BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. UNDOCKETED

In the Matter of

RENEWABLE PORTFOLIO STANDARDS.

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PROCEEDINGS: STAFF WORKSHOP

DATE: Thursday, September 27, 2007

TIME: Commenced at 9:43 a.m.
Concluded at 3:13 p.m.

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

REPORTED BY: MARY ALLEN NEEL, RPR, FPR
PARTICIPANTS:

BILL ASHBURN, Tampa Electric Company
CLAY BETHA, Buckeye
MARTHA BROWN, FPSC Staff
JOHN BURNETT, Progress Energy Florida
SUSAN CLARK, Radey, Thomas, Yon & Clark
JEFF COOPER, Lake County
BEN COWART, City of Tallahassee
MARK FUTRELL, FPSC Staff
BOB GRANIERE, FPSC Staff
ANNE GREALY, Florida Power & Light
JUDY HARLOW, FPSC Staff
CAYCE HINTON, FPSC Staff
CHRISTY HERIG, FlaSEIA
RYAN KATOFSKY, Navigant Consulting
ROGER LEWIS, Lakeland Electric
BOB McGEE, Gulf Power
JOHN McWHIRTER, McWhirter Reeves
BARRY MOLINE, Florida Municipal Electric
Association
JON MOYLE, Moyle Flanigan
JENNIFER SZARO, Orlando Utilities Commission
BOB TRAPP, FPSC Staff
KAREN WEBB, FPSC Staff
RICHARD ZAMBO
MR. FUTRELL: Okay. Good morning. I think we're going to get started. I'll ask Martha to read the notice.

MS. BROWN: Why I'm not sure. Pursuant to notice, this time was set for a staff workshop to discuss renewable portfolio standards in Florida. The purpose of the workshop is set out in the notice.

MR. FUTRELL: Okay. I'm Mark Futrell with the staff, and I would like to welcome everybody to the workshop today to continue our dialogue on renewable portfolio standards.

We tried to do a little different setup to afford parties more opportunity to come to the microphones, so feel free. If you want come and want to speak, find a microphone. We've got several over here. If you don't intend to speak, if you'll make sure a microphone is available for the folks that do want to participate. But again, hopefully this will -- we may have to do some handing back on the mikes here, but hopefully this will be beneficial today.

Again, today the focus of the workshop is to look at in more depth compliance and enforcement issues associated with a renewable portfolio standard. And before we get into our discussion today, we want to have
two presentations. We've had -- Ryan Katofsky with Navigant Consulting is back with us. He was at our last workshop. Again, Ryan is over here. He is here on behalf of -- as part of the EPA's outreach program to assist states as they explore these kind of issues. And he will be followed by Judy Harlow with our staff to kind of tee up the questions that we're going to be discussing today.

And if some of the staff would like to come up to the table, that might make more room for folks to come to the microphone.

So at this time, if Ryan would come up, he's got some remarks, some prepared presentation. His slides are available behind on the bench, and the other documents are back there that we also circulated to the distribution list.

Ryan?

MR. KATOFSKY: Thank you, Mark. Good morning, everybody. It's a pleasure to be here.

I was asked to provide some overview of three areas that relate to renewable portfolio standards. I was asked to talk about renewable energy certificates, sometimes called renewable energy credits, green tags, and there's some other terms used; to talk about compliance mechanisms that are used in existing RPS
programs; and also talk briefly about some enforcement issues as they relate to compliance with RPS.

So let's sort of jump right in and talk about how a REC is born. You know, the first time that someone introduced this topic to me, the idea of an attribute that you could buy and sell, it took me a while to kind of get my head around it, but it's a pretty well established concept today, and it's in use in a number of markets.

The idea is that you have a renewable energy generator, and whereas before there was this concept of RECs, they basically had one commodity to sell, which was the power, now they have two commodities to sell. They have the power, and they have the certificate, and what the certificate embodies is the attributes of that electricity. So the concept is that not all electricity is created equal, and there are many, many attributes that you can track.

For example, in Massachusetts, I get a quarterly sort of content label with my electric bill. It's kind of the equivalent of a nutrition label that you see on food, and it tells me the product mix, it tells me the emissions, and it even tells me how much of my electricity was produced with union labor, and it's an example of the attributes associated with the
electricity that is sold to me. And that's essentially what a renewable energy certificate embodies. It embodies a range of attributes.

It also would embody whether or not a particular generator is qualified under one RPS or another. So if you have multistate REC tracking systems, you can see whether that REC qualifies in one state and not the other based on its attributes. And part of this whole notion of RECs is the idea that the generators have to be registered and certified under various RPS programs, so that's an aspect of REC tracking. I'll talk a little bit more about that later.

And once you've sold the REC or once you've separated the attributes from the power, then the power that is sold from that facility, if it's sold separately from the REC, it has no attributes. It is referred to as null energy, residual system mix, or other things. Essentially, it is -- that electron is now just like any other electron, because I've separated the attributes, and I've actually put a value on those attributes.

That's the concept of a renewable energy certificate, and it has some value in simplifying how transactions and how compliance are treated, and it also has implications for voluntary programs.

So if you take a look at, just furthering that
topic, how the RECs might be used in various markets, you have a renewable energy generator. They can produce what is sometimes referred to as bundled renewable energy, so that is the energy with the attributes, and then that can be sold, for example, as a green pricing or a green power product to customers. So that top row represents what we typically think of when we think of, say, a green pricing program, where the energy and the attributes are sold together.

The middle row, you take the REC and you separate it off from the energy, and you can do the same thing. You can sell a REC-based product as a green power product, so where the customer doesn't change the way they purchase electricity, but in addition to, say, the electricity they buy, they're also buying RECs from a generator. And that's something that's available in a range of states. I actually do it in Massachusetts. I actually buy Massachusetts RPS-eligible RECs for my own purpose. And the purpose of me doing that is to increase the demand for RECs in the marketplace and drive more renewable energy development, just like any other customer who belongs to a green pricing program.

The other thing that RECs obviously are used for is for RPS compliance, and that's the focus of what the subsequent slides will be about. In that case, an
obligated party under the RPS will purchase RECs equal to their obligation, and then they will retire them. So they're taken out of circulation once they're used for compliance, and then they would charge their customers, or the cost of that REC will be included in the price that they charge for electricity to customers.

MR. MOLINE: Ryan?

MR. KATOFSKY: Yes.

MR. MOLINE: Do you mind taking questions?

MR. KATOFSKY: How do you want to -- I'm happy to take questions as we go or wait till the end.

MR. MOLINE: Just to clarify, so when you're buying RECs at home -- Barry Moline, Florida Municipal Electric Association. When you're buying RECs at home, are you then competing with, for example, the utility for those same RECs?

MR. KATOFSKY: In effect, yes, because I'm just another -- I'm another buyer, yes.

MR. MOLINE: All right. Thank you.

MR. KATOFSKY: I don't buy that many, but -- a couple of megawatt-hours worth.

This slide kind of addresses some of the issues that relate to RECs in the market. I think there's two key issues addressed here. One is, what is the price or the value of that REC? What determines
that price? And then there's the issue of eligibility of that REC.

So if you think about -- you can look at a REC in a couple of ways. One is, you say, "Well, it's the above-market price of that renewable electricity relative to conventional generation." So it's the extra money we have to pay to support that renewable generation. So that's sort of a cost-based view of a REC.

The other way you can look at it is, it's the premium that somebody would be willing to pay for those attributes, so it's a -- it's someone who says, "Well, that REC is worth -- that electron is worth more to me because of its attributes." So you can look at it in two ways. You know, the first way is sort of the compliance version, and the second way is more of the voluntary version of a REC. But the end result is that the renewable generator receives additional revenue for their output.

If you look at compliance markets, what would set a REC price? Well, it's just going to be supply and demand for those RECs, subject to a range of market rules, which may include price caps, or there may be a ceiling price on how high a REC, a compliance REC will go. There may be credit multipliers in place for

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different types of technologies, and there may be what we call shelf life. There may be banking provisions, so if there's a particular -- if an RPS has banking provisions and there's more RECs available than are necessary in a particular year, if there were no banking provisions, then the price of those RECs you would expect to fall because supply would exceed demand. But with banking, you can roll some of those RECs over, and then that would have an effect on the current price.

MR. MOYLE: You mentioned price caps, at the top end a ceiling -- (inaudible; not at microphone) -- fall below a certain price.

MR. KATOFSKY: You want to come up to the microphone?

MR. FUTRELL: Jon, we're trying to transcribe this. And I think if we can have a quick answer -- maybe we can hold off on questions until the end and then have a Q and A period with Ryan, let him get through his slides. But if you want to go ahead and answer Jon's question --

MR. KATOFSKY: I'll go ahead and answer. The question is if there are also floor prices for RECs and not just ceiling prices. I believe that the way the RPS rules are written, they generally are focused on caps. There are other things going on in the marketplace where
people may be guaranteed a floor price for RECs, and I can think of two examples off the top of my head.

One, there is a -- I believe it's just a proposal where in New Jersey a utility is going to be guaranteeing a -- they're doing a forward purchase of solar RECs from customers. This is not in place yet, but they want to do that, and then they're guaranteeing a floor price to that customer for that solar REC. So there's a ceiling price set by the rules, and there's a floor price set by their arrangement with the customer.

In Massachusetts, the Massachusetts Technology Collaborative, which administers the state's renewable energy trust fund, has become a participant in the REC market as a way to help that market get going, and they execute contracts with generators that include various price guarantees. They do collars or floor prices or, you know, contract for differences, various ways to guarantee a minimum price.

So in voluntary markets, you know, the price of these RECs is really driven by what people are willing to pay, so that's the flip side of that. And in that market, there may differentiation. There may be customers willing to pay more for, let's say, RECs from a new facility versus an old facility or pay more for RECs from a solar project than a landfill gas project.
So there's actually differentiation of price in the voluntary REC market based on the type of REC that it is.

In terms of eligibility, some factors that you'll need to consider going forward relate to the ownership of RECs. So, for example, if an RPS is passed and then an existing generator becomes eligible and that existing generator has a PURPA contract, that PURPA contract probably didn't say anything when it was written about the disposition of RECs, so you need to figure out who owns those RECs under that circumstance. If there are customer-side resources subject to net metering, you would have to determine who owns the RECs under those circumstances. And then if there are state incentives involved, you may need to look at that as well.

The other very important issue is the relationship between the mandatory and the voluntary markets. And what has emerged as the best practice really, and that goes to my example I gave earlier, is that voluntary purchases typically are in addition to any RPS requirements, so they're not used for RPS compliance. And this relates to issues of property rights and what the intent of voluntary programs are. So I acquire the title to the RECs if I purchase them,
and therefore, the utility doesn't use them for
compliance purposes.

And then another thing that is going to become
probably more important in the future as various
emissions cap-and-trade systems get put in place,
particularly for CO2, because that's considered an
important attribute of renewables, being low or zero
CO2, is how are these -- you know, to the extent that
renewables get involved in various cap-and-trade
programs, how is the REC going to interact with other
policies, other programs, and just making sure that all
those things work together. Some of that is still being
worked out.

Just a quick slide on REC tracking systems.
This is basically the idea -- this is just the
accounting system for following a REC from the time it's
created until the time it is retired. And I'll actually
skip to one of the bullets near the bottom that says
these are not trading platforms for certificates. These
are tracking systems, so these are -- you cannot execute
transactions with these tracking systems, but you can
record and follow transactions with them. And they're
policy neutral, in the sense that a single REC tracking
system can work with multiple states, multiple programs.
So they're just really, you know, at the basic level, an
accounting system for following RECs.

In some cases, the REC tracking system is part of a broader -- what are sometimes called generation attribute tracking systems. That's the GATS in the PJM region. In New England we have something called the generation information system, the GIS. These track attributes of all generators in the region, and as part of that tracking, they include issues relating to renewable generation and RPS eligibility. In Texas they have a REC tracking system that is solely for the purpose of their RPS compliance. It doesn't track other generators. It just tracks generation for RPS compliance.

And then on the right-hand side there, you see some functions, but basically this is an accounting mechanism and a verification mechanism to make sure that RECs are not being used twice, to make sure that -- you know, that everything kind of adds up in the end.

So that's the five or so minutes on RECs, and now let's look at how they're used and what other approaches are out there for compliance with RPS. And there are three basic ways that RPS programs look at compliance. One is the use of RECs, and that is by far the most common way that states have pursued compliance with RPS, and it's an attribute-based system.
The other is to look at the contract path. So in this case, you have basically what we referred to earlier as the bundled renewable energy being sold to the obligated parties, typically the utilities, and they're buying both the power and the attributes together, and California is probably the best example of that approach. And in California, that's typically done with PPAs between the generators and the utilities. It could also be done by utilities building their own renewable generation if that were the way a particular state did it.

And then the third option, which as far as I know there's only example, New York, is the central procurement approach, where it's actually a state agency that acts as a single obligated party for the entire RPS program. And we'll talk more about each of these in a minute.

The reasons why you have compliance mechanisms, one, of course, you want to create a viable market. This market should stimulate investment in renewables, and yet control overall costs to ratepayers. You want a compliance mechanism that can ensure proper tracking and compliance with the targets, and then you want to verify that only eligible resources are being used. Every state essentially decides what types of
resources they want to include in their RPS. For example, some include hydro; some do not. Some have restrictions on the type of biomass that may be eligible; others do not. So every state has its own set of eligibility criteria, and you want the compliance mechanism to be able to help you with the verification of that.

So let's look at each one of those real quick. First, looking at REC-based systems, given that we've talked a little bit about RECs already, you can kind of understand how this one would work. Basically, an obligated party, typically a utility, or what are sometimes called load serving entities or LSEs, would have to purchase RECs equal to their obligation, and then we have the REC registries that contract this. And as I said earlier, you have REC registries that track this for multiple states, PJM in New England being a very good example of where multiple states use the same system.

What are some of the pros of this kind of an approach? Well, it's fairly easy to track compliance by following the RECs. It allows for flexibility mechanisms like banking and early compliance. And it facilitates the use of credit
multipliers. So, for example, if you had technology tiers or you had placed preference over one class of technologies versus another, you could create separate markets for those tiers or apply multipliers to certain technologies.

It addresses the issues of transmission constraints, so -- if you're following the contract path approach, you have to be able to physically deliver all that power to the obligated party. Here you can separate those two functions, the delivery of the energy and the delivery of the RECs.

And it's a way to incorporate customer-side resources. If customer-side generation is included, they can also generate RECs, and then you don't have to worry about how that power flows into the system.

Some of the cons, the main one is that you have to create this whole new market that didn't exist before, so you have to set up the rules, and you have to make sure that it functions. And we have examples where they functioned well and others that have been off to slower starts. So it's not a guarantee that if you create a REC market, it will instantly function as you expected it to.

And because of this notion of separating attributes and tracking attributes and paying for
attributes, if there are other policy regimes that also involve attributes such as emissions, you need to make sure that all the systems work together.

And some examples, Texas has a very successful REC-based RPS. Massachusetts has an RPS that I would say is becoming more successful as time goes by. It's taking time for it to get going. And then all the PJM states use this system as well.

If you look at the contract path approach, it's less common, but more consistent with how things are generally done in vertically integrated states such as Florida. In this case, you enter into PPAs or build capacity, and you're buying both the power and the attributes together. The terms of those power purchase agreements and the pricing of those are going to be subject to RPS rules and potentially approval by the Public Service Commission or other -- whoever administers the RPS.

And as I mentioned, you know, there are examples where utilities can build their own as opposed to having to enter into agreements with third-party generators. Here again, the obligated party is the utility or the load serving entity.

The pros of this system is that it tends to work within the existing structure, so if you have

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competitive RFPs for generation already in the state, this would just fit right in with that.

And it provides -- because you can typically get long-term contracts under these RPS programs, this provides a measure of certainty for the generators, and that helps them get financing. That, for example, has been an issue in some states, where the load serving entities were not willing or able to enter into long-term contracts, and then that made it difficult for generators to get financing. In California, you know, these contracts are long-term contracts, and it helps them get financing.

I think I mentioned the issue of transmission constraints. That would be a key issue here, that if you had significant transmission constraints, you would have to address that. Texas did address that as part of their RPS, where they had a lot of wind going in in west Texas and didn't have the ability to move the power.

And you also have to make sure that these contracts are auditable and it can be verified that they are compliant with the RPS. Examples are California, as I mentioned earlier. Colorado permits this. It's interesting to note that Colorado also permits the use of RECs, so you can do it either way. And if you go back a number of years, Xcel Energy in Minnesota -- this
is before the current RPS in Minnesota was put in place. Xcel was under a mandate to purchase a certain amount of wind and biomass power, and that pretty much fell into this contract path type of compliance approach.

The third is this idea of centralized procurement by the state. And again, New York is the one example that I'm familiar with. In this case, there is only one obligated party. It is the state agency that purchases the -- essentially, the RECs. So how it works in New York is that the state agency issues RFPs for essentially what amounts to renewable energy certificates, although the certificates are not traded or tracked like they are in other jurisdictions. The state is essentially buying just the attributes, and then the power from those contracts is sold into the New York ISO, either onto the spot market or through bilateral contracts. And as we talked earlier about the difference between renewable generation that does or does not have a REC associated with it, that power is devoid of the attributes.

So the pros of a system like this is that it does use attributes, but doesn't require you to establish a REC market. The state uses competitive solicitations, so that ensues that there should be competitive pricing, and it's got a fairly simple
tracking and compliance mechanism.

What happens after the state issues their RFP and gets their bids for the various projects, they then determine how much each of the utilities or the load serving entities need to charge their customers to cover the costs of their contracts with the generators, so the state agency determines what that surcharge is. The utilities collect it and transfer it back to the state agency, who then pays the generators.

The one issue I think with this approach might be that, you know, the state will get what it gets in these RFPs, and there is no automatic mechanism for compliance if they fall short of their target, so then the state would have to issue additional RFPs, and the generators would have to submit additional bids. So there is no automatic way to sort of -- if the market is falling short on capacity on bids for the RFPs, it may take some time for those signals to get worked into, say, the next round of RFPs, and so on. And we'll talk about compliance in a minute, and you'll probably get a bit of a better sense of what I mean there.

Moving on to the issue of enforcement, I think it's important to separate enforcement into two key areas. One is this notion of alternative compliance mechanisms, and the other is penalties, and I think most
of the focus is typically on these alternative compliance mechanisms. And what these are, as the name suggests, this is an alternative way for a utility to come into compliance with the RPS if there are not sufficient quantities of eligible generation to be procured or eligible REC\textsuperscript{s} to be procured. So by making these alternative compliance payments, the utility actually is complying with the law, even though the targets themselves are not being met. And they're typically subject to cost caps to control the overall cost to the ratepayers.

Penalties are really there for market participants that essentially don't play by the rules. So they either falsely report their eligibility or their generation, or if they're shown to have not made a good-faith effort in compliance, those kinds of things would be the subject of actual monetary or other types of penalties that could be imposed by the entity that administers the RPS.

So let's look at each of those two areas a little bit further. If you look at the alternative compliance mechanisms, they're there to do three basic things: One, ensure that the RPS functions, so if there's a shortage of REC\textsuperscript{s}, the alternative compliance mechanism kicks in, and the obligated parties will make
payments to the state, effectively, as a substitute for buying eligible renewable energy certificates or eligible renewable power.

And as I mentioned earlier, it ensures that this system is working, but it also means that there's not enough renewable electricity out there, so that leads to the second point, which is, by these alternative payments kicking in, that should stimulate project investment. It sends a signal to the market that there's not enough renewable energy produced, and those payments should be high enough such that it would encourage generators to come in and build more generation as a more cost-effective means of complying with the RPS.

At the same time, the issue of cost control is very important. You don't want the prices for these payments to go too high, because you want to be able to control the overall price impacts to customers.

So if you look at some what you might call best practices associated with these compliance mechanisms, setting that ceiling price, it should be high enough -- I put in quotes "significantly higher than the expected cost of compliance," so that paying it -- if it's being paid, it sends a strong signal to the market to come in and build more generation, but then
again, low enough so that it's not too burdensome on ratepayers.

A couple of examples here, in Texas, the alternative compliance payment is either $50 a megawatt-hour or twice the average price of credits in that year, so it's high enough to spur development. Again, this is just for the renewable energy certificate, so this is over and above the actual price for the power from the generators.

You can subject these to inflation adjustments. Massachusetts is an example. There are others. So it started off as $50 a megawatt-hour in Massachusetts. Now it's up to 54, $56, adjusted for inflation.

And if you have solar set-asides or other carve-outs for specific technologies, solar being the one that it's done for most commonly, the alternative compliance payments for those solar RECs or SRECs, you would expect that to be quite a bit higher than the ceiling price for the bulk of the market. And New Jersey is the best example probably of a state that has done this with solar RECs. They initially set the compliance payment for solar RECs at $300 a megawatt-hour, and I believe it has even gone up. They've just recently set that price for the solar RECs
for the next few years. That information should be available through their website.

The other issue that's important is the question of cost recovery of alternative compliance payments. And I would say it's common that these are subject to cost recovery, because they are considered a means of compliance. However, they're not necessarily automatically subject to cost recovery, and I've given a couple of examples here. In Delaware, the RPS rules state that they can be recovered in rates as long as they're the least cost measure, or if there's not enough conventional or renewable generation to meet the RPS. In Pennsylvania, they are specifically not subject to cost recovery, and in that sense, they actually would act as a penalty if they kick in.

The other question that comes up is, well, if we start collecting these alternative compliance payments, what do we do with them? And generally the idea would be to reinvest those funds in renewable energy development in the state. Again using Pennsylvania as an example, they have specific language that says it has to go to the sustainable energy fund and can only be used for developing additional alternative energy sources, although a certain percentage of it can be used for administrative
purposes.

Just looking quickly -- I think this is my last slide, just quickly at the issue of penalties. Just looking at two different parties that might be subject to penalties, one would be the renewable energy generator. Under what circumstances might penalties be levied? Well, if they falsely reported either the eligibility or, say, the production levels coming from their facility. What are the options? Well, you could fine them, or you could actually, you know, revoke their qualifications as a means of penalizing them.

If you look at the obligated parties that are purchasing or complying with the RPS, they could -- you know, what are some of the triggers there? Well, they may fail to acquire sufficient renewable energy or RECs, or again, they may falsely report or fraudulently report, say, resource eligibility criteria. You can levy fines, you can disallow ACPs in cost recovery as a penalty, or in restructured markets where you have third parties that are delivering energy to customers, you can bar them from taking on new customers, or you can actually revoke their operating license.

You know, I haven't looked into this issue of penalties in great, great detail, but I don't think there has been a lot of precedent yet for actually
applying penalties to various parties. In some states, the penalties may be automatic, in which case there might be an appeal process if someone felt that they were unfairly penalized. In other cases, the application of penalties is discretionary.

And the last point, you know, there may be force majeure considerations in the levying of penalties.

I think that is the end. Yep. That's me. So do we have a few minutes for questions?

MS. HERIG: I can't remember what slide, but on the value -- and I know there's not a lot of data out there.

MR. FUTRELL: Excuse me. If you would identify yourself for the court reporter, that would be very helpful.

MS. HERIG: I didn't hear you. What did you say?

MR. FUTRELL: If you would identify yourself.

MS. HERIG: Christy Herig, and I'm here representing the Florida Solar Energy Industries Association.

In states where the ACP is actually a penalty, don't the REC values often track below that, sort of close below that? I mean, the last time I looked,
Maryland was around $42 a megawatt-hour, but New Jersey was 218.

MR. KATOFSKY: Well, the 218 in New Jersey you’re referring to would be for the solar.

MS. HERIG: Right, but it’s because your ACP is so high there too.

MR. KATOFSKY: Yes. So if a market is functioning as you would expect it to, you would expect that the actual market price would be below the ACP. Even if there were a shortage of RECs, they might still track a little bit lower because there would be some administrative, you know, back office costs in procuring RECs as opposed to just paying the alternative compliance payment.

MS. HERIG: Right. But my observation is, they do seem to track just below it.

MR. KATOFSKY: Yes, and that really would depend on supply and demand.

MS. HERIG: Yes.

MR. KATOFSKY: I mean, in Texas, the Texas RECs historically have been far below the ACP because from the get-go, they had abundant quantities of RECs, whereas in Massachusetts, they’ve had several years of deficit, and if you look at spot prices, effectively, those are tracking very, very close to the ACP.
MR. MOLINE: Barry Moline, Florida Municipal Electric Association. I have three hopefully quick questions.

One is, are national and state RECs based on the attributes of what is defined as renewables in that state versus what might be defined as renewables elsewhere, so therefore you can trade something --

MR. KATOFSKY: Well, there is no real -- I mean, in terms of national RECs. So each -- if a state has its own RPS, then there is a definition of what qualifies in that state. For the voluntary market, which is effectively a national market -- a good example would be, federal government agencies have renewable energy procurement requirements, but they don't have constraints on where they can get those from, so they can acquire RECs from out of state, from across the country, and so on. So in that sense, there is a national voluntary market. There are independent bodies that will certify those RECs in various ways, the Green-e symbol, for example.

MR. MOLINE: For example, if we have waste energy as an option, that may not be an attribute that is attractive to another state or region, so that REC may be defined differently.

MR. KATOFSKY: Correct, correct. And even
within a -- going back to the -- New England is a good example, because it has multiple states within the same control area, and they have multiple RPS. A generator in Maine may qualify for Connecticut with its biomass facility, both not in Massachusetts, because they have different definitions within those two states.

MR. MOLINE: So there are different types of RECs in those states.

MR. KATOFSKY: Yes, or different attributes, or different eligibility. But they're all tracked under the same single tracking system.

MR. MOLINE: Okay. The second question is about REC tracking. You gave the examples of PJM and ISO New England. Are there any issues of confidentiality? I mean, FRCC, for example, has issues of confidentiality if we chose that route. Have they addressed those?

MR. KATOFSKY: I'm not aware. It could be that they've been addressed. There are certain things that the tracking system will track and certain things that it won't.

MR. MOLINE: And then finally, sort of one of your last slides about the alternative compliance payments, how do utilities prove, in our case, to the PSC, that there's not sufficient renewable energy
available to then therefore meet the cap and not a
penalty -- I mean, I guess the penalty would be no cost
recovery, but how would we prove that?

MR. KATOFSKY: I don't think there's a lot of
experience with that yet, so I'm not sure what the exact
mechanism would be for demonstrating, say, you know, we
did to our best, but we just couldn't get it out there.

I mean, if it was an RFP-based process, then
you would just look at what came in from the request for
proposals, and you would see if there was either
sufficient renewable energy offered up in those
proposals or if the pricing was, you know, below the
ACP, or maybe some of the other terms within those
contracts just didn't pass muster.

MR. MOLINE: Okay. Thank you.

MR. TRAPP: Jump in, Susan.

MS. CLARK: I was going to ask a question on
the --

MR. TRAPP: Could you identify yourself?

MS. CLARK: Oh, Susan Clark.

I was going to ask a question on the
registering and the certificates, and there are entities
that do that. Are you noticing that when states start
an RPS program that they're using existing registrars or
tracking systems? Are there some emerging as people who
do that in many states, or does each state sort of create their own tracking register, certificate, or whatever?

MR. KATOFSKY: There's only three or four existing tracking systems that are sort of -- you can think of them as multi-regional. There's New England, there's PJM, there's -- the Western states have one, and then there's a Midwest, so there's really four. And then there's Texas, which is its own system.

So those systems grew out of these -- as these states started to go down this path, these registries, these tracking systems were created. And then as additional states -- so PJM might be a good example. As additional states passed their own RPS programs, they just -- as part of that, they said, "We will just use the existing PJM generation attribute tracking system as the means of tracking our compliance." So, you know, you have in these regions the -- essentially, the infrastructure was there for many of these states. The early states, you know, that were doing this, that's where these registries were first created.

And they weren't just created for RPS compliance, for example, this issue of labeling. So if you want to be able to track the attributes of all generators so that you can make consumers aware of where
their power comes from and what its attributes are in terms of emissions and fuel mix, these tracking systems allow you to do that. So it wasn't just for RPS that these tracking systems were created.

MS. CLARK: And how are they funded? Is it funded by those people who want the certificates? In other words, there's a cost for registering?

MR. KATOFSKY: Yes. And there could be surcharges, like, say, per REC you have a small surcharge that helps fund the system. But it would be sort of a collectively funded activity.

MR. TRAPP: Could I jump onto that --

MR. KATOFSKY: Yes, please, yes.

MR. TRAPP: -- question and ask -- you know, we're the PSC, and we're used to regulating utilities and not necessarily putting together other companies, organizations, or whatever, for tracking or whatever.

I'm Bob Trapp with staff, by the way. I violated my own rule.

Could you share with us to what extent these REC programs are being self-administered at the utility level, where utilities actually go and verify the RECs, account for the RECs, possibly with some state auditing or something like that? Or are most of these programs being developed at a kind of statewide level outside of
a PSC type authority?

MR. KATOFSKY: Well, I mean, the PSC may be the -- the registries themselves are created by -- you know, you basically hire someone to set it up, establish it for you, and the question then becomes who runs it. All right? Is it a state agency? Or you could actually outsource the running of the registry to a third party as well.

I don't believe that the -- you know, the utilities themselves wouldn't necessarily be the ones to do the auditing. I think they would want to verify. So if there was a generator, say, of a wind farm and they registered with the tracking system and they got certified for the various -- you know, they would be independently certified as being eligible for, you know, RPS programs A, B, and C in this region. Then that information would be available to the utility, so the utility would know that if they bought RECs from this entity, that this entity was properly registered and accredited for that RPS program. And then you could have -- the PSC or some other state agency could serve the auditing function, so going in and looking at the transactions, verifying that facilities that say they're eligible are actually eligible and so on.

MR. TRAPP: So in order to have a uniform
system, you really couldn't have 55 separate utilities defining their own RECs. You basically would have to set up some kind of central authority to do that function.

MR. KATOFSKY: I think it would be more efficient to do it that way. Now, there are examples of states where -- I think Colorado is one that comes to mind where the obligation to be in the RPS is based on the size of the utility. But then they gave municipal utilities and co-ops the option of opting out, but then self-certifying. So there are examples of that out there.

MR. ASHBURN: Ryan, Bill Ashburn with Tampa Electric. I assume the generator that's a renewable generator sort of qualifies into one of these tracking systems, saying, "I'm renewable," and they check it and so forth.

MR. KATOFSKY: Right.

MR. ASHBURN: Do these tracking systems talk to each other to make sure that the REC that generator sold in, say, New England isn't being resold again into Texas, and how do they do that?

MR. KATOFSKY: That's right. There has to be the ability to ensure that the same REC is not sold in multiple jurisdictions.
MR. ASHBURN: Right. So do these tracking systems all talk to each other and trade information, or what happens?

MR. KATOFSKY: You know, I'm not an expert in that area. Typically -- I mean, generally speaking, you know, Texas to New England is an example of where there's no physical connection, so --

MR. ASHBURN: Right. But the REC is not subject to transmission or anything. It's just an attribute.

MR. KATOFSKY: Right. But if someone tried to buy -- if someone in Texas tried to buy a -- you know, they couldn't buy a New England REC in Texas because a generator in New England couldn't register with the registry in Texas.

MR. ASHBURN: Okay. So the registry in Texas, for example, excludes all generators outside of their footprint.

MR. KATOFSKY: Right. So that registry would say, okay, you're eligible or you're not eligible.

MR. ASHBURN: Okay.

MR. KATOFSKY: It gets messier when you have adjacent control areas.

MR. ASHBURN: Right.

MR. KATOFSKY: So, for example, a wind farm in
New York can sell to the NYSERDA, which is the state agency that does the central procurement in New York, but they can also register for RPS eligibility in multiple New England states. Provided they can deliver the power to New England, then they can also sell the RECs in New England. So you would have to -- in that particular case, you would have to verify that (a) they didn't sell the attribute to NYSERDA; (b) if they sold it into New England, that they also had a contract for delivery of the energy to New England; and (c) that they only sold it to one entity in New England.

MR. ASHBURN: Do you know if these separate tracking systems are talking to each other or coordinating --

MR. KATOFSKY: You know, they probably are coordinating to some extent, particularly in the Northeast, but it's not something I know a lot about, unfortunately.

MR. ASHBURN: Okay. Thank you.

MS. HERIG: I'm not certain, but I think they have a unique identifier so that once sold, it gets retired. It can't be sold again.

MR. KATOFSKY: It's retired, so it's out of the system, yes.

MR. TRAPP: Let me ask about that, if I could.
I'm Bob Trapp with the staff. If you have multiple attributes that you're trying to take advantage of in a REC system, such as CO₂ reduction, and then promotion of renewables, economic development, fuel diversity, all of these multiple reasons for doing this, is there any reason why you can't count a REC twice?

MR. KATOFSKY: Have your cake and eat it too?

This is an interesting issue. For example, in some states, there are set-aside allowances for emissions trading programs, so the state administers an emissions cap-and-trade system for, say, SO₂ or NOₓ, and they say, "We're going to take 5 percent of all of those allowances, and we're going to give them away for free to eligible renewable generators that are non-emitting."

So they've essentially given the renewable generator something that they can then sell into the market, so it's additional revenue to the generator.

That is separate from a REC, but some have argued that if you sell off essentially that set-aside allowance, then your REC is not whole anymore. It's less of a REC, because you've sold the emissions attributes to somebody else. So there are -- I think people would fall on both sides of that argument.

MR. ASHBURN: Does that make it a wrecked REC?

MR. KATOFSKY: A what?
MR. ASHBURN: A wrecked REC.

MR. KATOFSKY: A wrecked REC. And just to make things more complicated, my initials spell the word "REC."

So those are things that need to be addressed as you go forward. You know, you could say in that particular example, you know, if the goal is to promote these renewable generators to the greatest extent possible, then why not give them a set-aside allowance and allow them to maintain their eligibility, full eligibility under the RPS?

But others may fall differently. If you tried to sell that REC in the voluntary market, you know, someone like a Green-e, which is the Center for Resource Solutions, they do this independent Green-e certification, they may say, "Wait a minute. You've sold off the CO₂, and you've sold off the SO₂, and this REC doesn't have all the attributes it used to have."

So this is a definite issue that, you know, you need to deal with. And if your goal is to promote renewables to the greatest extent possible, you might have one philosophy. If you're really trying to make sure that all the property rights and all that are fully accounted for, you may come out differently.

MR. TRAPP: But there's nothing inherently
wrong with -- I mean, this is a fictitious financial instrument. There's nothing inherently wrong with making it a multiple coupon certificate where you tear off the left corner to meet a PSC RPS requirement, and then you tear off the right corner to meet some other, maybe a DEP environmental requirement.

MR. KATOFSKY: Yes, you could do that, because you could define the --

MR. TRAPP: You just have to coordinate.

MR. KATOFSKY: You define the eligibility the way you see most appropriate, yes.

MR. MOYLE: I had a couple of questions. Jon Moyle with the Moyle Flanigan law firm. And the questions I had related to markets, because I think this is largely sort of a discussion about how to set up a market that works in Florida.

I presume from some of your earlier answers that there hasn't developed any kind of secondary market for these property rights. Is that right?

MR. KATOFSKY: Yes. I mean, you don't have a hugely liquid REC market, for example, so a lot of transactions for compliance are just bilateral agreements between generators and buyers, and then they register those transactions with the registry.

There was an earlier question about
confidential information. You wouldn't necessarily have
to disclose, say, the price you paid under that
transaction, but you would have to disclose to the
registry that there was a transaction.

But there isn't yet a -- you can go, you know,
to evolution markets or other brokers, and you can go
and purchase RECs on the voluntary market. But I would
say there's not a huge -- there's not like a big trading
platform where you can -- like the equivalent of like a
NYMEX or a CBOT.

MR. MOYLE: What in your opinion is the most
developed market in the country for these RECs? Is it
up in the Northeast?

MR. KATOFSKY: You know, Texas has been
functioning quite well for a number of years. The
Northeast is coming along. They've had issues with
sufficient quantities available, particularly in
Massachusetts, and that's starting to change. But I
would say the Northeast and Texas are two good examples,
yes.

MR. MOYLE: And given the question that TECO
asked about Texas and I guess the geographic issue,
would I be correct that given Florida's unique
geographic position, that the Texas model ought to be
something we should take a hard look at, in your view?
MR. KATOFSKY: You know, I haven't thought too much about that. I think Texas has some unique characteristics that allows it to function pretty much as its own island, effectively. I mean, there's limited interconnection, and there's ample wind resources within the state, so they set it up that way. I'm not as familiar with that issue in Florida as to how much you could, say, wheel in from out of state.

MR. MOYLE: And then the final question I have is, just related to your experience and whatnot in terms of trying to establish a market that promotes renewable energy, would you mind just expanding a little bit on your views as to the compliance penalty as it relates to how that should best work? You know, recovery, some portion of recovery, what's your feelings on that?

MR. KATOFSKY: My feeling, I mean, you know, if investments are -- there's regulated states and there's deregulated states. And the regulated model, if you're making what you might call prudent investments in either procuring RECs, or in the absence of RECs that are available, paying the alternative compliance payment, it seems reasonable to me that you would be eligible for the cost recovery, at least partially. But I think that's the decision for this -- it's not for me to say what this group ought to decide, but that seems
reasonable to me.

MR. MOYLE: Thanks.

MR. ASHBURN: Bill Ashburn of Tampa Electric again. You mentioned shelf life.

MR. KATOFSKY: Yes.

MR. ASHBURN: What kind of shelf lives are being applied to RECs, and are they consistent across the various markets?

MR. KATOFSKY: This is the issue of banking, so can you save a REC for later. Anything beyond three years I think you wouldn't probably find in the market, but there are jurisdictions that allow banking, say, for up to three years. And it has an important sort of smoothing effect on the marketplace.

MR. ASHBURN: I was going to ask for the rationale for the life. I mean, what leads you to determine it should be three years instead of two or four or whatever?

MR. KATOFSKY: I'm not quite sure. I would think if it had too long of a -- you know, it's just a question of making sure that the dynamics of the market in terms of building additional capacity and so on, so there is a -- if there's some element of "use it or lose it," it will encourage generation to continue to be built.
MR. ASHBURN: Okay. Thank you.

MR. MOLINE: Ryan, Barry Moline again.

There's five states and the District of Columbia that allow energy efficiency in their RPSs. Is there a separate type of attribute for a negawatt REC?

MR. KATOFSKY: Yes. They call them white tags.

MR. MOLINE: One tag?

MR. KATOFSKY: White tags.

MR. MOLINE: White tags.

MR. KATOFSKY: In some places, yes.

MR. MOLINE: And those, how are they different than RECs?

MR. KATOFSKY: It would all depend on how the rules are written in a particular jurisdiction. A negawatt, as you call it, or a white tag or energy efficiency, if that's an eligible resource, then there would have to be a way of accounting for that. And in that sense, it would function similar to a REC, I would imagine.

MR. MOLINE: So in the state, assuming that the energy efficiency is an eligible resource, then they could be traded?

MR. KATOFSKY: Yes, traded or some sort of --

MR. MOLINE: Or purchased.
MR. KATOFSKY: Retired, purchased or retired as a means of demonstrating compliance.

MR. MOLINE: So that's allowable in other states?

MR. KATOFSKY: It's allowable in some areas. And it may be subject to -- you have cases where there are multiple tiers within an RPS, where efficiency would be in one tier but not another, and there would be price differentials, say, between those two tiers, or you may have limits on how much of the RPS you could comply with with the energy efficiency component.

MR. GRANIÈRE: Ryan, Bob Graniere. That white tag part, that would essentially not be the same as a REC, though. I mean, wouldn't that be -- wouldn't the white tag also apply if a state were to suggest that it would have a renewable portfolio standard and an energy efficiency resource standard?

MR. KATOFSKY: Yes, you can do them totally separately as well; that's correct.

MR. GRANIÈRE: Then you could do them totally separate, and then they would be -- so a white tag would be a white tag, and a green tag would be a green tag, and they wouldn't necessarily have the same attributes.

MR. KATOFSKY: Well, they definitely don't have the same attributes. It's a question of whether or
not they both -- they may both qualify. So, yes, they
have different attributes, but they may both be
essentially what would you call an eligible resource,
yes.

MR. GRANIÈRE: Okay. I just wanted to clarify
it.

MR. McWHIRTER: John McWhirter with FIPUG. Is
there any accreditation organization that accredits
white tags?

MR. KATOFSKY: Unfortunately, I'm not familiar
enough with it to answer the question.

MR. McWHIRTER: It seems to me that since the
consumer is the ultimate obligor with respect to most of
these things, if you could give incentives to consumers
for energy efficiency or avoided energy cost, it would
go a long way toward educating the public. Are you
aware of anything in the nation that is going along
those lines other than existing conservation programs?

MR. KATOFSKY: I'm not familiar, I'm afraid.
Sorry. There may be, but I'm just not familiar.

MS. CLARK: Can I ask a question about using
RECs or contract path? You show on your slide 8 that
Colorado also uses RECs. Can you sort of give the
history of why RECs were used, and are there issues with
doing both?
MR. KATOFSKY: It was just, I think, for --
you know, I don't know the details of how they came to
that decision, but it just provides another means of
compliance. If you're thinking of an RPS as having,
say, a certain degree of flexibility as to how you would
comply, then you can say either one would be
appropriate.

There are some jurisdictions -- I'm trying to
remember which one. I think there's one in PJM that
says that, you know, if you can demonstrate that a
sufficiently well developed REC market exists, then you
can start to use RECs for compliance, but until then,
you have to do it in a different way.

It's just a means of giving obligated parties
more flexibility. I don't know offhand what the rules
are for the eligibility of RECs in Colorado, so I don't
know if they've defined a geographic constraint for
those RECs or not.

MR. GRANIÈRE: Ryan, Bob Graniere. I think a
follow-up on Susan's question -- this may be outside
your area. I think I heard you say that it might be.
But I wonder if you could answer three questions for me.
They're all related to one another.

The first one is, about how long, in your
opinion, did it take to set up a functioning REC market;
(2) how long did it take to set up the organization that administers in some fashion the functioning REC market; and (3) what was the cost? And I'm sounding like that guy in that movie, Back to School, Rodney Dangerfield. And the subquestions are, how many -- do you have a breakdown as to what were coordination costs, what were information costs, and what were transactions costs?

MR. KATOFSKY: Well, the first -- I think I can answer the first question, maybe the second, and not the third. And certainly I never accept subquestions.

MR. GRANIERE: Very wise.

MR. KATOFSKY: Different markets have had different experiences. So when Texas got going, they were actually in a situation where they had sufficient RECs off the -- you know, right off the starting line. So they had a market that worked well, and they had a fairly -- they had a power market that was also functioning well, so they had no trouble in meeting their obligations, and the REC market functions well in Texas.

In Massachusetts, we had a very different experience. Excuse me. I'm going to suck on a lozenge.

In Massachusetts, they had issues relating to contracting for more than a year at a time for the incumbent utilities that became essentially the default
service providers, and as a result, there were some banked credits in Massachusetts allowed. So for the first year in Massachusetts, which was 2003, the RPS obligation was met, but largely through banked credits. Then '04, '05, '06, and into '07, alternative compliance payments were being paid.

And a key issue there was the fact that the capacity was not being built, and it wasn't being built for a couple of reasons. One, it was proving to be very hard to site projects in New England, and the other one was the way that the unbundled market was functioning in terms of how the load serving entities were procuring their energy.

And they were -- the idea was that the default service providers in Massachusetts would be transitory, that the competitive market would kick in, so they were encouraged to pursue short-term purchase agreements, and you just couldn't take that to the bank. So now we are in 2007, and we're actually doing -- in terms of the fraction of the RPS obligation that's being met by RECs as opposed to alternative compliance, we're doing better in '07 than we did in '06, and people think that by the end of the year or into '08, we'll actually no longer be paying ACPs in Massachusetts.

So the experience has been very different.
Other states, to be honest, have much less time under their belts to see how these markets function. So time will tell, I think, to see how well these markets function.

And as I mentioned earlier, the Massachusetts Technology Collaborative did some innovative things with their assisted benefits charge funds to help kick-start, help encourage the contracting, long-term contracting for RECs in Massachusetts. So they stepped in. They saw a need in the marketplace to help it get going, and they did some very creative things there.

So that was the first question. The second question was -- on the question of how much did it cost, I honestly don't really know. The second question was on the issue of how long it took to set it up. I believe.

MR. GRANIÈRE: Yes. Excuse me. Bob Graniere again. How long it took to establish the organization that administered it. Because like in the Northeast, they all generally use the already established organization, an RTO or an ISO.

MR. KATOFSKY: Oh, I see what you're saying.

MR. GRANIÈRE: But I'm wondering about places where they didn't have those things, like out in the West. And even in Texas, they had ERCOT, so that was
okay too. I'm more or less thinking along the lines here for Florida, since there is no ERCOT, there is no PJM, there is no New England ISO or anything like that, so it says to me new organization somewhere. What's your experience with new organizations?

MR. KATOFSKY: I don't have a lot. I know that, for example, in an analogous area, some states have chosen to turn over their energy efficiency programs to third parties, so there is precedent for that. I mean, it's not an instantaneous thing, obviously, and it takes time to sort of set up the structure. But in terms of exactly how long and what the experiences have been, I don't have a lot -- I don't really have any information. Sorry.

MR. McGEE: Ryan, this is Bob McGee with Gulf Power. A couple of questions.

On slide 13 where you talk about the penalties, in the middle column, the triggers for the different entities, the obligated parties specifically, you state there that the failure to acquire sufficient renewable energy or RECs might trigger a penalty in that particular case. Would it also be true, given the definition of a ACP that it's a compliance mechanism, that it would need to be a failure to acquire sufficient renewable energy RECs or ACP payments?
MR. KATOFSKY: Yes, you could look at it that way too. And again, this was a general statement. If the rule said yes, if you pay your ACMs, your ACPs, then you're in compliance, but if you fail to do it for, shall we say, for not making a good-faith effort -- or there may be other circumstances under which you fail to do it. So even if you were paying the ACMs, ACPs, there may be circumstances where if you were shown not to be trying to comply in good faith, they could still levy penalties.

MR. McGEE: Okay. One other question. At the end of slide 11 and the beginning of slide 12, you talk about the fact that an ACP price level needs to be higher than the expected cost of RECs, but possibly low enough to control overall ratepayer impacts. I think what you're getting to there is the -- sort of a rate cap or an expense cap type of idea.

MR. KATOFSKY: Uh-huh.

MR. McGEE: What's your opinion about the interaction between, let's say, an expense cap and an ACP?

MR. KATOFSKY: I think the answer may be that you would maybe look at one or the other, so an ACM, ACP works really well in, say, a REC-based system. If you didn't have a REC-based system and it was more of a --
it you did more of a contract path system, then you
might subject those procurements under that to, say, an
overall expense cap. So I don't think you would
necessarily need to have both, because the alternative
compliance mechanism that's based on, say, buying RECs,
especially, replacing a REC purchase would function in
a similar way to a more sort of deliberate expense cap.

MR. McGEE: Okay. I guess thinking through
the purpose of an ACM and the desire to make it as high
as possible to make it useful to run the REC market, but
also, for an expense cap to be reasonable, it seems like
you've got cross-purposes going on there, trying to
manage an ACM at a high level, but also at a low level.
And maybe the two of those might work together a little
bit more efficiently where you've got one, you can set
it as low as you want, and the other, you can set it as
high as you want based on the criteria that you need
there.

MR. KATOFSKY: I don't know if I have an
answer for that.

MR. FUTRELL: Ryan is going to be with us
today for the rest of the day, and there are a lot of
these areas we're going to get to as we walk through
some of the questions. I would like to give him a
chance to catch his breath and restore his voice for a
minute and let Judy walk through some of the questions, and then Ryan will be here for our dialogue to go back forth, and we can ask him --

MR. KATOFSKY: Thank you.

MR. FUTRELL: -- some of the follow-up questions. Thank you, Ryan.

MS. HARLOW: I'm kind of in the awkward position of going after the guy with all the answers. I have questions.

Mark Futrell asked me to kind of frame the questions we wanted to discuss today to have a more focused workshop on compliance and enforcement issues. As we go throughout the day, if you look at Ryan's presentation and then the questions I have today and then put those together, those are really what we want to discuss. And as you move forward after the workshop, we'll have a period for written comments, and we would appreciate any further comments you have in writing. Mark will let you know the schedule for that at the end of the workshop.

I'm Judy Harlow with staff, and I would like to talk first about RPS compliance. There are basically two verification methodologies or compliance mechanisms, and we would like to talk about today what's the best mechanism or combination of these to use for Florida.
Contract path, as Ryan discussed, gives you a bundled product of attributes plus energy, and the same can be thought of for utility ownership of the renewable facility. And in contrast to that, we have renewable energy credits, and Ryan talked to us about a state where there was a combination of the two, or you might consider using one as you move forward until the renewable energy credit market is more fully established. So we would like to discuss today if the parties or the persons today have any opinions on which of these or combination you think is best for Florida.

So once we have a verification or compliance methodology, we need the talk in more detail about how do we make the system work. And also, as was brought up from the question and answer period with Ryan, we would also like to consider, if energy efficiency is included toward compliance, what kind of verification methodology would we also need for conservation.

There are some common issues across verification methodologies, and these are some of the questions that staff has at this point in time. We would like to know what's the best way to administer a verification of compliance. In other words, should the PSC do this? Should we have a third party do this? We don't have ERCOT or another ISO system, so how would
that work for Florida? How would we handle the tracking function?

Also, should we have a weighting system based on specific objectives of the RPS? And there are several ways to do this. Ryan discussed the multiplier approach or some kind of a tiered goal approach to meet specific objectives.

Also, should Florida have some kind of a safety valve, such as the alternative compliance payment that we discussed earlier? If so, some of the detailed questions we would have about that is, who would administer such a payment, how would the funds be used, and should the IOUs recover alternative compliance payments, and if they don't, this acts as a penalty.

The last question on this page is, should self-service generation be counted toward goals? If it is, how do we do that? How do we capture those small PV systems, as an example, that are currently on people's homes without high administrative costs? And we would also want to look at our large industrial customers that self-serve, and how would that be included toward the goals. And a similar question would be with conservation. How would we count -- should we count conservation? If so, how would we do it? How do we capture the efforts of consumers behind the meters, for
example?

Also, there are some specific issues that deal
with RECs alone. These are some of the questions that
staff has about a REC system for Florida if we decided
that that should be used. Should out-of-state credits
be counted? If so, should we have some kind of a
regional limitation, for example, a requirement that the
energy be delivered to Florida or could be delivered to
Florida? And we discussed double counting earlier. How
would we track these credits so that there would be no
double counting, and how would we coordinate with other
regions to ensure that there's no double counting?

Also, what kind of flexibility measures should
be included in an RPS for Florida? Ryan discussed
credit flexibility systems such as banking. You could
also borrow from future production of RECs, and also
there could be a true-up period included to give
utilities time to comply with their goals.

We would like to look at how often utilities
should be reviewed for compliance. Many of you are
familiar with our conservation goals process that we
have here in Florida. The Commission sets those goals
for utilities every five years. But we also have a
review process that's ongoing where the staff is
continuously reviewing the utility's compliance toward
those goals, and we have reporting requirements on an
annual basis. So we would like to talk today about
should we set up something similar with an RPS so that
the utility's compliance could be tracked.

And also, what's the best way to ensure
compliance? Should we have some type of an alternative
compliance payment? And then you have issues with how
high should it be set, what about the penalties, or
should we simply have aspirational goals as we start the
RPS?

If we do indeed have penalties, what are the
specific issues we should look at with that? How would
you apply penalties, when would penalties be applied,
what would happen with these funds, who would administer
the funds, similar to alternative compliance payments?

Should we have exceptions for force majeure
issues? And one of the ways that we know that you could
do this is by extending any kind of a true-up period
that you had, or you could also reduce the obligations
due to force majeure.

And again, just like with alternative
compliance payments, should IOUs receive recoveries on
penalties? Is it truly a penalty if recovery is
allowed?

As we're looking at whether compliance has
been met, do we need a baseline of current renewables? And as you know from attending the past workshops, the staff has been working on this and getting your input on what renewables we currently have in the state. And Mark Futrell later will introduce a revised version of that, and we can discuss that today.

Also, what reporting requirements are there? If we have a REC system, do we need additional reporting requirements, or is REC tracking sufficient to see if utilities are in compliance?

And finally, should there be a process over time to review the RPS itself and see if the RPS the way it is currently set is in the best interests of Florida and its ratepayers? And one of the ways to do this would be by setting up an automatic process, such as I discussed with the conservation goals, in which we review goals on a five-year basis, and then we reset those goals as necessary. Or should we simply have an ongoing review process with no automatic process for review set in place?

These are just a few of our questions, so from our point of view, there are a lot of questions, and we really appreciate everybody's input today and look forward to continuing to discuss an RPS for Florida with you.
Thank you.

MR. FUTRELL: Thanks, Judy. We would like to ask that as we walk through our discussion today that we stay within our questions that Judy has laid out and move through that. Certainly there are going to be offshoots from many of these questions, and we'll develop them as we go forward, but we would like to try to keep the dialogue within these questions. And then when you file your written comments, if you so chose, to respond to these questions, you certainly have the opportunity to embellish if you want, but if you would use this as kind of a template for filing your written comments.

And just to give you a heads-up while everyone is here in the room, we're looking to have a transcript available about October 5th, and you can contact the staff if you would like a copy of that, Judy or myself. We also request that comments, written comments be filed by October 16th, which is a Tuesday. That would be very helpful to us. And if there's any -- if you think there's going to be a problem with that date, let us know before the end of the day, but hopefully that will give you sufficient time to take away from today and look at the transcript and get us something in writing.

So we're going to start off with looking at
the questions about the various methodologies. I think Ryan has gone into a lot of discussion about that. We had some good questions about it.

I guess one question I've got that, Ryan, maybe you could start off with is on this idea of a contract path versus the RECs approach. Is there any state -- with us being a regulated state, is there any tendency you've seen in the country as far as one approach being used in regulated versus deregulated states, and what the pros and cons may be, putting it in that kind of context?

MR. KATOFSKY: Yes. I think there are very few examples of the contract path approach being applied, so almost every state uses the RECs. The two examples that I came up with for the contract path was California, which has sort of gone back, you know, towards regulation. They kind of undid their unbundling to some extent. And there's this example of Xcel in Minnesota, and I think Colorado allows for contract path as well.

But there actually are very few examples where RECs are not used. The vast majority today use RECs. So I would start with looking at Colorado and California, frankly, as two examples where contract path -- and I guess Colorado is still a regulated state.
MR. TRAPP: As I understand it -- and I put this question to principally the utilities here. Bob Trapp, staff. As I understand it, using a REC system, as Ryan discussed in his presentation, you would need some form of administrative system for verifying, tracking, whatever. You would need some kind of marketing system.

And my question to you is, is that something that the PSC should do? Is it something that the collective utility industry should do? Is it something that individual utilities should do, 55 separate programs? Or is it something that we need to look elsewhere within state government to do? Has anybody got any opinions?

MS. GREALY: I don't think of it as being the role of the PSC. I was thinking -- first I was thinking of the FRCC, and then I thought, no, rule that out, keep them focused -- Anne Grealy, FPL. Sorry.

So then the other entity that came to mind was FCG as a possibility, but I definitely didn't see it. I mean, we haven't talked about it among ourselves. We can. But I didn't really see it as a role of the regulator. You know, you would be overseeing it, of course, you know, looking at compliance. We talked about the auditing function. But administering it, I
didn't see that. But we haven't --

MR. TRAPP: I don't see the FRCC -- I mean, the FRCC has got a pretty defined role now, and --

MS. GREALLY: Yes, I agree.

MR. TRAPP: -- I think the FCG has got a pretty -- but certainly their model, it seems to me, for something that could be put together as a collaborative effort from the industry working with the PSC and vice versa, to use that model to establish, you know, the tracking systems, the rules, the regulations, the trading, and even perhaps a broker, where you could centralize the trading within the State of Florida of Florida energy credits. Susan?

MS. CLARK: This is sort of asking Ryan to comment, but as I understood it, in the other states it is generally a third party that does it. It isn't the state that takes over the role; is that right?

MR. KATOFSKY: That takes over the role of administering it?

MS. CLARK: Yes.

MR. KATOFSKY: Specifically sort of the tracking system or sort of the enforcement? I mean, those are different --

MS. CLARK: As I understood it, the tracking and administering of it. Maybe I've got them --
MR. HINTON: No, that's --

MR. KATOFSKY: You have cases where third parties may basically run the tracking system. Enforcement typically falls to a state agency of some sort, obviously, but they wouldn't need to be involved in the day-to-day running of sort of the compliance mechanism; right?

MR. TRAPP: I guess that's part of my confusion, you know, what role would each party play in this. Because I think the PSC would want to have input with respect to definitions of what attributes a REC has, how those attributes could be used with respect to the RPS program versus some other programs. So I have a difficulty in my own mind thinking of it as a truly independent third-party organization that has contracted with the utilities to do this, and the PSC has no authority over those contracts, has no authority over that third-party individual.

Similarly, we don't have direct authority over the FRCC or the FCG historically, but we've found ways by which to get around that by using our regulatory authority with the individual utilities that are members of those systems. So I guess I'm still thinking in our historic vein of a utility member-based organization that would put together the necessary committees for
administrating, tracking, verifying, measuring, that type of thing, pursuant to the guidelines that the PSC would put forth, you know, in rulemaking.

MR. GRANIERE: Bob, could I sort of get you on that one?

MR. TRAPP: Yes, Bob, go ahead.

MR. GRANIERE: Basically, I think what you're talking about here, Bob, is setting up a REC RTO.

MS. GREALLY: Oh, God.

MR. TRAPP: Don't use that word, though.

MR. GRANIERE: I know, but that basically is what that model is. It's essentially an ISO or an RTO, or whatever you want to call it, that handles RECs, and that's what it is.

MR. ASHBURN: Yes. It's a REC tracking organization.

MR. GRANIERE: Yes, that's right, a REC tracking organization. I mean, basically, that's what it is.

MR. TRAPP: As long as there's no federal regulation involved.

MR. GRANIERE: And then you would go through the whole thing. And that was the new institution that I was talking about when I asked the question to you.

The question that I also have that's related
to that, out of all of the REC programs that you have out there that you're familiar with, because I'm not familiar with all of them, apparently, because one of the things I've never seen is a state that is traditionally regulated that has a REC program at the present time.

MR. KATOFSKY: Yes. I mean, almost every -- almost every single state uses RECs. Again, the only one that I can think of that would allow them would be -- you know, Colorado does allow them. Other states have provisions to look at it in the future as REC markets evolve.

MR. GRANIERE: But are those states traditionally regulated, or are they restructured?

MR. KATOFSKY: I think they're traditionally regulated. I don't have -- there's 20 some odd states now with RPS. I don't have them all off the top of my head, but --

MR. GRANIERE: Because what I'm thinking right now is that to move RECs into a traditionally regulated state would be cutting edge area stuff and not something that you're going to learn a whole lot from from looking at some of the other states that have the restructured and these other mechanisms available to them which are not available to a traditionally regulated state.
MR. KATOFSKY: I would tend to agree.

MS. HERIG: In Colorado, it is a traditionally regulated state, and the reason they did go with two paths was because of that, to allow -- and Ryan got to that, to allow the flexibility for individual consumers to make the investment, as well as the utilities, because they really did expect the initial investment to happen with the utilities. And I would say Florida is most like that.

I would also point out -- you know, Ryan's -- it would be his third slide. It had really sort of a complicated flow chart, but if you look at it and sort it out, the path that really applies to Florida is just the renewable energy generation, the RECs in the RPS being sold to the obligated party. So I just wanted to make the comment, let's not get too complicated right off the bat.

MR. TRAPP: Well, one of the observations -- again, Bob Trapp, staff -- that I would make is that so far in our discussions, we've been talking about three areas that I think have been contemplated counting against the RPS goals, and they're basically -- we've talked about whether conservation, energy efficiency, however that is defined, may count. We've talked about customer-owned renewable generation that is either sold
by a purchased power arrangement, or it can be a conservation measure, actually, being defined as counting, and we've also talked about utility-owned generation counting toward the RPS.

And I just throw this out. It seems to me that if we can develop a system of assigning a REC for each one of those program areas, that's the simplest, most efficient way to be able to account for everybody's input into this system. Then it's just a matter of managing each component, how do you deal with a bunch of residential, small kilowatt-hour RECs, and then how do you deal with large cogeneration type RECs, and then how do you deal with utility-owned and rate-based RECs.

I guess we can do that without RECs, but we wind up with a myriad of programs. And it just seems to me that if you put them on a common basis of issuing everybody a kilowatt-hour piece of paper for what they've produced that can be counted, that's one simplifying step in the process. So I would be interested in your reaction.

MS. CLARK: As I understand -- this is Susan Clark with Radey, Thomas, Yon & Clark. I apologize. I haven't been saying that. As I understand it, what you are proposing is the way -- a common denominator for all those things. And I think we heard Ryan say that by
having RECs and contract path, you increase the flexibility. And I certainly think that's something that we want to do, at least initially, is to have the maximum amount of flexibility in how -- if there's an RPS established, how to reach that. So initially I think that's a good idea.

MR. TRAPP: Would you generally agree that that entity that produces the renewable kilowatt-hour is the entity that should get and own the REC?

MS. CLARK: You know, Bob, I would say yes. My hesitation to some extent is thinking if you have other programs that are designed to promote renewable or promote a specific type of energy or address some other issue, how do you -- you know, how is that allocated? What is the fair way to allocate it?

But generally, I think as I understand RECs, you count it as it's generated, so it would make sense that it's part of whoever is generating it. But then you can have, I would say, a variety of legal instruments or legal ways of treating that.

MR. TRAPP: But I'm really -- yes, I agree there's legal ways of submitting property rights, and you're, I think, generally free to do that. I'm trying to think at the policy level, though. And I agree, there may be other policies that have gone before the
one we're trying to create now that may complicate the picture, but I'm trying to think in terms of -- let's think as if we're using a clean slate here and just look at RPS, design a good RPS system that maybe acts with tradeable RECs, and then if we have to go and adjust other policies or see how they fit with regard to this one, we can do that. But I'm trying to start with basic policy principles.

And to me, if you generate it, you should own it. If you own it, you can go into the market and sell it. That's how you get the money to incent you to generate it in the first place. That's just my little simple logic that tells me that should be the basis for our policy.

MR. McGEE: Bob, this is Bob McGee at Gulf. And I have one comment about that as it related to customer-sited generation that might be net metered, for instance. And I know there's another workshop series associated with that, but let's just take that as an example.

A customer may own a generation system on-site behind the meter, and by your description there, own the RECs. But I could also see an argument that said because they are net metered and there is a subsidy associated with the net metering, those RECs might...
belong to the general body of ratepayers that are
subsidizing through the net metering arrangement.

There's also another issue at hand there, and
that is incentives, significant incentives that might be
paid from the state level for a particular generation
type at somebody's location behind the meter. Does that
then allow the State to take possession of the RECs for,
let's say, statewide REC compliance?

MR. TRAPP: You mean like a conservation
program or --

MR. McGEE: Let's say -- let's use the example
of PV, which is given a rebate of $4 a watt, which is
essentially half the cost of the installed equipment if
they get it installed and are awarded the rebate. Does
the State then have any claim to -- and I think you said
it correctly. It's a property rights issue. Does the
State then have any claim to the renewable energy
attributes of that by virtue of the fact that they've
just spent some money on that particular facility?

So those are a couple of issues that I think
need to be talked about. I don't think I would agree in
general that anybody who owns the facility would then by
default own all of the renewable energy credits
associated with it. And those are two examples.

MR. GRANIERE: Bob.
MR. TRAPP: And again -- let me just finish the thought, Bob, and then we'll come to you. Again, my basic difficulty with this is, when those programs were established, they were established in the vacuum of no RPS. Now we're dealing with an RPS. Should the RPS be tweaked to conform with those old policies, or should the old policies be changed to conform to the RPS?

An example, with respect to, okay, net metering, well, how much is net metering worth? What kind of subsidy are you getting from net metering? I mean, should we just take increment of subsidy there and subtract it from what we're trying to provide in the RPS? You're getting into arguments like that.

With respect to the government incentive program, did the law say that the State wanted to keep those attributes? I don't think it did. Do we want to go back and change the law where it does now capture those property rights?

I think it is important that we take that into consideration as we design and perhaps issue such as set-asides, multipliers, and things of that nature. Maybe if solar needs a 5-to-1 multiplier, as was discussed in the last workshop, maybe if you count out the current state subsidies or incentives and net metering and other things, maybe that multiplier only
needs to be 3-to-1, and maybe that could be a consideration here.

But I just kind of want to start with the pure base of, if I generated it, it's mine, if I can sell it in the market and get some price for it, it incents me to build it. And then I guess we need to work on the devilish details.

I think Bob Graniere wanted to --

MR. GRANIERE: I would just like to respond to your scenario, because I think it's not quite as complicated as you're making it out to be. Bob Graniere.

The situation that you put out said that the person would be net metered. That's the equivalent of selling a bundled renewable to the utility, because basically you're selling the renewable and the energy to the utility. So at that point, it would be -- the REC would move along with it to the utility.

The fact that the met metering is pushing the meter backwards, it's essentially the utility buying it, so it seems to me that that's just the sale of a bundled bit of renewable to the utility at the retail rate, which is what is generally considered to be the fair, just, and reasonable rate because it's the fair, just, and reasonable rate. So therefore, that REC would move
its way into the utility's pocketbook.

But that would only be for the REC that --
that would only be for the REC that actually found its way into the distribution system. The renewables generated that stayed in the house, those RECs would stay with the owner, because they never got pushed out of the house. They stayed in the house, and so they would get those RECs.

Now, there would be a metering issue with all this other stuff about how do you account for those, yes. I mean, that's a technical issue. But as to who has ownership, it's pretty clear. Now, if, however, the money, the amount of compensation that came to the utility was the as-available energy price, for example, or something else, well, then you've essentially unbundled the renewable attribute from the power, and then, of course, the REC would stay with the homeowner.

So basically, at a conceptual level, this is a fairly simple problem at the implementation level, which is mainly a metering problem, and there's a lot of cost involved with that. And so in the interest of actually getting a renewable portfolio standard at a reasonable cost, and I know you're all expensive and all tied up in there on reasonable cost, I wouldn't worry too much about those, because, you know, how much do they
That's all.

MR. MOYLE: Bob, Jon Moyle with Moyle Flanigan. I seem to recall, at least on one point, about who owns the renewable attributes, that the rulemaking that was engaged in a year or so ago on renewable energy, I think there was language in there that said with respect to generators, that renewable attributes are owned by the generator. So it seems that that bridge has already been crossed there. Now, to the extent that you get into net metering or whatnot, I would argue that probably sets a little bit of a policy direction.

But I wanted just to comment on your initial question, which was what role should the PSC play in this process, and provide a comment there and then ask Ryan a question, if I could. But it seems to me that the PSC has to play a key role in this renewable energy process and the REC process by virtue of the fact the Governor has issued his executive order.

If I understand what's going to happen in this process, we're going to have workshops, and eventually we're going to go to rulemaking, and you all are going to have rules that will have to be enforced. And while I think you have the option to say should we do this
in-house and track this and administer this in-house, or
should we contract with Ryan or somebody like Ryan to
help us do that, I think that's an option.

But it seems to me that the PSC has to play a
key role in this. And I would suspect the Legislature
will be seeking information about how we're doing
meeting renewable energy goals and things like that, so
I think you've got to be there playing an important
role.

But the question I wanted to ask was, is there
any other state -- because he's the expert on what is
happening in other states. Is there any other state
that has had an administration of RECs in a way where the
public entity was not involved and the whole program was
sort of administered by a utility organization?

MR. KATOFSKY: I am not aware of any examples
where it was just the utility sort of setting -- you
mean the utility setting the rules, basically, or --

MR. MOYLE: Yes, just in terms of reporting
and tracking and things like that. I mean, I think my
view is, and this is a personal view, you've got to have
transparency to have the market work, and if you don't
have transparency, it's a negative impact on the market.

MR. KATOFSKY: Right. So utilities as parties
to an RPS may have reporting requirements, but typically
those reporting requirements would be spelled out either in legislation or in some kind of rulemaking. But they might be required to send quarterly or annual reports on how they're doing with compliance and other aspects, and the state may also be required to do a report as well.

MR. MOYLE: Thanks.

MR. COOPER: Can I chime in? My name is Jeff Cooper. I'm with Lake County government in central Florida.

I think I see a little mouse hole to get my two cents in this thing. The staff asked the question about, in my view, sharing and participation in the program. And I think the gentleman was correct that the rule of who owned the renewable generating issue was settled last year.

But in terms of the REC -- and this is where Lake County is concerned. We have a waste energy facility, and in fact, we see us as providing the supplier, as a fuel supplier. And in order to understand the issue, we've separated the players out to fuel suppliers, energy producers, and wholesale purchasers so that we could keep everybody separate. And we think everybody should participate in the game, and we think that as a result of participating in the game, we should also be compensated.
Now, obviously, I'm not looking for 100 percent compensation, but I would like a little piece of the pie so that I would then be entitled or have the incentive to participate in more renewable energy. For example, if I was part of the REC process and I was to receive a payment or a portion of a payment or a little piece of the payment, then I would be encouraged to expand my renewable energy facility and thus contribute to the renewable energy goals that are set up for the state and for the local -- for the individual power company that is dealing with this.

And there, that makes everybody a participant in this. So not only would we get a payment, but the person who actually produces the energy, the renewable energy, gets a payment. And then, of course, the person who has to -- who actually buys it would receive a portion of that payment as well.

And I don't think it's very difficult to separate the money. You can do it by percentages. You can use a simple calculation, and that's kind of the process that we went through. We said, well, what if it was, you know, based -- let's say the payment was $800,000, and you turn around and you say, okay, we got 25 percent, and the other got 25 percent, and then the actual purchaser got 50 percent. You know, whatever
percentage you want, it's immaterial, the percentages. You set them up, and that's what you share.

And in the same regard, the banking is a real important issue too, because even though -- let's say a utility would have, let's say, a 10 percent requirement at some point in time. Then they would have to turn around and say, okay, I've got 9-1/2 percent, and I have to buy a half a percent to meet my goal. So since RECs are cheaper than alternate compliance payments, okay, but I know I'm going to be able to meet my goal in two years, so I want to go out, and I want to buy three percentage points of my requirement. Even though I only need a half a percent, I want to be able to do that. Okay? So you see all this banking and all these other things, but even in the banking scenario, they still have to pay for who's supplying the renewable energy.

Now, if in fact they are supplying the -- for example, if you have solar or you have wind, where you're taking it that's there, then you get that portion of the payment anyway. So it can work, and it can work in terms of splitting up the payment, and it's just a matter of how much everybody gets.

I don't know if that makes sense, but that's kind of what we're looking at. We want to be a participant, and we want an incentive, and that's a way
to incentivize the local population to get involved in renewable energy.

MS. HERIG: Just a quick comment on the little PV system and the whole Colorado situation. Ryan, I welcome you to correct me, but the last I heard, for little PV customers, they were actually letting the utilities provide an up-front payment, you know, a capital payment, similar to the Florida program that's being run by DEP now. But by the utilities doing that, they owned the RECs for the life of the system, and it was a real simple way for them to do it.

Any corrections, Ryan?

MR. KATOFSKY: I'm not aware if that's going on in Colorado or not, but I am aware that there are at least one or two utilities that are talking about what effectively amounts to a forward purchase of solar RECs, and that's essentially a way to finance the system. You know, the forward purchase comes in the form of basically an up-front lump sum which pays for the system, and then the title to the RECs is essentially like the loan payment, if you want to think of that in a fairly simple way.

MS. HERIG: Right. So that would, you know, get it into the RPS that you're talking about.

MR. KATOFSKY: And that's --
MR. TRAPP: But you start with the principle that the RECs are owned by the solar producer.

MR. KATOFSKY: That's correct.

MS. HERIG: That's absolutely correct.

MR. KATOFSKY: That's correct.

MR. TRAPP: But if that solar producer wants to sell them in advance, over time, the rate, negotiate, let's make a deal --

MS. HERIG: Yep.

MR. TRAPP: -- it's up to them to say yes.

MR. KATOFSKY: Right. So there's a contractual arrangement between the buyer and the -- essentially, the buyer and the seller in this case.

I'll add one comment on this issue of property rights and attributes. Of course, if you go back enough years, this issue didn't exist at all. Now, typically when contracts are written, say a power purchase agreement is written, and that power purchase agreement, let's say for argument's sake, includes the bundled REC, there may also be provisions where the purchaser says, "We also have rights to any new attributes that may arise in the future, even if they are not yet defined in the market."

So they're being very explicit now about what they're buying. So they're buying all the attributes,
even attributes that people haven't conceived of yet. So whether it's -- or that are not actively traded in the market. So people have become much more aware of this issue, obviously, because of this concept of attributes being separable products from the generation.

MR. MOLINE: Barry Moline, Florida Municipal Electric Association. I think the structure that Bob described is -- Bob Graniere described is generally reasonable.

There's a few other, I don't know, considerations or monkey wrenches that I would consider, and that is, the first question is who's required to comply, and the answer is utilities. I mean, we're the ones that -- somehow through the process of working with our customers, we're the ones who have to report, do whatever we need to do with the Public Service Commission or whatever the independent body is to make sure that we're meeting whatever goals there are. So if a customer owns a REC, somehow it has to be channeled through a utility to get to the compliance component or activity.

As a result of that, you know, there are state rebates, and if the State chooses not to be interested in the RECs, that's fine. If the utility provides an incentive to a customer that may be in addition to the
state incentive, then that customer installs a system and it goes online. But for the utility incentive, that project may not get developed, and I would say as a utility that the utility should therefore have the RECs.

In the case of -- even where a PV system looked like conservation because it was just the customer independently alone having a PV system on his house that reduced energy consumption, if there is an incentive involved from the utility to the customer, the utility should be the one that owns the RECs.

So if there -- however, if there's a completely independent customer investment that involves maybe just the State, who doesn't care about the RECs, and the utility provides no additional incentive, then in that case, I would think that the customer should own the RECs. The utility doesn't have any rights to it, didn't ask for that investment to be made. It looks, you know, for the sake of this discussion like conservation. Those RECs belong to the customer. But where the utility makes an investment or an incentive to get a project going, in that case, the utility should own those RECs.

MR. GRANIERE: May I respond to that, just to see if I think I know where we're going? Bob Graniere. I would agree with what you said if the utility made up
the difference between the state incentive. For example, let's talk one kilowatt of PV at the current $8,000 price. Okay? If my understanding is right, about half of that comes from the State for 4,000. Now, if the utility were to provide the other $4,000, essentially put it on and then up it goes on the house, I would have to totally agree with you that since the state portion is a subsidy, a true gift to the homeowner, that the utility would get the entire REC, because essentially they bought it. Right?

However, let's say the utility only gave 200 bucks. Wouldn't you think that it would be right to somehow split that REC?

MR. MOLINE: No, I don't. I think that what's important is for the utility to find the price point that tips the customer to make the investment. The customer also has a benefit as well of lower energy bills, so the utility is doing, you know, good marketing to convince customers that you get an investment or a rebate from the State, and in addition, we'll provide this incentive to you. And but for that incentive, you know, those customers might not do it, but because we'll provide that additional amount, we're interested in those RECs.

MR. GRANIERE: Okay. Let me ask this then.
From what I'm hearing you say, any contribution by a utility gives them ownership of the REC. And then I would think that the next argument would be that that contribution should be recoverable from the ratepayer, if I'm right. So then I would guess what I would have to say then is that when the REC is retired or sold at some value, that you take that value, and wouldn't you credit it back to the ratepayers and lower their bills?

MR. MOLINE: Bob, unfortunately --

MR. GRANIERE: Unfortunately, somebody's got to get the value. I mean, that's what it boils down to.

MR. MOLINE: Unfortunately, I can't answer that question the way you would like me to, paint me in a corner, because I'm a municipal utility. So to me, those belong to our community.

MR. GRANIERE: Yeah, right. See, that --

MR. MOLINE: So I can't answer that question the way --

MR. GRANIERE: Well, you can for yours.

MR. MOLINE: As a regulated utility by the PSC. I'm sorry to do that. But, Susan, if you want to go for that -- you know, you don't have to.

MR. GRANIERE: Excuse me before you come in, Susan. I guess what I heard --

MR. MOLINE: You don't have to either, but --
MS. CLARK: I wasn't planning on answering that.

MR. GRANIERE: I guess what I heard then, Barry, is that in your case, because you're owned and locally governed and all those neat things, that you indeed would credit your bill back.

MR. MOLINE: The bill back to the general ratepayers.

MR. GRANIERE: Yeah.

MR. MOLINE: That would be a benefit to the entire community, so the way you said it, the answer is yes.

MR. GRANIERE: Okay.

MS. HERIG: Just a quick. You know, typically the utility is going to take that REC and retire it to meet their RPS obligation. But I think the regulators here regulate that whole cash flow within the utility, so, you know, I just think it's sort of -- you know, if they were to sell it, that becomes part of their revenue, you know.

MR. TRAPP: I think the only difference I may have with Barry's premise is, I start off with that we don't have to assign RECs to these people. We can say, "Utilities, build renewables. 100 percent of compliance with the RPS has to be from you building renewables."
don't think that's wise, though. I think we should all be partners in building renewables.

And having said that, if an individual homeowner builds something for whatever reason, he should have the rights to the REC. Now, if that homeowner wants to negotiate away, and by that I mean if he says, "Gee, the only way I can really build this is if I take the City of Tallahassee's incentive program that's only to give me 10 cents on a dollar for my REC," that's a business decision the customer has made to accept your 10 cents on a dollar.

So I can kind of agree with you on that concept, but I start with the basic premise that the REC producer is the REC owner, and therefore the decision-maker on how to dispose of that REC, recognizing under the rules of the game, the only place he can -- the only thing he can do with that REC is sell it to some utility or retire to it try to drive the market price up. That's the only clarification I would put on your example.

MS. SZARO: Jennifer Szaro from Orlando Utilities Commission. Just to give you an example of how we've tried to address the issue in our solar incentive program, we did want to focus on customer-sited systems. We felt that was the most
cost-effective, and when we did our financial analysis, it did prove to be the most cost-effective method, was to give an incentive rather than trying to self-build everything, not to mention it supported our distribution system much better that way, and we could look at doing some supply-side management if we had battery backup on-site.

So our incentive that we've just submitted to the Public Service Commission includes a five cent over retail production incentive for PV and a three cent production incentive for solar hot water, which we meter with a Btu meter. And we have a contract with the customer that says that if they participate in our program, we will net meter them, and we will give them the five cents in return for the REC, the idea being it's their REC. We feel that there has to be a market transaction to purchase that REC, and we're making that transaction with them.

And if we go to a compliance market and the market value of that REC goes up, we would look at making sure that we're offering them a competitive offer. And if they choose to sell that REC to someone else, that's their right, but we want to make sure that we are able to bring in as much to our community as we can through customer-sited systems.
So we spent a lot of time with our legal staff to make a simple contract that would address the issue effectively, acknowledge the customer's ownership of the REC, and yet help us meet our own compliance goals.

MR. FUTRELL: Let's, if we could, take about a 10-minute break and let the court reporter and everyone take a little stretch. So let's get back together in about 10 minutes.

(Short recess.)

MR. FUTRELL: Okay. Let's get started, if everybody will take their seats.

Okay. I would like to before we move on -- we've talked a lot about RECs this morning, and before we leave really the first page of Judy's notes, I would like to get a little bit more into contract path and try to explore about where that stands. Bill, do you have a --

MR. ASHBURN: Yes, I just have a thought. I would like to get back to Judy's stuff. We like Judy. But on the contract path stuff, if that's the one we want to do -- and maybe we do want to do a mix of the two. I don't know. But, you know, I was thinking about tracking. We do have kind of a tracking mechanism that exists, at least in FRCC, that could be used for that if you use contract path and tie the energy to the REC...
through the OASIS.

    And the OASIS has got a tagging mechanism that tags transactions. You could set up some sort of a tagging mechanism which tags this industry as green or whatever, and that would be one way you could at least have a tracking mechanism for the contract path approach.

    MR. TRAPP: Does that only work, though -- Bob Trapp, staff. Does that only work, though, for the large to-grid transactions?

    MR. ASHBURN: Right. This is Bill Ashburn again. I guess I didn't give my name. It would have to be stuff that was able to transmit over the transmission system, which has to be more than a megawatt and that kind of thing.

    MR. TRAPP: Right.

    MR. ASHBURN: And it would only be in the FRCC. Anything outside of the FRCC would have to get tracked some way through it as well. But the OASIS does have a tracking mechanism with tags that maybe with minor programming or some sort of setting of codes, you could track those kind of transactions. I just thought I would mention that that's out there.

    MR. TRAPP: That's what I'm struggling with, is that I think there are a lot of existing systems that
are out there that --

MR. ASHBURN: Yes. That's one I know of.

MR. TRAPP: -- probably could be pulled

together. The question then becomes how do you
coordinate all of those different entities and
everything?

MR. ASHBURN: Right, right. That wouldn't
necessarily --

MR. TRAPP: Some kind of central --

MR. ASHBURN: That wouldn't obviate the need
of some central accounting mechanism or getting it to
you, but there is a tracking mechanism for larger
transactions where you could maybe set up something for
green tags to it or something. I just thought I would
add that.

MR. TRAPP: And under -- you know, Ms. Clark
raises her preference for a third-party entity to do
this, and I think I also have a preference for a
third-party entity to do this to, to, if nothing else,
pull together all the disparate pieces. But them my
concern becomes what role does the PSC have in oversight
with regard to that third-party entity? We have some
indirect inputs into FRCC, FCG, those types of industry
organizations. Of course, the FRCC now is a federal
agency.
But that's the relationships I'm trying to work out in my own mind, is how you would set up -- given that we don't have any other legislative directive in terms of the establishment of such an agency, I have to look at it from my back yard. So how would the PSC interact to create -- certainly I don't think we have staff or budget to do it at the PSC level, so I always look to the industry, you know, the conventional role we have of we run around with a big stick -- we think it's a big stick -- and let you all do the lion's share of the work, and we just make sure you kind of do it right.

MS. CLARK: Bob, I guess my reaction to that is, that has worked in the past for the various ends you were trying to accomplish. And as I was talking to Ryan at the break, he indicated that -- I've got to be careful. I think he indicated that most of them were done through a third-party administrator, where it may have been a proposal that the state put out that was responded to. As he recalls, it was part of a whole deregulation package, so we are somewhat different.

But those are things I think we can think about. There is precedent for actually having an agency or an entity that has some oversight by the Commission. In telecommunications you have the Relay system. I don't know if that's still functioning, but --
MR. TRAPP: Just discussing the idea, there's nothing that prevents, I don't think, the industry to come together as a group to jointly fund and contract with a third-party agency, while at the same time preserving the role that the PSC has over regulating the individual members of that organization. I guess that's the kind of model that I think of when I think of FRCC before it became a federal agency, the FCG --

MS. CLARK: Right. And you had done that with EPRI as well, and the research --

MR. TRAPP: EPRI, and working with PERC and all those things. There are contractual arrangements that the utilities become members of, and then the PSC kind of does our regulation of the individual utilities, depending on what level of regulation we have over those entities.

MS. CLARK: It has worked in the past, and I think it is something that should be looked at in this context.

MR. GRANIÈRE: Bob, along the lines on that -- Bob Graniere. One of the things we might want to think about is -- and I think Jon Moyle brought this up. And, Ryan, correct me if you think I've gone too far here. Usually on something like this, you would want to have -- we would want to have all -- we would want to have
transparency, which means all the stakeholders are represented in that particular organization. And then when all the stakeholders get represented in that particular organization, they work out their agreements for tracking and that kind of stuff. And then what happens -- and I hate to come back to this RTO stuff, but basically that's the system of what an RTO looks like. And the RTO actually is regulated. It's light-handed regulation, but it actually is regulated by FERC.

So I would think that an organization like this that would be only for Florida, the PSC would take on the role that FERC currently has with these ISOs and RTOs. And the actual tracking thing, to avoid this problem or this perceived problem of the utilities being the only parties being involved in the tracking and verification and all that stuff, if there's full stakeholder participation in it, then that gets taken care of, and then it's done.

Now, that's the plus side, but the downside is that it usually takes a fair amount of time to put together an organization like that.

MR. FUTRELL: So in the interim, is the contract path -- to get to that point where Bob is talking about, is the contract path kind of the bridge
to get you there? And also, as far as the contract path, how do generally those systems deal with smaller generators? Is there room in a contract path approach for home generators, self-service generation? How is that accounted for?

MR. KATOFSKY: I'm not quite sure now California deals with that. Do you know?

MS. HERIG: No, I'm not sure how California deals with it. I was going to say something else.

MR. KATOFSKY: Yes, I mean, clearly that would be an issue with smaller generators. I mean, if you had large cogenerators and so on, I think they could participate more readily. So having something like certificates as a means of compliance does help with the small generators.

I know New York, their system resembles a contract path system in the sense that you have long-term agreements between the generators and the state as the obligated party. They actually carved out a small percentage of their RPS that they refer to as the customer-sited tier, and they haven't -- so they're actually handling the customer side of their RPS in a totally different manner.

So that's another -- and it does create a separate -- you know, in terms of complexity, I guess it
does create an additional program to manage, but they chose not to -- you know, because of the approach they chose for what they call the wholesale tier, you know, they just carved it out altogether.

MR. TRAPP: Could you just briefly -- aggregators, aren't there businesses out there that have the business of aggregating small renewable credit loads to package to transfer to a utility?

MR. KATCFSKY: Yes, there are companies that have that as part of their business model, so they would aggregate up from the small generators and issue a -- they have maybe a very simplified standard contract that doesn't take a lot of negotiation or other -- you know, it's not time-consuming, so you have a fairly simple, you know, fixed price arrangement or other kind of arrangement where you acquire the title to the RECs, and then they could sort of bundle them up and then be a participant in the market, yes.

MR. TRAPP: I think you also mentioned in your presentation this morning that -- was it New Jersey that was putting it on the bill? It appears to me that if a utility has got a meter, they ought to know what's going on behind it, and they ought to be able to communicate through their customer relations to try to act as aggregators themselves on the bill.
MR. KATOFSKY: Right. I don't think it was specifically putting it on the bill, but it was getting involved in the forward purchase of solar RECs. So obviously, New Jersey is an example where they have a very explicit market for solar, so what happens on the customer side is particularly important, because that's the primarily means of complying with the solar component of the RPS. So they spent more time thinking about how to handle that customer-side resource because it's the primary means of compliance for solar.

And this forward purchase is one example, essentially where the utility is taking that hassle away, if you will, from a small generator trying to figure out how they're going to sell their -- I mean, a two-kilowatt system maybe will generate three RECs a year, right, three megawatt-hours, roughly, a year. So to go through, you know, all the -- you know, if you have to register and everything else for three megawatt-hours, it would be a bit of a hassle.

MR. TRAPP: Right.

MS. HERIG: And that's the same thing I think that's going on in Colorado. It's a contract between the utility customer and the utility. So it's a contract path, and the RECs are -- you know, the market is starting to emerge using that contract path, you
know, until you get something set up.

MR. ASHBURN: This is Bill Ashburn. What about the shelf life thing? Can you purchase farther ahead than three years, which is the shelf life for these things, or is there a limit there?

MR. KATOFSKY: The shelf life refers to RECs you already have title to, so it's not the issue of -- the forward purchase is a separate issue. You can have a contract to purchase RECs for more than three years out, but if you hold a -- some jurisdictions allow you to hold RECs that you already have title to for a certain period of time. As an obligated party, I could go out and, you know, execute a 10-year agreement to purchase RECs, or longer, if I chose to do that. That's different from what I would refer to as shelf life.

MR. ASHBURN: Can you count those forward RECs towards your current RPS requirements, or do they only apply to the year they accrue?

MR. KATOFSKY: I don't think there's -- I think to do -- there are some states, I think, that allow what we call early compliance, but I don't think it would be for using future RECs.

MR. ASHBURN: Okay. And what happens down the road if you've bought future RECs for ten years, and five years out the house gets trashed out for some
reason and the device is gone?

MR. KATOFSKY: Hopefully there's some insurance. I mean, there might -- I assume that the contracts would cover some of those provisions.

MR. ASHBURN: Yes. That simplified contract is getting more complicated; right?

MR. KATOFSKY: And that's an interesting point. I mean, that would be, you know, the main reason, I suppose, if you've got a rooftop system. You know, it's unlikely to otherwise break, although, for example, things like inverters do tend to require replacement, and that would be an issue.

What happens -- you know, as a homeowner, if my inverter fails, how quickly or how likely am I to get it replaced? Well, if I had an obligation to sell RECs -- and in the case of New Jersey, you know, solar RECs go for several hundred dollars a megawatt-hour, so it's not 10, $15 a year that we're talking about. You know, if I'm on the hook for a 1,000 or $1,500 worth of RECs in a given year to deliver, then I'll probably get my inverter fixed.

MR. TRAPP: Bill, could I ask you -- you brought it up, so I'll ask you. Why would you give a life to a REC longer than the calendar year in which you were required to meet a goal, given my understanding, at
least, that the goals that we're supposed to be looking at are 20 percent of all electricity produced is supposed to be renewable?

MR. ASHBURN: Why would you get, or why would somebody want --

MR. TRAPP: Why would you give it a life more than the calendar year that --

MR. ASHBURN: Somebody may want that.

MR. TRAPP: Well, I say that. The --

MR. ASHBURN: If the requirements --

MR. TRAPP: The REC is going to renew itself each year by generation.

MR. ASHBURN: Right, if we're talking about things like PVs, which generate the same amount maybe every year. But there may be technologies which vary with seasons or with -- you know, maybe you have a crop-based system and you have a great year, and then the next year there's a drought and you don't have anything. So there may be some need, you know, because you have to meet that amount every year, to bank some of it in a big year and use it in a lean year or something.

MR. TRAPP: So you're talking about to finance the renewable more than to meet the goal of the utility.

MR. ASHBURN: Right. I think the forward contracts he's talking about are helping finance the
renewable. But from the utility's standpoint, you may want to look at some averaging or some ability to bank in a bad year and use it in a year when you need it.

MR. TRAPP: It comes to the discussion points of the last workshop of are we going to create annual goals, or we going to create five-year goals, or are we going to go out in time somewhere?

MR. ASHBURN: We don't have any hydro here, but there's years when there's lots of water and years when there isn't so much water because of drought and so forth, so they may be able to have a year when they're just swimming in RECs because there's so much water being produced because it's a wet year, and the next year there's a drought, and you may want to be able to carry that forward and average it over your obligations. That's why you may want to do that.

MR. TRAPP: Would you only want to bank surplus RECs? In other words, you have to meet your goals for whatever --

MR. ASHBURN: Right. That's what I'm saying. You may have to --

MR. TRAPP: And whatever carryover --

MR. ASHBURN: Exactly. You may have a 10 percent obligation, and you've got 15 percent of RECs this year because it was a great year for water or
something, and you bank them for a future period.

MR. FUTRELL: Anything else on the contract path line that would be stumbling blocks or concerns that -- this looks like something that can be easily -- when you begin something, you can easily move into and find your way and then move into these other compliance methods as everything develops and experience comes along.

MR. KATOFSKY: Right. I mean, clearly, you sort of have the infrastructure today in Florida to take that approach.

I guess the one point I brought up in the presentation is this issue of transmission constraints, so that would be one thing to look at. So if you found -- and I'll take the Texas example. You know, they had concentrated wind development in one part of the state, and they were having curtailment of the wind output because they couldn't deliver it to load. And so in parallel to their development of RPS, they also pursued policies and regulations that facilitated the building of more transmission. And today they have something called competitive renewable energy zones, I believe, CREZ.

So there are rules in place now in Texas that help facilitate transmission to ensure that they don't
run into bottlenecks related to the delivery of the
energy. And, of course, even though they have RECs, you
can only produce a REC if you can generate the
kilowatt-hour or the megawatt-hour, so the transmission
constraint still has a real implication for even a
REC-based program if you can't generate the power
because you're curtailed.

So that would be like a parallel activity that
you might want to look at. You know, if you identify
regions of the state that you have more, you know,
basically export potential, if you will, of renewables,
then you want to look at that else you need to do to
ensure delivery of that energy.

MS. HERIG: I haven't dug into it completely,
but the whole eminent domain issue here in Florida, and
the third party, and the large systems, and the creative
financing that's going on in California may become an
issue in the contract path here in Florida and is
something that really the lawyers need to dig into.

MS. HARLOW: Ryan, could you talk to us --
this is Judy Harlow with staff. Could you talk to us a
little bit more about how we could use our existing
system where the contract path methodology is already
kind of in place and move toward a REC system, to kind
of use the contract path and then transition into a REC
MR. KATOFSKY: The transition could occur — you know, I guess you could buy yourself as much time as you wanted, say, to implement a REC-based system if you started off with the contract path. And then initially, for example, you may implement that REC-based system, but you may have existing obligations under bundled contracts. But it wouldn't be that difficult, say, to take that bundled contract and essentially split it into two contracts, one for RECs and then one for energy.

And I believe that's what happened in the first couple of years in Texas as well, that even though there was a separate market, there were existing contracts that essentially transitioned over into a separate — you know, the obligation was met with bundled energy.

There's also no reason why you couldn't — even if you were operating in a state, you know, with a REC-based system, you could still execute bundled contracts and just deliver both — basically deliver both commodities simultaneously to somebody. So they're certainly not incompatible with each other.

MR. McWHIRTER: People are tolerant of me asking dumb questions, and I appreciate you being so as well. But it seems to me that if you're going to sell a
REC in advance under the contract path or analyze it, you've got to analyze it in terms of kilowatts as opposed to kilowatt-hours, because you're looking at the kilowatt-hours that a kilowatt will produce as opposed to measuring it in kilowatt-hours, because the only way you can measure it in kilowatt-hours is after the fact, as to what you actually delivered. I didn't see any analysis in here of megawatts or kilowatts as opposed to megawatt-hours.

MR. KATOFSKY: Right. I mean, RECs are clearly measuring energy and not capacity. There has to be an accounting mechanism, so a settlement period or a true-up period where you -- if you contracted for X number of RECs as energy, after that quarter or that month, if it's -- and I think to the earlier comment that some generation is variable, wind generation is highly variable by season, even by year. You can have a windier year and a not so windy year. And your contract, you know, may have basically an estimated amount, but you may get more or less in any particular year. But you're not -- you're still accounting for it as kilowatt-hours or as energy, you know, within a defined settlement period.

MR. FUTRELL: Ryan, a contract path approach, how does -- talk about how -- if a utility is a
distribution utility or purchases a predominant part of their power, how is it able to identify the various sources through system sales, you know, where there may be some combined amount of renewable and traditional fossil generation? Does that lend itself to being able to identify that for the utility to be able to report its obligation?

MR. KATOFSKY: Right. If you take California as the -- you know, that's really the best example of the contract path approach. They enter -- for RPS compliance purposes, they are entering into contracts to have renewable energy delivered, so the individual contracts have to be auditable to see how much was actually delivered under those contracts, so you would look specifically at how those particular generators performed and where they delivered their power to, I think. So you would look at it that way.

Now, California also has -- they have existing contracts, because in California they're at about 10 or 11 percent, I believe, renewable today, and they have a goal of getting to 20, and those existing assets count toward their goals. So there's both existing delivery and new delivery that's going to come online, but it's the individual contracts, I believe, that are audited or traceable, if you will.
MR. HINTON: Ryan, under contract path, does -- this is Cayce Hinton with staff. Doesn't that particular methodology assume a certain availability of renewables within the region, or also the ability to import the actual renewables? If you're tying the attributes to the energy, you've got to actually have the energy for that to be successful.

MR. KATOFSKY: Right. You have to be able to physically deliver it, yes.

MR. HINTON: We were talking about transitioning from contract path to a REC system. Well, what if your goal is contract path? What if you want to actually produce and use renewable energy, but you don't currently have enough available to meet your RPS? Wouldn't a REC system then be used to transition into contract path?

MR. KATOFSKY: Oh, I see. So you're saying -- let me make sure I understand. You're saying you would first allow, say, REC purchases, and you would allow a lot of discretion, say, as to where those RECs would come from?

MR. HINTON: Yes. You would be able to purchase a REC from the Midwest --

MR. KATOFSKY: Iowa.

MR. HINTON: -- until you're able to build it
or purchase it directly from, you know, Georgia or wherever.

MR. KATOFSKY: I think that would be -- it would probably the first time that anybody did it that way. Technically, I suppose you could do that to establish a market, but I think, if anything, the trend is the other way. You know, the trend is towards RECs, not away from RECs.

So if you were to establish, say, a contract path approach, I think one way to mitigate what you're referring to would be to make sure that the first year where the obligation begins is far enough out in the future that you would be able to meet that obligation. So you would give enough lead time to get those contracts in place.

MR. HINTON: If your goal was to actually, like I said, build renewable or actually purchase renewable energy, still wanting to have a REC system, though, the two aren't mutually exclusive.

MR. KATOFSKY: No, they're not necessarily mutually exclusive. You could have a period where the REC eligibility would change. You could say, well, for the first X years, we'll allow RECs from, you know, Florida and all neighboring states, say, with or without physical delivery, but starting in year X, we're going
to also require physical delivery to accompany
out-of-state RECs, or you might say starting with year
X, we'll just look inside the state for our renewables.
You could phase it.

You could have the -- you know, there's
certainly precedent for states going back in and, you
know, reassessing the issues of eligibility and taking a
look at -- you know, percentages might have been
increased in several cases where states looked at how
they were doing it and they said, "Well, let's actually
raise the standard." They have people look at --
biomass eligibility is a good example of where states
grapple with what type of biomass, what type of
technology, and they do change the rules. So, yes,
there's no reason why you couldn't phase in different
types of eligible resources.

MR. McWHIRTER: From the viewpoint of a
utility dispatcher, as I understand it today, you try to
-- your optimum dispatch is to dispatch the lowest cost
generation available. When you get into a REC system,
is that going to change the dispatch order if you're
running short on your kilowatt-hours or megawatt-hours
for renewable energy? Are they going to dispatch the
more expensive renewable energy and charge customers for
that rather than the less cost energy?
MR. KATOFSKY: I'll have to think about that one for just a second. I guess my first reaction would be that a REC-based system shouldn't change the way plants operate, because the -- and it would depend if it was a bid-based system or a cost-based system which determines essentially the dispatch stack. But my first reaction would be that the REC market would operate independently of how power plants actually function.

You know, certain types of renewable run when they run also, so wind and solar basically run when the resource is available. And when they run, their marginal costs are close to zero, so they should dispatch when they're available to run. Other renewable resources would run, you know, more like a traditional power plant, like a biomass facility would want to be a base load facility. And again, I think it would depend on the way the rules were written for the physical market, but I don't see how those would necessarily change as a result of layering a REC on top of that.

MS. HARLOW: If we go back to Mr. McWhirter's question, it seems to me that it's the goal that's causing the change in dispatch order, the goal itself, not whether it's done with a contract path or a REC system. And maybe that's appropriate, because if we have a statewide goal for renewable energy, I think it's
a policy position that costs will go up, because if they weren't going to go up, we would be using more renewables today than we are. So it's the goal causing the change in the dispatch order if it happens.

MR. ASHBURN: This is Bill Ashburn. Is it sort of changing the dispatch from least cost to least emission?

MR. TRAPP: Well, my engineering side of me says if it changes unit commitment, the types of units you're building. But it seems to me I agree with Ryan that, you know, the fuel price is going to affect the actual dispatch unless we create --

MR. ASHBURN: Unless we're obligated to get to a certain percentage of emissions in a year, and therefore we've got to dispatch more expensive units to run to make the RECs.

MR. TRAPP: That may cause you to go out of dispatch.

MR. ASHBURN: Right.

MR. TRAPP: And therefore you're saying --

MR. ASHBURN: That's what I'm saying. Under certain circumstances, it could be a least emission dispatch rather than a least cost emission -- least cost dispatch.

MR. TRAPP: Could be, could be.
MR. KATOFSKY: I think you can also think of it as maybe, say, a least cost -- it's the least cost dispatch within the constraints of the goal; right? So that would be the purpose of an RPS, would be to achieve the objective at the lowest possible cost.

MR. ASHBURN: Right. And as you said, certain renewable resources are probably must-run. I mean, if they're solar, they're going to put out what they put out, but some may be dispatchable based on -- you know, they are dispatchable because they're biomass or something like that.

MR. KATOFSKY: Right. But as a biomass operator, you would want to run it as much as you could; right?

MR. ASHBURN: Right. But you would likely be -- the contract with the utility -- because as you said, you're splitting the RECs from the energy, so it may be that the utility has cheaper energy to run at certain times of the day and doesn't dispatch the biomass, and that reduces the amount of RECs, which goes against your RPS requirements. So you may have different requirements on those two scales.

MR. KATOFSKY: Right. But presumably the REC covers those -- you know, would make the energy component of the biomass plant competitive; right?
Because you're getting a premium for the attributes, the actual energy you deliver you can deliver essentially at the market price.

MR. ASHBURN: Well, presumably. Some of these units are going to run for 20 years, 30 years. I mean, over time, the cost of units change, and their dispatch changes over time as well, depending on what gets built in the meantime.

MR. KATOFSKY: Yep.

MR. McWHIRTER: Could a Florida utility either build a plant, a solar plant, say, in Arizona, and charge the Florida customers for the RECs attributable to that plant?

MR. KATOFSKY: If the rules allowed them to do it, yes. If the RPS rule said we can buy RECs that are made in Arizona, yes.

MR. McWHIRTER: And would that be in the public interest, in your opinion?

MR. KATOFSKY: I would say that the general -- one of the motivations for RPS is to have local benefits, so something like that is not typically allowed in RPS.

MR. FUTRELL: Okay. If there's no other questions at this time, let's take a lunch break and come back about 1:30. Thanks.
MR. FUTRELL: Okay. If you'll take your seats, we can get started.

What we would like to talk about first before we get back into the questions that Judy had teed up for us is the renewables assessment data, the legal sized spreadsheet. We provided copies. We also e-mailed it out yesterday. And Karen Webb has done a real good job for us of compiling the data that came in from the last workshop, and we would like to kind of go over that and let Karen kind of talk about where we are. And if anybody has any questions or wants to make any points about the data that's here, this is a good opportunity for you to do that.


I guess all of you have a copy of the long worksheet, and this was the corrected version of this subsequent to the last workshop, where we asked the utilities and others to please -- if they thought any corrections were required, to please submit those, and we've since changed that in here in the spreadsheet. We also changed the format a little bit of the feeder sheets to make it a little bit easier to read and make it a little more uniform.

Some questions were raised during the break --
I don't know if you want to go in that -- in regards to the self-generation. You see on the summary sheet, if you start from the bottom, there's total, above that, conservation, above that, subtotal, above that, self-generation. If you go across, you'll see a zero under capacity. That doesn't mean zero. That probably should have just been left blank, because we pulled that from ten-year site plan book, that load and resource plan, and they just didn't list capacity in the area where we were pulling these numbers from, so that probably should have just been left blank. What we were focusing on was the energy, that number there, the 3,526,000.

We called FRCC in regards to some of the complaints we were hearing that those numbers might be incorrect, underestimated or what have you, and the response was, "Unclear as to where that number came from." So if you know of a particular site that has some clarifying information as to where -- everywhere that this can be pulled from, we would definitely appreciate that.

In addition to that, we've heard from Mr. Zambo. You'll see the footnote, the cross footnote. Post-workshop comments submitted was 517.5 megawatts with 2,791,000 megawatt-hours. And this line, I
suppose, confused some people, judging by some of the
comments we heard during the break. That number, the
734,000 megawatt-hour number, is the difference between
the FRCC number for energy and the number that we pulled
from the post-workshop comments that we got from
Mr. Zambo. Now, that's likely due to other industries
that were not represented by Mr. Zambo, or it could be
due to a difference in calculation of how FRCC computed
that 3,526,000 number.

But again, we've gotten some feedback from
Mr. McWhirter and Mr. Zambo and Mr. Treshler as to how
we might go about clarifying that, but any
clarifications are welcome.

MR. TRAPP: Karen, could I just clarify what I
thought I heard you say? The number reported by the
FRCC in the load and resource plan is the 734,000? Is
that I heard?

MS. WEBB: No, sir. The 734,000 number
represents the difference between what the FRCC book
gave us for energy and what Mr. Zambo gave us for his
clients' energy.

MR. TRAPP: So FRCC is reporting 3.5 million?

MS. WEBB: Yes, sir.

MR. TRAPP: Of which Mr. Zambo has accounted
for 2.79 million?
MS. WEBB: Yes, sir. And our question is --

MR. TRAPP: Where the other difference comes from?

MS. WEBB: First of all, we want to know how did FRCC get their numbers, because we've had some difficulties getting from them how they calculated that number. So first of all, is that number correct, the 3,526,000, but second of all, who would make up the difference between Mr. Zambo and what FRCC is reporting. Is it citrus? Is it sugar? Is it pulp and paper? Who all is it?

MR. TRAPP: Well, I think these -- again, I want to emphasize the importance I place on these numbers. They show a wealth of potential renewable gigawatt-hours that are out there that could be counted toward an RPS and that may have additional value if we go to some type of a REC program.

So it seems to me that it would be incumbent upon all the parties to try to get that number accountable and in the program and credited if that's the direction we wind up going. And that's open for discussion. I would love to discuss that.

But the way I read this chart, we've got three potential areas that may contribute to meeting the goals that we're trying to strive for, and we need to talk
about each one of them, conservation, self-service
generation, and utility purchases and construction.

That's my stump speech, and I'm sticking with
it.

MS. WEBB: Very unanimous.

MR. ZAMBO: Well, Karen, I'll give you some
comments if now is the appropriate time.

MS. WEBB: Sure, sure. I was going to bring
up next what we talked about on the break about breaking
up the self-generation, but you would probably explain
that better than I would, so please go ahead.

MR. ZAMBO: I'm not sure about that, but I'll
give it a try.

Before we get into that, though, on the
self-generation, I think I mentioned to you during the
break, all self-generation in Florida that I'm aware of
is not necessarily renewable. There are some fairly
sizable natural gas-fired facilities out there that are
used for self-generation, which leads me into my issue,
and that is that I think you ought to break the
self-generation down by technology or by energy
resource.

MR. FUTRELL: Richard, if you could just
identify yourself for the court reporter.

MR. ZAMBO: Oh, I'm sorry. Rich Zambo
representing renewable generators.

The fertilizer industry is a pretty good example, because they've got, at last count, 370 megawatts of installed capacity or operating and installed capacity. And of that, only 15 megawatts is being sold pursuant to firm capacity and energy contracts, so you've got -- 355 megawatts presumably would be included in the self-generation number, but you have no indication in either your demand side or your supply side charts here.

I would say you put that in your list on the demand side so that you can create a -- this chart can act as an inventory. You can look at it and see what you've got installed in the state in each of the different categories, MSW, waste heat, landfill gas, and so forth.

Also, the numbers I gave you, I probably wasn't clear in how I presented them, but those -- I think we combined some municipal solid waste along with the waste heat. The waste heat numbers are the ones that are primarily used for self-generation. The municipal solid waste are typically sold to utilities. So I would be happy to work with you and help you get those numbers to match up with what I've got.

But I don't know what else is -- I don't know
what the FRCC has included in that number, but I do know there's generation out there. Almost all the sugar companies generate using small power producers. Some of them aren't even connected to the grid. They generate during the season when they're making sugar, and they provide their own power, and when there's no sugar to be produced, they just shut down and go home. And I know the pulp and paper industry generates from wood waste, from bark, from different chemicals that are produced in the process. I know there are some chemical plants up in the Panhandle that produce combustible gases as part of their process, which probably also are renewable. So I don't know how you go about finding out what those are, but I think there's some significant numbers.

And with that, that's about all I have to say, except I would encourage you to list the waste heat under the demand side and the supply side where it's appropriate to do so.

MR. FUTRELL: I would like to ask -- I don't mean to pick on Bill, but there's a lot of self-service in your territory, in TECO's territory. To what extent do you or does the company keep up with that potential out there, what's out there, and then how do you report it to FRCC, if you know?

MR. ASHBURN: I'm not sure I can answer how
we -- I'm sure our resource planning department reports whatever they do to FRCC. I don't know exactly where they get it.

But I agree with what Rich says. Particularly for the phosphate industry, there's an awful lot of generation they use internally to themselves, so it's sort of self-supplied generation, but then they sell excess to us or to Progress Energy or that kind of thing, or in the market. So there's a mix of their capacity which would fall under the waste heat quantified, and part of it is self-supplied, meeting their own load, and part of it is exported out to us, so it might be a good idea to have it mixed.

And I'm sure someone like Steve Davis can get theirs, or Rich can accumulate all of theirs. As he said, there's other entities like that out there in the forest area, the pulp and paper area, I assume, and other areas.

MR. TRAPP: The more important question to me is, should that self-service generation be counted toward the goals, and if so, how do we go about establishing -- putting them a REC program? How do you as TECO identify how to administer RECs to them, or if we're going to a third-party entity to do it, how do we go about getting the RECs to those people so they can be
counted?

MR. ASHBURN: I think that's a really good question, and I think it also depends on whether you're going to go for a REC program or a deliver the energy program. I mean, if you go for this contract path approach, their contract path is internally to themselves. Do you count that or not? If you go to a REC program, then I assume there would be some process, just like we talked about with the solar, that they could acquire a REC for having produced it. The fact that they internally used it, they can then sell that REC to somebody who needs RECs.

MR. TRAPP: Well, again, it seems to me the economics on the customer side of the meter are different than the economics on the utility side of the meter, but they both contribute to the goals, all the goals we listed of environment, economic development, fuel diversity, and what have you. So again, I would entertain the thought of potentially including them in an RPS type goal counting system. I think if we don't, the burden is clearly on the utilities. You've got 1.39 percent you can count.

MR. ASHBURN: No, I totally agree with you.

MR. TRAPP: It's a long way to 20.

MR. ASHBURN: I think if the technology
qualifies, as their waste heat currently does, I think that technology should count, or the RECs or the attributes associated with it. Whether it's used internally or sold out to a utility or somebody else, I think the generation itself should count and be available for use towards meeting the goals.

MR. COWART: My name is Ben Cowart, and I'm with the City of Tallahassee, and I would like to address your question about why should a third party participate in an RPS.

Having friends that are in the phosphate industry and having come out of the phosphate industry, I think that what we'll see is that these self-generators are going to be part of DEP's overall goal for reduction of emissions. And if we're looking at the state as whole in reducing our emissions and RPS is a part of that, then even if they return nothing to the grid, there should be some credits captured, because there's a liter of CO₂ or a gram of SO₂ that's not being emitted that they get no credit for, yet they're being ratcheted down and treated just like any other power boiler or utility that's out there, but they're being excluded from this because they don't return anything to the grid.

And I think that big picture needs to be
looked at, that they should get some kind of benefit. They should be able to acquire some kind of RECs and, you know, sell those, or be able to trade or do what they need, because we can't look at them separately. It's a big picture issue.

MR. ASHBURN: Bob, this is Bill Ashburn again. I have a related question to this, and maybe Ryan can help some. What is the measurement? Is it the gross output of the generator, or if there's a net use of the power for the generator to operate, say, a municipal solid waste operation, for the cranes and so forth, how is that measured around the country?

MR. KATOFSKY: Probably differently in different parts of the country.

MR. ASHBURN: What a shock.

MR. KATOFSKY: I would think, though, if you had internal consumption -- you know, say you had gross output at the generator terminals, but you could deliver X megawatt-hours either for internal use beyond what might be considered sort of the parasitics of the power plant itself, I would think you would measure it net of the internal consumption to make the plant run.

MR. ASHBURN: Right.

MR. KATOFSKY: So it's a net calculation one way or the other, I would guess.
MR. ASHBURN: So net of the use of the
generator itself, whether it's internal pumps and all
that kind of stuff.

MR. KATOFSKY: Yes. I haven't actually looked
specifically at this issue, but I would suspect that
would be the way that you would do it.

MR. TRAPP: And then again, how do you verify
that?

MR. ASHBURN: Right, exactly.

MR. TRAPP: I mean, we regulate you guys.

MR. ASHBURN: Right. I've heard that.

MR. TRAPP: Who can get behind the meter and
verify --

MR. ASHBURN: Well, as an example, for cogens,
when we do our normal connections with them and do our
avoided costs and all those things, we require a meter
on their generator. And that's an issue that always
comes up, where is the meter, is it ahead of or back of
certain parasitic loads and so forth, and that's set up
at the time it's all set up. But managing that is a
problem over the years as, you know, people hook up the
things ahead of or behind the meter, that we're
measuring the output of the generator. And that's just
a management issue or a contractual issue to maintain.

MR. BETHEA: Clay Bethea with Buckeye. We
produce biomass electricity now. Most of it is used -- well, all of it is used internally. But if you do not include us in the RPS where we can sell our credits, the fear that I see is that you have a lot more demand on biomass. And as the demand goes up, the price goes up, and the RPS credits are going to help pay for that demand. And then you put us at a disadvantage, just because we invested that capital years ago and saw the advantage years ago.

So if anyone is generating energy and using it internally, well, that's energy they didn't have to get off the grid, and so they should be included, and you should be able to sell those credits, because at the end of the day, if you just look at north Florida and the general area of Tallahassee, there's a potential of 3-1/2 million tons of biomass that's going to be required within the next five years if some of these plants come online, if everything you read in the newspaper.

You know, I keep hearing people say, "well, we're going to use the municipal biomass." There's not that much municipal biomass coming out of Tallahassee or anybody else, Orlando. So you're going to put a demand -- you know, you're trying to drive biomass use or renewables, so everybody is going to have to be included
so that as the market drives prices up, you don't drive everybody else out of business that was doing it beforehand.

MR. GRANIERE: Excuse me. Could I interject here on this, just for an effort to do something? Let me create a hypothetical, and then maybe we could sort of get at it, you know, all these ins and outs.

Suppose just for the sake of argument that the utilities and all of the excess met the renewable portfolio standard of whatever it was for that year. Then I would submit that the internally generated RECs are valueless within the state, and you could only sell them outside the state. So it seems to me that the only time that there's value for these internally generated RECs is when the utility or some responsible party has to buy them for compliance. Am I wrong there?

MR. BETHEA: I don't know.

MR. GRANIERE: It seems to me -- you know, it's sort of like the idea, the utilities generate, and they've come up with 150 RECs, and they've sold -- and they've bought excess energy at the retail rate, and they've come up with another 50 RECs, and all they need is 200 RECs for that month. Well, they've got their 200 RECs. And all those internally generated RECs, I would say who would you sell them to? Nobody wants them.
MR. ZAMBO: Could I respond, Bob?

MR. GRANIERE: Sure.

MR. ZAMBO: Well, one thing I see is, there may be a situation where the utility wants RECs, but not energy. But it's true -- what you're saying is true of whether it's internally or whether it's sold. If a utility has no need for the RECs, they're not going to buy the power that the RECs are associated with, nor would they buy the RECs of self-use or self-generation. I would think the self-generation RECs may be more flexible, because they could be used -- they're unbundled, so to speak, from the actual flow of energy.

MR. GRANIERE: Just to respond -- Bob Graniere. Just to respond, Rich, you're absolutely right. And if you're able to sell those particular RECs on the national market or international market, well, good for you. And that's what I see.

MR. ZAMBO: But I'm not referring just to the national or international market. I'm referring to the Florida market.

MR. GRANIERE: Sure. Bob Graniere again. What I'm saying is that in the hypothetical I created, the demand for them in the Florida market would be zero unless they wanted to buy them to bank or something like that in the scenario that I put up.
MR. ZAMBO: But in your scenario, how do you distinguish the demand for the bundled RECs and the unbundled RECs? You must be making some assumptions. A REC is a REC, whether it comes with energy or whether it comes without energy, so I'm not sure what --

MR. GRANIERE: No. All I'm simply saying is that the responsible party has accumulated in some fashion all of the RECs that it needs without having to buy an unbundled REC from self-generation. I'm saying in that case, the only value that the unbundled REC from self-generation has is more than likely outside of the Florida market. However, if the responsible parties couldn't come up with enough RECs, then the unbundled REC from self-generation would have a value here in Florida.

MR. ZAMBO: And conversely, if the responsible party bought up all the unbundled RECs and no longer had a need for bundled RECs, those would have no value in the Florida market.

MR. GRANIERE: Well, actually -- Bob Graniere. What would happen then is that -- the answer would be that the unbundled RECs were more than sufficient to meet the portfolio standard, and that would say that self-generation by the people was more than enough to serve 20 percent of the load of the thing and has
actually displaced 20 percent of the load. And there is an interpretation that would say, yes, you've met your renewable portfolio standard under those criteria.

So I would think that in the grand scheme of things, which is exactly the criteria that would be used if the system that we're talking about was all PV, because basically, PV, most of it, at least when it's on houses and things, is for internal generation. And so as a result, the only thing that shows up on the grid would be the excess, or the excess of the excess, however you want to call it. So as a result, yeah, you're absolutely correct. But the point is that that's what it means.

MR. TRAPP: Bob, if I could just respond staff to staff here, I think you're right. I can't disagree with you. I think if you've met your goal, your renewables goal, then RECs may have a zero value. But RECs aren't the only thing in the game. You know, the actual -- the RECs are there because we don't think we're going to meet the goals, and they're to provide an incentive to build technology that will meet the goals and therefore cancel out the RECs.

But what have we done? I disagree with you. The self-service generator is contributing to the grid. It's called negawatts. And that generator is going to
be dispatched, quite frankly, by the retail rate. Those kilowatt-hours that are sent to the grid are going to be dispatched at the utility's avoided cost rate, or incremental cost rate.

So I guess the confusion I have with your hypothetical is that it starts with the assumption that we've met the goals, and I don't think we have.

MR. GRANIERE: Well -- Bob Graniere. I totally agree that I started with the assumption that we met the goals. But the only purpose of that assumption was to try to clarify the argument that was going on, which was what kind of value does a REC hold if the power is used for internal consumption, and that's the only thing I addressed. And what I addressed was that if no one needs those RECs, they're valueless.

MR. TRAPP: That's true. That's true.

MR. GRANIERE: That's all I said.

MR. TRAPP: That's true.

MR. KATOFSKY: Can I just jump in for just a second? Ryan Katofsky. I think this hypothetical is, I think, a little bit confusing, because the first question to answer is whether or not -- what are the eligibility criteria for basically having possession of a REC? So is behind-the-meter generation eligible or not? And then the market sets the price for RECs,
whether there's -- if there's too many RECs in the
market, then the price goes down.

So I'm not sure -- and I think it's more of a
fundamental question as to if you allow the RECs to be
-- if you allow an existing behind-the-meter generator
to have RECs and they have RECs that have value in the
market; right?

MR. GRANIERE: Bob Graniere once again. All
I'm simply saying is that I'm not presuming that the
market is perfectly competitive and that it's all
transparent and it's running back and forth and people
are buying RECs instead of building things. What I'm
saying is that suppose there were bunch of people in
Florida who decided, you know, it's in our best business
interests to build this stuff, it's just in our best
business interest to build this stuff. And if they make
that conclusion that it's in their best interests to
build this stuff, then the people who do this stuff on
their own are just doing it on their own. There's not
going to be any REC market in here for them. So it's a
business decision on their part too.

So what I'm saying is that you have an
assumption in your thing too, which is that they're not
going to come up with enough to meet it on their own.
And I'm just saying, nice assumption, but I'm going to
take that one away and make my own assumption, which
says, what happens if they do come up with enough to
meet it on their own? That's all I'm doing.

MS. HARLOW: This is Judy. I'm not sure if
this is on. Is it on?

This whole discussion, I got a little lost in
the middle of it, frankly. But the point that came to
my mind is, it seems like there's a lot of agreement
that we want to include self-generation, we want to
include behind-the-meter with small systems for
customers, and how do you do it?

And it seems to me that that implies you have
to have a REC system, because if you have to have a
bundled product, I don't see how you can include
self-generation. That implies an unbundled product. So
is that the case, that you have to have a REC system in
order to include self-generation, and if we went with
conservation, even behind-the-meter conservation
efforts?

MR. KATOFSKY: I don't know that it means you
would have to have one, but I think it would be a fairly
straight -- a more straightforward way to do the
accounting if you did want to include all those
different resources. But you wouldn't necessarily have
to do it. Take the New York example again where they
just -- they created a separate tier for customer-side resources as part of the RPS.

MR. ASHBURN: Judy, I don't think you have to. I'm not sure it's both. But most of the people who are self-consuming their power behind their meter have the opportunity to sell us the power. You know, we'll do a buy-sell, or you can consume it behind your meter. So if there's something in the process that says it has to be a bundled product that we buy in order for them to get REC credits, they could easily contract with us to buy-sell, so that they would buy all their internal needs and sell us all their generation and not just use it behind the meter. I mean, that's an option, so that's why I don't think there's any incredible difference between self-generation behind the meter as far as REC value and having sold us the power as a REC. Essentially, it's the same thing.

MR. FUTRELL: Any more discussion on that topic?

Now I would like to move on to another question in Judy's list, alternative compliance payment, and I guess throw it out for discussion on. Is the idea of an alternative compliance payment essentially a method for a utility that's obligated to meet a goal to essentially not invest in renewables, depending upon the
price there?

And I think you had some comment in your slides, Ryan, about that. Is that effectively what an alternative compliance method is?

MR. KATOFSKY: I'm sorry. Say again.

MR. FUTRELL: Is it not simply a method to avoid essentially investing in renewables?

MR. KATOFSKY: I don't see an alternative compliance mechanism or payment as a way to avoid investing in renewables. I think the main purpose is to help create the demand that will then encourage the investment. If you know that the alternative compliance payment is $50 a megawatt-hour, then that gives a generator confidence that there is a market for his output where the REC will be worth up to that amount. So that's main motivation for having an alternative compliance payment, so it creates that certainty for the investor in the project.

And then the flip side of that I think that's equally important is the issue of cost control. So it's a safety value, if you will, or it's a ratepayer protection plan that ensures that even if 100 percent of the RPS were met with alternative compliance payments, it would only mean a small percentage rate impact or cost impact on a customer's bill.
So those are the two main purposes. I don't see it as a way of avoiding compliance. If there were weak enforcement provisions and, you know, the alternative compliance payment were very close to the market price, say, you know, some obligated parties may just say, "Well, it's just easier to pay the penalty, because there's not much financial difference, and we just don't have to worry about doing all that contracting and all that other stuff we need to actually comply. We will just pay the penalty." So that is a possible outcome.

Now, if that were happening time and again, then you would have to take a look at the program and say, "Is this doing what we want it to do?"

MS. HARLOW: Ryan, I think you said in your talk earlier that in Massachusetts, you had seen the movement away from the compliance payments and toward actual renewables, and I wondered if you would -- I guess you were talking about the compliance payments giving renewables certainty, and that gave them the certainty that they would receive a certain amount of revenue. Is that the reason they're moving in Massachusetts? And also, have you seen that occurring in other states that had RPSs that had an alternate compliance payment?
MR. KATOFSKY: The best example -- in Massachusetts, we actually did have the case where the obligated parties were paying a substantial portion of their obligation with alternative compliance payments.

In Texas, you've never had that happen because they've had RECs in excess of their requirements, so a -- you know, the $50 a megawatt-hour cap in Texas, or 200 percent of the actual price. The actual price for RECs in Texas is around 10 to $15 a megawatt-hour, so quite reasonable.

In Massachusetts, the price for RECs basically bumps up against the alternative compliance payment because they're supply constrained. So that has sent that signal that there is a market for RECs that is -- you know, that is close to that alternative compliance payment. You know, if you think about it in rough terms, a $50 alternative compliance payment roughly doubles the revenue to a generator, roughly, you know, thinking of a four or five cent wholesale market. So that does send a pretty strong signal.

The challenge in Massachusetts was really one of getting projects built in a timely fashion, which is why they fell behind, essentially, on their compliance. And it's now three or four years later, and they're starting to catch up, effectively. But having that
compliance mechanism in place kept that signal in the market that, you know, eventually, if we build this stuff, we know it's going to be worth -- you know, that REC is going to be lucrative enough that it's going to make our project viable.

So it has done what it was supposed to do. I think if they were still in a situation where they were falling further and further behind, then they would have to start taking a look at what's going on. But since they're actually in a situation now where they're coming into compliance with actual RECs as opposed to the alternative payments, then that's a signal, you know, that something is working.

MS. HARLOW: I keep going back to the idea of certainty for the renewable generators, because if you're somebody that's happy with the idea of an RPS, Florida is kind of behind the curve, because we're behind 26 states. So in a sense, we're competing with those other states for those renewable generators. So I think it's important if we do end up with an RPS that we build some kind of certainty into the market so they know if I come in, if I put my foot this market, I can stay in it.

And that was one of the points we've had stressed in earlier workshops by the PV people, is that
we have limited capacity to create these systems right now, and so we're going to put our efforts where we get the biggest bang for our buck and we have that certainty.

MR. KATOFSKY: Right. There's a couple of interesting dynamics taking place, particularly in the wind and solar markets in the last two or three years, which is that the demand for the products globally has been so high that there's basically pent-up demand in the market. You know, the German solar program is so aggressive, and even states like New Jersey that had a very aggressive rebate program couldn't get product.

So that's a -- I view that as somewhat temporary. So if there is sustained demand for this stuff, then the capacity will be there eventually. So there are some short-term -- call them growing pains, if you will, related to product supply. And the same can be said for the wind turbine market.

But in general, you're right. It's important to set the rules and the compliance mechanisms in such a way that if someone comes, you know, they'll want to come here and build here, and they can compare that opportunity in Florida to other opportunities they have around the country.

MR. TRAPP: I want to throw one at the
utilities. With regard to the alternative compliance measure, here's the problem I have with it. I don't know what to do with the money. They collect all this money. The PSC is going to go build renewables, or they're going to -- so I'm going to do a Bob Graniere on you. I'm going to give you a hypothetical.

Instead of calling it an alternative compliance measure, why don't we call it a cap and penalty system? We set a cap. If you spend that much on renewables, you're forgiven if you don't meet the goals. If you don't, we come after your return on equity by a couple of hundred basis points. That's more workable from a regulatory sense, in my view, so I throw that hypothetical to you and let you comment on it.

MS. CLARK: I think Bob McGee wanted to respond to that.

MR. McGEE: And I appreciate you bringing that up, the cap piece of it, because I wanted to address that.

Let me wind back, though, before I answer that and answer a question that Mark had earlier, and that was, would an alternative compliance payment be a way to avoid investing in renewable energy. And I think it would be if those dollars, if those ACP dollars were not invested in some renewable projects, which addresses
your question, what do you do with those dollars. If you do something with those dollars that later helps the renewable industry in some way that the State deems appropriate, it could be -- you could view an ACP essentially as a different form of a REC.

And hang with me here for just a second. A REC is something that you purchase or you pay for the attribute after it's generated. An ACP is something that you pay for in compliance with a renewable portfolio standard which, if invested properly and efficiently, would benefit or create some renewable energy in the future. Now, the timing is a little bit different, but it's another way to view it.

So in my mind, those things are not incompatible, and they both go towards compliance, and then neither one trigger a penalty, because they're both meeting the goal, essentially the long-term goal of helping the renewable industry in the context of an RPS, assuming that an RPS is something that is desirable.

The other thing was Ryan's comment earlier about the main point of an ACP, and that is to create some certainty of price in the REC market, and I agree with that particular position. That's what an ACP is for. And given that motivation, what do you want to do with an ACP? You want it to be high enough that
somebody can fit some real projects in underneath whatever that number is. But that is counter to the goal of not wanting to raise consumers' rates too much. So you've really got these two conflicting goals going on, and you're trying to solve them with one particular mechanism called an ACP we're talking about here.

I would suggest that you may want to use an ACP in order to set the cap and make the cap -- or make enough head room for real projects to get done there, but also implement an expense cap, which is similar to what Barry Moline had floated early on, which was -- I think he labeled it as a revenue cap. I'll call it an expense cap, the total amount of expenses made by a utility in compliance with the RPS might not be any more than some percentage.

Now, I'm going to differ with something that Ryan said earlier. He said that an ACP works well as a cost control, that it's a ratepayer protection plan, and even if all the renewable portfolio standard was met by an ACP, you would have a small percentage increase in the customer's bill.

Now, let me give you an example, and I'm get into some numbers here. Assuming a 20 percent RPS and a five cent ACP, that's a one cent per kilowatt-hour impact on all your customers' bills, one cent per
kilowatt-hour. And let's assume it's a ten cent per kilowatt-hour average cost we're looking at. That's a 10 percent increase in the bill. That's much higher than the number that we have talked about earlier as a potential expense cap at 1 percent.

So my point there is simply, there is a scenario that says if you set your ACP high enough, it's not a very effective expense cap or revenue cap or rate cap. You may need to have both of those mechanisms working there and interacting with each other.

MR. TRAPP: I'm still not sure you've answered what I do with the money.

MR. McGEE: One scenario would have the money going to the existing mechanisms that are in the state for incenting renewables right now. I believe the PV incentive was funded at 2-1/2 million last year. I think in Massachusetts, in one year there was a large number of dollars, much higher than 2-1/2 million, that came through the ACP. And certainly you wouldn't want to design one to funnel that much money through it, but I think it could be used effectively in that way, because right now it's coming out of general revenue, I assume, the state budget.

MR. TRAPP: You got outside the PSC boundaries. My question was, what can the PSC do with
MR. McGEE: I'm not sure I have an answer for that.

MR. TRAPP: Again, I hear what you're saying, and I don't disagree with you, but I think again, I'm trying to determine what as a staff member of the PSC I can, with the authority I've been granted, recommend a program that will work, and I don't know what to do with the money under the ACP. It sounds to me like I've got to go outside the agency to do what you want to do or are proposing. And if that's true, that's fine. If that's the only alternative I've got, that's fine.

But again, what if we just penalize you 200 basis points if you don't meet the spending target?

MS. CLARK: Well, I think John Burnett may want to comment on the authority --

MR. BURNETT: You got my attention with basis points, Bob. You brought me back to the table. John Burnett on behalf of Progress Energy Florida.

Bob, your question is a good one. Under the current jurisdiction of the Commission, I guess the operative question is to back up and say, does the Commission have the authority at all to have a REC system or an alternative compliance system at this point? That's, I think, the first threshold question.
That would largely drive, I think, the answer to your question under the current paradigm as we sit here today with the law right now.

If an RPS standard is put into effect by the Legislature, I would hope that the Commission would get some guidance from the legislative body as well as to what the Commission should do, how they should do it to some degree, and what they should do with the funds. I would think a legislative purpose and objective would be set forward that would identify the policies and analysis behind why the RPS is there in the first place and the objectives that it's made to accomplish. I think that would tell us and the Commission a lot with how the money should be done and would drive a lot of the questions we're talking about here today.

But to your point, under the current paradigm and the current jurisdiction the Commission has, I'm not sure that they could do it at all, because I think that would be a de facto penalty which may be covered by statute already. And I don't know if the Commission could hit a utility as a basis point penalty under the existing statutes for buying something over avoided cost. In my opinion, that would exceed the Commission's jurisdiction.

MS. HERIG: I just wanted to say that there
are analyses floating around in other states in which they've said, okay, we do not want to have more than a 1 percent rate impact and look at the term of the RPS implementation and then figure out what the alternative compliance penalty is relative to not exceeding that rate impact. So it is tied together. And other states have also used that money to do community projects and low income projects, you know, but keep it in the renewable deployment still.

MR. KATOFSKY: Ryan Katofsky. And there are a number of states that already have existing mechanisms for collecting what they call system benefits charges. So you may not have it here, but other states already have, you know, sort of -- let's call them obvious places where those ACP funds might go.

And just on a slightly humorous side, hopefully, where I live, unfortunately, a one cent a kilowatt-hour change is small, so --

MR. TRAPP: Humorous for us, maybe not for you.

MR. ZAMBO: Could I follow up with a few comments? As far as your statutory authority, I think you've got it in 366.92, which gives you the authority to establish goals. It would be foolish to assume you could establish goals but couldn't enforce them. So I
would say in light of that statutory provision, plus the general legislative mandate to encourage renewables, it seems like those two things would work together.

And the other thing is, I'm not sure it's foregone conclusion that this is going to cost money. There may be savings. I mean, renewable energy, bringing renewable energy in may reduce fuel volatility, may reduce fuel costs, may reduce the need for utilities to build new power plants. I mean, I keep hearing that it's above avoided cost, but I don't know that there's evidence. To me, it's not de facto that this is going to be higher cost. I think as the fellow from the Public Counsel said when he was here last month at the workshop, he said the risk is not in building renewables, the risk is in not building renewables.

And I think the value -- that needs to be quantified. We're talking about caps. I think that needs to be quantified and maybe used as an offset to those caps.

That's all I have. Thank you.

MR. FUTRELL: Ryan, I've got a question, a question from your presentation. You were talking about penalties, and you said in some cases, renewable generators may be subject to penalties. And is that subject to the REC tracking administrator providing
penalties, or does the State PSC in that?

MR. KATOFSKY: I would think it would be whoever is responsible for the actual RPS administration as opposed to the tracking function. They would be the people that would have the discretion to levy the penalties if that was appropriate. So the tracking function is separate from who has responsibility for actual compliance, because one is just basically an accounting system, and the other is actually providing the enforcement. So it would be whoever had the authority to do the enforcement, and I don't think that would be the -- you know, if there was a separate entity that was managing the tracking system.

Take a case where -- most of these tracking systems are multistate tracking systems, so there's no -- ISO New England doesn't do the enforcement of RPS, because each one of those is done at the individual state level. So it would be the people at the state level with responsibility for implementing the RPS that would have the ability to assess penalties.

MR. FUTRELL: So in most of those cases, the enacting legislation has given the state body authority over these types of generators in this particular instance.

MR. KATOFSKY: That's right. So if there was
RPS legislation, it would say, you know, that the fines would be this, this, and this, and under these circumstances, and it may define an appeal process or direct the agency to develop one or whatever.

Again, I don't think there's a lot of precedent for actually assessing penalties. I haven't seen a lot of that yet. I think either the program is not far enough along, or there has been a preference for taking more of a collaborative approach to addressing any problems that may exist.

MR. FUTRELL: As far as assessing where the -- in the case of an alternative compliance payment or even penalties, where those levels are, are there usually provisions among the states to have some regular assessment of where that level should be to adjust to how the REC market is performing?

MR. KATOFSKY: Yes. I would say generally speaking, the legislation that creates RPS includes periodic review and allows for that adjustment to occur. And I don't know whether they're specific enough that they say every four years you have to address the issue of how much the ACP should be or if they're more general, saying every X number of years, you need to assess how the program is doing and make some adjustments.
I know that in New Jersey, they've had
recently a lot of work on the solar REC market where
they have made changes to that solar REC ACP, just in
the last couple of months, I think, actually. So
they've actually gone and revisited that cap, and
they've changed it.

MR. GRANIÈRE: Mark? Just one question for
you, Ryan. Bob Granière. Given the uncertainty
involved in these things -- and let us suppose that
there is a fairly substantial RPS. Would it be better,
in your opinion, to have a review after a preset number
of years, or alternatively, to apply continuous
monitoring and evaluation, especially in the early
years?

MR. KATOFSKY: That's not something I've
necessarily thought about before. I would think there
would certainly be continuous monitoring, you know,
annual reporting and so on. What the triggers would be
for conducting -- say, opening up a new docket or what
have you to actually consider making changes, typically
that's specified in -- you know, there is a
predetermined period when that's going to occur. That's
my understanding.

Would you want to make that more frequent in
the early years, and then maybe require some triggers in
the out years, you know, as long as there are -- you
know, if there haven't been any penalties levied or any
ACPs paid in four years, then that suggests that
everything seems to be functioning, and you don't have
to, you know, do a significant review. I think that
would just be up to you to decide what you thought was
most appropriate.

MR. GRANIERE: Well, what I'm -- Bob Graniere
once again. What I'm thinking of here is that being a
classically regulated state, and also having reporting
requirements like we do in other areas, conservation,
energy efficiency, things like that, and we have annual
reviews for cost recovery, it seems to me that in states
with that particular set of mechanisms already in place,
that continuous review and evaluation of what has
transpired in the prior year, all of those mechanisms
are already in place. And I would think that -- why
would it not be advantageous to use those mechanisms
rather than say we'll go back and see it after five
years or four years or three years.

MR. KATOFSKY: Seems reasonable to me.

MR. GRANIERE: Thank you.

MR. KATOFSKY: If you wanted to build it into
your existing processes, I don't see why that wouldn't
make sense.
MS. HARLOW: Do you need a review like that if you've got something -- I forget which state you said, but the ACP kind of floated with the REC price over time, and it was either this many dollars per megawatt or it was 200 times the REC price. So that's to me a self-correcting mechanism. But I guess you would still need a review process of the RPS for other aspects of it.

MR. KATOFSKY: Right. There's many aspects to the RPS. And think -- that particular example is Texas where they have the 200 percent or $50 cap. So for the Texas example, they haven't had to do reviews because their targets were not being met. They remain ahead of their targets, frankly, but they've made reviews for other -- they have reviews for other reasons. Maybe they want to reconsider the kinds of resources that are eligible.

A good example, when they actually -- or if they're consistently ahead of targets, does that mean they should be raising their targets? And that's in fact what they did. And when they did that, one of the things they addressed in that particular case was, well, all they were getting was wind, which is not necessarily a bad thing. But when they increased the target, I think the original target was 2,000 megawatts by 2009 or
something like that, and now it's 5,000 megawatts by --
I think it's 2015, but don't quote me on that. But what
they did in the process of adjusting the targets is,
they also said, "Well, we are only getting wind power,
and we want to encourage some other forms of generation
in the state."

So even though multiple other forms of
generation are eligible, they weren't getting any it, so
as part of the adjustment to the target, they said,
"Well, we want 500 megawatts of the target to be set
aside for anything but wind." So that was an adjustment
they made to the RPS in response to what they were
seeing in the market.

And it wasn't because the RPS wasn't working,
and it wasn't because the costs were excessive. It was
just a decision that they made as part of that
adjustment to create essentially a carve-out for
non-wind technology. So it was just a response to an
observed trend in the functioning of their RPS.

MS. HARLOW: You said before they redesigned
in Texas, they were getting all one resource, and that
was another thing I was wondering about. If you didn't
have multipliers or some kind of a tiered approach and
you just kind of let it go, how would you -- are there
other mechanisms to encourage certain types of resources
to be developed? Because some resources either have a high capital cost, or for whatever reason you can't get them, or they have a low capacity factor. I'm just wondering, how do you get those resources without a multiplier or a tiered goal approach?

MR. KATOFSKY: Right. You know, one of the -- I guess if you sort of think of it in its purest sense, an RPS is meant to be a least cost way of achieving renewable generation, and you let the market figure out what is that mix that is going to give us the least cost. If you have other things you want to promote, then you can create multipliers, tiers, set-asides, different alternative compliance payments for different technologies or different resources.

But what you do tend to see is, different parts of the country tend to be getting different mixes of resources. The Northeast is getting a fair bit of biomass and not that much wind. New York is getting probably more of a mix of things. There's some good wind resources in parts of the state, and in other parts of the state there's good biomass resources. And in Texas, it has been primarily wind. California is getting a mix. They've actually gotten some very large contracts signed on solar thermal electric in California.
So you will see regional differences based on the resources in terms of what's cost-effective to build or easier to site, or whatever the reasons are for people choosing one resource over another.

So again, you know, if you wanted to promote one particular technology, then you would have to be explicit about it. Otherwise, you know, the idea is to let the market sort it out, for lack of a better term.

MR. FUTRELL: Let's talk about the idea of banking RECs as a method of compliance. Is it typically allowed to go up to about 12 months, is what we see, or is there a typical method that's out there for allowing banking to go on?

MR. KATOF SKY: I'm not sure what's typical, but again, I think the banking period is relatively short. I don't know of any that are out more than three years. So again, there's -- I don't know that there's any magic formula for determining what that appropriate banking period is.

One thing I will say about banking is, if you think about supply -- let's say there were no banking whatsoever, so you think of supply and demand curves for RECs. When the supply -- when the demand is met in any given year, that incremental REC has almost no value whatsoever if there's no banking provisions.
Conversely, if you don't meet enough of -- if you don't have enough RECs, then that last REC will go right up to whatever the maximum allowable price is. So banking is a way to smooth out that marketplace and allow for sort of more -- you know, essentially cost averaged REC pricing. So it is an interesting and I think a valuable tool to consider.

MR. GRANIÈRE: Mark, if I could ask the responsible parties to -- Bob Granière. I'm on now. Bob Granière. If I could ask the responsible parties or who may be the responsible parties, what are some of the things that you prefer in terms of the questions that we've been asking?

Right now I'm hearing what Ryan thinks, and I certainly know what I think, but I really don't know what you think. So is anybody willing to talk about some of the things? You know, do they prefer continuous monitoring, do you prefer safety valves, do you prefer -- you know, what do you prefer? Or are you preferring anything, and, boy, I've got a blank check. I would be happy as could be on that one.

MS. CLARK: You know, Bob, we are actually learning along with the staff and appreciate these workshops. And with respect to the specific issues, we will respond in our post-hearing comments.
But as you've heard from the people who have made comments today, you know, we are looking at the idea of an ACP, the notion of an expense cap, that you do need those safety valves, what are the -- how do you set the goal, I mean, what are you trying to achieve by that? We've provided you our thoughts in post-hearing comments already, and we will be prepared to do that here.

MR. GRANIERE: Bob Graniere once again. All I'm just thinking about is that this particular workshop was on compliance and enforcement, and that sort of moves us past the setting of the goal. You know, whatever the number is, that's what the number is. You know, whatever those things are, that's what they are. And we could start this discussion from, we have one of these things, how would we comply with it, how would we enforce it, and that's what I'm trying to think about.

You know, I've heard some stuff about RECs and will RECs be the primary means of compliance. We've heard alternatively that maybe the bundled contract path would be the primary means of compliance, or alternatively, whether the primary means of compliance is the utilities building and owning the renewables. We've heard all of these options and things, but what I haven't heard and I don't think anybody has heard is any
sort of leanings on the part of the responsible parties for what their preferences are.

MS. CLARK: If I can just back up a little. You're indicating how you would do compliance and enforcement is not somehow tied to how you would set the goal. I would suggest to you that what you would do as far as compliance and enforcement has a great deal to do with how you set the goal. As Judy has said, is it aspirational, is it specific, how soon does it have to be met, what is it going to include? So, you know, your initial decision on that will influence all these -- responses to all these factors in an RPS.

MR. GRANIERE: Bob Graniere once again. I totally agree with you that there is a tie between the two. So I guess the question that I would ask is, if I were to find -- if you were to offer what your preferred compliance and enforcement was, then I can backward induct, so to speak, into what would you like to see the goal look like and whether it's mandatory or aspirational, all that stuff you talked about.

So basically, what I'm saying is that, you know, if you'll give me the back end, I could backward induct. If you'll give me the front end, I can forward induct. But if you don't give me any end, I'm kind of stuck.
MR. TRAPP: I think staff is very interested in, you know, in what your positions may be on all of these issues. And I know that we're certainly getting an education here too, but at some point in time, we are going to have to turn to some kind of specific proposals.

But before we do, let me ask you -- there are still some questions here on the page we may want to go through, and I think we need to get through that. I would like for you to be thinking about what kind of additional education we might need to get into in our next workshop, because I think we have scheduled one, another get-together in November. Maybe that's the time we want to begin to explore some brass tacks.

I know that we have been working with Bob McGee at Gulf on an example that he very graciously provided in response to a question from the last workshop with respect to multipliers, and I know the area of multipliers has been touched on today, but not in any great depth. And I think staff was thinking about perhaps getting into that a little bit more, the impact of multipliers on REC pricing, incentives, and that type of thing. But should we include in the program next time brass tacks?

MS. CLARK: You mean the actual elements of
how we would design a program?

MR. TRAPP: Yeah. Are y'all at the point of construction?

MS. CLARK: Well, we have provided you in previous comments some of our thoughts on additional education on the various subjects, and I know that you're putting together a list of existing renewables. You know, I think that would be -- to the extent we get down to more detail, we would be prepared to respond to that and provide you our ideas as well.

MR. TRAPP: Thanks for the offer. I guess we'll work on a schedule.

MR. FUTRELL: Let's talk about if anybody has had any thoughts on the flexibility measures Judy had mentioned there. One of them was a true-up period, which as I understand it is allowing for some months possibly after the deadline, for example, an annual goal period, to allow for there to be some true-up. Does have been have any thoughts about that as a potential mechanism?

MS. CLARK: I think one of the things we talked about is maybe looking at it over a several-year period, because you might have one year that you meet or exceed your goal and one where you don't, and the thought was to do some averaging over some period of

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MR. TRAPP: I think that may be part of what Bob might be getting to. In your thinking -- Bob Trapp, staff. In your thinking, are you thinking about annual goals that have to be met, or are you thinking about, you know, period goals, in three to five years we would come to it and say, "Here we are." What kind of approach?

MS. CLARK: What we talked about early on in -- my recollection is, in one of these workshops, we talked about you would do it similar to what you do with conservation goals. You would provide annual reporting, but you would do some review and readjustment on a periodic basis. That could be three or five years or some basis like that, so you get an idea of what the trends are, and do you need to revisit those things. But on a yearly basis, you would know what was happening.

MR. TRAPP: Right. I would certainly appreciate that. I do recall, though, that the legislation on the FEECA goals was fairly broad with respect to its ordering. It said, "Commission, you set goals. Utilities, you go do programs." Here I think the challenge we're faced with is 20 percent, so I'm looking for some guidance on how to reconcile the
absoluteness of that 20 percent.

MS. CLARK: I think, Bob, you talked about that before, and that was -- as I recall, one of the things you put out there was the notion of, you know, an aspirational goal of the 20 percent, but then when you look as you do a more near term goal, you would do an assessment of what you thought was available in that term, near term, and set the goal in that way. And it would seem to me that that sort of addresses how much you might use in an alternative compliance mechanism.

MR. MOLINE: Bob, Barry Moline. There's a sort of balancing act in your question that is -- we've heard 20 percent, or we know we have 20 percent as a target. We don't have a time frame for it. And the balance for the time frame is how much is available, and how much is available depends on whether we include efficiency along with renewables. So there's multiple questions or multiple variables in the equation.

But to answer one specific question that you had, we would prefer -- I don't know what we call them, you know, bins or, you know, a goal, a five-year goal and a 10-year goal and a 15-year goal or something like that as opposed to an annual incremental goal, because that allows for some flexibility and timing of bringing resources on, just to give you one little piece of an
opinion, since you were asking, Bob.

MR. LEWIS: I'm Roger Lewis from Lakeland Electric. And just to put this in the most simplistic of terms, if we try to do a lot in a short time frame, the cost is going to go like this (indicating). But if we take our time line and we spread it out a little bit, the costs are more reasonable. And I've heard discussions about a 1 percent cost cap for the consumer. And if we implement a 20 percent RPS, given the technologies that are available today, over a short time period, we're going to blow through that ceiling in no time at all.

MR. TRAPP: We also haven't talked about cost recovery? Do y'all want cost recovery? We don't have jurisdiction over the munis and co-ops, but do the IOUs want cost recovery?

MS. CLARK: I think we have answered that already in some of our comments. Yes. And another aspect of that would be transparency to the customers so they understand their contribution to this RPS standard.

MR. TRAPP: Do you have a rate case coming up?

MS. CLARK: Bob, we have looked at various ways of doing that, and one of the things we thought about is the use of existing cost recovery clauses or something similar to that. I think that helps in
encouraging the renewable resources in much the same way that cost recovery clauses for purchased power and conservation I think have that incentive aspect to them.

MR. BURNETT: Bob, may I ask a question? I'm backing up just one second. John Burnett, Progress Energy.

Bob, you said something earlier. You said the absoluteness of the 20 percent goal. I guess I want to throw out a question. Is it the staff's position or I guess anyone's position that the PSC is mandated as we sit here today to enact a 20 percent RPS?

MR. TRAPP: I'm not the PSC. I'm just staff.

MR. BURNETT: Well, I understand, but --

MR. TRAPP: You know, I'm nont mandated to do anything, except we're trying to educate ourselves here and come up with a program that, you know, meets some of the desires that have been put in place before us. I don't know --

MR. BURNETT: I think --

MR. TRAPP: I'm not a lawyer, but let me give you a response. The direction that we got from the Governor was a request for the Public Service Commission go look at this, and it had numbers, 20 percent, and some other things in it. So I think certainly that's the target which we're framing our discussions around,
but I don't know that anything is cast in concrete, and we certainly have room for, you know, rational discussion and decision-making here. And ultimately, staff's role in this, as you know, we'll have to put together some kind of recommendation for someone and take our best shot.

MR. BURNETT: And I ask that question really not to be cute, but it really drives the process. If we're saying 20 percent is absolute, there's no budging, that's largely, in my opinion, going to drive the answers to every single question, you know, you and Bob and everyone else asked today. It's like, "We've got a number. How do we get to it?"

If it's not absolute and we have goals, we just have a goal out there, an objective, if our objective is to do X, let's say -- I'm going to throw one out in air. Our objective is go reduce greenhouse gas emissions. If we say that's our objective, it's not tied to a number, but there's a goal out there, I may get to that in a different way.

So what is preventing me from providing, I think, meaningful input on the table is the ability to come up here and say, "What exactly are we doing? What is our target bogey?" I mean, in a military state of mind like I have, I start with my mission, take hill,
and if I'm going to go take the hill, then I figure out how I'm going to do it. I can't get my arms around what my mission is.

MR. TRAPP: Well, I can only express my own personal belief. You know, the military charge I see, I feel strongly motivated by meeting a 20 percent goal, so --

MR. BURNETT: Understood. And in that framework, I think the answer to that question would be what do you do. If you set that goal, you have to ask yourself how can that be obtained within the current jurisdiction that the Commission has under all of the direction or all the power that the Commission has been granted by the Legislature under the existing statutes, what can I do to get the utilities there.

And if that's the case, I would probably say you would want to have a tiered approach. You would want to let the market talk and speak and the available resources speak, and you would get together an analysis and say right now we're after 2 percent, so maybe we see where we're at in five years and ten years or whatever, and see if that's obtainable under the current jurisdiction. And if it's not in a three-year or a five-year period, then maybe the Legislature needs to do something to change that.
But to me, that's a really simplistic view of it, but I thought it was important to note that. Again, it drives to when you set that firm objective, it's largely going to answer, I think, a lot of the question.

MR. GRANIERE: Could I get bit of clarification? Bob Graniere, a little bit of clarification. Let's -- if I heard what you were saying, let's just for the sake of argument say that there's a simple objective, the one that you put out, which is reduce greenhouse gases. Would something like reduce greenhouse gases this much, but don't use a nuke, would that be okay?

MR. BURNETT: I mean, I think if you set the objective, then everyone has to come to the table and say, "What's the best way to meet that objective with all the competing interests?" And the competing interests, you know, are obvious, availability of resources, feasibility, time frame, cost-effectiveness, impact on the ratepayers.

So I don't think in a vacuum you could make that decision. I think you have to say, if I've got an objective, I take all the ways I could get there and give them rankings based on all the stakeholder interests and realistic factors and then figure out the best way to go.
MR. GRANIÈRE: Okay. How about if I asked reduce greenhouse gases at zero chance of polluting the land?

MR. BURNETT: Same answer. Now you've got two missions, and you take your available ways to get there, take all the stakeholder interests, do the evaluation, and come up, I think, with the best bang for your buck.

MR. GRANIÈRE: So that answer would be no nuke, and the other answer would be nuke; right?

MR. BURNETT: Again, I'm saying the answers are driven by, you know, whatever the results show.

MR. GRANIÈRE: Okay. So basically where we are is, we're back to the point that if there's multiple objectives and we don't want to get into a long, drawn-out thing of trying the rank these multiple objectives and everything else, then wouldn't that say that basically what we're really doing is, we're doing a continuous balancing act, and we really don't need that much information because we have all of the multiple objectives, and we don't have them ranked?

MR. BURNETT: I object to the form of the question.

MR. GRANIÈRE: Which is generally the case when I ask a question, unfortunately, because usually answering it is a little bit harder than you want it to
be.

But in any event, you know, I've had those situations. You said you come from a military background. Believe it or not, I actually have a little bit of that too. And there have been times when you had to look over your shoulder a lot more often than you want to, and I think that that's what this is right now. This is a situation where, because of the multiple objectives and everything else, there's a lot of looking back and seeing where you're going and what has happened and what you did. That's all I'm simply saying.

MS. HARLOW: Maybe you all need an easier question, so can we go back to the cost recovery issue?

Susan, you said that you guys were looking at a cost recovery clause. Would that be for all expenses, including whether you own the assets or not, or are you just talking about alternative compliance payments and things of that nature?

MS. CLARK: I think as I recall -- and I think we put this in comments, or we discussed it at a previous workshop. It could be a new cost recovery mechanism. You could use existing the cost recovery mechanism.

And it seems to me that -- now, you asked the question, if the utilities self-build, would you handle
it a different way? I would stay I might. It would
certainly be -- I think you would have to look at that
and see what is the most appropriate way to do it. I
will say I think that by doing it sort of separate from
rate setting, to me it has the advantage of being more
of an incentive, since you don't have to wait for a rate
case to get that cost recovery.

MR. MOYLE: Can I ask a question from you
all's perspective? And there's a lot going on in this
arena right now, as we saw yesterday with -- and I would
commend Florida Power & Light for announcing the solar
project that they did with former President Clinton and
the Governor. There's a lot going on, the Governor's
executive order at 20 percent. You know, I think we've
had good discussions about market forces and whatnot.

But I guess the point made by the gentleman
from Progress I think is a good, valid point. And
Mr. Zambo pointed out the statutory authority says you
all can adopt goals. It seems to me that a lot of what
we're discussing today may be influenced by what the
goal is. I mean, clearly, if you say, "Okay. We're
going to do the 20 percent" -- Bob, as you said, that's
kind of where you think we need to go. Then when you're
looking at what should be included and multipliers and
things like that, I think a lot of that would drive some
of that debate and that discussion.

But I guess what I was trying to understand is, we have the workshop today and comments, and we have a workshop, I guess, in November. I mean, is it anticipated we will move forward with a rule before the end of the year or at some point? Where is this sort of going, if I can be so direct?

MR. TRAPP: I think, you know, from the staff perspective, we're just trying to get a handle on the issues, the magnitude, scope, and breadth of the issues.

I agree with you, John. Set a goal. Fine, here it is. 20 percent, that's your goal. But without any more clarification or edification, I don't know what you do with it. So that, I think, is the reason that we're trying to get into depth with some of the -- fortunately, we do have other states that have led the way. We have expert help from our consultants from EPA helping us to see what other people have done so that perhaps we can create a better mousetrap here. Right now we're in an educational process trying to pull all this together.

But, yes, I think our ultimate goal is to try to comply with the Governor's request. He asked us to, you know, look at this in terms of renewables and solar and wind and 20 percent and come up with a new program
and rule. If rulemaking is the way to do that, then that's the way to do that, and we intend to get there.

As far as absolute timing, I can't tell you right now. All I know is Mark is going to announce to you in about a minute and a half that we're going to meet again for education on the -- what's the date? A date, and continue down this line of trying to educate ourselves.

I can't make a recommendation myself until I feel like I know a little bit more about what all is available out there to, you know, try to put in the program. And you know us engineers. We get over-prescriptive sometimes and like to have too many I's dotted and T's crossed. And maybe it's overkill, but we want to learn so more if we can.

MR. MOYLE: And I'm not -- I mean, I think this is a good process, and we have good resources. And to name names, I mean, FPL Energy is operating in states all over the country and is familiar with, I would presume, RPSs all over the country. And I think with everybody trying to work together, we can get there. I just was a little curious as to the anticipated timing on that, so thanks for the response.

MR. FUTRELL: Okay. If we don't have any other questions, I think we've addressed most everything
that was in, if not everything that was in staff's list. We appreciate everybody's participation.

As Bob said, we're planning another workshop. We have a tentative hold date on November 5th, and we will get -- we'll try to firm that up, firm that date up and get the announcement out as soon as possible, and also formulate an agenda well in advance to give you a heads-up on exactly what we want to see covered and any other outstanding questions.

MR. TRAPP: Just for discussion purposes on the upcoming agendas, as I think I mentioned, we certainly haven't formulated an entire agenda and would like your input on other areas that you think that we need to address.

One the areas that came up at the last meeting and that we've been exploring some hypotheticals with in the post-workshop comments from that meeting are the use of multipliers to incent certain high cost industries such as solar. We would like to pursue that some more. That's going to be perhaps a little more detailed and technical than what we've done today, and hopefully we'll be in a position to share some of that information with you before the workshop so we can all be on the same plane about the hypothetical. That's one area that we would like to talk about more, is multipliers and how
do you do them, what effect do they have.

And then I guess we also discussed about do
people want to begin to reveal system analysis and put
things together in kind of proposal. I certainly would
entertain that if you would like to do that. Any other
areas, please pitch in.

MS. HERIG: Christy Herig, FlaSEIA. If you're
going to look at multipliers, I suggest you look at all
three mechanisms to influence the market portfolio, and
that's multipliers, tiers, and set-asides.

MR. FUTRELL: Okay.

MR. TRAPP: That's a good suggestion.

MR. TWOMEY: Mark?

MR. FUTRELL: Go ahead, Mr. Twomey.

MR. TWOMEY: Mike Twomey. To try and get just
a little bit more clarification on where we're going to
go sequentially here, I may be wrong, but I thought the
Governor asked that y'all, the Commission start
rulemaking before the end of the year. Is that correct?
Or he didn't except that you would have rulemaking
accomplished by the end of the year, did he?

MR. TRAPP: I don't have the executive order
with me, Mike. I don't recall. I think that may have
been the case with respect to interconnection and net
metering, but I'm not -- I can't remember if it was the
case here or not right offhand.

MR. TWOMEY: Well, help me understand. I assume it's your attention after these workshops at some point to actually start the formalized rulemaking process; right?

MR. TRAPP: That's the only way I know that we could initiate policy here at the Commission.

MR. TWOMEY: I mean, you have to propose a rule. At some point, you're going to propose a rule, if I understand the process correctly, and then there will be hearings, and the parties in this room, presumably, and some others that haven't taken much of an active role yet, but have an extreme interest in this, in the outcome of this, would then have an opportunity to participate in the rulemaking hearings and so forth going on; correct?

MR. TRAPP: I think that's correct. And this educational process to me is the precursor to that. I think this is an opportunity for people to begin to frame the rule. Staff's objective in rulemaking, quite frankly, is to try to have the parties reach consensus, and thus, the more education we get, the more understanding we have, the more commonalities we can develop, the quicker the rulemaking will go. So that's why we're apparently taking so much time on this
process. If we can get people at a central plane of understanding, I think we can get the rulemaking over fairly quickly.

MR. TWOMEY: And I would commend you taking your time on it and being thorough. I was trying to look ahead so I could tell my clients where we think we're going to be by the end of the year. And it strikes me --

MR. TRAPP: I don't have a date certain for you.

MR. TWOMEY: Right. But I'm just trying to -- without a date certain, it strikes me that we're going to have another workshop. You mentioned an agenda. What's the agenda going to be for?

MR. TRAPP: No, no, no. The agenda for the workshop. We're trying to formulate the agenda for the next workshop.

MR. TWOMEY: So it strikes me that we have -- probably it's going to be difficult to start any formalized rulemaking before the end of the year, or if you do, you'll just get into it, given that we're almost at the beginning of October.

And I would just add too, as everybody in this room that is aware of the statutory requirements of rulemaking, I would commend to you being very specific
about what your statutory authorization is.

Thank you.

MR. FUTRELL: Okay. If there's not any other follow-up comments, thank you for attending, and we'll be in touch. Thank you.

We also have a -- we have a sign-up sheet in the back and over here on the side, if you'll make sure you sign up.

(Proceedings concluded at 3:13 p.m.)
CERTIFICATE OF REPORTER

STATE OF FLORIDA:
COUNTY OF LEON:

I, MARY ALLEN NEEL, Registered Professional Reporter, do hereby certify that the foregoing proceedings were taken before me at the time and place therein designated; that my shorthand notes were thereafter translated under my supervision; and the foregoing pages numbered 1 through 177 are a true and correct record of the aforesaid proceedings.

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

DATED THIS 4th day of October, 2007.

MARY ALLEN NEEL, RPR, FPR
2894-A Remington Green Lane
Tallahassee, Florida 32308
(850) 878-2221

FLORIDA PUBLIC SERVICE COMMISSION