.)

CHAIRMAN BAEZ: Go back on the record.

Ladies and gentlemen, we had, we had said -- as you can tell by your agenda, this is a pretty ambitious moving along of the issues for the day. As, as you can also tell, the Commissioners had quite a few questions of ICF. And at the risk of suspecting that the same may be the case for a lot of the participants that are going to be making statements, I think it's pretty evident that we're not going to finish by the 2:00 that was set forth in the agenda. As a result, I think in order to allow us some time to be humans and what not, we are going to -- what I plan on doing is at least taking the first two presenters in this next segment, and we're going to go ahead and break for about 45 minutes so we can give the Eatz Cafe a little bit of business, if possible, and then continue with the presentations. So don't feel -- I hope this doesn't create any travel problems for those people that are here, but I just, I've got to deal with the reality that 2:00 is just not doable from the length of the presentations and the questions and the comments. So with that, I will get out of our own way.

Ms. Bass, do you have something else to add?

MS. BASS: No.

CHAIRMAN BAEZ: No? Okay. We can go ahead and take --

MR. ROSE: Excuse me, Commissioners.

CHAIRMAN BAEZ: Yes.

MR. ROSE: I just wanted to get back to the number that you had asked us for.

CHAIRMAN BAEZ: Oh, okay.

MR. ROSE: Most of the people hiring in Day 2 have a salary of $75,000. But when you take in the average, it works out to be like $89,000. There's not as many, if you will, administrative staff that are being added. They're there and available on Day 1. So you had said $150,000. When you take $89,000 times a multiple of around 1.6, you get close to $150,000 average.

CHAIRMAN BAEZ: Commissioner Deason, if you don't have a follow-up on that, we can go ahead and take FMPA. Or I guess there was a, there was an order change. So Mr. Miller is going to go first.

MR. MILLER: Yes.

CHAIRMAN BAEZ: Okay.

MR. MILLER: Thank you, good morning. My name is William Miller. I'm appearing on behalf of Seminole Electric Cooperative. Also appearing on behalf of Seminole will be Mr. Bob Davis of R. W. Beck, a firm that was retained by Seminole and by FMPA in connection with the ICF study. Mr. Davis will speak to certain technical issues regarding the ICF presentation. Following Mr. Davis will be Mr. Bob Williams on behalf of FMPA.

Seminole has been concerned since the inception of the ICF phase of this proceeding that a great deal of time and money would be spent in a largely applicant-driven exercise to prove that a GridFlorida RTO flunks a cost benefit test, a test that almost by definition cannot be passed without taking into account the very qualitative benefits that this Commission found in December 2001 warranted the formation of a GridFlorida RTO. Not surprisingly, our low expectations regarding the ICF study have been fulfilled.

Now Mr. Davis, on behalf of Seminole and FMPA, will discuss that there has not been enough information provided to date to make a reasonable assessment of the validity of the ICF results, and that those results that have been provided reveal important technical flaws in the ICF study, flaws which have the effect of greatly overstating costs and understating benefits.

My comments will address broader conceptual concerns in the ICF study which render it of little value in determining how best for this Commission to proceed. I should note at the outset that my remarks are not intended in any way to belittle the efforts of ICF, which has done what the applicants instructed it to do. So when I say that the ICF study is misguided or flawed, I am not being critical of ICF. Rather, I'm expressing long-held concerns with the marching orders that ICF received at the outset of this proceeding. And I'm reiterating the view expressed by Seminole in this very room when the ICF study was first announced by the applicants. Seminole observed then that by not being able to quantify the qualitative benefits that were determined by this Commission in December 2001 to warrant the formation of a GridFlorida RTO, that the study would be at best irrelevant and at worst misleading.

Now aside from the point just made regarding the failure to capture the qualitative benefits, the two main concerns that Seminole has regarding the ICF study are, first, that it did not study the correct cost structure of an RTO, and, second, that the base case or starting point from which the incremental benefits were computed did not reflect current reality with the consequence of minimizing estimated benefits of an RTO.

First, concerning the cost estimates for operating an RTO, ICF studied how much a greenfield Day 1 and Day 2 RTO would cost in Florida. Not surprisingly, the ICF study showed that the costs, though not substantial on a megawatt hour basis, would exceed the quantitative benefits. What ICF should have studied was how much a GridFlorida transmission provider performing certain fundamental transmission-related functions would cost and what the expected quantitative and qualitative benefits would be. I'm reluctant to call this paradigm a Day 1 RTO because Day 1 implies Day 2, which Seminole from the outset of this proceeding has maintained is undoable and unrealistic due to the market power concerns in the state of Florida.

Seminole believes that one of the many problems with the ICF study is that by assuming a Day 2 RTO is coming, it made erroneous assumptions regarding Day 1 and Day 2 needs and costs. The second concerning quantitative benefits, there are several main concerns.

ICF created a base case that was intended to mimic today's cost of utility operations. Unfortunately, the base case established by ICF does a poor job of reflecting actual utility operating costs, instead modeling utility operations that are much too efficient and economical vis-a-vis the real world. Because quantitative benefits were derived from modeled differences between this overly optimistic base case on the one hand and the modeled RTO markets on the other, very low benefits were computed by ICF. Benefits that Florida can obtain from greater transmission access and more efficient generation can only reasonably be estimated if the modeling of today's markets reflect significant inefficiencies, which in reality are present but in the ICF are absent.

Another important flaw on the benefits side of the equation in the ICF study relate to the arbitrary and artificial hurdle rates to make the ICF computer model function. Mr. Davis will address those in more detail in his presentation.

Returning to the cost side of the equation, what are the key functions that a GridFlorida transmission provider should perform? The answer is dictated by the need to have an independent transmission provider in Florida providing nondiscriminatory access to the transmission infrastructure so that all players, be they vertically integrated utilities like the applicants, be they independent generators like Calpine, Reliant and others, or be they TDUs like Seminole and FMPA, are able to compete in an active wholesale competitive market. To achieve this, a GridFlorida transmission provider should administer the OATT and the OASIS, it should conduct meaningful regional transmission planning, it should eliminate pancaking, it should do the ATC and TTC calculations and perform similar essential transmission-related functions. It should also have adequate stakeholder import on the board so that the board remains cost conscious and focused on what will benefit retail customers in Florida.

As a footnote, I would note that that is a change of position by Seminole, which heretofore has argued very strenuously for a completely independent board. But our experience in looking elsewhere in the country in terms of escalating costs has convinced us that having a board with more stakeholder input will be beneficial in Florida in terms of keeping track of what's happening in Florida, in terms of doing what's right for Floridians and in terms of more meaningful cost control.

Now what -- we've talked about what a good Florida transmission provider should do. What should it not do? What it should not do, in addition to windows, it should not do markets. Let me repeat, it should not do markets. **When I say** markets, what I mean is LNP and FTRs for congestion in day-ahead and real-time markets. Even if the experience with such Day 2 markets in other sections of the country were positive, and, needless to say, the jury at best is still out on that, such markets would not work in Florida given the insurmountable market power concerns in this state.

Wholesale customers and retail consumers in Florida will benefit greatly from a GridFlorida transmission provider that performs the basic functions just described and works in conjunction with the Florida Public Service Commission to ensure that there's adequate generation and transmission in the state and that costs are controlled. There's no doubt that to perform these functions, the GridFlorida transmission provider will require office space, but it will not require 97,000 square feet plus 25,000 square feet of redundant space for a Day 1 RTO, which is what ICF has programmed into its study. It will not need 194 full-time equivalent employees, which is what ICF has programmed into its Day 1 RTO. We think it can be done efficiently with a far, far smaller staff. And it will need systems, but it will not need $33 million of new systems, which has been programmed by ICF into its study.

We believe that the systems can be acquired economically by converting existing infrastructure and outsourcing where possible, called by some a brownfield approach. In short, we believe that when you move from the

GridFlorida Cadillac greenfield model presented by ICF to a more efficient Honda model that is limited to scope and inexpensive to run, the result will be one that greatly benefits Florida electric consumers.

I'd like to conclude my remarks by referring to certain findings by this Commission in its December 20, 2001, order in this proceeding. Quote, as a policy matter, excuse me, we support the formation of an RTO to facilitate the development of a competitive wholesale energy market in Florida. In the long-term the efficiencies and benefits identified through our evidentiary hearing should put downward pressure on transmission and wholesale generation rates and, in turn, on retail rates.

Later you said, based upon the evidence in the record, we find that the central benefit associated with each utility's participation in an RTO is the facilitation of an improved wholesale electricity market encouraging competition among wholesale generators by removing transmission access impediments and restrictions. Further, the record indicates that an RTO will potentially improve the current peninsular Florida transmission grid. The record indicates that additional operational efficiencies among utilities and the consolidation of planning and maintenance can be achieved by participation in GridFlorida. We believe that the efficiencies and benefits identified above will in the long-term put downward pressure on transmission and wholesale generation rates and, in turn, retail rates while maintaining or enhancing quality and reliability of service.

In stating your clear preference for an ISO, the Commission noted, quote, we believe a more cautious transitional approach is prudent for peninsular Florida at this time. An ISO would capture benefits associated with integrated transmission planning, operations and pricing.

The Commission also determined to stick with physical versus financial markets because of market power concerns finding as follows: The GridFlorida companies have not developed procedures to deal with localized market power on a real-time basis.

And, again, in your September 3, 2002, order you stated, the GridFlorida companies have not met the requirements of our December 20 order to demonstrate that localized market power has been adequately addressed.

In brief, Seminole believes that the Commission has already signalled its agreement with Seminole regarding the type of organization that is necessary and appropriate for Florida retail consumers to enjoy the benefits of an open access transmission system administered by GridFlorida ISO. We urge the Commission to move swiftly to put such an organization in place, keeping in mind that the ICF study fails to address, much less undermine, what this Commission found to be appropriate and in the public interest in December 2001.

Thank you very much. Mr. Davis is the next speaker, but I'm happy to field any questions of a nontechnical nature.

CHAIRMAN BAEZ: Commissioners, do you have any questions for Mr. Miller at this time?

Mr. Davis.

MR. DAVIS: Good morning, Mr. Chairman, Commissioners.

CHAIRMAN BAEZ: Good morning.

MR. DAVIS: My name is Robert Davis. I'm a Senior Director with R. W. Beck, Incorporated, an independent engineering consulting firm retained jointly by Florida Municipal Power Agency and Seminole Electric Co-op to provide a technical review of the ICF cost benefit study.

We would like to take this opportunity to provide the Commission an alternative interpretation of the results presented thus far and identify several issues that we strongly recommend that the Commission consider when forming your decisions.

Before I start, I would like to acknowledge that ICF has done a commendable job of managing a very large study endeavor, including interpretation of problematic data sources, difficult modeling requirements and managing diverse opinions and feedback from many sources. While I do have issues with several aspects of the study, the staff and representatives of

ICF have performed admirably during this study and deserve our respect.

That being said, first I would like to -- excuse me. There we go. That being said, first I would like to state that during our review of the study we have made several attempts to obtain information from ICF. However, even when our requests are specifically structured to protect against the release of confidential information, ICF has been extremely reluctant to provide any substantive detail. To date, ICF has provided, primarily provided stakeholders with only limited graphical based results similar to those that the Commission has seen today and general verbal and written discussions. Our decision to draw attention to this issue is not motivated by sour grapes. Quite the contrary. We are attempting to protect the interest of our clients and the Florida ratepayers, and through this process we hope to assist the Commission in making an informed decision. Any independent review of the ICF study, whether by us or by others, will require access to more information than has currently been provided.

It should be noted that ICF has provided some useful information and projections of modeled generating unit capacity factors and RTO development and operating costs, although not nearly in as much detail as we would have requested. We have used this data along with other general information to develop our findings presented here today. Based on our review, we believe the study results are flawed. We find that benefits are greatly understated and costs are overstated.

With regard to the quantitative benefits presented by ICF, we have uncovered a significant bias in the model and the reported results, which we will describe over the next three slides.

ICF has established a base case model that produces an overly efficient simulation of generation dispatch and operating costs. The base case, the case from which all incremental benefits are measured, produces model costs that are significantly less than actual operating utility operations. We have estimated the amount that the base case underpredicts operating costs to be greater than $2 billion over the study period. Because this model calibration error is many times larger than the benefits that ICF is reporting, the reported benefits are unrealistic.

Another way to demonstrate the poor calibration of the base case model is to compare model generating unit capacity factors to actual history. ICF performed this study for 2003. We looked at their projected results for 2004 compared to actual 2004 operations.

The chart in the Slide 4 demonstrates that there was a significant serial bias in the way that generating units are modeled. Contrary to the assertions made by ICF here today, the low cost generating units have been modeled to have much higher capacity factors than actual history indicates -- it's not coming through very clear, but these are the items in the top right-hand corner of the, of the graph -- while high cost units have been modeled at much lower capacity factors than actual history. The conclusion being that the simulation model produces a base case dispatch that is too efficient, which significantly understates RTO benefits. For clarification, if the model was perfectly calibrated, model capacity factors would lie along the vertical line on the chart -- diagonal line. Excuse me.

ICF presented the results of its calibration analysis at the October working group meeting. These results did show a relatively good calibration of the model to history for 2003. However, several changes were made to the model since the time the calibration was performed, such as modeling of additional generating units that were apparently missing from the calibration, changes in hurdle rates, changes in losses and wheeling, and changes in reliability-must-run units, to name a few.

ICF has stated that they did not recalibrate the model after making such changes, which has resulted in the calibration error seen in the preceding exhibits. I will note that ICF states that they have devoted significant effort to developing a well benchmarked commitment hurdle. If this is true, then significant increases in the dispatch hurdle rates will be required to benchmark the study.

On the subject of hurdle rates, it is important for the Commission to understand the significance of these assumptions. First, all quantitative benefits produced by the study are a direct result of the assumptions adopted for the commitment and dispatch hurdle rates, which incorporate pancaked wheeling charges. This issue is important enough to reiterate: All quantitative benefits reported by ICF are derived from the modeling of hurdle rates. Considering that the quantitative results of this study depend so heavily on the assumptions used for hurdle rates, it may be surprising for the Commission to learn that hurdle rates are an artificial modeling construct and no exact science exists for developing these assumptions. Hurdle rates have only one purpose: To introduce inefficiencies into a simulation model that otherwise would produce results that are too efficient. And as we can see from the preceding slides, the hurdle rates thus far adopted by ICF were insufficient.

If the Commission will bear with me for a moment longer, I'd like to expand the discussion of hurdle rates just a bit further. Hurdle rates are artificial and cannot be estimated or observed in actual utility practice. Instead, they are a function of the data and algorithms of the simulation model. As such, there is no such thing as a hurdle rate that is too big or too small. A hurdle rate is whatever it takes to cause the model, simulation model to produce the benchmarked results.

However, benchmarking is not an exact science and different analysts can profess similar accuracy, but produce different study results. Hurdle rates are subject to the bias of the analyst developing the assumptions. ICF in its response to stakeholder comments admits itself that calibration is not a perfect exercise.

Moreover, when more than one hurdle rate is modeled, as was done for this study, being the dispatch and commitment hurdles, there are an infinite number of possible solutions for setting the relative weight that each hurdle rate contributes to the analysis. This means that the apportioning of hurdle rates between dispatch and commitment values and the apportioning of different dispatching commitment hurdle rates across the GridFlorida network is arbitrary. And as such, Day 1 and Day 2 benefits cannot be reliably segregated. There is no way to accurately determine what benefits are attributable to a Day 1 market versus a Day 2 market. Perhaps all potential benefits should be assigned to Day 1.

Furthermore, Day 2 benefits were modeled for this study through the elimination of commitment hurdle rates, and, as such, benefits that can be derived from more efficient generation commitment are all assigned to Day 1 -- excuse me, Day 2. However, improved access to transmission rights under a

Day 1 RTO should allow utilities to better manage both short- and long-term firm transactions, which would result in more efficient unit commitment decisions. These benefits are not captured by the cost benefit model for the Day 1 analysis.

In their presentation today, ICF has stated that most benefits of the RTO would be derived from changes in operation of mid merit generating units. However, a review of statewide generation diversity suggests that significant economic opportunities exist throughout the entire supply stack and not just for mid merit units.

Moreover, ICF's assertion that benefits are primarily limited to changes in operation of mid merit units is further evidence that the model is poorly benchmarked. Since low-cost base loaded units have inaccurately been committed and dispatched at levels approaching their maximum available limits, few to no benefits remain to be extracted from these units. In actual practice, these low-cost units are not fully utilized, and potentially significant economic benefits can be extracted through more efficient operation.

Our review of the data and general results presented thus far indicates that several other crucial modeling assumptions may be missing or have been overly simplified in the model. While we recognize that simplifying assumptions are a necessary evil when developing a generation simulation model, our review indicates that many crucial assumptions may have been omitted from the model. We have asked for corroborating information from ICF regarding these issues, but our requests have largely been ignored.

As previously mentioned, we have reviewed estimates of RTO implementation and operating costs developed by ICF and the applicants. Our review indicates that these estimates have resulted in a significant overestimation of Day 1 costs. ICF was tasked by the applicants to develop cost based on a greenfield design, which does not leverage existing systems and facilities. Further, the facility, systems and employee counts developed by ICF and the applicants appear to represent a Day 1 configuration that assumes transition ultimately to a Day 2 market. Given these factors, we estimate the Day 1 costs could be at least 25 to 50 percent lower than the estimates presented by ICF.

Given our concerns regarding the model and cost estimates, we feel it is imperative to test the accuracy and sensitivity of the cost benefit study to changes and assumptions. As such, the stakeholders have requested that the applicants direct ICF to evaluate certain sensitivity cases. However, the applicants have generally refused to adopt the recommended sensitivity cases. These cases include the modeling of lower RTO costs through elimination of unnecessary systems, facilities and staffing; higher fuel prices to more accurately reflect recent and anticipated trends and to test the sensitivity of the model to fuel price assumptions; and recent changes in resource expansion plans for utilities in the southeast to understand how sensitive the model and results are to changes in resource plant.

So based on our findings, what can we conclude about the quantitative analysis performed thus far? The base case is too efficient, which has artificially lowered the modeled benefits. The calibration error implicit in the model is actually greater than the benefits being measured, which renders the results of the model unusable. Cost estimates for the Day 1 RTO are excessive and leveraging the existing systems was not considered.

If the study cannot be relied upon, on what can the Commission base its decisions today? As the Commission noted in its December 2001 order, the Florida consumers are likely to benefit from an RTO. Many of these benefits are difficult to quantify and can only be defined in qualitative terms. Qualitative benefits include an independent, consistent system to compute ATC, improved access to transmission information and services, elimination of pancaked charges, improvements in generation operation, improved system reliability and planning for transmission upgrades to reduce the costs of supplying power to all Florida consumers. All of these benefits can be obtained through the implementation of a Day 1 type market.

So what conclusions would we like the Commission to take away from this presentation? First, the quantitative study results presented to date do not provide information on which, on which the Commission can base any decisions. Second, when interpreting the study results, the Commission should cautiously consider that benefits are principally derived from two arbitrary modeling assumptions: Commitment and dispatch hurdles. And, third, that qualitative benefits are significant, and on their own are sufficient to support the implementation of a Day 1 RTO.

I end my presentation today with the following recommendations for the cost benefit study, should the Commission and the applicants decide to proceed with the study at this point.

ICF should remit all requested information to allow for a comprehensive investigation of the study by stakeholders and the Commission. ICF should work closely with the stakeholders to recalibrate the base case prior to finalizing the study or proceeding with any additional analysis. **And** ICF should work with the stakeholders to develop and model the recommended sensitivity cases. I would now be happy to entertain any questions from the Commission.

CHAIRMAN BAEZ: Commissioners, questions of Mr. Davis? No?

Mr. Davis, can you explain to me the recalibration error? You, you cite to about two, it looks like $2 billion.

MR. DAVIS: Correct.

CHAIRMAN BAEZ: Is that -- now where would you apply that -- I guess that has one, that has costs, some costs going up. And can you walk me through the effect that that has, if it were to be corrected?

MR. DAVIS: Sure. And what we were trying, what we were trying to do there, it's actually derivative of the information that's presented on the next slide, on Slide 4.

What we see here is effectively that base case or base loaded type resources are operating much too efficiently at much too high of a capacity factor, while -- and this is under the base case scenario -- while peaking type resources or high cost units are operating at too low of a level compared to actual history.

So what we're attempting to do here is say if these units had operated more as they had in actual history, what would be the difference in the results for the base case? And what we've identified is on an annual basis about $260 million, the cost would be increased in Florida if the model had captured this effect. So what we've done is capture that $260 million estimated over the entire ten-year study period to figure out implicitly in the model what the error is that's currently being modeled, and to also demonstrate in the previous slide how that calibration error compares to the actual benefits being computed, demonstrating that the calibration error is much larger than the benefits that are being calculated.

CHAIRMAN BAEZ: If, if -- and I thought I heard ICF say that they had used actual capacity factors.

MR. DAVIS: For 2003, that's correct.

CHAIRMAN BAEZ: Which is what, which is what would establish this, this calibration.

MR. DAVIS: That's what would have established their original calibration, correct, as reported by them in 2003.

CHAIRMAN BAEZ: So then where, where is it, where is it that the error occurs? If they're using, if they're using actual data, how do you -- if it is actual, in fact, how do you say, well, all of the sudden the base case is not realistic if actual data is being used?

MR. DAVIS: A couple of different things. Because the 2003 information had already been calibrated and it was only run for the calibration case, there was no actual rerunning of that calibration information once the model was finalized, we had to review 2004 for the purposes of our evaluation to investigate how well the model was being calibrated currently after many changes to the model.

What you'll see in Slide Number 5 is our estimation of what changes occurred to the model after the point in time that ICF finalized their calibration to the point in time that they actually ran the final base case. These are all changes that would affect the underlying goodness of fit (phonetic) or the calibration of the model, which, based upon information and statements made by ICF, have not been adjusted for or the model has not been recalibrated to take these into account.

CHAIRMAN BAEZ: Okay. Thank you.

MR. ROSE: Even though we're out of order, if at some point you could allow us to respond to this, we'd appreciate that.

CHAIRMAN BAEZ: You know, Mr. Rose, at the risk of -- I don't mean to shut you down, and that really isn't my intent, but I think in order to keep it moving -- and I mean no disrespect to either you or Mr. Davis. I want to try and keep the dueling consultants at a, at a minimum, keep the information flowing this way. And I hope, I hope you understand. We're trying to take everything into consideration, and I do appreciate your desire to defend it, to defend your, your process. But if we get, if we get into this back and forth, then it's going to become very unmanageable. And I'm already a bad enough manager as it is.

MR. ROSE: I understand that.

CHAIRMAN BAEZ: I'll let you, I'll let you have a minute to respond.

MR. ROSE: Okay. Okay. If you could just flip your looseleaf notebook to Exhibit 5, Page 68 and 69, where we show our calibration results, have an R squared of .99. That is

99 percent out of 100. I do think it's worth recognizing that our calibration is quite good.

MR. OFORI-ATTA: What is important to recognize is that consultants are very smart and sometimes the information they present can be misleading.

If you look at my colleague Bob Davis's presentation, he's looking at 2004, what we projected, versus 2004 actual in the market. What we calibrated, just to clarify, was 2003 actual is what we used. What he's comparing -- we all know what 2004 was like in Florida. We can count the number of hurricanes, we can count the number of unit outages. In our model maybe for the unit in actual 2004 -- we didn't calibrate to 2004. In 2004 if a unit was out -- and many units were out because of the hurricanes for a significant period of time. We ran a modeling that -- we were modeling a projected unit, you know, maybe modeling two weeks' outage for 2004. So I want to just make sure that everybody is understanding the information that has been presented by R. W. Beck on behalf of Seminole and FMPA.

CHAIRMAN BAEZ: Your point, your point being that the reason 2004 data wasn't used to, as, as part of the model or as part of correcting the model is because 2004 could have arguably fallen into an extraordinary year category.

MR. OFORI-ATTA: That's correct.

CHAIRMAN BAEZ: All right. And let me stop you right there. Otherwise, we're -- Mr. Davis, take what was said and --

MR. DAVIS: I would in general agree it was an extraordinary year. Unfortunately, that's the only data we really have to compare to for performing this evaluation. It's obvious that, based upon statements made by ICF that recalibration was never performed after many fundamental changes were made to the model. So we were left with a very, not only limited information, but also an improper year perhaps to evaluate.

But if you look at Slide Number 4, what I think you'll find is this isn't just a few units. This is a pervasive issue. Most base load units are operating --

CHAIRMAN BAEZ: Mr. Davis, let me stop you. You're pointing to a slide and now all of the sudden I have three presentations. So which slide, which slide are we talking about?

MR. DAVIS: It's Slide Number 4.

CHAIRMAN BAEZ: Your Slide Number 4. All right.

MR. DAVIS: My Slide Number 4. Yes.

CHAIRMAN BAEZ: Okay.

MR. DAVIS: This really isn't just a handful of units. It really is a pervasive condition. And it also indicates a very serial bias condition where base load units are operating in one fashion, high cost units are mid-level and peaking units are operating in another fashion.

So I would suggest that the argument that 2004 is an improper year, while it contains some merit, is not an explanatory statement for what we're seeing in the model.

CHAIRMAN BAEZ: Thank you. Commissioners, any other questions of Mr. Davis? All right.

Next -- I've lost my agenda. Ms. Bass, can you --

MS. BASS: Yes. Bob Williams will be speaking on behalf of FMPA.

CHAIRMAN BAEZ: Thank you.

MR. WILLIAMS: Good morning, Commissioners. I had already changed mine -- since you said we were going to do two people, I had changed mine to good afternoon. But -- well, it is good afternoon.

My name is Robert Williams, and I'm here representing FMPA and our positions on this. FMPA fully, is fully behind and agrees with the comments that Bud Miller made, and we support the concerns, of course, that our joint consultant, Bob Davis, has just completed.

We continue to think that Florida consumers would benefit from a basic RTO that independently performs RTO functions such as nondiscriminatory transmission access, elimination of pancaked rates and centralized planning and expansion.

As Mr. Miller noted, these, these are benefits this

Commission has already found to exist in the 2001 order and which were not quantified in the ICF study. As FMPA and Seminole noted in our July 14th follow-up comments to the June 30 workshop, it was reiterated.

The study results should come as no surprise given its design flaws, as Mr. Davis pointed out. Thus, the study results do not detract from the FPSC's finding that a basic RTO would yield significant benefits for Florida consumers and should not discourage the Commission from pressing forward on a course towards implementing a basic RTO.

If the FPSC were to proceed in this direction, it should clearly restrict the RTO by charter and express order pursuant to grid bill authority from getting into a Day 2 market function. Some in this room, of course, will disagree with that, but we would prefer not to have a Day 2. And the reason is the cost of a Day 2 market and the market power problems.

But as the agenda requested in this workshop, we have given thought to what measures, if any, this Commission should consider implementing in lieu of an RTO that would allow utilities to capture benefits resulting from a coordinated transmission system.

First, let's dispose of "if any." Given this Commission's past findings, doing nothing is not an option in our opinion. At a minimum, the Commission must push forward to accomplish the key objectives identified in its orders regardless of the organization form. And we're open to any organization form that we can work out.

As Mr. Miller highlighted, the Commission's December 2001 order found based on record evidence that Florida consumers would benefit in the form of improved wholesale competition and lowered transmission and generation rates from the numerous benefits of an RTO. A few -- not to try to duplicate what Mr. Miller said; some of it's duplication. Encouraging competition among wholesale generators by removing transmission access impediments and restrictions, potentially improve the current peninsular Florida transmission grid. The record indicates that additional operational efficiencies among utilities in the consolidation of planning and maintenance can be achieved by participation in GridFlorida. Eliminate pancaked rates, improve regional reliability and more efficient allocation of transmission capacity, improved emergency response, more efficient treatment of loop flows, and capturing the benefits associated with integrated transmission planning, operations and pricing.

Achieving these benefits without the basic RTO structure may be challenging, but we see avenues for capturing at least a significant portion of these benefits.

Integrated transmission planning. Build on the FRCC's newly adopted transmission planning process, develop a mechanism that comes closer to RTO planning protocols and has the teeth to ensure that upgrades will save Florida consumers money are made whether they are deemed reliability or economic upgrades.

The FRCC process is a coordinated planning process, not the single system planning process that was envisioned in the GridFlorida planning protocols and which the Commission found to be beneficial. For example, it is not clear that the FRCC process will evaluate the cost-effectiveness on a peninsula-wide basis of measures that would provide greater access to lower cost supplies in Georgia by expanding the Georgia ties or applying new technologies to existing ties.

Even if the planning process identifies that joint upgrade with shared costs is more efficient in terms of both dollars and impact than two separate ones, the FRCC process provides no mechanism to force that to occur.

The process is largely toothless with the possible exception of a situation where an upgrade is required to meet reliability purposes. But even PJM conceded in recent testimony, and PJM is one of the leading RTOs in the country, that the focus on reliability upgrades is leading to a minimalist grid, not the robust grid required to support competition that the federal policy as well as this Commission envisions. Thus, a mechanism needs to be in place that ensures that cost-effective upgrades get made even if they go beyond the bare minimum required to keep the lights on.

Along with that comes the responsibility of integrated transmission pricing. And to be effective, a more robust planning process should be accompanied by mechanisms to share the cost with broad benefits beyond the local transmission system in a fair and equitable manner.

GridFlorida had a region-wide cost allocation for all new upgrades. We can debate whether that is the right answer or whether the region-wide cost allocation is required for only upgrades that meet certain criteria or whether joint ownership or consortium ownership, another item suggested by PJM at the FERC technical conference, can be a useful tool.

However, a highly integrated system like Florida, it does not make sense to always place the full cost responsibility on the system where the upgrade is made, nor is participant funding the answer.

In the March 2004 pricing workshop applicants proposed to restrict participant funding to limited circumstances; that is, upgrades for generators wheeled out of Florida or without a contract to serve load in Florida. And there seemed to be general agreement that participant funding should not be applied in a more broad manner in the state.

Elimination of pancaked rates in an RTO structure is not a prerequisite for eliminating pancaked rates and the resulting barriers to competitive markets and impediments to efficient generation planning. Various concepts can be explored such as joint rates to reduce balkanization within our isolated peninsula.

In short, we believe the right answer remains in a basic RTO. But even if the Commission does not want to take that step, it should not close this docket. Instead, it should set a course toward achieving at least a substantial part of the benefits of a basic RTO through other measures. As a follow-up to this conference, participants should be asked to comment on the appropriate steps, and at a minimum the Commission should establish a collaborative process with a work plan and defined goals and time lines to see if we can make progress in reducing costs and enhancing reliability for all Florida ratepayers.

That's my comments. Thank you.

CHAIRMAN BAEZ: Questions, Commissioners? Commissioner Deason.

COMMISSIONER DEASON: I just don't know how to take your very last, your very last statement there. Are you receding from the fact that there should be an RTO, that there should just be a collaborative to try to discuss how to derive efficiencies outside of an RTO?

MR. WILLIAMS: We're open to the potential that if the Commission doesn't want to -- we would prefer a basic RTO. We agree with Seminole that a Day 1 type RTO is what we ought to do. But if we can't do that, we're open to trying to do the best we can to get as close as we can to that idea, get as many of the benefits of that element as we can.

COMMISSIONER DEASON: Okay.

CHAIRMAN BAEZ: Thank you.

MS. BASS: Okay. Our next speaker is with Calpine. Joe Regnery.

MR. REGNERY: Good morning, Commissioners. My name is Joe Regnery. I'm here representing Calpine and our associated affiliates. I have the pleasure of speaking on behalf of the stakeholder groups that are the independent generators, as well as the power marketers. I get to be blessed to speak on two stakeholder groups this morning.

To begin with, Calpine Corporation has participated in this RTO development since, since 2000, and we, we would like to discuss some general comments associated with the ICF study and the results that have come out. We, as Calpine, would be asking this Commission not to make a go or no-go decision on GridFlorida based on what we perceive to be an underdeveloped benefit assessment and an unnecessarily high cost structure modeled by ICF. Instead, we'd ask that the Commission seek more data from ICF in the form of a revised model and additional sensitivities that address the issues in our specific comments.

The specific comments I'd like to address are with regard to the benefit study process and results and then on to the cost study process and results. I'll start with the benefit study.

Specifically, we would like there to be a sensitivity around -- to be run without hurdle rates. And when I speak with hurdle rates, I speak specifically with certain hurdle rates, certain commitment hurdle rates for import capacity from Georgia. The rationale for that concept of hurdle rates is to, is to artificially create inefficiencies in the model as had been discussed so that the model can reflect behaviors that financial mathematical constructs of the model cannot capture. These unexplainable behaviors have historically gone away or been significantly reduced as transparency comes to the market, and the range of benefits should be reflected. And we'd like there to be sensitivities associated with hurdle rates to capture that. And, in particular, we speak to the hurdle rates associated with the commitment for import capacity from Georgia.

The next point associated with the, the RTO benefits side is the modeling of qualitative RTO benefits. Sensitivities regarding the beneficial impacts of qualitative benefits should be performed. The rationale would be all parties have expressed and acknowledged the qualitative benefits of the RTO. **People have expressed the inability** to in a way capture those in a quantitative manner. **However,** attempts to quantify these significant benefits -- and during the course of the stakeholder process we raised the idea of taking a probabilistic sensitivity approach to quantifying these, these qualitative benefits. Our requests were not, were not, were not responded to. And we would ask that given further that these qualitative benefits do average the lower cost of power on a cents per kWh basis, that ICF should be directed to reflect these benefits probabilistically in sensitivities that capture a fraction of a cent reductions in average cost of power.

We have taken the effort to try and analyze the capacity results and the impacts associated with the capacity results on the benefits side, and we have come to an initial conclusion, which we would like the, the experts to seek and to model would be the sensitivities associated with reducing on a fractional basis, on a cents per kilowatt hour basis the results.

We have found that by going -- by having an impact of simply reducing the cost of power on a cents per kWh basis by less than five-tenths of a cent, five-tenths of a cent on a kWh basis in our initial evaluation would show that it would bring the cost benefit analysis from a negative position from a cost benefit basis to a neutral position from a cost benefit basis. And so we'd like to see these sensitivities run.

The, the -- one of the significant impacts of that is, was a question that was asked this morning by Commissioner Deason, and it stems from the aspect of long-term forward contracts and biliteral contracts and the transparency associated with those being qualitatively reflected rather than quantitatively reflected.

Being that Florida is structured around the Power Plant Siting Act for the expansion of new generation, often all of the new generation that is added is added based upon bilateral contracts, particularly in the context of IPPs as we cannot build new generation unless we are doing it on a, on a long-term forward basis to facilitate the demonstration of need. And so to the extent there's transparency improvement associated with going to an RTO, we feel that a significant portion of the benefits will be reflected in the long-term forward contract market as that is one of -- that is, for us, the primary market within which we participate.

The next would be the modeling of announced coal projects. We feel that there has been a model step change in the way the ten-year site plans have aligned with respect to fuel diversity in this state, and the current ICF study does not reflect that. It reflects in its base case the 2003 numbers as the base and then the 2004 Ten-Year Site Plan's -- Ten-Year Site Plan announcements as the expansion plan.

But given that there have been a number of changes to that expansion plan in the 2005 Ten-Year Site Plans that incorporate the increase of solid fuel facilities, that there should be a revision to the model to reflect the announced number of solid fuel facilities.

Also we have recognized that there has been an elimination of a significant amount of coal by wire import under the UPS agreements that Florida Power & Light has as well as Progress Energy has, and these also are not reflected in the UPS study. They are continuing to reflect imports from the Miller Coal Unit that will not exist after 2010. And so we would ask that these, these adjustments be made to the base model to be more reflective of what everyone is currently planning as the, as the market structure.

The rationale for it again is that the announcements of solid fuel facilities, revisions to the UPS agreements, the support that this Commission has, has given to increase of solid fuel facilities in the state as well as on an import capacity and the major positive financial impact that such facilities have on variable energy. This model is testing variable energy. And when you change the fuel mix from what is a base load capacity product from an intermediate capacity product, you can see significant swings from our estimation associated with the benefits and costs.

The other -- one of the other aspects of the study that we would like to have reanalyzed from a sensitivity perspective as well as a model improvement perspective is that of the term of the analysis the benefits of the RTO are long-term. They stem with a generation expectancy as well as a transmission expansion expectancy; whereas, generation plants range in 30-year life cycles and transmission, transmission wires range in very similar life cycles or even greater. And yet we are looking at a test study period that only examines a period of 13 years.

Our rationale is that they should be extended. We should go out to a period that, that exceeds 20 years or longer to really analyze whether or not there should be a go or no-go decision associated with the cost benefits of a GridFlorida RTO.

We feel that in this scenario, if you go to a 20-year or longer life cycle or study period, the benefits would continue to accrue well beyond the study period and they would far outweigh the costs.

Our specific comments with respect to the cost side of the GridFlorida RTO center around the greenfield RTO nature. A sensitivity reflecting the benefits of a brownfield RTO would be more economically efficient. Our rationale is that a greenfield RTO is economically irresponsible given the significant infrastructure that is available and the lessons that have been learned by other RTOs.

We have, we have 11 control areas that are represented here today. Many of them are already operating the infrastructure EMS systems that we're talking about embedding in this greenfield RTO. Many of them have what would constitute redundant employees if we were to go forward with this RTO. We feel that there either has to be a net recognition of the reduction of systems and staff at the utility level on a cost benefit analysis basis for the full impact of the RTO to be captured, or that those same infrastructure and staff be utilized as a supportive role to the RTO so that we do not have to go to an oversized or overredundant RTO system.

ICF can meet the applicants and stakeholders to establish a more cost-effective structure using a brownfield RTO that capitalizes on existing infrastructure and personnel rather than duplicating them while still maintaining independence.

The next aspect that we feel has to be addressed in the overall model, if there is going to be revisions to the model, and any sensitivities that are done on the model reflect capital recovery. Capital recovery should reflect a ten-year capital recovery term, as suggested by the FERC representative. It currently is reflecting a five-year recovery term.

Capital recovery term has a significant impact on the model results and conclusions. Extending the term for capital recovery is a quick model input change that can provide useful information regarding the model results.

The FERC representative previously suggested this change at our, at our April 2005 stakeholder meeting, and we would support that analysis being done on a sensitivity basis.

The next aspect would be the recapitalization assumptions. We would ask that a sensitivity reflecting a reduced recapitalization amount be performed. Our rationale for that is that recapitalization amounts and associated interests appear to us to be excessive. Providing a sensitivity regarding the amount of recapitalized equipment would provide a useful information regarding the model results. We think that is something that should be looked at.

The next aspect of the, the cost associated was addressed by, again by Commissioner Deason in his early, in his questions earlier this morning, and that is the elimination of Day 0 costs. The model and any sensitivity should reflect the elimination of Day 0 costs. Rationale: These are sunk investigation and development costs. They exist whether or not the RTO goes forward and should not be included.

In summary, Calpine continues to strongly support GridFlorida as an RTO and recommends that the Commission not decide on the prudence of GridFlorida until ICF revises its model and runs the additional sensitivities that we have outlined in our specific comments. I would, I would like to once again reiterate that I do believe that ICF has done an extremely, extremely good job in trying to model what is a very complex system. I do believe that there are some fundamental flaws in the assumptions, and most of our comments here today go to sensitivities around the assumptions. Thank you.

CHAIRMAN BAEZ: Commissioners, questions of Mr. Regnery?

Mr. Regnery, you, you've also raised the idea of a brownfield alternative. And if I can steal something that -- I don't want to put words in Mr. Williams' mouth, but he, he spoke a lot about whatever the adequacy or the inadequacy of the FRCC process is right now. In your concept of a brownfield alternative, does -- how does -- how would the FRCC, whatever exists now or whatever could be changed, how would that figure into your, your, your concept of a brownfield alternative?

MR. REGNERY: I haven't given it much thought, to be perfectly honest. But I can, I can, I can try and give my off-of-the-cuff comments.

I am very impressed with what has transpired lately with Mr. Wiley and the FRCC and his efforts to establish the Transmission Planning Committee. I think that is a, that is a step improvement from where we once were. I do believe it has a long way to go. I believe they are adding permanent staff to support those efforts. But the focus of FRCC being a reliability focus and the focus of an RTO being an economic focus, they don't necessarily coincide; they overlap, but they don't necessarily coincide. So I believe from my perspective I would see the FRCC's role as a support role to the planning group at the, at the, at the GridFlorida RTO level, and I believe as far as efforts to consolidate the overall ten-year site plans and the transmission expansion plans that are being conducted at the FRCC level in an effort to make conclusions associated with reliability, that presents a great deal of positive input that goes into the RTO's planning efforts associated with planning it from an economic basis. Knowing the fundamental basis of the reliability needs only allows you to, to build an even better robust system from an economic basis. And so I think it's a, I think it is a parallel, but a very much supportive and needed role associated with FRCC. And, again, I am complimentary to the steps that have gone on to date and recently.

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

Thank you, Mr. Regnery.

MR. REGNERY: Thank you.

CHAIRMAN BAEZ: We are -- it's about 12:45, and I think now is probably a good time to break for lunch. We're going to do it for about 45 minutes and come back and reconvene at 1:30, where we'll continue our presentations. Thank you.

(Lunch recess.)

CHAIRMAN BAEZ: Go back on the record. And I see here where we left off with JEA.

MS. BASS: That's correct.

CHAIRMAN BAEZ: Mr. Para.

MR. PARA: Bud Para with JEA. JEA feels that ICF has made reasonable assumptions and has created a reasonable model for the GridFlorida cost benefit study. We've been working on the study for a year now, and ICF has been very open to our comments and our suggestions. They haven't taken all of our suggestions, but they've been very open to hearing them. We've had lots of meetings with ICF, and that's one of the reasons why it's taken us so long and why this study is going to cost us so much.

The stakeholders and applicants have made suggested changes to the assumptions in the model, and even where those are also reasonable, we don't think that they would change the result. The result being that GridFlorida's costs will exceed the benefits. And that's easy to see on ICF's last slide where it shows a ten-to-one cost over benefits ratio for Day 1 and a three-to-two cost over benefits ratio in Day 2. And on -- if you look at the graph, the line never starts coming up, back up towards zero. We're losing money as we go on through Day 2. If I read that graph, those graphs correctly, it looks to me like we would spend a total of about $2 billion in cost in order to gain about $1 billion in benefits. And the costs are much more certain and they're front-loaded than the benefits.

There was some discussion about the qualitative benefits and risks, and I would suggest that they're as likely to be, they're as likely to result in additional net cost as they are to result in additional net benefits. And one example I would give on that is on ICF's Slide Number 50 where they show the, for each of the RTOs, existing RTOs they showed their employee counts by year. And there you'll notice that for every RTO in every year the employee count goes up. None of them have flattened out. I think what we see there is that it's very difficult to control the cost of an RTO, and we don't know yet how much they're going to cost. The result, the costs are exceeding benefits and an RTO is just not right for Florida, at least not today.

JEA believes as we go forward that it would be worthwhile for the Commission to encourage the stakeholders, including the GridFlorida applicants, to get together to identify any significant problems with the provision of transmission service in Florida and to investigate alternative ideas to improve the transmission system.

For example, as has been mentioned already, the FRCC's transmission, coordinated transmission planning initiative, that is one example of how we can work together to improve the transmission in Florida without incurring the substantial cost of an RTO. And that ends my comments.

CHAIRMAN BAEZ: Questions of Mr. Para?

COMMISSIONER DEASON: I have a question. You made reference to, I believe it was Page 56 of the ICF presentation; is that correct?

MR. PARA: Reference to the last slide where they show the total costs and benefits.

COMMISSIONER DEASON: Yeah. I think you made the reference that if, that if you -- that you interpret that to mean that there's going to be some $2 billion in costs and about $1 billion in benefits for a two-to-one ratio. Is that -- did I understand you correctly?

MR. PARA: Yes, sir.

COMMISSIONER DEASON: Maybe we need clarification because I didn't understand it that way.

MR. PARA: Well, I could be wrong. I see a roughly $775 million in costs for Day 1 and a little over $1.2 billion for costs in Day 2.

COMMISSIONER DEASON: And I may be wrong, but the way I interpreted it was that the Day 2 costs included the Day 1 and they were cumulative and it was a net present value. So it wouldn't be a two-to-one ratio. It would be a ratio of whatever $1.25 billion is to $968 million, whatever that ratio is, but not two-to-one. Now I may be misinterpreting.

MR. PARA: I could be wrong. Could we ask --

MR. ROSE: The judges rule on behalf of Commissioner Deason.

COMMISSIONER DEASON: That's always wise.

(Laughter.)

MR. PARA: That is wise.

So the, so the total cost through -- I took those to be incremental costs and benefits.

MR. McCARTHY: No. The total cost for the 1.25 included Day 0, Day 1 and Day 2.

MR. PARA: I stand corrected. The benefits will recover right about two-thirds of the cost. Still a bad deal. Thank you.

CHAIRMAN BAEZ: Other questions for Mr. Para? Thank you, sir.

MS. BASS: Okay. Our next speaker is representing the Florida Municipal Group, Mr. Gary Brinkworth. And he's down here at the end of this table.

MR. BRINKWORTH: Mr. Chairman, members of the Commission, my name is Gary Brinkworth. I'm the Manager of Strategic Planning for the City of Tallahassee's electric utility. I'm appearing today on behalf of the Florida Municipal Group or FMG, an ad hoc advocacy group formed by Gainesville Regional Utilities, the Kissimmee Utility Authority, Lakeland Electric and the City of Tallahassee to better coordinate our participation in these GridFlorida proceedings.

In reviewing the results of the cost benefit analysis for GridFlorida, ICF appears to have studied what it was commissioned to study. There was no directive that it look at a brownfield RTO. The results of ICF's study speak for themselves, considering the significant gap between the costs and benefits contained in the study. The FMG is hard-pressed to see how GridFlorida could become cost-effective either in Day 1 or Day 2 mode. This result is not inconsistent with that reached in the SEARUC study in 2003. In that study, SEARUC's consultants determined that in the absence of a participant funding mandate, a regional RTO in the southeastern US would not be cost-effective.

Some of the stakeholders in this proceeding have suggested that ICF rerun the cost benefit study in such a manner as to ensure the costs of a Florida RTO come in below the projected benefits. The FMG does not support additional studies based on other assumptions that may or may not demonstrate there is value in formation of an RTO. Instead, we recommend that the Commission accept the results of the ICF study and close this docket, and then direct the applicants and stakeholders to undertake any evaluation of other actions that could be implemented short of formation of an RTO that would result in real cost savings for Florida's electric consumers.

There are, we believe, some structural alternatives to an RTO that may work for Florida. One possibility is the use of an independent coordinator of transmission or ICT. This concept is being explored at the FERC in an Entergy case, Docket Number EL05-52. Other public utilities have announced that they are considering a similar approach.

Another possibility for realizing competitive benefits in Florida would be the reactivation of something like the old Florida broker system, perhaps on a basis that permits bid-based power supply sharing subject to some kind of cap.

RTOs are intended in part to foster the development of competitive energy markets. The FMG believes there are a number of actions that would be required before Florida was truly a competitive market, only some of which could be addressed by the formation of an RTO in the state. Based on the results of the ICF study, it's questionable that an RTO would facilitate an energy market in Florida that offers cost savings to all electric customers. Instead of continuing the pursuit of GridFlorida, FMG believes participants should concentrate on pursuit of those changes in power supply markets and planning practices that could be implemented for the benefit of all our customers. And that concludes my remarks.

CHAIRMAN BAEZ: Thank you, Mr. Brinkworth. Commissioners, questions of Mr. Brinkworth? Thank you, sir.

MS. BASS: Our next presenter is representing the Florida Industrial Power Users Group, Mr. John McWhirter, and he's at the other end.

CHAIRMAN BAEZ: You know, I'm going to start feeling it. Somebody's got to pay.

(Laughter.)

CHAIRMAN BAEZ: Mr. McWhirter.

MR. McWHIRTER: I didn't hear that, Mr. Chairman.

CHAIRMAN BAEZ: No, I wasn't talking about you, Mr. McWhirter. The whiplash. The whiplash.

MR. McWHIRTER: I have specific instructions from my client to come here today and not offend anybody as I normally do, and I'm going to try very hard to do that. And it's not going to be very hard because I want to compliment this Commission and especially ICF for its hard work and all the other stakeholders that have put in time and energy on this project.

When the Commission first became interested in studying the RTO concept, it designated, I believe, 11 stakeholders. Nine of them were utility representatives and the other two were consumer representatives, the Public Counsel and FIPUG. And the theory -- the Public Counsel took the position early on that this was a FERC matter and not a Public Service Commission issue and kind of held back. FIPUG didn't have a significant budget, although we recognized that consumers in Florida are the trickle down beneficiaries, to use a Reaganism, of the RTO. And the concept of an independent system operation giving numerous suppliers that can provide more efficient generation to the market in a competitive market place is very appealing to my clients. And we followed, although not in great detail, we followed with interest the work of the stakeholders. And I want to compliment not only the work of the stakeholders but the work of this Commission over the years in what it's done in connection with the grid.

And somebody accused me early today of going to give you some history, and I guess I will. Essentially, as the last speaker pointed out, we had the Florida cap broker system. And the Florida broker system arose out of the concept that oil and gas had become extremely expensive. Florida had the good fortune of having some coal burning generation and some nuclear generation. And this Commission opined that if you could get the less expensive generating power from that source with the low cost fuel to the utility that had high cost fuel and displaced those generators with lower cost, there would be a benefit to consumers. And you set up the broker system and there was a sharing of revenue, and it was essentially a brownfield system that's not too dissimilar from the Day 1 operation that's proposed by the ICF study. And that worked extremely well.

Later congressional interests for the same reasons that came about to get the best utilization of generating facilities, Congress and FERC followed up with a concept to encourage independent suppliers, and so independent providers and wholesale marketers and QFs were encouraged. And, amazingly, those people came in and they provided power that had a heat rate of some 30 percent less than the existing generation. And there was a strong need to get that power into the system. But FERC recognized, Mr. Naeve will probably tell you more about this as he goes into his presentation, FERC recognized that that power was not getting to the end users. And so what it did in a series of orders culminating in Order Number 2000 concluded that they had to have open access and simultaneous information system. I think that's what that acronym means. Open access, meaning everybody could get on the power grid, and system information, which is the key thing that I'm going to talk about a little bit more later, people know what the cost of electricity is so they can have access to the cheapest power and let it flow. But it didn't flow as rapidly as it should have, and FERC came out with Order 2000, which directed that the utilities go forward with regional independent system operator programs, regional transmission organizations, and this Commission promptly followed suit.

You had concern though that when these new el cheapo power plants came online that we would have stranded investment of existing utilities. And as a result, you were very sensitive to the fact that Florida may have stranded investment, and you provided benefit number two to consumers. Without increasing base rates, you directed that the utilities accelerate the depreciation of some of their units that were likely candidates to fall by the wayside in the merchant market. And as a result of that has recently come to light in that we find that Florida Power & Light has depreciated its system $1.5 billion more than it says it really needed to, and Florida Progress, some $600 million more. So the rate bases of these utilities has gone down as a result of that secondary benefit you provided by providing a stranded investment quick write down. And we consumers applaud you for what that's done to the utility rate bases in Florida.

The third benefit arose when the original GridFlorida applicants determined that they would form GridFlorida and they would have the utilities convey all of their transmission assets to GridFlorida and take back an equity position in GridFlorida. This Commission studied that proposal, recognized that the rate regulation would move from Florida to Washington, DC, for the transmission aspects. You had concern about it, but you expressed your concern by saying, wait a minute. If the utilities have a utility plant and one-third of the value of their rate base is composed of the transmission system, maybe we ought to study base rates to see if when that transmission system goes away, if it goes away, there shouldn't be a reduction in base rates. So you required both Florida Power & Light and Florida Progress to file minimum filing requirements. We had a base rate case in both of those utilities, and the third benefit came about in that FP&L agreed to reduce its rates in 2002 by $350 million a year and Progress agreed to reduce its rates by $125 million a year. And that was certainly a benefit that was a direct outgrowth of the studies this Commission has given to the RTO program. So you provided to us major benefits for which I greatly applaud you at this point in time.

Now we have before us a situation in which the proposal appears on the surface to cost more than the benefits provided, and there are obviously more than one school of thought on this. Theoretically speaking, it makes sense to the trickle down consumer who will benefit if the RTO is successful that RTOs ought to go forward. And to that degree we agree with the merchants, we agree with Seminole, we agree with the Florida Municipal Authority, Power Authority to give those utilities access to the transmission system. We also agree with them that their bite -- we ought to send the group back to the drawing boards to see if it can't be done in a more economical manner. $1 billion is a pretty substantial cost and an ongoing cost of over $100 million a year to operate the system with no reduction in base rates and, in fact, a potential cost increase seems to be not really what would be in the consumers' best interests. So we think the idea to go back to the drawing boards to give it further study is, is very important.

There are some specific consumer concerns that I hope you will address as you address this further, and that is we still have in Florida, although the ICF study looks only at intermediate plants, the ones that can reduce the cost a little bit, there's some low cost fuel plants still out there. And there's no -- and the utilities have an obligation to serve their customers and that's to provide electricity, but they don't have an obligation to serve them from specific generating stations.

And a concern I have is that if you are a utility that has low cost power and if you sell that power in the wholesale market, and right now you have, the Commission has a provision that the staff has recommended knocking out on a couple of occasions, you have a provision that says if you sell the wholesale power, the utility selling the power can keep 20 percent of the gross proceeds of the sale. So that makes an incentive for the utilities with the low cost power to sell that power in the wholesale market and maybe even buy back more expensive power for the retail consumers. We think this is a potential grave danger that should be carefully examined.

One of the other things that gives me concern and hadn't really been fully brought to light is what I believe to be the essence of the OASIS program, and that is information, a bulletin board that shows what the current cost of electricity is every hour of the day for the spot market transactions.

The ICF study shows that there will be transparency, but we don't have enough detail on that. And I think in the study you should give directive to the stakeholders that you want to make it very clear that it's important to this Commission and to the consumers of the state of Florida that they know what power costs are and that those costs be published. And if the utility is electing to operate its own more expensive utility and then selling its power on the wholesale market because of the opportunity at the Commission, that should be strongly discouraged. But the only way you can know if that's happening, since many of these transactions happen by telephone calls and bilateral transactions, is to have an open and apparent and transparent idea of the costs.

Another thing is for independent power producers, if they know where the high-cost facilities are, it helps them in their location of power plants to put in less impact on the transmission system.

So I would suggest to you that those are safeguards that I haven't heard mentioned here today, but certainly something that this Commission should be interested in.

And, finally, it seems to me, my latest understanding is that there's 17 separate control areas for the utilities in the state of Florida. With the ISO or the RTO or the GridFlorida, as you might wish to call it, there's an opportunity to reduce that to one major system operator who can determine the least costly power available, and that should result in substantial savings to the utilities that can be shared with or retained by the utility for its own profitability, but hopefully shared with the customers.

In summary, I'd like to say to you on behalf of the trickle down beneficiaries of the RTO, we recommend that you send the stakeholders back to the drawing boards to come up with a more economical approach, and that you take steps to ensure that the interest of consumers are protected in some modest way. Thank you very much for your time and attention.

CHAIRMAN BAEZ: Questions of Mr. McWhirter? Thank you.

MS. BASS: Our next speaker is Mr. Mike Naeve on behalf of the GridFlorida applicants.

MR. NAEVE: Thank you. My name is Mike Naeve and I'm appearing on behalf of the three investor-owned utilities in peninsular Florida.

First, we would, on behalf of myself and on behalf of the, the investor-owned utilities, we'd like to thank ICF and express our appreciation for their contribution to this analysis. We've heard a number of people today speak about the analysis. I think every speaker so far has acknowledged the, the expertise and the quality of the work. People have taken exception to what ICF was asked to study, but nobody has taken exception to the intellectual integrity they brought to the study, to their industry expertise and knowledge and the quality of the work they did, and we feel the same way and appreciate very much what they've done.

The preliminary ICF results show, among the many results they show first that the markets in Florida today are pretty efficient compared to many markets in the United States. I think Judah Rose said they're somewhere in the 95 to 98 percent efficiency range. That still means though that there's 5 to 2 percent efficiencies out there potentially that can be achieved, savings that can be harvested or benefits that can be harvested for the customers in the state of Florida, and that represents a lot of money. When you talk about a market that's big, 5 to 2 percent can be a great deal of money. We probably could never get to 100 percent efficiency. I don't think anybody ever achieves 100 percent efficiency. But, nonetheless, there are significant savings that can be accomplished. And for some of these savings it may well be that the costs to achieve them are simply too great and we can't capture all of them. But, nonetheless, that still raises the issue, is there a way that, that, that the companies and the participants in this market in Florida can achieve some portion, perhaps some significant portion of the benefits that have been identified by ICF?

ICF has looked at one particular model for achieving those benefits, a phased model, a Day 1 and then a Day 2 model, and they found at least for that particular approach the costs at least are projected by them to exceed the benefits.

Other people have suggested alternative models, we've heard several alternative models today, and others have suggested that we go back to the drawing boards and see if we can't come up with some way to capture these benefits. The applicants in this case agree with that. **We think we should** look at this pool of benefits, we should go back to the drawing boards and see if there is some reasonable way, some cost-effective way to capture those benefits or at least the ones that can be captured in a cost-efficient way.

So our proposal is that we wait for ICF to complete its study, and then within two months after the completion of the ICF study the applicants take the study and evaluate it and see if they can't come up with a strawman for achieving as many of these benefits as can be achieved in an economically efficient way. Obviously, once we propose that strawman, I'm sure other parties in Florida will have alternative ideas and will want to express those ideas. But we would propose then, however, that between now and 60 days the Commission can decide what it wants to do in the way of additional proceedings, but that 60 days from the date of the ICF study we come back here and present to you an alternative approach for trying to capture some of these benefits. We certainly, in developing that alternative approach, will take into consideration what we've heard today from each of the parties that have presented their views, and we can't tell you today what we're going to come up with because we have to, have to conclude that. But that would be our proposal.

CHAIRMAN BAEZ: Commissioners, questions of Mr. Naeve? Commissioner Edgar.

COMMISSIONER EDGAR: You know, in some of the discussions earlier there have been recommendations or proposals referring to a brownfield structure as opposed to the greenfield. And I admit when I hear the term brownfield, I still think of environmental remediation and tax incentives. So I guess my question to you is when that term is used in this context, what does it mean to you?

MR. NAEVE: I think that term means, and certainly the proponents of a brownfield approach can correct me if I get this wrong, but I think that term means taking advantage of existing facilities, existing infrastructure to the maximum extent practical and seeing if there are ways that existing facilities can be implemented or utilized to achieve some of these benefits. I think we actually need to kind of step back and, and look at all the alternatives we've heard today and other approaches as well and see if we can make some judgments as to which of these categories are cost-effective and what benefits will come from each approach and are those benefits, do they, do the benefits outweigh the costs.

CHAIRMAN BAEZ: Mr. Naeve, and I'm sorry to interrupt, but just as a follow-up to that, you said, make use, what it means to use, to make use of existing infrastructure and existing facilities. Does that include existing structures or processes that are already at work?

MR. NAEVE: I think it would be both processes, but it would also -- it would be both existing processes, but also --

CHAIRMAN BAEZ: I guess I'm referring to, like, human infrastructure, if you will.

MR. NAEVE: Human as well as computer systems and software and so forth, control centers.

CHAIRMAN BAEZ: Okay. I'm sorry, Commissioner Edgar.

COMMISSIONER EDGAR: That's okay. Thank you.

CHAIRMAN BAEZ: Mr. Naeve, and perhaps -- I know that we have another, we have a representative from each of the companies that are signed up to speak.

MR. NAEVE: That's correct.

CHAIRMAN BAEZ: But as far as your understanding of the dynamic of creating an RTO, and obviously that's in question, or even, or even some, some alternative to that, as has been suggested and discussed, the, the idea of displacement, there was some reference to -- I think Mr. McWhirter said the magic words of "rate base" and so on. I guess the dynamic of establishing whatever we're going to call it, whatever we would call it and in whatever form it may take, involves, involves the migration or at least the, the actual applicants not performing some functions. And that would, may necessarily involve some reduction in their, in their own expenses, albeit a migration outward. Is that something that's contemplated to your knowledge?

MR. NAEVE: I hate to prejudge where the applicants will come out on this.

CHAIRMAN BAEZ: Sure.

MR. NAEVE: It could. I think we're going to step back and look at where are the savings that are achieved in the ICF study, where are the potential savings? And there seem to be several buckets there whether -- what ICF calls market inefficiencies, some of these are qualitative and some are quantitative. But that's, you know, better coordinated planning and better calculation, you know, independent calculation perhaps or better coordination of the calculation of ATC and TTC. There's de-pancaking is a potential source of benefits; it's also a potential source of cost shifting as well. But it's something that we need to look at. Improved unit commitment and then improved unit dispatch seem to be two areas where significant savings have been identified. So we're going to look at each of these buckets of potential savings and ask how can we achieve these and what's the most cost-efficient way to go after it.

CHAIRMAN BAEZ: And I, and I realize that. And that, that appropriately addresses the four corners or stays within the four corners of the study. And I guess what I'm reaching for or at least trying to confirm or not, that, that there is, that there is a, there is a corresponding reality outside the four corners of that study. I mean, ICF has done, I think, a yeoman's work in trying to make sense of all of this and really taking everything that certainly they thought was appropriate into account. And obviously there are those that differ with how much of, you know, how thorough it was or whatever, but I'm not really trying to get into that. There is some acknowledgment that that has a scope and that that scope does not necessarily intend -- extend to the ripple effect that it has on, on what stays behind as an IOU. Is that, is that fair to --

MR. NAEVE: Well, I think, at least what I've heard today is some disagreement as to how, how significant the, the savings are in each of these buckets. And I think we're going to hear more of that when the utilities speak, and also disagreement as to what costs are associated with achieving savings in these buckets and how, what's the best way to achieve the savings in the buckets.

I have not -- I think, at least if I listened carefully, I think most people would not disagree that these are the potential sources of savings, that they're going to come from one of these, these broad categories. So -- and how one goes about them, you know, will, will affect, you know, what the responsibilities of the, of the, of the utilities in the state end up being and what they would not be. But I actually, again, think that depends on what one decides is the most cost-effective way to go after these savings and which of these benefits can actually be achieved in a cost-effective way. Not all of them will be achievable, but I think many of them will be and we just need to figure out what's the right approach. And then we'll have to step back and say how does that affect the structure of the industry, how does that affect jurisdictional allocations, all of these kind of difficult issues.

CHAIRMAN BAEZ: Okay. Thank you. Commissioners, any other, any other questions? Thank you, Mr. Naeve.

MS. BASS: Next, Greg Ramon, Tampa Electric Company.

MR. RAMON: Good afternoon. ICF performed its work with diligence, professionalism and appropriate independence. And the ML (phonetic) is useful and the results are indicative, if not precisely accurate, of the costs and benefits that could be expected from the GridFlorida RTO. Tampa Electric believes that the costs calculated by ICF of the RTO are indicative of the level of costs to be expected should GridFlorida be brought to life as currently designed. The ICF work was comprehensive and the RTO capital and operating cost estimates are clearly compatible and in line with existing RTOs and ISOs.

Tampa Electric believes that the benefits calculated providing the basis for those concerns.

forward from this point to seek ways to secure the maximum amount of these benefits, while reducing the costs needed to secure them. These ways could entail any number of different incremental costs are huge. And we should at least look at a cost-based approach, what I call broker plus, resurrect the broker. But remember that those production savings in large part come about from unit commitment kind of savings. But we, we should at least look at a cost-based approach.

If we are earnest in our efforts, we will achieve these and possibly other wholesale market changes that will bring benefits to Florida customers. That concludes my remarks.

CHAIRMAN BAEZ: Thank you, Mr. Ramon. Commissioners, questions? Thank you, sir.

MS. BASS: Next for Florida Progress -- Progress Energy Florida, Nina McLauren.

MS. McLAUREN: Thank you. Progress appreciates the opportunity to speak on the ICF cost benefit study, and we agree with the comments that Mike Naeve made. We support the ICF cost benefit study and their conclusions, and appreciate their thorough and independent work on this effort.

Progress Energy believes that the findings of the ICF study are directionally correct. However, we believe that the Day 2 cost estimates are too low and the benefits are too high. We believe, in other words, that there is even a greater spread between the RTO costs for a Day 2 RTO and the benefits that would be derived from such a structure.

I'm going to give you a few examples of why I believe that and our company believes that, and then FPL will give some examples of why they believe that the benefits may be overstated.

First, Progress Energy had a large part in the development of the GridSouth RTO. So we believe that the cost estimates for a Day 1 RTO are accurate for what ICF came up with in their cost estimates for a Day 1 RTO. But, however, for the Day 2 RTO we believe ICF's cost estimates are too low for the following reasons, some of the following reasons.

First is that ICF developed their benchmarked, their RTO cost estimates using the ISO New England and also the New York ISO RTOs. And those are two of the lowest cost RTOs operating today. These RTOs developed from tight power pools, which is a very different starting point than the GridFlorida application would be. Also, GridFlorida is significantly larger than either of these other RTOs.

Other RTOs have experienced a significantly larger Day 2 start-up cost, as evidenced by the Midwest ISO, which had $250 million just in start-up costs for their Day 2 market.

Second, the RTO cost increases over time. We -- there was some discussion about that this morning when we just looked at the FTE count for some of these RTOs and how they have increased each year after they have been implemented.

Industry history indicates that there is an increase in RTO costs from 10 to 20 percent per year. This has not been reflected in the ICF study.

Third, we believe that the number of the FTEs reflected in the ICF study are too low for a Day 2 implementation. They estimate 354 FTEs, which is a lot of folks, but still significantly less than the RTOs that are operating today with Day 2 markets. The PJM, MISO, ERCOT RTOs all have over 600 FTEs, and, of course, that drives up the costs dramatically.

Fourth, we believe that the Day 2 development costs are understated because there was not very much consultant fees in that estimate. And to develop a Day 2 market, it requires specific expertise to put in such a market, as we again experienced in the GridSouth implementation. So those are a few aspects on the cost.

I would like to turn next to addressing the greenfield. We've heard a lot about a greenfield and an RTO -- and a brownfield. So I would like to just state why we believe that the greenfield implementation was a reasonable assumption for the ICF study.

RTOs have been built in the United States in three different manners. The first is that they have been an outgrowth of existing power pools such as PJM, New York ISO and ISO New England.

Second, they have been an outgrowth of reliability councils. ERCOT, SPP are examples of that.

Then, third, they have come from a greenfield such as the Midwest ISO, the California ISO and many other proposed RTOs such as GridSouth, SeTrans, WestConnect and RTO West. Florida does not have an existing power pool. Florida does not have separate computer and personnel infrastructure that is being used solely for reliability coordination. We can't use existing control center infrastructures to implement a GridFlorida RTO. Not to say that we couldn't look at other structures and other functions that we could maybe leverage some of the infrastructure, but for a complete FERC compliant RTO that especially does Day 2 markets we wouldn't be able to use those infrastructures. And why not? Because those existing control centers and systems were put in to do the work of our companies in supplying reliable and economic transmission and generation control. That's the primary function of why these systems are in place today. An RTO is a level above existing control centers. They provide some direction to these control centers but they do not replace the functionality that we currently perform today. The control centers and systems in Florida do not contain the infrastructure nor the staffing necessary to support a FERC compliant RTO.

Also, a greenfield implementation would help with a number of other aspects that FERC was, was trying to get after in an RTO formation such as independence. Again, if we want to look at other structures, we can look at other structures.

The Commission, you fellows and ladies, have asked us to take a look at different measures that we could consider in lieu of an RTO that could capture the benefits of further coordination of our transmission systems. I wanted to focus first on the number of things that are being done right today. There is a number of things that is being done right.

First, this Commission plays a key role in the power plant and transmission siting within Florida. This provides the appropriate regulatory oversight needed to ensure reliable and economic power is provided to our Florida customers. I think the best measure of our past and current successful coordination of transmission is the high degree of power system reliability that we experience here in Florida. And I think that we need to not lose sight of that.

Also, the FRCC currently provides a high degree of transmission coordination activities within our region. The FRCC supports numerous committees that foster the reliable economic operation of the FRCC region, they help us with our coordination of the available transfer capability, the ATCs. Also we have a Florida OASIS or the FLOASIS. We have reliability coordination that's currently being done. We have our traditional transmission planning process that is supported by the FRCC, and now this new, improved transmission planning process. Also, each of our organizations have marketing organizations that currently look at the purchasing, buying and selling of power for the most economic advantage to our customers. However, Progress Energy stands ready to look at different alternatives to derive even greater benefits to our customers. However, examining the options will take time. We need to be prepared to look at the scope adjustments as well as the cost reductions.

In summary, Progress Energy agrees with the findings of the ICF study that an RTO is not cost-effective for the state of Florida. The RTO costs are real. The RTO benefits are elusive. Recent RTO cost benefit concerns have been expressed by the following organizations: The PJM Industrial Consumer Coalition, ELCON and APPA.

The Florida electric customers currently enjoy an economic and reliable supply of electric energy. Any changes in the electric system must ensure that those benefits are not lost. Thank you.

CHAIRMAN BAEZ: Questions of Ms. McLauren? Is it Mr. Croes? They had to, they had to brief me on that before.

MR. CROES: Okay. Good afternoon, Commissioners. My name is Robert Croes, and I'm representing Florida Power & Light.

And I'd like to start off like many other people have by complimenting ICF on the study. It was a huge undertaking for which ICF is to be commended for carrying it out so professionally and, more importantly, so independently. Even we couldn't get everything we wanted from them.

Florida Power & Light also concurs with Progress Energy's comments with regard to the understated cost estimates. And while FPL supports the overall conclusion of the study findings thus far, we feel that the benefits provided in the Day 2 scenario are significantly overstated.

I will go through two examples hopefully that will illustrate why the Day 2 benefits are overstated. And you heard ICF mention this morning something about perfect execution of the model, and I intend to address that.

ICF has also acknowledged that the model has perfect information and operations, and in one of the sensitivity cases they're currently studying will attempt to quantify some of these real-world inefficiencies that will further reduce the level of benefits. And so with that, I'll get into my two examples.

First of all, as far as perfect information, the model has no demand uncertainty. The model predicts with tremendous accuracy what tomorrow's load is going to be, and it never overcommits, it never undercommits units. And we know especially in Florida whether or not it rains, whether or not a unit trips is very difficult to come up with the proper commitment on a day-ahead basis on a regular basis.

So this perfect commitment efficiency contributes to overstated benefits because these over and undercommitments add incremental dispatch costs compared to the perfect commitment case.

In the, in the base case you've heard ICF mention that the dispatch and commitment hurdles try to model the market inefficiencies. Well, over and undercommitment is one of these market efficiencies that they're trying to model. So when they did the calibration test -- and the calibration test is, is merely a guess and check. They guess at these dispatch rates and they run their production model and see how close they got to actual dispatch. And then after maybe 100 iterations they got what they were comfortable with on the hurdle rates for the dispatch and commitment. So part of the job of those hurdle rates is to identify these market efficiencies. And in the base case they modeled them with these hurdle rates. **They were a proxy for over and** undercommitment. However, in the Day 1 and Day 2 case when they removed the models, the hurdles, they went back down to zero, they effectively removed the inefficiency associated with over and undercommitment, which even in a perfect world, in all RTOs today you can never get that perfect because, you know, there's going to be rain clouds, there are going to be units that trip, and it's going to be very difficult to commit accurately on a daily basis.

So, in other words, the Model 2 -- the Day 2 model does not capture the costs and inefficiencies associated with over and undercommitment and, consequently, overstates the benefits. And this is part of their sensitivity study that ICF is performing in order to capture some of these real-world inefficiencies and the fact that the model is too perfect.

The second issue where I think the model overstates the benefits is the use of marginal cost bids. ICF could not and chose not to simulate each participant's bidding behavior. So the production cost bids were based on the marginal cost of production in the Day 2 market, which is reasonable. However, evidence from existing RTOs this year have pointed out that bids from units on the margin are actually marked up above marginal costs. And I have two examples to follow.

The California ISO as recently as May 4th, 2005, presented in a market presentation to FERC findings that short-term price markups existed on the order of 5 percent. So, in addition, in PJM's March 8th, 2004 state of the market report by its own market monitor states that the markup index lies somewhere between 3.4 percent and 12.3 percent. Furthermore, the report also states that during 2004 units using petroleum and natural gas, which are more likely to be on the margin, were actually marked up higher, an average 12.5 and 8.7 percent respectively. So the bottom line of all this is that the bid markets that exist in today's RTO and ISO competitive markets were not modeled by ICF. Therefore, the total production costs for Day 2 are understated, and this consequently overstates the benefits for Day 2. So this is just two, two examples.

These real-world behaviors and inefficiencies that were not modeled by ICF would have a negative impact on the benefits, which currently are not accounted for in ICF's results, as I stated. It is FPL's opinion that the $968 million of benefits stated in the final Day 2 estimates is a theoretical maximum and that the benefits resulting from the sensitivity cases that attempts to model these real-world inefficiencies would provide somewhat of a better indication of the type of benefits we can expect. And that concludes my remarks.

CHAIRMAN BAEZ: Commissioners, questions?

COMMISSIONER DEASON: Yeah, I have a question.

CHAIRMAN BAEZ: Go ahead, Commissioner Deason.

COMMISSIONER DEASON: You said it was PJM where the study was done concerning the markups; is that correct?

MR. CROES: Yes. It was actually done in both PJM and California ISO.

COMMISSIONER DEASON: Okay. And theoretically in a perfectly efficient market there would be no markups? Is that, is that what --

MR. CROES: I assume it's an economist's dream that bids will all be bid at marginal costs.

COMMISSIONER DEASON: And why were -- was -- in those markets was there a, generally an excess of demand over supply? Was that the reason? Or what -- did they say what the reason was? I know it's not because people just wanted to make more money; right?

MR. CROES: Well, it's a competitive market and I'm sure they're free to bid what they think the market will clear at, and I suspect that's all it is.

COMMISSIONER DEASON: Would an economist say that if, if in the short-term you have excessive markups and it's not an efficient market, that there would be entrants into that market such to the point that it would drive prices down to marginal costs?

MR. CROES: I don't disagree with that. All I'm reporting on is the findings that they found from the market monitor in 2004 was not the case in '04. It may come down in '05. I don't know.

COMMISSIONER DEASON: Okay.

CHAIRMAN BAEZ: I have a question or maybe it's a clarification. I wanted, I wanted to let Mr. Croes make his comments so that I could kind of pose a question to both of you or, frankly, to any of the applicants or all of them.

But something Ms. McLauren said struck a chord with me, and perhaps I'm hearing wrong. Okay? But if, if the general message of the applicants based on ICF's study is that, is that the GridFlorida RTO or a GridFlorida RTO is not cost-effective, the logic following from that was that it should not be pursued, at least that's a suggestion, and yet there's some receptiveness to exploring other ways of capturing savings or benefits that may be out there.

But Ms. McLauren raised, raised something or it seemed, it seemed almost a warning: The issue of FERC compliance. And I guess I'm, I'm trying to get straight in my mind what -- and, and we, you know, reasonable people are going to disagree, and I'm assuming FERC will disagree even itself, and we'll get a chance to hear from a representative from FERC in a minute, as to what compliance is. There may be differing, differing opinions of what that is.

But if that's a goal, can any compliance with FERC at this point, based on what you're, based on what we're seeing, is any compliance with FERC cost-ineffective? I mean, is that --

MR. NAEVE: I think the answer may well depend on what is required by FERC. Certainly what ICF studied was a full, full-blown RTO with standard market design. And the ICF numbers at least suggest that that model is not cost-effective in Florida. I think the position, it would be useful to hear from the FERC representative on this issue, but I think the position that the Commission has taken is that, that RTOs of that type are not the only model that they would accept, and that they have become somewhat more flexible in recent years and are willing to explore alternative models, particularly if a full-blown model is not cost-effective at a particular region.

We've had discussion or mention today of an Entergy model that was approved by the Commission in an initial order pending rehearing, but that's something that is less than a full RTO. The Southwest Power Pool RTO doesn't contain all of the features that an RTO with standard market design would contain.

I believe FERC has taken the position that, first, that this is not mandatory, that it is voluntary, that they would like to see movement in all the regions, that in each case it's probably dependent on the structure in the market in each region and what is achievable and what benefits can be achieved. But I guess I'll leave it to kind of the FERC representative to speak to what is necessary.

But to the extent that it is, in fact, voluntary, then I think in some ways it's just what is best for the region.

CHAIRMAN BAEZ: Well, and that's really what I wanted to get straight in my mind or at least confirm my understanding of it is that we're not really, is the last thing, and this is just me talking, but the last thing I want to do is see the

Florida Commission be placed in a Catch-22. You know, to have a desire to do something in the best interest of ratepayers, in the best interest of Florida long-term, and yet it have, yet it not be enough.

And, and, Mr. Naeve, I hear you saying that that may well be in play, and I suppose we'll hear, we'll hear from FERC shortly and --

MR. NAEVE: I don't presuppose to speak for FERC and what they will find acceptable or nonacceptable.

CHAIRMAN BAEZ: It's merely your opinion. And I'm sure if someone --

MR. NAEVE: Yeah. My opinion is they've shown considerable flexibility in, in recent months. And I, I think they do take into consideration the unique features of each market and the extent to which there are institutions in place in each market to implement certain changes and the cost effect in some markets compared to others. But, again, I think they can speak for themselves on this issue.

CHAIRMAN BAEZ: Very well. Any other comments or questions, Commissioners? Mr. Croes?

MR. CROES: I have one more comment. ICF has requested just two minutes for rebuttal if you can somehow squeeze that in.

CHAIRMAN BAEZ: Yeah. I think we've got enough time to do that now. And, Mr. Rose, I apologize for earlier trying to tamp down y'all's input beyond your presentation. But if you've got something to add at this point, go right ahead.

MR. ROSE: Thank you very much. Appreciate all the kind comments. And I've participated in a lot of proceedings and haven't actually seen a lot of unanimity, so I don't want to overemphasize some of the negative features, but there were just a few comments that were made related to our calibration and particularly related to 2004. And I believe that if we calibrated 2003, I referred you to where we were 99 percent accurate in our calibration. And if we had the opportunity to calibrate 2004 and do the study from that basis going forward, I don't believe our results would be significantly different. It would show, again, a very high degree of calibration and a degree of robustness in our study.

There was a talk, some talk about -- I'm referring to the comments of R. W. Beck -- that our choice of the hurdles was arbitrary or needed more work. Every study of this type has used the same methodology that we have used in terms of the hurdles. And I believe, as we demonstrated in the document, that regardless of how you chose the hurdles, we would still end up with a situation in which the benefits are not changing very much. We don't consider a change from $116 to $106 million a major change in benefits.

There have been requests of us to provide additional data. I think everyone has overall said we've been working well with them, and my hat is off particularly to my colleague Kojo Ofori-Atta. And so overall we've had positive comments. But I did want to mention that we are, we are constrained by the obligations of the confidentiality not to reveal confidential information, and so, so there are some limits that are there.

I would say that we have identified substantial potential benefits on the order of a billion dollars, and we do feel that our overall results on the benefits side, to the extent that we're within the scope and looking at the issues that we had there, we think are robust results and we stand by them. And if you want to add to that.

CHAIRMAN BAEZ: Thank you, sir.

MS. BASS: Our next speaker is from FERC, Bob Machuga.

MR. MACHUGA: Good afternoon. I'm Bob Machuga from the Federal Energy Regulatory Commission. I'm here speaking directly on behalf of Pat Wood, the Chairman of the Commission, to convey his views.

Given the lateness in the day and the need for people to catch planes, including myself, I am going to limit my remarks to some general comments since several of the stakeholders have already commented on many of the issues in greater detail.

Pat Wood would like to see the GridFlorida process move forward. He believes there are significant benefits to be realized by the RTO. However, he believes that the costs in the ICF study are much too high and that they need to be reduced. In his view, the study seems to inappropriately front in the cost and conversely back in the benefits. He'd like to see some of those start-up costs amortized over a period of, say, 10 to 15 years instead of five years, and maybe extrapolate the benefits to 15 or 20 years when they're more likely to be realized.

Like some of the other parties, Pat believes that the GridFlorida, you know, that the utilities, GridFlorida utilities should, you know, look for creative ways to leverage the existing infrastructure such as facilities, systems and even, and I guess even to the extent of its first short (phonetic) transitional period.

The ICF greenfield study doesn't reflect the net cost savings associated with a lot of these duplicative facilities and personnel. You know, there are, I think it's like EMS system, OASIS -- you know, we've heard about high employee counts and the extreme FTE salary and benefit numbers here.

As far -- we are also concerned about the arbitrary nature of the hurdle rates used in the benefits calculation and, and believe that the benefits seem to be pretty understated based on the analysis we've heard from other parties here.

And I guess finally the study clearly indicates that there are quantitative benefits related to long-term bilateral contracts and investment inefficiencies which really need to be quantified and can significantly change the results of the study as a whole.

I guess to summarize, Pat Wood would like to see the customers realize the benefits of the GridFlorida RTO and that the ICF consultants revise their bases and assumptions of the GridFlorida cost, GridFlorida cost benefit study to provide a more reasonable analysis of the costs and the benefits of the RTO.

CHAIRMAN BAEZ: Questions of Mr. Machuga? Thank you, sir.

Ms. Bass?

MS. BASS: That was the last of our speakers.

CHAIRMAN BAEZ: That was the last of our speakers. I guess now we're compelled to discuss -- yes, sir.

MR. MILLER: I wonder if I could make a modest suggestion, and this will be very brief.

CHAIRMAN BAEZ: Now is the time.

MR. MILLER: We were pleased to hear Mike Naeve suggest that 60 days after the ICF exercise is completed that the applicants will get together and put out a strawman or some such thing within 60 days. I would simply like to suggest to the applicants that they make that process inclusive and include the active stakeholders in those deliberations before the strawman is thrown out. We think that would advance this process greatly. Thank you.

CHAIRMAN BAEZ: And Mr. Naeve -- I heard Mr. Naeve allude to some, some kind of vetting process. Is that -- or are we putting words in your mouth?

MR. NAEVE: Well, we think, of course, it's up to the Commission to decide what vetting process there is. But our assumption would be that that's the beginning of a process, that the applicants certainly have to decide what it is they think before they have an opportunity to discuss it with other parties. And once they lay out their proposal, then I think there would be a -- or I would assume the Commission would want to have some form of process where there's input from all the stakeholders before we reach a --

CHAIRMAN BAEZ: Well, and before I make that assurance to the gentleman from Seminole, as, as far as, as far as I'm concerned anyway, I can't speak for my colleagues on that, but I would expect to see efforts made at, at an inclusive process, whatever that form takes.

Now if your suggestion is directed at us trying to make some kind of pronouncement now about what we've got to do going forward, I think that that, that necessitates a little bit more discussion among our side of the equation in order to be able to do that, and I'm not about to get into that here. I don't think this is the time or the place to be doing that. But -- and actually at the time of, at the time you raised your hand, I was turning over to Ms. Bass to try and ask her what we should be considering in terms of next steps.

COMMISSIONER DEASON: Mr. Chairman, before we hear from staff, can I make a comment?

CHAIRMAN BAEZ: Commissioner Deason, please. Absolutely.

COMMISSIONER DEASON: Okay. I can understand the need for the applicants to have an opportunity to put together a strawman, considering what has been, you know, presented thus far. But to me as one Commissioner, it would be helpful that before that strawman is brought to us and we give everybody an opportunity to comment on it here, it would be better for there to be an opportunity for everyone to comment on it during the process before it is brought here. And I think it would be better able to focus on areas of agreement and areas of disagreement, and it would just facilitate my understanding.

CHAIRMAN BAEZ: Oh, I absolutely agree. Now I don't know how we accommodate -- we have to find a way to accommodate that principle in, in whatever steps going forward. Now I don't know whether to discuss this as a way of backing into it or what. I know for certain that Mr. Rose and his colleagues need to finalize the study because there was, there was some --

MS. BASS: Correct.

CHAIRMAN BAEZ: -- reference made to at least one sensitivity study. I don't know if there are more in the offer. But certainly there is a little bit more work to do before a final product comes out.

I would also say that although we have concentrated much on, on the possibility of alternatives and so on, I confess I'm not even sure how, how we give that as guidance in anything less than a general sense that our feeling is, and I think you saw from the questions that was posed on the, by Roberta and her people on the agenda, you know, that's something certainly that we'd like everyone to consider. So there seems to be some consensus that that can go on in a productive fashion, and I would leave that to staff who's been so ably handling it so far to sort of set the tone in terms of what kind of process should be left. And you've heard at least two of us say, and I'm sure -- I don't want to twist Commissioner Edgar's arm right here on the dais, but I don't know if she has any objection to giving that as some kind of direction that some kind of inclusive process before it gets back to the Commission in whatever way, you know, leave them and others decide to come back, but that that should be included.

COMMISSIONER EDGAR: I'm not sure what the most, what the best process is to do that. But I know that being new to some of these issues, I would like the time to be thorough and deliberative, at least in my thinking. And so, you know, a couple of options or a range of options and input from the various stakeholders as to benefits, costs, alternative impacts, et cetera, would be very helpful.

CHAIRMAN BAEZ: And I would say that thoroughness and deliberativeness should be something that everybody should be trying to, trying to take on.

Roberta, any suggestions, or, or is it a matter of, you know --

MS. BASS: Well, at this point I don't think we have any specific steps in mind. We haven't really set out a time schedule. I do know that one thing we're looking for is a finalization of the ICF study. It's my understanding there's still some sensitivity analyses that are being conducted. And when those are done, I'm not sure whether or not we'll go through another stakeholders' work group or what, what the process will be at that time, but I do know that I think this Commission needs the benefit of a final cost benefit study.

I think we should also take advantage of all the information that's been provided today by all the stakeholders. There's been a lot of different ideas passed around about how if this Commission does not go forward with a structured RTO, how we could capture benefits that will provide cost savings to the ratepayers. So what I would suggest is that we take, take some time to review the transcript of this workshop and to look at what has been provided and perhaps, as you said, maybe on this side of the equation we can talk about a direction and talk about what we think, what the process needs to be on a going-forward basis. But I would rather review everything that was said today in that before we do something definitive.

CHAIRMAN BAEZ: And I'm sure that we can gain some time because I don't see that as being dependent on ICF finishing, finalizing its study obviously. And I'm not going to put ICF on the spot here as to when that's, when that's going to take place. But it should be soon and --

MS. BASS: No. I think we can do that simultaneously. With them finishing it, we can kind of regroup and see where we're at and then perhaps provide some guidance. If the applicants wish to go forward with a strawman, perhaps we can provide some guidance on what this Commission thinks the involvement level should be of the stakeholders or what we're looking for.

We're also still looking for some additional information from the utilities that Commissioner Deason asked about: The benefits that may be achieved by the individual utilities that were not part of the cost benefit study. So those are still things that we need to look at. So I would say let's take some time and gather the information we have and think about a process going forward.

CHAIRMAN BAEZ: Very well. Any, any questions or comments, Commissioners?

I want to thank you all for coming out. I think you gave, certainly you gave the Commission a lot of food for thought, and I'm sure anyone else that was listening as well. I want to thank you all for your input. It's all well-taken. Have a good day everyone. We're adjourned.

(Workshop adjourned at 2:50 p.m.)

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

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

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

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

DATED THIS 31st DAY OF MAY, 2005.

Linda Boles

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