BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. UNDOCKETED

In the Matter of

INTERCONNECTION OF SMALL PHOTOVOLTAIC SYSTEMS; NET-METERING OF CUSTOMER-OWNED RENEWABLE RESOURCES AND INTERCONNECTION OF CUSTOMER-OWNED RENEWABLE RESOURCES
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PROCEEDINGS: STAFF WORKSHOP

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TIME: Commenced at 9:30 a.m.
Concluded at 5:45 p.m.

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

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P R O C E E D I N G S

MR. FUTRELL: Okay. If everybody will take their seats we will resume the workshop here.

Okay. We left off in Section 5(a), Sub 4, which is the indemnification language. Staff has tried to clarify that by specifying in the first sentence that the customer shall hold harmless. That was our, as I understand, our main change there to try to clarify that situation. We would like to have -- get some input on this statement, especially the idea we heard in some of the comments about a symmetrical, this needs to be symmetrical. I'd like to get some comments about that.

And, Jason, I know you had some thoughts on that, too. Could you talk about that, please?

MR. KEYES: Sort of two items. Usually where there is indemnification language in the rules it is bidirectional, so the utility indemnifies the customer as well. But, also, when you're talking about indemnification, you're usually talking about holding harmless and indemnifying the person against third-party claims. So as this language reads, we're saying -- if I've got a solar installation, I'm not going to blame the utility unless they have been negligent, and usually you would have to prove some sort of negligence anyway.

But you usually don't refer to the other person, to the other party when you are talking about indemnification.

It's about third-party indemnification. So what that means is I'm running my solar system, my neighbor has a problem, my neighbor goes to sue the utility, the utility wants indemnification that I say I won't blame the utility, and I will hold you harmless and I'll defend you against the claims by my neighbor against the utility.

And, the other way around, if I've got a great big system and I've got money and my neighbor wants to go after me when they have a problem, that the utility will indemnify me and say, yes, if it's our fault, and I didn't do anything wrong that they will indemnify me. So for some reason this language is broad and it doesn't -- the way to fix it is to say indemnify the investor-owned utility for all losses to third parties resulting from the operation of the customer-owned renewable generation.

And it comes up a bit, actually up in the previous section where they say that there will be a statement in the interconnection agreement that you won't blame the utility for damage from normal and abnormal conditions. And I would want to say something there about abnormal conditions not caused by the negligence of the utility. So, for instance, if the utility didn't install a surge protector and a surge destroyed my system, I think that I'm within my rights to blame the utility for having just fried my million dollar system.

MR. FUTRELL: Any comments?

MS. CLARK: Is he proposing language? I mean, I'm not sure --

MR. FUTRELL: I'm not sure.

Are you proposing language in the previous section, Sub 3?

MR. KEYES: Yes, Sub 3. By the way, on the numbering, just when you go back to it, there's a 5.A, there isn't a 5.B, so it makes sense instead of having 5.A --

MR. FUTRELL: We've already picked that up. We caught that.

MS. CLARK: Is there a page and a line that I can look at?

MR. KEYES: Page 5, Line 1, so damage from the normal and abnormal conditions not caused by the utility's negligence. And I suppose it will come after operations, abnormal conditions and operations not caused by the utility's negligence that occur on the electric utility system.

MR. FUTRELL: Could you repeat that?

MR. KEYES: And other system components from damage from the normal and abnormal conditions and operations, not caused by the utility's negligence, that occur on the electric utility system in delivering and restoring power.

So if it is the utility's negligence that caused the problem, then it would still be liable for that.

MR. FUTRELL: Does everybody have that language? Any reaction to that proposed language?

MR. KEYES: Then you've got the language for Section 4 there, just adding a provision that the customer shall hold harmless and indemnify the investor-owned utility for all loss to third parties resulting from the operation.

MS. CLARK: Mark, I don't know that I have an initial reaction to them, a concern, but to me those are the things that we need time to look at and think about and their implications and compare them to other rule provisions to make sure we can be comfortable with those changes.

MR. TRAPP: Can that be embraced in your post-workshop comments?

MS. CLARK: Yes.

MR. TRAPP: Thank you.

MR. HINTON: Could you also address the matter of Subsection 4, I guess it's 5.4, the indemnification language, making that symmetrical, or is the customers indemnifying the utility for loss of third parties due to operating their system, but also the utility indemnifying the customer for the loss to a third party?

MR. TRAPP: Do we have a sentence for that or is this just a concept we want to address?

MR. HINTON: I know that in IREC's model they have it going both ways, so I am going to punt to him to come up with some good symmetrical language.

MR. KEYES: I will be happy to. And, actually, IREC's language is good. We just went through this in New Mexico, and that language gets so thick when you try to do a bidirectional. You say one party identifies the other party against the first party, it gets confusing.

MR. HINTON: I already made one attempt and failed miserably.

MR. KEYES: And it works pretty well if you just break it out into two separate clauses, so there is what you've got here and then a second sentence that says a provision that the utility shall hold harmless and indemnify the customer for all losses to third parties resulting from the operation of the utility's electric distribution system except when the loss occurs due to the negligent actions of the customer. And I'd be happy to write that out, but, basically, it's a lot cleaner to just have a second sentence to say that, instead of trying to somehow force it all into one sentence.

The other thing that happens in indemnification language is the standard in contracting has been that you indemnify everybody. So it's not just the utility, you would be indemnifying the utility and their directors and their shareholders and anybody else you can think of, and the same would go for the customer. And so you can add a third sentence to the language, and I'll provide that, what we have in New Mexico, that says when we talk about -- in this section when we talk about this customer or the utility, we mean everybody associated with it.

MR. FUTRELL: Any other comments on the indemnification?

MS. CLARK: Comments on what?

MR. FUTRELL: The indemnification provisions.

Good. Okay.

Let's move on to Section 5, Line 9, where you get into the insurance requirements. We touched on that earlier where it would be one million dollars for Tier 2 and no more than two million for Tier 3, and that the utilities would recommend but not require insurance for Tier 1.

Yes, sir.

MS. SHEEHAN: Mike Sheehan with IREC. I guess -- let me give you a little background on who I am so you'll understand the context of my next statement.

First off, I have worked for three different utilities, Commonwealth Edison Chicago, Virginia Power, Puget Sound Energy. I have 30 years of utility experience, plus I work with IREC, as a consultant to IREC. But I was also a member of IEEE 1547, and under that context this question of liability is very perplexing to me because I'm not quite sure in the 30,000 systems that are out there on photovoltaics in the system in the United States, I know of no instance where photovoltaics or inverter-based systems have caused a problem on the utility. So I would like to know the cause of why this, the cause being what level of insurance and why insurance is so onerous in this section.

MR. FUTRELL: Again, we recognize that to try to encourage small systems -- we understand for residential most of it is covered in general liability insurance. For larger systems, it appears that for business owners, good general liability insurance it's wise to have levels of this amount. We checked into the availability. In areas that availability is not an issue; affordability doesn't appear to be an issue; it appears to be good sound business practice to have this. We also, by increasing Tier 3, by doubling Tier 3, we felt we needed to recognize that by increasing the insurance requirements for those larger systems.

MS. SHEEHAN: Yes, but I'm still perplexed by what problems are they going to be fixing by having this reliability on the systems. And, first off, I'll have to have a context of what problem exists from a PV system that could feedback to the utility system and cause that kind of a problem. And the analogy I would use is in the northwest, you have the Grand Cooley Dam behind you, and this a 10 kW or a 100 kW system. I'm not quite sure I understand the kind of system as what is going to drive what here as far as cause a problem. And most of these inverter-based systems don't have any kind of capability. Again, the 30,000 that are in existence today, I've never heard of one -- as a member of the EEI Committee on Distributed Generation, I've never heard of a PV or inverter-based system causing problems. Is this really proportional to the kind of problem that's out there?

MR. FUTRELL: So in your mind there is -- do you support no requirements for insurance provisions?

MS. SHEEHAN: Well, at a much higher level than what's here in the Tier 1 and Tier 2. And I would say in the New Mexico arrangement 250 kW is where the insurance started kicking in.

MR. FUTRELL: Okay.

MS. SHEEHAN: So it is a much higher level than here. And I'm just sort of perplexed by how the number got to where it is here. What is the basis of how it was started and why it was such a level.

MR. HINTON: I can tell you the original PV rule had a requirement for $100,000 of liability insurance. That rule only went up to 10 kW. Looking at a number of states, some states don't require anything, some states require more than what we are requiring here. We kind of came down in the middle. And, frankly, that is one of the questions that I was going to raise, as well, you know, asking the utilities what are they looking to guard against by having this liability insurance and does the indemnification language that's already in here now obviate the need for liability insurance in the eyes of the utilities, and if you can give me some specific examples of why you think it should --

MS. CLARK: Here is what I think people seem to be forgetting, at least what I hear the question being asked is, is the damage from this facility to the utility system or the utility system to this system. What about the third parties? This liability is also designed to cover damage to third parties' property or person. And it seems to me that it is entirely appropriate to require that kind of insurance when you operate these kind of generation systems, even if they are inverter based.

And with respect to the indemnification, I don't think that cuts it for this reason: You may be responsible, but if you don't have the assets to pay for that responsibility, what good is it to the person who was injured? That is what insurance does for you. It provides the funds that if there is damage to a third party, either property or person, that the insurance is there to cover it.

Along those lines, it seems to me that the rule suggests it's good for customers, even small customers, to have the insurance, 100,000 in insurance. And I think we heard at the last workshop that's not a significant amount. It's what people seem to normally carry anyway. We heard from one gentleman regarding how much it cost for him. I think they have $2 million worth of coverage, and it was not significant.

But it does have the effect of having the money there if there is damage, not just to the two parties in this contract, but also to third parties. For that reason, we would also suggest that it not be just a recommendation, but for Tier 1 it be a requirement that they carry the 100,000 in liability insurance.

MR. HINTON: Just a little commentary before I let you guys respond, too. As somebody who used to run a small business, from my perspective you have got to be crazy not to carry liability insurance when you are running a business. And from the small business I was involved with, we carried a million dollars worth of insurance, and that's why I didn't see this as very onerous at all. Because we already had this, and we were a very small business.

So just from me approaching this, you know, personally, I wouldn't install anything that generated electricity if I didn't have liability insurance just because of the potential of, you know, causing injury or damage to some third party. And the state of things these days, everything is going to go to court in that situation. So that was just my own personal perspective in looking at this.

MR. GRANIERE: I have a question. On this liability insurance, what protection is the utility getting against action by the customer? I'm not quite understanding that.

MS. CLARK: You're asking what protection the utility is getting from an action by the customer?

MR. GRANIERE: Right. The customer has the insurance.

MS. CLARK: Right.

MR. GRANIERE: Okay. And presumably the customer does something that kicks in the insurance. How does that impact the utility?

MS. CLARK: Well, to my way of thinking would be what if something happened to the utility's distribution system because of something that happened, maybe it didn't island (global phonetic) or something like that. And then the insurance is there to cover that damage that the customer has caused to the utility system. It also covers when that damage occurs to a third party.

MR. GRANIERE: Okay. Presumably, then, the utilities are self-insured. So if it were to go the other way, then the claim could go against the utility, is that correct?

MS. CLARK: Yes. If the utilities are liable for their negligence, there would be a claim against the utilities for that.

MR. GRANIERE: So, basically, the utilities carry self-insurance, and so this is just a symmetry for the other people to have insurance.

MS. CLARK: Bob, I'm not sure if they are self-insured. I'm not sure how they would cover these kind of things, but they would be liable, and presumably it's fair to say that they would be considered a deep pocket, the one to go after. And by the customers having this insurance, it will hopefully have the advantage of having those claims being able to be paid by those insurance rather than having a lot of incentive to go after the utility as opposed to the real entity that was liable.

MR. GRANIERE: And then this indemnification language, if I understand it right, that takes care of a third party going after the utility if it was the generator's problem, and vice versa, it prevents a third party from going against the generator if it was the utility problem. Is that basically what we have got there?

MR. KEYES: That's correct. I believe that Ms. Clark's point is that that doesn't help the utility if the customer doesn't have insurance to cover the damages. And my point is that there hasn't been a case.

MR. GRANIERE: You know insurance -- I mean, this is, you know, insurance is like insurance. There is actually some people out there in the world who never have a car accident, but they have insurance all the time. So, you know, I don't think that's a reason for not having insurance, but I am just trying to figure out what it actually does and, you know, because as far as insurance is concerned, I think that most insurance arrangements to avoid adverse selection require a whole lot of symmetry to make sure that all of the parties aren't gaming the system, and that's what I'm just talking about.

MR. KEYES: It is unlike car insurance, and there are lots of car accidents. I mean, I don't have asteroid insurance in case one hits my home, because while it has happened probably sometime, it is very, very, very unlikely. Well, it is about unlikely as a PV system causing damage to my neighbor.

MR. GRANIERE: Taking the chance of jinxing myself, I haven't had a car accident in 25 years, but I pay that every year, far too much, of course, but I pay that every year. So that's just the way it is.

MS. CLARK: I'm not sure that I was answering a question when I made my point about the fact that we think that Tier 1 customers shouldn't -- you shouldn't just make the recommendations, you should also have it as a requirement in the rule that they carry that, liability insurance.

MR. HANSEN: I don't know where I read this, but it was a government document stating that solar photovoltaic systems were very, very safe and they have never had an accident which would require some kind of a lawsuit. That's in government documents, if you look it up on the Internet, but I don't have it in hand right now. And I agree with the gentleman down there, that having insurance for the sake of having insurance is ridiculous. Like he said, a meteor could hit you on the head, but I don't know if I would buy insurance for that. Thank you.

MR. JONES: Dell Jones. I guess what I would like to know is just, if possible, the utility could just point to a case in a worst-case scenario from an actual occurrence that actually happened to justify some of these insurance requirements. Because as we have heard already that, you know, there is no known cases. I have a hard time understanding from -- especially the small systems, I mean, 10, 20 kilowatts. I mean, if I try to imagine the worst-case scenario, I can't imagine how I could cause harm to a neighbor or the distribution system with that small of a load. Like I say, it just doesn't follow logic with -- I mean, just show some support of the fact that insurance is needed based on some actuarial information where occurrences have happened, and then we can take up the issue. But just to have insurance for something that could, maybe, possibly, sort of, might happen doesn't really make a lot of sense to me.

MR. FUTRELL: Would you like to respond?

MS. CLARK: You know, I guess I go back to the notion that I was reading in a case or something where electricity and the generation of electricity is an inherently dangerous business to be in. It seems to me that one of the issues we have talked about is the need to make sure these things get islanded so there is no feedback. I can't tell you the things that may, in fact, occur. But it seems to me that the amounts of insurance that you are looking at are things that residential customers and businesses should be carrying anyway. And for that reason, I don't see it as onerous, and it does protect not just the utility and the customers, but third parties who likewise may be injured by whatever accident may occur, or negligence.

MR. FUTRELL: Mike, I would like to ask you a question. You referenced 250 kW as kind of a break point, what levels of insurance would be, if any, in your mind.

MS. SHEEHAN: Well, before I answer that question, let me step back and say within the question of insurance and doing damage, the IEEE 1547 requirement is for 30 kW and smaller to have the anti-islanding. And the question of insurance is if the inverter doesn't work, the inverter manufacturer is on the hook. I mean, the customer is not going to be on the hook. They will be sued, but they will go right to the inverter manufacturer who didn't perform, and then the UL process kicks in.

So I think there is a whole question of how that insurance and the revenue is going to be captured and how it is going to be paid back. So I think to assume that the customer is going to be paying all of that back is probably a notion that sounds good, but in reality the inverter manufacturer has to be the one that stands behind that, and the UL process and all the testing and all the requirements that went into determining what was safe and what was not safe. So that is the first statement of where that fits in.

And I think the number I remember was a million dollars in New Mexico. I think that was -- for the 250 kW system that was the number that they used. And, again, that 250 kW in New Mexico was the number. Below that you are talking about a system that is not -- I mean, it is very unlikely for any kind of system to be feeding back and causing problems with the utility system.

Remember, the utility system is a very robust system. And to assume that a PV system can go back and hurt the utility or impact the utility -- and I agree with the comment that third party is an issue, but there is a complicated issue when you come back to inverter-based technologies that have been UL approved. And, again, 30,000 of them out there in space. We are not talking about accidents that happen every day. We're talking about accidents that have never happened. So what are we trying to insure for, what are we paying for and what is the customer getting for the benefit? And I think, you know, the risk aversion part of the utility, I understand the basis for that, and I appreciate what they are trying to get at, but I think the question has to be where is it prudent to be making those decisions? And I think that is where you step back and say 30,000 systems in the U.S., there is a lot of places where this is not required, at what break point do you make it, 30 kW, 250? I think there are a lot of different numbers you can choose and they may be arbitrary at times, but you may want to go back and revisit this as you get more and more comfortable with that line or where that demarcation can take place.

MR. REEDY: A technical contribution to the discussion is that one of the challenges with the islanding protections and testing of that is that it is almost impossible to create a scenario in the laboratory where a system will island. I mean, you can do it in the laboratory, obviously, but if you start applying any of the real world to it, it becomes a challenge to even test the capability of it. San Deao Labs (phonetic) has done most of the work in this area, and it's just almost inconceivable in the real world for a small system to create an island that gets beyond the building that it's in.

MR. TRAPP: I'm just curious. I thought of a crazy hypothetical out here. We seemed to be focusing on islanding problems and things of that nature, but it seems to me we get complaints all the time about somebody picking an avocado out of their in neighbor's yard and getting fouled up with the electric lines and winding up suing the electric utility. If you are commingling electrons on that power line from a customer source or the utility source, doesn't that make you a party to that lawsuit?

MR. REEDY: It's an interesting question, but I think if you say yes, and so pro rata, the eastern interconnection is one party and you are the other. The eastern interconnection is some, you know, several hundred thousand -- somebody tell me, it's huge -- gigawatts, and that is one logical way to do it. Say, yeah, you are one one-millionth of a party to this damage, that might be a rational way to do it.

MR. PALECKI: I gave an avocado seed to my brother ten years ago, and I made sure he planted it in his backyard away from the power lines, and it produces good fruit and it's safe.

MR. REEDY: In Miami it is mangoes.

MR. GRANIERE: I have a question. Oh, go ahead.

MR. TOTH: Bill Toth. One thing I don't see in the language for liability insurance, many companies especially some of them that are going to be putting in the larger systems will be able to self-insure for these amounts. I don't see any provisions in here for allowing self-insurance.

MR. FUTRELL: So that would be self-insurance in --

MR. TOTH: They have asked us to back up that amount.

MR. FUTRELL: Right.

MR. TOTH: I know that is done frequently in the environmental industry.

MR. FUTRELL: Uh-huh.

Jason.

MR. KEYES: There is language like that in the FERC rules as well, that if the customer can show evidence of ability to self-insure, then the utility won't be unreasonable about allowing them to self-insure.

MR. FUTRELL: Is there some sort of a means test or something they have to show?

MS. KIESLING: Actually, it doesn't go into any great detail. There is some discussion of it in Order 2006, FERC Order 2006. So you could prove that through your balance sheet or through evidence of some letter of credit or something.

MR. TOTH: Or assets, things of that nature.

MR. FUTRELL: Right.

MR. KEYES: One other point. When you asked Mr. Sheehan about the anticipated costs, he responded that in New Mexico they require a million dollars of insurance for systems over 250 kW. The discussion at that point is what sort of costs could we anticipate? And the worst scenario that the utilities came up with was that a transformer got blown, a major transformer got blown, and that would be on the order of 100,000 or $150,000.

And the other scenario is that you have a utility lineman out there who gets hurt because the islanding didn't work. There are two parts to that one, as Mr. Sheehan pointed out. The inverter manufacturer is in big trouble then. But, also, for the lineman to get hurt, the lineman ignored the first rules of operating on a line. You always assume that the line is live, and you ground yourself. So that was generally accepted as not something that would be the fault of the customer.

MR. FUTRELL: Any comments on the self-insurance, idea of self-insurance?

MS. CLARK: You know, I think it would depend on what is adequate evidence of self-insurance. I wouldn't imagine that would be a problem as long as the money is there and available for the payment of any claims.

MR. FUTRELL: I would ask if you have got some ideas on language to provide that in your comments.

Yann.

MR. BRANDT: Yann Brandt. I have a general question about -- you know, the example Mr. Hinton pointed out is that, yes, most businesses have general liability. Are we talking about a general liability policy or are we talking in specific an interconnection liability insurance specifically naming the utility as an additional insured under that policy? If we're talking about the latter, yeah, every business has general liability insurance for daily business.

I'm sure that if you bring to an insurance company I want an interconnection liability insurance, naming the utility as an additionally insured, for an insurance company that really knows nothing about UL standards, IEEE standards, it's going to be a bigger problem. And I'm actually going through this exact example right now where I'm asking for my insurance to name FPL as an additional insured under my interconnection agreement. I'm going through a series of technical questions. Why do we have to do this? What can go wrong? They need to know what the extent of the possibility of the damage is to assess what the increase in cost is going to be before they can just issue that insurance.

If we are talking about just a general liability insurance, that's day-to-day stuff that we can get. But if we are talking specifically to that interconnection, we have to be more specific in, one, the language of the rulemaking, and, two, that the insurance companies are aware of the lack of possibility of damage to the grid and to the utility. Before we go down that road, we are going to cause a whole backlog of insurance training and education before we are able to get that insurance.

MR. HINTON: In our mind at this point we are just discussing general liability insurance, not a specific policy, although we may be disagreeing up here.

MR. BRANDT: Is that the same thing that the utilities are looking at or are the utilities thinking it's a specific interconnection insurance naming them as an additional insured?

MR. TRAPP: I guess, I was under a different understanding than Cayce may be, because I'm relying on the provision of this in our current interconnection and standard rule, Rule 17.087, which is referenced both in our cogeneration rules and in our renewables rules for purchased power contracts between renewables and/or QFs and utilities. And I thought we were paralleling that here to some degree in that it's pretty specific in that language that this holds the utility harmless, has them specifically listed as an insured under the policy, and it's an interconnection policy. So I thought that is what we were doing, was basically doing an interconnection general liability policy.

MR. HINTON: Bob, from my perspective --

MR. TRAPP: Am I wrong?

MR. HINTON: Well, I was looking at the original small PV rule and the insurance requirements there that requires $100,000 for these 10K systems. And it states the homeowner's policy that furnishes at least this level of liability coverage will meet the requirements of insurance. To me that was going toward the liability policy already attached to a regular homeowner's policy, not specifically designated for an interconnection. And so I just extrapolated that out to the business general liability, as well.

MR. FUTRELL: We carried forward that I have a general liability policy. We carried that forward into this rule.

MR. TRAPP: I guess I assume, though, that the people that -- because I was not a party to that rulemaking. The staff that were involved in that rulemaking, I just assumed had researched that a homeowner's policy would meet the requirements of the basic insurance interconnection standard requirement here, and there was a parallel and carryover there. If we're talking about a different type of insurance, I think we need to make that clear.

MR. HINTON: Yeah, from my understanding, it wasn't. From my understanding, it was the $100,000 liability policy that you generally get with your homeowner's policy is what they were talking about here.

MR. TRAPP: To cover what situations, though?

MR. HINTON: Just general and any liability situations.

MR. TRAPP: Anything that happens. And then are you carrying that concept over into the million and two million dollar policies? I think that may be the question that the parties are putting before you here. Are the one and two million dollars the same concept, or just general liability for anything that happens?

MR. HINTON: Well, that was --

MR. TRAPP: Or was it more specific to interconnection?

MR. HINTON: Well, we may need to address that. In my mind it was -- I had in my mind the general liability policy that a business would carry. I spoke with my own homeowner's policy provider, and I also contacted the insurance provider that I used to have a business liability policy with a decade ago or so, and asked them specifically if I had a PV system on my roof is this policy going to cover occurrences that result from me having this PV system. Both of them said, yes, at this point it's not being excluded from general liability policies. They said that may change, but right now it is not being excluded so it would be covered.

I know that the people at the Department of Insurance that we spoke to about this had some concerns that even though it is not specifically excluded, that insurance companies would start to try do exclude after the fact. You know, a claim comes in, and the insurance company would say, well, no, we never contemplated that. So they have that concern. But right now -- I mean, in my mind going forward that this was just a general liability policy. If we need to change that, we need to change it.

MR. TRAPP: Well, I think that clarifies things well. And if that's our starting point, that's our starting point. And if that is what staff is intending, if we were at agenda today, if that was the explanation for this rule language, that's is what you all need to comment against. Because, again, I thought we had adopted some looser language, but still captured the intent of this rule. And you're saying that's different, and I think everybody needs to know that.

MR. FUTRELL: Any other comments on insurance before we move to the next section?

Okay. First, Section 6 is the section on manual disconnect switch, and we have combined language from different sections into one.

MS. CLARK: I'm sorry, Mark, I was sort of distracted by you talking about insurance. We did have a question on 5.B.1, not necessarily related to the insurance issue. Oh, I'm sorry. What are --

MR. FUTRELL: 5.B.1?

MS. CLARK: B.1. Let me see.

MR. FUTRELL: We're not there anymore.

MS. CLARK: The old 5.B.1. I'm on Page 5, Lines 22 and 23. Are we beyond that or not?

MR. HINTON: That's the new Section 6, we are about to discuss it.

MR. FUTRELL: Manual disconnect switch.

MS. CLARK: Then I am not too late. I will wait until you finish talking about that, and I'll jump in. Thank you.

MR. FUTRELL: Again, we have combined language on the disconnect switch. Lee Colson with our staff has put together a line diagram to try to capture our understanding exactly where the disconnect switch is. We have gotten some mixed signals from different sources. We would like to have a little discussion today about how it's implemented, try to get an understanding of it. Obviously, from our research and from the previous workshop there was a discussion about the need for the disconnect switch. It is inconsistent across the states. Some have good reasons not to require it; some have good reasons to require it.

We talked with an engineer at National Renewable Lab, and he understood both sides of it. He seemed to think it was a good idea, but, again, there are good engineers out there on either side of the issue. We want to talk about that and also talk about using this diagram as a basis to try to understand exactly where the disconnect is happening, who it's benefitting, understand how it is set up and what parties are benefitting from the inclusion of the disconnect switch.

So, Lee, would you mind walking us through your diagram?

MR. COLSON: Yes.

Lee Colson, Commission staff.

What I did was I put together, as he said, a simplified schematic of a photovoltaic installation. You can see that we started at the photovoltaic array. What I understand is that there is a manual optional disconnect for the DC side. It goes into the inverter. The inverter is an automatic AC disconnect. And on the -- form the inverter I put in what I labeled -- it's optional, it's may be a meter, because some of the customers were concerned, they wanted to know how much of the PV system that they were using and how much was being supplied to the utility. So that's an optional meter, a monitor. And then it goes into the customer panel. The customer panel will distribute it to the customer, or if you have any excess it will go out to a smart meter, which is optional, or to a directional meter owned by the utility. And that's what we are understanding is happening there. If you all would have comments, we would gladly appreciate it.

MR. TRAPP: Let me focus this by going to the IOUs first, because I think you all are the ones that want the switch.

Do you still want the switch?

MS. CLARK: Yep.

MR. TRAPP: Arkansas and California say, yes, except for systems with inverters complying with IEEE 1547. And then there are a couple of other states that take that viewpoint to IEEE 1547 pretty well covers it for the manual disconnect. And then based on the chart that Karen put together, it looks like it's yes or no; yes or no; yes or no; yes or no.

MS. CLARK: Bob, I was kidding you when I said yep. I'm looking at that and trying to digest it. I'm not an engineer, and I'm hoping one of our folks that's helping us --

MR. TRAPP: The first question is if you have got one of those IEEE things that we adopted earlier --

MS. CLARK: Say that again.

MR. TRAPP: If you've got one of those IEEE standard island inverter, utility approved inverter thingies has a switch in it already, do we need a redundant switch?

MS. CLARK: Tom Sanders is going to come up and talk to you about this.

MR. SANDERS: Thank you. Tom Sanders, Florida Power and Light. It's my understanding that the visible disconnect switch, where visible is the important word, is what is needed. The inverter may provide the isolation and theoretically provides that isolation automatically, but it is not a visible break that you can see. And I think that's a problem that our people would have, and the fire department, for example, has, and that is why currently the standard is to have a visible disconnect switch.

MR. TRAPP: Is it your standard or is it the fire department's standard?

MR. SANDERS: I'm not that familiar with the fire department. It is just my understanding that that would be their need, to see the visible break as our people do, as I understand most people that work with electrical appliances are interested in seeing a visible break.

MR. TRAPP: I understand the concern, but I'm trying to get at jurisdiction here. My understanding is based on copies of the 1547 standard that staff got, it makes reference in there to local building codes, things of that nature, which I assume would cover fire concerns about the PV, you know.

Okay. The utility comes out, they pull the meter, no electricity to the facility, except there is a PV in there doing something. That's the fire department's problem. If it's covered by the code, and they have required the switch. So I guess what I am getting down to, why do you need the switch?

MR. SANDERS: Well, our interest there is to disconnect it. If there is a problem with the PV system, and we have a need to disconnect, then we want to be able to isolate the device and still be able to provide the customer power.

MR. TRAPP: So you are not satisfied taking the meter out?

MR. SANDERS: Well, if we take the meter out, then we don't have to provide power at all.

MR. TRAPP: Right.

Your turn.

MS. SHEEHAN: Mike Sheehan, again, with IREC. I guess I have four -- the best practice is what I would like to start off with. First off, I think you put your finger on it. The first question is jurisdiction. Having the utility go on the customer's side and require equipment on the customer's side of the meter is problematic from a jurisdictional point of view, because that is National Electric Code, and that's not part of their privy. Again, the fire department has the requirement to do that on a PV system, and most PV systems have a disconnect on themselves.

Second, I think there is a liability question that most utilities have not recognized. And, basically, if you look at the California utilities because they have gone through it so many times, the liability question is once you put that switch on the other side, the customer's side of the meter, the linemen or the person that puts that lock on, that is a qualified worker. A qualified worker walking into a customer's facility, and if there is anything not in compliance with code, they are now liable for what is going on within that facility.

I think the utilities had better think twice about requiring a qualified worker to walk onto somebody's place, put a lock on there and then say, hey, this is required, because the third question is the precedent. You set the need to open and close this switch, if something goes wrong and you don't open and close that switch every time, and you have thousands of these on the system, I think you are going to have another precedent where you have to open and close these systems every time you have an outage, and that is something I don't think they want to be doing.

And the last system is best practices, and it goes back to your comment about who does it and doesn't do it. You will find out that the utilities that have a lot of these systems figure out, hey, at some point there is a break point we want to have this where we can feed back in the system. Whether that is 100 kW, 200 kW, you want to have a switch there, but you're going to operate that at a lot higher level than at the customer's site like this. And it is typically not a 10, 20 or 30. It is way up a lot higher than that.

MR. TRAPP: How high?

MS. SHEEHAN: Again, each state does it differently. I would say 100 kW or 50 kW, in that range is where it typically would take place.

MR. TRAPP: So Tier 2, Tier 3?

MS. SHEEHAN: Again, you do that at the transformer. You wouldn't do it at the customer site. You might do it at the transformer, just disconnect them at the transformer.

MR. TRAPP: Which takes the whole customer load out.

MS. SHEEHAN: Right.

MR. FUTRELL: Yes, sir.

MR. CASTRO: Orlando Allen Castro (phonetic) with the Orlando Utilities Commission. Just to clarify. I mean, I think we also note that -- we should note that we need to be talking also about all renewable generation. Because we have been focusing a lot on inverter-based technologies, which, of course, there are the unlikely events that these inverter-based technologies, as you mentioned before, which would fail to operate and would island. But we need to look also beyond that and look at the other types of technologies that may require the manual disconnect.

On the other side of that, I do agree with you as well with the fact that once you get beyond a meter you are looking at NEC requirements, or guidelines, or codes versus the National Electric Safety Code. So, you're right, once you go beyond the meter, you need to start looking out whether we are qualified to even work beyond the meter. So those are just some comments.

MR. TOTH: Bill Toth. My question would be if you're going to put a system on, it has to meet with the requirements of Section 3. In Section 3, those various IEEE and UL codes, do those cover the issues that we are talking about in those standards? Is it already covered? Are we beating a dead horse here?

MR. CASTRO: Again, I think IEEE does address manual disconnects, visual open breaks. But, again, as to the details as to what side, I'm not very familiar with that. But I do remember seeing in IEEE 1547 addressing manual or visual open breaks.

MR. TOTH: I can agree with that. I don't know if it was a requirement, though. Do you remember whether it was actually required?

MR. CASTRO: No, I don't, sorry.

MS. SHEEHAN: It is not required in 1547.

MR. JONES: And on the manual DC disconnect that powers up the inverter, basically, that's a code requirement. So there is the DC disconnect to the inverter that would shut the whole inverter down. So you have a disconnect that's usually located right at the inverter, and it's an open-air disconnect as, you know, the code requires. So, you know, to have one on the AC side of the inverter and one on the DC is just redundant.

MR. HINTON: Well, I think the problem at the DC disconnect is that's going to likely be up on the roof, would it not?

MR. JONES: No, they are typically located within arm's length of the inverter.

MR. HINTON: The inverter is down at ground level, not up on the roof?

MR. JONES: Well, they could be, but it's not typical to have it up on the roof. In a residential system, a large commercial system that inverter could be located up on the roof or it could be located down below.

MR. HINTON: Okay. Because I think the utility's concern is they want it accessible, so they could walk up to the house and flip the switch.

MR. JONES: Well, a surefire way is just pull the meter.

MR. HINTON: And that leads to another question that I had, if I could. You mentioned the problem with pulling the meter is that you can't provide service to the customer if you pull the meter to disconnect the PV system or the renewable system, is that correct? I thought you just said that.

MR. SANDERS: Yes. Just looking at this diagram, if you pull the meter, you have disconnected the customer in addition to the PV system.

MR. CASTRO: With the manual disconnects, all they do is lock out the renewable generation; the customer would still be able to receive electricity from the utility?

MR. SANDERS: Right. Just as it is shown here in the diagram.

MR. FUTRELL: So your understanding is that diagram accurately captures how you are understanding the systems are being installed, and where these disconnect switches are located?

MR. SANDERS: That's right.

MR. FUTRELL: And it is your understanding it is consistently installed in that manner?

MR. SANDERS: That's right.

MS. SHEEHAN: Going back to my point earlier, I think if you step back and ask the liability question, once you have got a utility worker on the other side of the meter, and they are a qualified electrical worker, there is a certain liability that they are going to be taking on. Then the second part of that equation is if you now operate or require that switch to be operated, and you don't operate that switch, every time there is an outage or every time there is an event, what kind of liability are you setting yourself up for?

MR. TRAPP: Could I ask the question this way? If we just leave this out of the rule, does that prevent a utility from addressing it in their standard interconnect contract with some kind of case-by-case consideration?

MS. SHEEHAN: I would consider that to be very onerous, because that is a very haphazard way of doing it, because you don't know what your costs are going to be.

MR. TRAPP: Well, I guess what I'm saying is, is this an issue that needs to be completely litigated and all the Ts crossed and the Is dotted in the rule format, or is it something that could go on as an implementation issue in contracts?

MS. SHEEHAN: Well, from the best practices point of view, I think if you look at where the utilities are that have the most PV, I would say New Jersey and California, and in those examples you will find that this disconnect is not required.

MR. TRAPP: But how do they address it in the rulemaking? Do they say in the rule it's not required or do they just omit any mention of it at all?

MS. SHEEHAN: They omit the requirement.

MR. TRAPP: This is what I'm getting to. If we omit it, if we completely omit it from the rule, it's not a rule requirement, does that prohibit a utility from addressing specific problems they may have with a certain type of installation in their tariff? For instance, the gentleman -- I missed your name. But the gentleman mentioned --

MR. CASTRO: Orlando Castro.

MR. TRAPP: Mr. Castro mentioned that this may not be a problem for solar inverter type applications. But what if it is a problem for a rotating machine application? Is that something that can be addressed on on that type of case-by-case basis in the standard interconnect tariff as opposed to having to address it in the rulemaking? That's my question.

MS. SHEEHAN: I would say that that should be a practice if you are going to have a synchronous machine, you would want to have that as a disconnect, you would want to have that there. But, you know, as a photovoltaic or any kind of asynchronous generator that goes through an inverter-based system, I don't think there is a requirement to have it. There is no need to have it. But, you know, the question is going to be if somebody has a Honda generator in the backyard, do they have a requirement to have that? There is no requirement to put one of those on, and yet there are lots of people out there who have Honda generators in their yard.

MR. TRAPP: There were a lot of problems with people plugging those Honda generators into their house circuits, too, and creating all kind of havoc that I think the government was trying to address, too. I think what I'm hearing you say is if we put a solar exemption in here, you're all right.

MS. SHEEHAN: I would say inverter based.

MR. TRAPP: An inverter exception, similar to the way California and Arkansas have done.

MS. SHEEHAN: Yes.

MR. GRANIERE: I have a question on the -- Bob Graniere -- on the idea that you can't pull the meter because you want to keep giving service, but can you give me an example as to when that would happen? When would there be a situation where you want to keep giving the house service, but you would want to go out and do the manual disconnect?

MR. SANDERS: Well, in the event that you had a problem on the system or any of the other reasons that is listed that would allow the utility to disconnect the customer's generation and lock that switch in the open position. So for any reason that's currently in the rule that would give us the right to disconnect the generation, you would want to still be able to, and I think the customer would still want to receive service.

MR. GRANIERE: So I would guess that that benefitted you guys, and so why wouldn't you want to pay for that?

MR. SANDERS: Well, it also benefits the customer. You can receive service.

MR. GRANIERE: Well, then, how about sharing the payment?

MS. SHEEHAN: Can I step in the middle of this discussion just as a third party to the discussion? I think there -- and this is my utility hat speaking, so I'm speaking in terms of using a meter as a disconnect switch is not considered to be proper and safe, because it's not a load break switch. It's okay to disconnect the meter when there is no load on it, but it is not okay to be doing it while it is under load. And there is a safety issue with pulling meters under load, and that is kind of the question that's on the table that hasn't been spoken to.

And I want to make sure it is clear that using the meter as a switch -- there are states that say less than five kW, they have done testing and all of that kind of stuff, of when they can pull it, but that is for like small wind and small hydro systems. So I would be concerned about doing that as a disconnect switch in thinking it's safe and it's the customer power. It's not the customer power issue, it's a safety issue related to the meter.

MR. SANDERS: I would like to add to that as someone who actually has pulled meters before earlier in my career. And you can draw quite an arc. As a matter of fact, it's standard practice when you pull the meter is to grab the meter and yank it out quickly to the side of your head just in case you do draw an arc. It's not a load break device.

MR. REEDY: On that subject, I have looked at the -- Bob Reedy. I have looked at the reasons listed. The first two are emergencies. The first is emergencies. The second one is a hazardous condition. I don't think that saying that we are going to keep the customer in service because there is a hazardous condition, but we are going to keep them in service is a particularly rational way to go at it. And with those two conditions, I would say the proper way to disconnect the house would be to pull the jack and the transformer, which would, in turn, turn off the neighbors. But we are still talking about a hazardous condition or an emergency.

And we are talking about something that, as we have seen before, has never happened in the history of these systems, especially with inverter-based systems. Then we go on and we say, okay, we are going to exercise this switch if there is a power quality problem. Now, power quality problems, if you have worked in that area of the utilities, are very mysterious, they take a lot of research and investigation to determine where that harmonic is coming from and what we're going to do about it. And we often find it is something, an insulator that's cracked and causing some noise or something of that nature. But we certainly don't go start shutting off systems because there's a power quality complaint. It's a due process. It's a long and lengthy thing. So we have time to engage the customer, discuss it. And, ultimately, if they are found to be the source of it, they can be ordered to turn it off, and there is a process for doing that.

Then the fourth one is failure to maintain insurance requirements. And I find it hard to believe that we are going to not follow some sort of process that involves discussion and lawyers and everything rather than going and shutting off somebody. Because, I will tell you, if I have a system that is worth a lot of money to me, and it's generating, and you don't agree that I have the right kind of insurance and you shut me off and it costs me a lot of money, I'm going to have something to say about that.

So the reason I work through these four conditions is to say if there's an emergency, and if there's a problem that warrants shutting off the PV system, then it warrants shutting off the entire load. And there's a way to do that now that is safe, and we don't have to even pull the meter. We can disconnect the transformer. Because these disconnects have to be, as written here, near the meter for the load. Sometimes that can involve a lot of money because the system may be remote and require a lot of wiring. So it is not a cavalier thing that we are talking about. And we look at the other states, look at the experience they have, they found the solution, is you don't need to do that on an inverter-based system.

MR. HANSEN: I have that exact same problem right now. If you require the disconnect switch to be next to the meter, it's going cost me another $1,000 for my little system because the system is not located close to the meter, and I have to run a separate wire. Otherwise, I use the existing wire that feeds that area and that feeds that wire. So it would cost me an extra $1,000 at the meter if the disconnect has to be located near the meter. Thank you.

MR. FUTRELL: There are several states -- there are some states that require a disconnect switch except for the inverter-based systems compliant with 1547. Is that something that anyone has particular heartburn about, that concept? And, again, requiring a disconnect switch except for inverter-based systems that are compliant with 1547.

MS. CLARK: I heard Bob Trapp ask that question about carving out an exception for the inverter-based, and I don't know that the potential installers have -- if that is what would satisfy what they are concerned about.

MR. TRAPP: My understanding was they nodded their heads yes, so I think it's in your court.

MR. SANDERS: That still doesn't give us the opportunity to lock the device open if there's a problem.

MS. CLARK: And I do recall in one of the workshops somebody from the utilities talking about an instance where they did want to lock out the system but continue to provide the customer with electricity because there was something wrong with the system, and there was a need to be able to just isolate that portion of the service, but I don't remember the particulars of it.

MR. TRAPP: Well, I'm disturbed a little bit because I'm hearing what I think is an entire industry over here saying that, you know, they think they have demonstrated their case in other states, that they have such a problem-free record that they really don't need this extra expense. But then I'm hearing my local utilities over here saying in an abundance of caution, because we are going to act like -- is it Missouri that makes you show things? Show me, show me, show me.

So I don't know what to do other than to challenge you again, if you could come up with some examples of horrendous things that have happened because somebody did not have one of these switches. That would help me a whole lot.

MR. FUTRELL: Okay. Bob Reedy talked about the conditions --

MS. SHEEHAN: I just wanted to add one more comment, and I just want to make sure it is a clarification. One of the reasons why inverter-based systems are so much more inherently safe is they are injections as current based, as opposed to synchronous generators that generate voltage. And being a voltage device, I think the synchronous generators require an open disconnect for a safety reason, that's why they can feed back and control the system. So islanding is a lot more -- it's a possibility -- there's a higher probability of islanding with a synchronous generator than there is with an asynchronous generator. So if you just keep that in mind, the asynchronous generation is inherently only in just current. It doesn't inject voltage. That is the reason why inverter-based systems are so much more inherently safer.

MR. CASTRO: But going back to the question of whether leaving it up to the standard, the IEEE 1547, it does state when required by the area EPS operating practices and readily accessible, lockable, visible break isolation device shall be located between the area EPS and the DR unit, which is essentially saying between the utility and the photovoltaic system. It doesn't mention or doesn't specify exactly where, but it is just saying somewhere along the lines in between. The only problem I see with that is that if you -- here it's vaguely saying that it's up to the utilities. So if you don't address it in this rule, you are going to have an issue with consistency across the board with different standards.

MR. TRAPP: Would you read that statement again?

MR. CASTRO: Under IEEE 1547, 4.1.7, isolation device. When required by the area EPS operating practices a readily accessible, lockable, visible break isolation device shall be located between the area EPS and the DR unit, DR referring to distributed resources, and the area EPS referring essentially to local utility electric power system.

MR. TRAPP: That is the point of clarification I was looking for. The authority there is referenced when required by the utility.

MR. CASTRO: When required by the utility, which I'm assuming that means it's up to the utilities under IEEE.

MR. TOTH: Excuse me. Bill Toth. And where does it say that it needs to be located between what and what?

MR. CASTRO: Between the area EPS, which is the electric power system, essentially, the local utility power system, which would be under the guidelines of the National Electric Safety Code, which is up to the point of meter, that's the area EPS, and the DR, which is the distributed resources, which is any type of distributed generation or renewable generation. But it doesn't specify exactly where, whether it would be beyond the meter, after the meter, or before the meter.

And, again, it goes into the issue, which I would argue is that the visual break or whatever kind of break it is, so that we are not violating National Electric Code, would have to be before the meter. Whether it's beyond the meter, right after the inverter, you know, you raise a good argument. You know, you can't sit there -- how can the utility come in and lock it? I mean, we're not going to -- from my perspective, we wouldn't want to make ourselves subject to those type of liabilities.

MR. TRAPP: And that is part of the conflict I'm having with this whole thing, because my recollection of our rules say that the utilities are to establish a point of delivery, and that's a precise point. Anything on the customer's side of the point of delivery is inside wiring. Anything on the other side of the point of delivery is utility-owned operations. And it seems difficult to me to install a switch that effects inside wiring that is a utility piece of equipment. Although, I do recognize the meter is kind of floating in that equation sometimes, depending on whether you have got an overhead or an underground situation.

So it seems to me from a practical sense you want that piece of equipment to be under the National Electric Safety Code, not the National Electric Code. And at the same time, you don't want it interrupting necessarily the full load of the customer. So I've got kind of a definitional problem.

MS. SHEEHAN: And if I could add some comment. Basically, in 1547 it's a consensus document. And so in the consensus process there is a need to recognize that it was inverter-based technologies and synchronous generators and asynchronous generators. And I think the question is how you harmonize all of those. And the answer here is leaving it up to the local area utility was the way it was harmonized to agree upon -- as you stated, there was a whole bunch of states that are in some cases, some states in another case. And the point is that with this amount of information, with 30,000 of these things out there, and not having a problem with inverter-based technology, I think that the disconnect switch is going to be a thing of the past.

MR. TRAPP: Uh-huh. And therein lies part of my problem. Because we have taken great pains, I think, in this proposed rule to recognize and basically assume as our own the 1547 standard. Yet here I'm hearing an argument that says, no, on this specific issue let's vary from the standard and write something that differs from that consensus viewpoint.

My understanding of this proposed rule is it's almost exactly the same language that is in the standard, let the utility decide whether they need a disconnect switch. But you are saying for PV, no, we don't need one.

MR. REEDY: I would suggest that Orlando's -- excuse me, I should ask for recognition. The point that Orlando brought out is well met, absolutely with the scenario we propose. If there is a hazardous condition or an emergency, pull the transformer, go to the house that is offending, pull the meter, boot it, lock it, they're disconnected, end of story. The other customers are fine. We meet the objective of that, and we meet the requirements of the utility.

MR. TRAPP: And you contend that's in conformance with 1547?

MS. SHEEHAN: Yes.

MR. REEDY: Our expert says yes.

MR. HINTON: I thought 1547 said somewhere between the distributed resource and the electric power system. That would seem to well into the local electric power system if you are going to the transformer to do the disconnect.

MR. REEDY: Well, the mechanism was to -- because it's not correct to pull the meter on the house under load, it is just a sequence. You just use the transformer to disconnect that house and all the others that are on that transformer because it's an emergency. And then we disconnect the -- pull the meter, boot it, and put it back in and lock it, which disconnects that house, and then we re-energize the transformer. That is the sequence that meets everyone's requirements. The utilities pull transformers off all the time.

MR. FUTRELL: I just want to go back with Orlando, if you would. Is that your understanding, that the transformer would meet the requirements of 1547, the scenario Bob has described?

MR. CASTRO: In my opinion, I don't think so, just because, like you mentioned, you are going further into the EPS system. I mean, I agree that under emergency operation that would be something that a utility can do and certainly has exercised before.

I guess my understanding, the way I interpret the 1547 standard is essentially trying to put those measures so that you are not affecting other customers while operating the system for one particular customer. And so it goes back to, you know, I guess for lack of better words, you are going to have the other customers suffer for something they don't have in place. That's just an opinion.

I would suggest having it closer to the meter, but, again, would the meter suffice as a visual break. But considering the fact that you cannot pull that meter under load, that's is where I think they are going with the recommendation of having a visual, lockable, readily accessible disconnect.

MR. FUTRELL: Questions?

MR. REEDY: I have a question, Orlando. How do you disconnect a nonpaying customer?

MR. CASTRO: In those procedures -- because I'm not very familiar with that. I don't work in the RPS section or in the metering section of our department, but my understanding is if not under the opening up a transformer, you know -- it's a good question. I don't know.

MR. REEDY: I would suggest you pull the meter. And the person doing that work would tend to listen to make sure air conditioners are not running and minimize the load and probably knock on the door, that's the courtesy part, and see if anyone is home. But there is a provision, and it's done every day, hundreds of times a day around the state of Florida, and I think that we're creating quite a convoluted scenario here that says we can't do this under an emergency or hazardous condition, and I don't believe it. So I think we are covered.

MR. HANSEN: I think I answered my own question. I was going to say why don't you just throw the main and lock the panel. My main happens to be outside, and the question -- I guess most of them are probably inside, I don't know, but that is okay.

MR. FUTRELL: Any other comments on the disconnect? Okay. Comments on the conditions for disconnect.

MR. SANDERS: Excuse me. Just one other comment on the switch location. Mr. Trapp had commented about the point of interconnection, and the point of interconnection generally is at the meter. And in this case where we have the distributed resource connected on the customer side of the meter, we look at that point as a common point where one leg is coming in from the utility to the meter, and another point is to the service to the house, and at the same point the switch then goes to the distributed resource.

So in this case in the picture, it's on the opposite side of the service box as the meter which, you know, gives benefit to the connection for the customer where he can disconnect the distributed resource and still receive service. And it all kind of meets at a common point, which is why we want the switch as close as possible to that common point. I know in some existing locations that may not be the case, but going forward it makes sense to do that.

MR. TRAPP: And I believe what you have just described is required in the Chapter 17 rule for interconnection of a location very close to the point of delivery. But, again, that rule was designed, I think, for very large, I mean, very large interconnections in the tens and 20s and 30-megawatt or higher range.

I think the question that I'm struggling with here is for these small systems, very small systems down to the residential, Tier 1 in particular. Do we need that level of, you know, engineering precision? And then how far into Tier 2 and Tier 3 do we have to reach to get to that level of engineering precision? And I'll be honest with you, I'm struggling with it; I don't know what the answer is.

MR. SANDERS: Well, I do know for a number of people that have installed generators for hurricane emergencies, they have switches that they have put in place so that when power is lost, you know, they throw the switch and they take the power from the unit. So there is that switch there that they use in those cases.

MR. TRAPP: But do you control it? Do you control that switch?

MR. SANDERS: No, that's a customer-controlled switch, but it is still a switch.

MR. TRAPP: A switch.

MR. SANDERS: A visible switch.

MR. TRAPP: Right.

MR. COLSON: Bob, I have one question for the utility, for the investor-owned utility. In the diagram that I drew up I put in a smart meter, and the question I would like for you to answer is if the utilities are now installing smart meters, would you still need that disconnect switch?

MR. SANDERS: That smart meter is a utility meter?

MR. COLSON: Yes.

MR. SANDERS: We only have one meter that's a smart meter that can register all the power that needs to be monitored going and coming in the utility's service territory as opposed to going into the customer's service. So I'm not familiar with having series meters, unless one of them isn't a smart meter and we need one to monitor the power going in and the other to monitor the power going out.

MR. COLSON: It would be just one meter. I just had the smart meter as an option. If there was no smart meter, you would have a regular meter.

MR. SANDERS: If we had a smart meter, we probably wouldn't need a regular meter.

MR. COLSON: Right.

MR. GRANIERE: I have one question. Maybe I can get my head around this, because I'm really having a little trouble with this one.

I saw two disconnects up there. There was the DC disconnect and then there was this AC disconnect. Right? Now, if you push the DC disconnect button, the solar panels shut off, right? They just go away. If you push the AC disconnect button, what happens?

MR. REEDY: The solar panels also go away unless you have a battery storage system.

MR. GRANIERE: So the solar panels go away no matter which button you push?

MR. REEDY: Either one. You have to have synchronous connection.

MR. GRANIERE: So why do you need two buttons?

MS. SHEEHAN: Because you may want to work on the solar panels and leave everything else in place. You may want to work on one set of arrays and you want to shut that off. There are different arrangements you can set up. Schematically just one array, but you may want to set up and work on one set of the array.

MR. HINTON: You could also continue charging batteries, too.

MR. GRANIERE: Yeah. I mean, if you are charging batteries, but homes generally don't charge batteries, one thing. But that's okay. If they do; they do.

But from what I'm trying to understand is the idea was that if it wasn't an emergency the reason you need this switch is so that the utility can continue to send power into the house, but disconnect the photovoltaic system from doing anything, right?

MS. SHEEHAN: (Indicating yes.)

MR. GRANIERE: Well, if you push the manual DC button, that's exactly what happens. So why do you need the other button?

MR. JONES: Dell Jones.

In addition to that, many inverters have -- here's an idea, an on/off switch. So right on the face of the inverter you can turn off the inverter as well. So to go with a DC disconnect and an on/off switch on the inverter and then an AC disconnect -- and a lot of inverters now have little small bus fuses up underneath the inverter, where if you pull the bus fuse out of the bottom of the inverter, the inverter also goes off. So you have really got four means of shutting this thing off.

MR. TRAPP: But what we are really dealing with here is an issue of control. Who has control over those switches and buttons? Who's going to put the lock on them? And that's why I need more clarification from the investor-owned utilities as to why they need this level of control over whatever switch or button we've got.

MR. CASTRO: Orlando Allen Castro.

One comment about that. I mean, you're right. You have all of those measures in place to turn off the photovoltaic array, but I think what's important is the visual break. You know, could you use the removable fuse as a visual break? Possibly. But I think that's from a utility standpoint. As you guys may know, I mean, that's what they are looking for, is that visual break.

Going back to Bob's comment about, you know, just pulling the meter as a visual break, that certainly suffices, meets the criteria of the visual break. And I guess it just goes back to how you want to -- you know, the question whether the practices of pulling that meter under, whether it's load or not under load, I guess if you can turn off the main disconnect from outside and then pull the meter, if you didn't want to pull it under load, then you could possibly do that as well. So I think that might answer the question as far as meeting the requirement.

But I go back to how you word it in here in the rule, because if you don't put anything regarding manual disconnects, and you leave it up to the IEEE, for the utilities to follow the IEEE standard, then I can see -- you know, as we have already seen it where a customer will come in and say, well, we want to do this, this, and this; and we say, well, we are going to require, as an example, we will require this manual disconnect, because we are not required by this rule to do it, but it's up to our discretion under IEEE.

And the customer is going to say, well, wait a second, FPL didn't require this or Progress Energy didn't require this. So what's going to happen is, again, it goes to a matter of consistency. Somehow you've got to address whether the manual disconnect, whether it's going to be required or not, something should be mentioned in the rule.

MR. GRANIERE: Just a suggestion on that. If it's truly a matter of control, as Bob suggests, and I kind of agree with him, it would seem to me that when you want control you pay for it. So you want a meter, pay for it, or whatever it is. You know, you want the switch, pay for it.

MR. KEYES: One way to address this is to say that -- to address FPL's concern about being able to access the visible break is to require that there be a map at the meter and a sign that says there is a photovoltaic system disconnect switch map below. And, you know, for the gentleman down at the end to say, go behind the house, there's is a big switch, and use the

DC disconnect.

MR. HANSEN: That's what I want.

MS. CLARK: Mark, we had a question.

We had asked about a three-phase system, that the switch be gang operated. I think maybe we can address that concern as well when we respond to you about the need for the manual switch. We had tentatively thought of a way to address that, and that would be on Page 5, Line 23, to refer to an open position with a single utility padlock, just somewhere where you see that everything you have to turn off is in one location. And we thought that may be a way to address that. But we will cover those in our comments on the need for the manual switch.

MR. FUTRELL: Thanks.

We're going to take a little break, short break. We will come at 3:15, and we will finish up the conditions for disconnect and move on.

(Recess.)

MR. FUTRELL: Let's take our seats and try to finish this up.

MS. CLARK: Mark, Bob had committed that maybe we could come up with some language over lunch, and when it's your pleasure to do that, I'm prepared to suggest some language.

MR. FUTRELL: Great. Let's go ahead and do that.

MS. CLARK: This was on Page 4, and it was Lines

21 through 23. I guess let's start reading the sentence and pick up on some of the language Bob gave and some that we may be tweaking it just a little bit. It would read, "The customer shall notify the investor-owned utility at least ten days prior to initially placing the customer equipment and protective apparatus in service. And the investor-owned utility shall have the right to have personnel present on that date," period.

Then to address the previous suggestion we had with respect to annual testing, to insert at the end of that sentence, "Upon reasonable notice and at reasonable times, the utility may, at its own expense, inspect customer equipment and protective apparatus." That would be an additional sentence to follow the sentence that ends on line -- I'm sorry, Page 4, Line 23. Did I misspeak before and say Page 5?

MR. FUTRELL: Could you repeat that, please?

MS. CLARK: So the two sentences would read, "The customer shall notify the investor-owned utility at least ten days prior to initially placing the customer equipment and protective apparatus in service, and the investor-owned utility shall have the right to have personnel present on that date," period.

And then the next sentence would be, "Upon reasonable notice and at reasonable times, the utility may, at their own expense, inspect the customer equipment and protective apparatus."

We had another conversation about the other device that islands, that performs an islanding function or the automatic isolating function. This would be on Page 3, Lines 15 through 18. Upon looking at it again, we think if on Page 16 that comma is taken out, so there is not a comma after Subsection 4.A, and take that comma out and make it clear that what you're talking about is the device performing that function. That clarifies for us the understanding that not only must the equipment comply with Paragraph A, it must also comply with Paragraph B, that Paragraph B is not meant to be separate in any way. The two run in tandem. That was all I had.

MR. FUTRELL: Anybody have any comments on Ms. Clark's proposed language? If not, let's move on to the disconnect switch, the provisions for conditions for allowing disconnect. Bob Reedy touched on those earlier. Does anybody else have any comments on those provisions?

MR. HANSEN: I have a comment.

MR. FUTRELL: Yes, sir, Mr. Hansen.

MR. HANSEN: On Page 5, Line 21 and 22, I would suggest crossing out the "but in close proximity to," all right? And then on Line 24, right after padlock period, add this sentence: A map to show the location of the disconnect switch shall be provided at the utility meter location. The idea of this is that you could have the meter at some remote location and then the utility would know exactly where it was. Thank you.

MR. FUTRELL: Any comments on Mr. Hansen's idea? Any comments on the conditions for disconnect?

MR. TRAPP: If there's no comments on Mr. Hansen's suggestion, do I take that to mean concurrence?

MS. CLARK: I am glad you asked, Mr. Trapp. What I would like to do is I think we had commented to get back to you on that whole issue of the manual switch and whether it's needed for the inverter, and at that point we would comment on that suggestion as well.

MR. TRAPP: What about the solar folks down here?

MR. REEDY: Bob Reedy. Where I was headed in my mind was for the smaller systems there was no manual disconnect requirement on inverter-based systems, and then larger tiered, Tier 3 certainly maybe would be.

MR. TRAPP: So, we can expect a proposed carve-out from you in your post-workshops comments, is that --

MR. REEDY: Absolutely.

MR. TRAPP: -- fair?

MR. REEDY: Yes.

MR. TRAPP: Okay.

MR. FUTRELL: Okay. Cayce had a few questions to close this out.

MR. HINTON: And going towards when the manual disconnect switch is actually utilized, I was curious about how the utility notifies the customer that the manual disconnect switch has been opened, and when does the utility generally reconnect that, and should we have provisions in this rule that lay that out with specificity stating that, you know, you need to contact. Let the customer know that you have opened this switch, and when you plan on reconnecting.

MS. CLARK: Cayce, you would like information on how that is done now?

MR. HINTON: Yes. That was brought to my attention over the phone this week, that that is, you know, another hole that we haven't necessarily addressed is if this switch is utilized, how does the customer find out that their PV system isn't working anymore. And when, you know, do you let them know when you are plan on reconnecting.

MS. CLARK: I don't have the answer for that question right here, but we will answer it in post-hearing comments and get back to you, as well.

MR. FUTRELL: Let's move on to Section 7, the new Number 7, the administrative requirements. Cayce went through several of the changes in his summary earlier, providing a copy of the application on the web site, and also some of the notice requirements, provisions that are in there for going back and forth between the applicant and the utility. Any comments or concerns on the way we have changed Section 7?

MS. CLARK: Let me start out with one question. We had suggested that the customer begin parallel operations within 180 days after they execute the agreement. Our concern there was not having an end time when parallel operations must begin results in a stale application. The circumstances and conditions on the grid may have changed or the distribution system may have changed making that parallel operation maybe something that should be looked at again. We still think that should be in the rule and are curious as to what your thoughts were in not including that suggestion.

MR. FUTRELL: Part of our thinking was that it just seemed like there was a lot of moving pieces into getting a system like this up and running that the customer has to deal with, and it may not be feasible to meet that deadline. Hopefully, they will be able to, but there are a lot of other things happening. There's local code review. There is getting the system installed, the various contractors they have to juggle. There may be instances where that 180 may not be met. And it just seemed onerous to us to put that on the customer.

Bill.

MR. TOTH: Yes. Bill Toth. The other thing is many of these systems are guaranteed for, at least the ones that we deal with, for 20 years. If the system is on, and if it's going to change in 180 days, am I going to have to change in 180 days? Am I going to have to revamp my entire system after

I have already put it up?

MS. CLARK: I don't think that's what we are suggesting. We're suggesting that within 180 days of the application being made that the system be up and running. In other words, you can't wait three or four years from the time you've made your application and it has been executed by the utility to actually bring your system up and running. We weren't talking about when it was already running.

MR. TOTH: Bill Toth again. I understand that, but the principle is still the same. I mean, if it is stale in 180 days, that means my system is no longer compatible. I don't see why the 180-day requirement is there, because there are many things that can affect when that system is -- you know, labor shortages, material shortages. We have those pesky little things called hurricanes that can, you know, affect contracting and the ability to put that up there. I think that 180-day time frame is not really reasonable, considering the fact that once I have gotten my system on there it's going to be operating under those conditions for 20 years or more.

MS. CLARK: Let me be a little more specific, then. I think we had in mind a situation where you have somebody come in and say they are going to put on a 100 kW system, you know, maybe on one of these stores. You're in an area where there are a number of stores that could do the same thing. Currently, if you put one or two on there, you could accommodate it. And if those are up and running, then the third one you might have to do something different.

What happens if you have an outstanding application, you have the other ones applied for and running, and you need to do something in order to be able to put that third system on. There ought to be a time frame within which you know what your system is -- it looks like, and you are not concerned that there is another application out there that has been executed and may come on-line at some future time. It's just giving certainty to planning as to when a particular customer system may come on-line.

MR. TRAPP: What if instead of such an absolute cutoff, I mean, what if you were to start the sentence with normally 180 days and then describe what happens next. We can revisit, the utility may revisit, or the utility may express concerns or may -- the utility may evaluate change case, or a door opener, in other words, as opposed to a door closed.

MS. CLARK: I think that's --

MR. TRAPP: For your consideration.

MS. CLARK: I think that's one thing that we could think about, how to address the concern about a stale application that may affect -- because the system has changed, if they, in fact, put it in, you might run into problems.

MR. HINTON: Something along the lines of normally systems must be up and running within 180 days of a completed application. After 180 days the utility has the right to request an updated application, something along those lines.

MS. SHEEHAN: Mike Sheehan from IREC. I guess the question I have is the application is one thing, but I think the signed contract is really where the time clock needs to start, not at the point of the application. And, clearly, contracts sort of mean things to people, and so at that point that is something that I think should be -- and whether 180 days is reasonable is, and with material the way it is today, I would think that is pretty unreasonable. But some time frame may be worthwhile at least considering.

MS. CLARK: This is Susan Clark. We had referenced it with when the contract is executed by -- when the agreement is executed by the utility. So it would be at the time of contract, not application.

MR. HINTON: Yes. I misspoke in what I said.

You mentioned some time frame may be appropriate, but 180 days might not be it. Do you have an alternative suggestion?

MS. SHEEHAN: I'll look into it.

MR. GRANIERE: Does this 180 days, or whatever the time frame, have something to do with the service drop capacities or something like that, something about -- if I understood the example, there were three people there who wanted to put 100 kW on their roof, and they all presumably use the same facilities or some facilities that were common. And I think the example was if the first two come on, like when the first two come on, everything is okay, but if the third one were to come on, something would happen back farther that would require some upgrades or something, is that the idea?

MS. CLARK: I guess I'm just -- I think that those applications would be done with reference to the system as it is currently configured. And if you wait awhile, has that configuration of the system changed or have there been other customer-located systems that have come on that would affect -- maybe bringing another one on would affect the quality of the service in there.

Bob, don't take that to mean this is true. I mean, this is definitely what would happen. It's more an example of why you would be concerned that you don't have an extremely stale agreement out there that had you been looking at it at the time they intend to start parallel operations, you would have required something else for the safety of the operation of the system.

MR. GRANIERE: Yeah, that's what I was trying to get to. Once again, Bob Graniere. Because I was going back to that part of the rule that says 90 percent of the service thing which gets you to their meter, I think. And so, if it is always just 90 percent of that, right -- well, that pushes back a certain distance. But from what I'm thinking you're saying, it's somewhere even deeper in there that will require something to change if there is too many of these things on-line. Is that the general idea of what might happen?

MS. CLARK: I think that is the possibility.

MR. GRANIERE: So that's what you're trying to get to?

MS. CLARK: Yes, that's an example.

MR. GRANIERE: So that is what we are trying to get to. Okay. Thank you.

MS. SHEEHAN: Mike Sheehan from IREC again. I guess that is a queuing question that almost fits into the FERC requirements of when people get on-line and what the sequence of events are, and on one feeder if they reach a certain level. So there is a whole queuing question that leads you down a path of keeping track of what's in the queue.

MR. TOTH: Bill Toth. What if all three of those systems actually come in at the same time or within a week or two of each other? The first two systems are going to have one requirement, and then in order to fulfill the agreement or complete the agreement for the third one, those changes are going to have to be anticipated prior to that agreement being made or the first two can't come on-line. I mean, that has to be anticipated or in that third agreement. Because what if all three of them come on within 180 days, as they are going to, you know, as they are made, and the first two change the circumstances for the third one?

MS. CLARK: I think --

MR. TOTH: It would already have -- my point here is that situation or that requirement would have already been dealt with. Am I missing something here?

MS. CLARK: I think the idea is how long do you have to anticipate, sort of, the one system for which you have a contract out there still has to be accounted for in some way in your planning. I mean, if they haven't come on-line in three years, is it reasonable to assume that they are not going to come on-line? It just seems that there should be some end date beyond which the utility doesn't have to plan for that being part of the load or part of the configuration of the system.

MR. TOTH: Bill Toth again. I would agree that three years is unreasonable on the other end of the scope, but I believe 180 days is also unreasonable. There has to be some middle ground that we can reach with that. With construction being what it is down here, or at least down in the Bonita, Fort Myers, Naples area, that 180 days could be a difficult burden to meet.

MR. FUTRELL: Bill, what would be a reasonable number of days that you would consider acceptable?

MR. TOTH: Off the top of my head, that would be difficult. We will work on that. I know 180 days -- for instance, okay, several years ago if you wanted to build a house, you bought preconstruction and they told you they were going to build your house in a year. Well, a year came around, then they were saying, well, no, it is going to be 18 months. It's not that way now, but it was that way several years ago. So it's hard to put an exact number on that type of thing.

MS. CLARK: We would agree it needs to be a reasonable time frame.

MR. TRAPP: I, for one, hope we have these congestion problems, and I look forward to the next rulemaking where we address allocating system resources and things of that nature. I would encourage the parties, for the purposes of this rulemaking, to put something out there that we can deal with in the next few days.

MR. FUTRELL: Jason.

MR. KEYES: Personally, I think that a year is plenty of time. I agree, a half a year is kind of short. And I don't know what we are going to find by going back and reviewing it in any great detail, but a year seems like enough time to me.

And I believe that Mr. Toth's situation about the third system coming on-line in the same line section was addressed by Ms. Clark. I think she has got it just right, that the screen actually in FERC and in the IREC screens is 15 percent of line section peak load. So a line section is often -- peak load will be somewhere around 10 megawatts. And so if you get up to a megawatt and a half of systems on the same line section, then you ought to look at that next one.

So if there was half a megawatt, a half megawatt and then another a little more than half a megawatt, that that third one, even though they came in -- you know, it was Monday, Tuesday, Wednesday, the guy that came in Wednesday is out of luck, and he will have to pay to upgrade the system or at least to have the study. And so I think it's a reasonable suggestion to say, well, if number one drops out, and you don't need to have the extra protection for that third customer, you should not make the third customer go through all of that. And so at some point somebody ought to drop out of the queue. And I think a year is plenty, or is reasonable.

MR. TOTH: Bill Toth. If I had to pull a number off the top of my head, I was going to say a year, also. I think that's reasonable.

MR. TRAPP: We have got two one years. How about it, Susan?

MS. CLARK: We'll certainly address that in our post-hearing workshop comments. I do understand the concern with the ability to build and be on line in that deadline. And I think the utilities, you know, have the same idea that you need to make it match what is likely to be out there and what is the time period after which it becomes stale that you do want to relook at it.

MR. FUTRELL: Okay. If there is nothing else on

Section 7, the requirements --

Do you have something?

MS. CLARK: No, I think this is just a clarification. And this is on the rescheduling of the inspection. We don't understand that ability to reschedule to allow that 30-day period to be shortened. It has reference to when you can't schedule it in the 30 days, and you want it sometime after that. In other words, you couldn't have the customer request it be rescheduled and you wind up having to meet a 20-day deadline to do that inspection.

MR. TOTH: What section is that?

MS. CLARK: I'm on 7.D, and this would be Page 7, Lines 13 through 17, particularly the last sentence where it says the investor-owned utility shall reschedule the inspection within 10 business days of the customer request. In other words, on Day 10, suppose they have set a time for the inspection on the 28th day. The customer can't come in on the 10th day and say, you know, I want it rescheduled and get it rescheduled to within -- on the 20th day.

MR. HINTON: I think the intent of this is inspections have to be completed within 30 days.

MS. CLARK: Right.

MR. HINTON: Now, the customer may run into a problem getting their local code officials out there, and so they will say, well, I need you guys to come out later, because I'm still getting these local code guys, and so I will give you a call when that is done. And then once they give you a call, then within 10 days you need to go ahead and get in there and inspect.

MS. CLARK: Then we are on the same page.

MR. HINTON: Okay.

MR. FUTRELL: If there is nothing else, we will move to net metering.

As Karen summarized earlier, we made a couple of changes to recognize the customers continue to pay their customer charge or their applicable demand charge, and also changing at the end of the 12-month period the customer will be paid for any excess energy delivered at the utilities as available energy tariff. And, also, that also carries forward to when the customer leaves the system, any unused credits are paid at that same rate.

Comments on the net metering provisions.

Gwen.

MS. ROSE: Gwen Rose with Vote Solar. If I'm interpreting the met metering rules in general correctly, I think they are actually very good. And I want to thank you for drafting a sound net metering policy. I did have a question, hoping for clarification on the metering requirements. Generally, the nice thing about net metering is customers can use the meter they already have, it spins in both directions, and then you look at the net. And I'm not sure if I'm reading this as it requiring a dual register meter or not. Does it still allow customers to use their bidirectional meter as already installed?

MR. TRAPP: Do you want an opinion?

MR. FUTRELL: I think it does.

MR. TRAPP: My opinion is yes. However, I think the state is under certain federal and state, if not mandates, encouragements, to move toward smart metering. And I think some of our larger investor-owned utilities have taken steps toward that end. My belief, quite frankly, is the old mechanical kilowatt hour meter, if not currently demising, is going to be demised pretty soon. But I don't think this rule is requiring that there will be automatic replacement of those kilowatt hour meters. I think this rule only acknowledges the fact that the world is moving toward smart meters. That's all that was intended, and that those costs should be borne by the utility.

MS. ROSE: Right, as part of a general migration, all customers would --

MR. FUTRELL: Dell.

MR. JONES: Dell Jones. Actually, to that point, a single five-dial meter that spins forward and backwards, I don't know that it would really meet this requirement, capable of measuring the difference between electricity supplied to the customer from the electric utility and the electricity generated by the customer. Because a standard five-dial meter that spins forward and backward, at the point in time that you read the meter, it will actually read the net difference, but not a cumulative total of the amount of electricity generated from the renewable device. Because you would have to look at net, how much went out and net how much came back at all points in time, as opposed to some end-of-the month reading.

MR. TRAPP: I stand corrected. This rule requires net metering -- I mean, requires smart metering.

MR. JONES: Right. And that's what I am saying. To Gwen's point, then that would either be a dual registering meter or two separate meters. One meter as shown in this diagram that could actually measure the amount of energy being produced by the solar system and read in this diagram as meter sensor optional to smart meter. And that would calculate the total amount of renewable energy generated. And then, again, you've got the other meter all the way over to the right-hand side of the diagram that is not going to really capture just the net that went to the customer, because some is going to go, again, back into the grid.

MR. TRAPP: I stand corrected again. This may require two of those meters. I guess the point is the utility is going to pay for them, and pay for that metering, and the billing is going to be as if they had a single old register kilowatt hour meter.

MR. HINTON: It states that the meter has to measure the difference between the two. Wouldn't a single meter that is spinning forward and backwards still end up measuring the difference between the two, the net?

MR. JONES: Well, the way I read this is that it is the -- well, if it's the -- and delivered to the electric grid. So let's say one -- today I might put two -- my air conditioner is not working, it's a nice cool day, I might put two kilowatt hours back on the grid. But tomorrow if it is really warm, I might pull all of that back again. So, maybe it's semantics, but it is really whether it is a cumulative total that went back on the grid and a cumulative total that came to the customer's house.

MR. HINTON: Yeah. I think this could be read both directions. I read this and I see the key being the word difference, meaning it's going to be net.

MR. JONES: Well, that would be a calculation between reading -- you know, that's not really embedded within the meter. That's a calculation that you would make after you make two meter readings.

MR. HINTON: If you had dual metering capability. But if it's spinning, you have a spinning meter, it spins forwards and backwards, what you end up with is the difference between the two.

MR. JONES: Right. And I'm just pointing out that it seems subject to interpretation here.

MS. SHEEHAN: Mike Sheehan from IREC. Jumping a little bit ahead, if you go to Line 24 on Page Number 9, it says one of the requirements is that total kilowatt hour customer-owned renewable generation delivered to the electric utility. That would sort of imply that that has a separate meter on the PV system or on the renewable system. So I think there is a little bit of clarification that needs to go into how many meters there are and where the meter locations are.

MR. HINTON: Yeah. Taking into account the reporting requirements, I agree with Bob now. This does require smart metering.

MR. TRAPP: Smart metering, whether it's a smart meter or a calculation from old meters, I guess what I thought we were doing here was requiring the utilities to account for what generation was being produced by a renewable so we knew. Because I think it is important for us to know, but not to let that be a burden with respect to the net metered customer; hence the requirement for the payment by the utilities for the metering arrangement. I think the intent is, again, from a billing standpoint just to allow the customer to offset at retail his generation against his consumption. We view that as an extended means of conservation.

The problem comes in when you get beyond the meter and get on the grid, and then we have made other changes, proposed changes to price that are more akin to the way we do other cogeneration that enters the grid. But with respect to the metering, I think my intent was to know what was generated and what was consumed, so that we could track the progress of the program, and that that metering and tracking be accounted for by and paid for by the utilities and general body of ratepayers.

MR. FUTRELL: Karen.

MS. WEBB: Forgive me if I'm wrong, but it was my understanding from prior workshops and from talking with internal staff that there was some disagreement as to what type of meter would be required, so the wording was generic on purpose to put the onus on the utility to find the way to do this. If it is your existing equipment, that's fine; if you need something further, then see to that.

MR. TRAPP: That's fair.

MR. JONES: I was going to say, within most smaller and certainly larger inverters there is a calculation of the total energy that has been produced by the photovoltaic system embedded typically within the inverter. And again you have also got the standard old five-dial meter that can come right off of the inverter itself. And I believe that if we have a robust REC market, anybody that wants to participate in that REC market, you are going to account for how much total energy was produced and when and from what service address. And one of the things that I also see, if it's a reporting requirement that the PSC has that requires the utilities to come up with how much total renewable energy was generated through renewable energy resources, and it's only the IOUs that have to do this and not the municipal utilities, then you are really not capturing all of the renewable energy that was produced within the state of Florida.

MR. FUTRELL: I want to just interrupt you. The reporting requirements apply to all utilities.

MR. JONES: Okay.

MR. FUTRELL: We have made that clarification.

MR. JONES: All right. But I was going to say, I think that a REC market -- I mean, if it's just a simple five-dial meter that comes off of a system, those metering costs aren't really that onerous, and then a lot of inverters also have that in there. The question might be whether that -- accuracy and that complies with the, you know, whatever standards are going to be required for that meter to measure the total kilowatt hours received by the interconnected customer from the electric utility.

MR. TRAPP: Are we discussing Section 8 or are we discussing the REC section, because it seems to me your arguments seem to be more directed -- where is that section, Mark?

MR. FUTRELL: Section 9, Line 24.

MR. TRAPP: Yeah. It seems to me a lot of your comments may be directed more toward that section than the one we are on, or is there so much commonality between the two that we need to discuss them together?

MR. JONES: Well, it would be nice, at least from a system integrator's point of view to know whether, you know, there is going to be a requirement for a bidirectional meter that only accounts for how much goes out onto the grid and back again. And then it seems for a REC person or somebody who wants to account for how much total renewable energy they generated, they are going to have another meter in a different location, as well. So, I don't really have any comments on what's the better way to do it, but they are hand in glove.

MR. TRAPP: I agree with you, and staff has had a lot of discussion about these two sections, about how to put them together. You know, quite frankly, right now there is not particularly a REC market in Florida. There may be. We have got an RPS workshop process going on, and there is certainly legislation and gubernatorial interest in it. So Section 9 may be a look ahead type of section. But I agree with you, it can mesh very easily with Section 8, and the metering requirements, what the utility decides to do in Section 8 can have some influence and affect on your costs in Section 9.

MR. KEYES: I just want to chime in that I had the same reading of that, going back to where we were, Section 8(b) that Mr. Hinton had, that if you're just measuring the difference, that you can do that with a single meter. You know, a bidirectional meter at the end of the month will tell you the difference between generation and load. Given all of this discussion, I think it would be worthwhile to clarify that and say it measures the difference over the course of the month or something.

And then in 9(c) and (d), if you have got -- if you have got a requirement that the utilities will report the kW capacity of the systems, you can say for (c) and (d) that those numbers can be estimated based on available data. Because you're going to have an awful lot of systems. I would guess at least half of the systems will have some sort of production meter to measure the generation of the system. If you've got the measurement of the generation, then for half of the systems out there you can say, well, the other half probably works just about as well as the first half, and so you can get that 9(d), the total generation. And if you have that, just a mathematical formula, but it is really simple, to get to 9(c) about the total energy that was used by the interconnection customers.

MR. ZAMBO: I have got some comments on Section 8 if you are still on.

MR. FUTRELL: Rich, go ahead. We're still in this section.

MR. ZAMBO: Okay. Rich Zambo on behalf of the renewable QFs.

To be honest with you, this hasn't gelled to the point of it being an issue yet, because I just became aware of it this morning. So it's more in the nature of a concern. So I just wanted to share it with you and see what we can do. I'm on Page 8, Lines 18 through 20, and I'm thinking in terms of a commercial customer who is taking service under a demand rate, a non-time-of-day demand rate. It says regardless of whether the customer is selling electricity or delivering electricity to the grid, the customer shall continue to pay the customer charge or demand charge. How do you decide which one he pays? That would be one question.

And then another is there are stand-by tariffs out there, and I apologize, I haven't had a chance to research this, because as I said, this issue or concern just came to me this morning. The utilities typically have stand-by service for self-generating customers that requires you to take service under those tariffs if you generate, I think, 20 percent or more of your electrical needs.

So I'm concerned with how that is going to interplay with this rule. I know the rules are in different sections of the Commission's rules, but I'm not sure that is enough of a delineation. And so I'm just kind of raising this ahead of time, rather than we wait until we get too far down the road and then find out we have got a customer who is maybe paying a customer charge, a demand charge, and a stand-by charge, or none of the above, which would be the preference.

I guess customer charge makes sense, but -- and the other issue is if you are a -- our other concern is that if you are a general service customer, who doesn't have access to a time-of-day rate, you can theoretically totally eliminate your on-peak demand and yet have to pay a full demand charge under this wording. I would just offer that as food for thought, because I think that is ignoring benefits that these net metering customers are bringing to the system and potentially, you know, acting as a disincentive because they may not earn as much money as they think they would if it's only applied against their energy charge. And that's all I have.

MR. TRAPP: Do you want to respond or do you want me to? I'll take a whack at it, if you want.

Again, my own personal opinion of the rule draft was that with regard -- if I can get them in order, Rich. Your first point I think was the otherwise applicable demand charge and customer charge. I think that was intended to -- I think the rules are intended to look at residential, commercial and industrial customers and their imposition on the system and they would be, for the power they use, billed under the applicable retail rate schedule.

With respect to your question on stand-by -- and I would note, however, that the impact of a generating source on the customer side of the meter may impact your customer classification, may put you in a different customer classification. So to me maybe some clarification. The otherwise applicable says to pay the applicable. Maybe it should say to pay the otherwise applicable, or maybe that doesn't clarify, I don't know. But I think the intent was to charge you the rate schedule that your resulting demand and energy charges put you into, whatever that may be.

With respect to the stand-by charges, I don't think that staff -- at least I didn't contemplate that this rule would charge you stand-by rates, that this rule would waive you from the stand-by rate requirements that are over in the cogen side of things, because this is -- again, the customer side carve-out rule. And then with respect to the customer who was not a time-of-day meter customer, maybe not getting the full benefit of the coincident peak impact of his generation, I suggest to you that the customer's best interest is to get on the right rate schedule. And maybe he ought to get on a time-of-day rate schedule.

MR. ZAMBO: Well, that's if there is one for that customer class. I haven't looked at the tariff books. I don't know if all customer classes have access to time-of-day rates. But your point is well-taken, Bob, it would behoove the customer to take a look at the schedule. But as far as changing rate classes in the case of a PV system, for example, I mean, by definition they are not going to be generating at night. So if they are not on a time-of-day schedule, and they don't have batteries, they're going to have -- I'm sorry. If you are looking at the off-peak periods, they are going to still be setting a demand that they are going to get charged for.

MR. TRAPP: But if this is a residential account, most -- I mean, again, if you believe that solar tracks air conditioning and sun load and everything, it would seem to me their peak demand would be lower with a solar installation than it otherwise would have been.

MR. ZAMBO: Possibly yes.

MR. TRAPP: And the same thing with commercial to the extent that you're -- well, I don't know, Wal-Mart runs its refrigeration at night, but it probably doesn't have as much refrigerating load. It certainly has the same lighting load. Again, the air conditioner is variable. Industrial, two-megawatt industrial, that is the one I surely don't have a feel for.

MR. ZAMBO: They would probably be better off going back to a non-demand rate. You may end up getting people mitigating to different --

MR. TRAPP: Again, if their new load characteristics qualify them for a nondemand rate, I would think that that would be the rate they would be put on. I think that was the staff's intent. Please correct me if I'm wrong, anybody down there.

MR. GRANIERE: Bob Graniere. There is a tariff person here. When do the demand charges generally kick in in Florida?

MR. ASHBURN: Well, for us a demand rate kicks in at 50 kW. I think some of the other ones are at different levels. Some are at 25 or 20. It just depends. Each utility has a different spot.

MR. GRANIERE: And that applies to the peak demand?

MR. ASHBURN: Billing demand, yeah, which is monthly billing demand.

MR. GRANIERE: Oh, monthly billing demand. Okay. So that would apply to some of Tier 2 and all of Tier 3, then?

MR. ASHBURN: Well, we're talking about load rather than size of the generator, so it's hard to say.

MR. GRANIERE: Okay. How would that differ, then?

MR. ASHBURN: Well, it depends on how big the load is and how big the generator is.

MR. GRANIERE: Let's say you have a two megawatt system, and just for the sake of argument, there's someone that has a two-megawatt renewable system out there, and it meets all of the requirements, and it's being used primarily for its own consumption, okay? What is the load that we are talking about that would get charged the demand charge?

MR. ASHBURN: The part that comes in from the utility.

MR. GRANIERE: The part that comes in from the utility would be the part. So if that was under 50 kW, there wouldn't be one?

MR. ASHBURN: Right. Now, what we typically do is look over a period of time, Bob. I mean, you know, we start putting demand meters at lower than 50 kW to start looking at peak load. And usually there is a part in the rule that says if you hit 50 kW so many times in the last six months, or something like that. There is a variety of different tariff provisions depending on the utility.

MR. GRANIERE: So in that example from the fellow who sent in the letter, I'm just thinking of that example, where he was putting a system on his rooftop, but if was an empty warehouse, if you remember that letter. I'm just trying to get a sense for what the load would be that the utility supplied.

MR. ASHBURN: I didn't read the letter, so I don't know.

MR. GRANIERE: Oh, you didn't read that one.

MR. ASHBURN: It really depends on how big the generator is, how it's going to run, how big the load is, how much -- I think what Bob is suggesting is you look at what the service is from the utility into the building. And whatever that load shape is or demand would determine what tariff it would fall under. And I don't know, but I would think, depending on the renewable generator, how reliable it is, how much it operates, all of this stuff, is going to depend. If it is a PV, it is only going to run during the day for so many hours. So if it goes off because the sun went down, and it's a manufacturing building, the load goes right back up to what it was during periods you are going to get the full demand charge.

MR. GRANIERE: Okay. I'm just trying to get a feel for how it is done, so there is an idea for how that charge is kicking in.

MR. ASHBURN: It will affect the load factor. We can have very, very low load factor large customers, because they are using power at different times.

MR. GRANIERE: But none of that would affect the net metering part, would it?

MR. ASHBURN: No.

MR. GRANIERE: No. Okay.

MR. ASHBURN: No, I don't think so.

MR. GRANIERE: Yeah. I didn't think it would affect the net metering part. These would just be -- you know, this is the customer's characteristics determines whether it needs to get a demand charge. And if it does need to get the demand charge, then its usage characteristics determine what it might be.

MR. ASHBURN: Right. I think that is how I read the rule. That is how we interpreted it.

MR. TRAPP: That is the clarification I was seeking from you, Bill, in particular, since you are more rate-oriented. Did anything I say sound foul?

MR. ASHBURN: Well, I wouldn't ever say anything you said sounded foul, Bob.

MR. TRAPP: You're so gracious.

MR. ASHBURN: I don't know, I'm trying to go over all the things you've said recently about it.

MR. TRAPP: Basically, the fact that you have got a generating source on your side of the meter is going to change your billing characteristics for the purposes of the sales from the utility to the customer. And you're going to assess that as if it was any other customer with those kind of billing characteristics.

MR. ASHBURN: Right.

MR. TRAPP: That would apply to the generator part of it.

MR. ASHBURN: I think the one question you might have brought up in your conversation, because it is not here, is whether they would be on stand-by or not.

MR. TRAPP: And that's the one I was most interested in your opinion on, because, I mean, I think we have been going all along assuming that these would not invoke the stand-by rates, but I would be interested to --

MR. ASHBURN: I think all of the utilities have the same number of 20 percent. If you're generating in excess of 20 percent of your load with your own generation, you fall under the stand-by tariffs. I think all the tariffs -- I think all the utilities -- that goes back to stand-by.

MR. TRAPP: So you think these rules could kick in the stand-by?

MR. ASHBURN: Absolutely. I think they could.

MR. TRAPP: Do you think they should?

MR. ASHBURN: I think they should. They are still stand-by. I mean, the renewable generator still could be off and we have to serve it. So I'm not sure how it is different from the cogen, if it's off for maintenance or something else.

MR. TRAPP: Rich has identified as a major issue that hasn't been identified to date in this docket, then.

MR. ZAMBO: I have tried my best to distinguish this, but I didn't make any sense out of it, so I'm --

MR. TRAPP: You know, I'll have to be honest with you, I think staff, at least my dumb perspective, I just assumed that stand-by was out of the picture in these rules. But you're saying that they could -- I think we need to address that, everybody.

MR. ZAMBO: Well, in that case the applicable demand charge would then be the stand-by charge, not the normal billing.

MR. ASHBURN: That's for a demand customer, right? You are talking about a small residence there is no demand charge, so it's, you know --

MR. ZAMBO: Right. But would the stand-by rates apply to them? I don't know if the tariff is specific about a demand customer or not.

MR. ASHBURN: Well, ours says that if you are a GS or RS customer and you are stand-by, then you go onto the time-of-use rate.

MR. ZAMBO: Okay.

MR. ASHBURN: Which for a PV might be very beneficial, actually. But, you know, that's what our tariffs say. But for the demand rates, you're right, there is, you know, a demand based stand-by rate that is very specific, different. It has all the different demand charges, and I don't know that it would be different. I mean, you would just look at the load, again, going in, and we have a whole set of rules about those have been developed for a long time.

MR. ZAMBO: Right.

MR. TRAPP: But are they in -- are they in 17, Chapter 17 in reference to stand-by rates in the cogen tariffs in Chapter 17?

MR. ZAMBO: It is in 17, but it's a very vague reference.

MR. ASHBURN: The utilities came in for dockets and had their stand-by rates approved. There was a lot of rulemaking that went on back in the '80s about stand-by rates.

MR. TRAPP: You've got authorizing language in the rules, and then you've got the specific tariff implementation --

(Simultaneous conversation.)

MR. ASHBURN: And it may be a little different, depending on their own tariff structure, and so forth.

MR. ZAMBO: My recollection is that it ties it back to the FERC regulations. They have to be consistent with the FERC requirements. And I don't think the Commission has a specific rule. It was implemented by an order back in, gosh, '87, '88, '89, somewhere around there.

MR. TRAPP: Do you have a recommendation at this time, Rich, as to what you would prefer the rule to say?

MR. ZAMBO: I do not, because as I said, this just became a concern this morning. And so let me -- if I could, I would put that in some post-workshop comments. And I'm sorry to have raised it.

MR. TRAPP: Susan, do you know if the IOUs have a position?

MS. CLARK: You know, I think that as we were looking at this, we looked at the order. There was actually an order I think that required customers to be on the stand-by rate, and I don't -- sitting here now, thinking why the logic of that would change.

MR. TRAPP: And do you all?

UNIDENTIFIED SPEAKER: No.

MR. GRANIERE: Okay. I think I can think why the logic of that would change. Let me see if I understand. My recollection of stand-by rates was generally for a customer that was doing most of their own generation, and they were more or less separated from the grid.

MR. ZAMBO: No.

MR. GRANIERE: Well, just let me finish. And then get to a point is that if all of a sudden they fell down and they went off the system, that they needed to have power. Okay. That's not it?

MR. ASHBURN: No, that is not it.

MR. GRANIERE: Okay. So stand-by is that when they are not generating they draw power?

MR. ASHBURN: Right. That is the basis of it, and it is not even all. It's more than 20 percent of their load.

MR. GRANIERE: Yeah. And then you said that in order for that to happen, they actually have to be generating more than 20 percent of their load.

MR. ASHBURN: They have to have self-generation for 20 percent or more of their load.

MR. GRANIERE: Oh, 20 percent or more of their load.

MR. ASHBURN: Yes.

MR. GRANIERE: Okay. So in this world, then, it would seem to me that what happens is that the stand-by rate becomes whatever the normal rate is that they would have been on if they weren't doing anything, because that is -- so their stand-by rate would be their normal rate as if they weren't actually doing anything, so you wouldn't have to do anything.

MR. ASHBURN: No. The stand-by rate is intended to say that when you are taking the service that Bob was talking about, the normal service that you take, even though you are running your generator, you pay exactly what the otherwise applicable rate is for all the other customers. Then there is some conditions within the rate to deal with the fact that we are standing by to serve the load when your generator doesn't work.

MR. GRANIERE: So it is doing that. The stand-by thing is doing that?

MR. ASHBURN: Yes, but it only has components associated with the part serving that generator. Now, again, we're talking about the demand type, the large demand stand-by rates. Again, for RS and GS customers it's just the time of use rate.

MR. GRANIERE: It would just be the rate they --

MR. ASHBURN: Right. So there is no actual payment for -- you know, when the generator is down, otherwise, if it's -- when it's down, you pay whatever the time-of-use rate level is.

MR. GRANIERE: It becomes business as usual.

MR. ASHBURN: That's right.

MR. GRANIERE: Okay.

MR. ASHBURN: But it requires you, in that case, to be -- at least for Tampa, I don't know if all the utilities are that way, but it requires you to be on the time-of-use rate.

MR. GRANIERE: Right. But that's a tariff decision. The Commission can say yes, no, whatever. Right?

MR. ASHBURN: The Commission always retains that power, as you know, Bob.

MR. GRANIERE: I know. That's what I'm saying.

MR. ZAMBO: Well, let me just jump in here. If you get to some of those Tier 2 and Tier 3 customers, it's not going to be true that they would fall into RS or GS time of day. They will fall into a stand-by tariff.

MR. ASHBURN: The large demand one, right.

MR. ZAMBO: And the demand charge is based on their coincidence. So their coincident peak demand probability. And that was litigated 20 years ago through extensive hearings, and those numbers were based on the technology that was out there in those days. Maybe it needs to be relooked at.

MR. ASHBURN: What was designed at the time was it turned into a daily demand charge. So what happened was the Commission determined a certain percentage and said this much percentage is what you're standing by for, and I forget what it was, 17 percent or something like that. And they said, okay, that is sort of the typical amount that won't be around, and you will pay that every month, regardless of whether you take or not. And then if you used more than that, you pay that much every month. It turned out to be about two and a half days worth of demand charge. And then if your generator is down and you go into stand-by mode, you just pay a daily demand charge, which is the monthly demand charge divided by the 20 days, or whatever is, the billing days, and it just accumulates through the month. So it is not like you get hit with a full demand charge for the whole month. You pay a little bit and then it is a daily increment if your generator doesn't run very much.

MR. ZAMBO: Well, that's not exactly right, as I recall it. I'm questioning your description, but as I recall there is a demand ratchet in there, too, right? So if you set a demand -- if your generator was down for an entire month and you continued to do business as usual, you would set a stand-by demand that would then be yours for the next 24 months, I believe.

MR. ASHBURN: It could be.

MR. ZAMBO: I haven't looked at these tariffs for a while, but a lot of these things are -- this could become a real can of worms. This could become a real significant issue.

MR. GRANIERE: But are we in agreement that this might only be as significant issue for the large Tier 3s?

MR. ZAMBO: Bob, I haven't looked at those tariffs. Tom indicated as low as 25 kW, but I'm not sure if it's mandatory to go to a demand rate at 25 or it becomes optional. I just haven't --

MR. ASHBURN: Each utility is at a different point where it starts, and then you are into a demand rate.

MR. ZAMBO: Yeah. But it certainly could pick up some of these commercials, some of these commercial installations.

MR. ASHBURN: Right.

MR. ZAMBO: I will try to address that in post-workshop comments as best we can. Thank you.

MR. KEYES: So one issue I would see with the stand-by charge is, obviously, our solar generator goes down every time it's a cloudy day. So that doesn't seem appropriate to have that same sort of charge when it's a different sort of system than a cogenerator that you are counting on being there all the time.

And the other comment was on the demand charge. If my peak that is the basis of my demand charge for the next month was 100 kilowatts, that's something I did last month, and now I put in a solar system that's a 100 kW solar system, there should be some way of saying, gosh, my demand, my peak demand in the future is probably going to be a lot lower than it was before. It is probably not -- I'm probably not going to hit 100 kW again, to say as soon as the system gets installed, the demand charge ought to be adjusted down by maybe half the capacity of the system. So, for instance, in my example you would say, a 100 kW system just went in, we're going to say the demand charge is going to be based on 50 kW until proven otherwise, if it turns out the load is higher.

MR. ZAMBO: I would think it has less likelihood of having an effect on a PV generally, particularly a larger PV, say putting it on a store, like a Wal-Mart or something like that, because the load is going to come right back up at night when the PV is not running, and you are going to pay your full demand charge and there won't be any stand-by, because it goes away. So I think PV has less risk of the stand-by rate kicking in and causing any concerns whatsoever under the way this has been drafted. It may for something that is a much higher load factor.

Really, the stand-by rates were designed for things like Steve does, the high, high load factor renewable generators or other QFs that ran all the time, 90 percent load factors, that kind of thing, and would just go off occasionally on a weekend. But for a PV, I just don't think it's a big significant difference, because as the PV goes down, and it's on a big one, on a big store or a school, the likelihood is the school is still going to be running at night with a lot of load. And I just don't know that you are going to see a very big difference.

MR. KEYES: A school is actually the one example I could think of where it is closed down at night, and so you probably would affect demand on a school --

MR. ZAMBO: Perhaps, but they are also on in the morning when the sun isn't up yet.

MR. KEYES: Right. So I can imagine maybe it wouldn't affect the demand in a huge way. I would think it would go down, you know, if it went anywhere. I guess I need to understand better what happens with the stand-by tariffs, and it seems simpler from your explanation to say that stand-by rates won't apply to these systems or something.

MR. GRANIERE: Just an observation -- Bob Graniere.

It would seem that the stand-by rate doesn't really fall in when you are talking about intermittent power, that would be wind, solar, because, you know, it goes on and off every day.

MR. ASHBURN: If it's intermittent enough they won't hit 20 percent, so they won't be required to be on it.

MR. GRANIERE: Okay. Would that happen to solar because they go on and off?

MR. ASHBURN: I don't know.

MR. GRANIERE: Okay. Maybe it won't. How about one those digesters? What do you think would happen with one of those, because, you know, in general they are always --

MR. ASHBURN: I would think a digester would be a higher load factor, assuming the fuel was more around and available and wasn't relying on an intermittent source like solar or wind. I would think it's a higher load factor, but I don't know how big a digester could get.

MR. GRANIERE: But that would be a candidate perhaps for a stand-by charge is what you are saying?

MR. ASHBURN: Yes.

MR. GRANIERE: Okay. How about combined heat and power, how would that work?

MR. ASHBURN: Well, talk to Steve. He has basically combined heat and power. He has been on it for 20 years or so. Again, it depends on the size and how high a load factor it is on what the impact would be.

MR. DAVIS: Steve Davis from Mosaic. For our combined heat and power systems, we are already on a contract stand-by type of demand and we do pay it. You know, there are some advantages, believe it or not, is that one of the things if you really do need to be able to pull in power off from the system and know that it's going to be there. To the extent that you are just pulling power from the grid to replace what you would normally have supplied from your generator, that's actually billed on Tampa Electric's system anyway, and probably on everybody's at a slightly lower unit cost than what supplemental power is billed at.

But, you know, it's sort of a -- just something for people, especially, you know, like sort of commercial type of endeavors to be aware of if you were going go out and install, let's say, a solar cell on top of a commercial operation building. I guess when I read this, the concern that hit me would be that the interpretation could be that you would still pay the full demand charge as if you -- you know, let's say you do have a good month where there is nothing going on as far as -- you know, you could almost just balance out total kWh coming in the door versus total kWh going out the door and still have to pay your demand charge, which would, I think, radically impact the economics of these systems that you are contemplating installing.

MR. TOTH: Bill Toth. I had a conversation with staff, and let me just see if I understand, and I'm dealing with a commercial building here, okay, the example that you gave. The commercial building operates from 8:00 to 5:00, let's say. Those are its normal operating hours. Peak demand is going to be during that time, because they're going to be shut down 6:00 o'clock or so for the next, you know, 12 hours or so, 12, 16 hours. That is also the peak generating time for my solar system.

Now, if I'm a commercial building that has a demand charge, and I'm producing energy down to a level where I'm not incurring those demand charges during the day, I'm not paying demand charges. I'm only paying for what I'm using. And if I'm not using enough to be in a demand situation, then I don't have to pay the demand charges for that period of time when I am not using that demand.

In the evening when I shut things down, I'm not in a demand situation. I'm using very little energy for the next 16 hours, you know, 15, 14, whatever it is, and I'm not paying demand charges because I'm not at a level -- so I can actually reduce my demand charges to zero, let's just say for the sake of this discussion under the scenario. What I'm hearing here, or what I think I'm hearing is now I've got to go to a stand-by rate, or am I incorrect in my interpretation of my conversation with staff on how this is going to work?

MR. FUTRELL: Bill, if you have some thoughts on that, but it's my understanding that even if you have some -- at night there is some draw on the system demand at night, then you would pay a demand charge based upon what you -- the demand in the evening.

MR. TOTH: For the draw in the evening, correct. But I'm saying if you don't.

MR. ASHBURN: Or the early morning. If the building starts up or 7:00 or 8:00 in the morning, the sun may not be up in the winter, for example, and there could be a demand there, yes.

MR. TOTH: No, but my question is if my solar during -- let's just say it's a six-hour period which is when my big demand time is, and I'm offsetting that kilowatt hour usage that is now putting me in a non-demand situation, it could even be I'm producing more putting back into the grid at this point where I will be taking it out later. I understand if I am taking it out later and I'm demand, I'm still paying the demand. But I'm not paying any demand charges during that period of my peak performance when I am putting back into the grid. Is that understanding correct?

MR. ASHBURN: The demand charge is based on a 30-minute measurement, that's typically for all utilities, 30-minute measurement in the month. So if any 30-minute period during the month, during the demand area, assuming you're not on a time-of-use rate, it gets a little complicated. But on a standard rate we pick a 30-minute period, and the highest demand that we see from you is what is multiplied times the demand rate, whether it's at 7:00 in the morning, 3:00 in the afternoon, 4:00 in the morning, it doesn't matter.

MR. TRAPP: But, Bill, I think -- to try to clarify here. I think what I heard you say, at least for the Tampa Electric Company system, was that if the customer produces 20 percent of his consumption with his own generation, the applicable rate tariff he now qualifies for is not a retail residential/commercial/industrial GS or GSD, but stand-by rates.

MR. ASHBURN: That's right.

MR. TRAPP: So you have just transformed yourselves from a GSD customer to a stand-by customer, and those rates will be applicable.

MR. ASHBURN: Right.

MR. TRAPP: If you are at less than 20 percent for the TECO system, total generation relative to total consumption, then you would be on the otherwise applicable residential/commercial/industrial rate schedule, which could be a general service or a general service demand rate, and the demand charge you're going to be charged is going to be based on your -- what is it, a 12-month peak?

MR. ASHBURN: Well, we look at a 30-minute period in the month, and that gets applied by the bill. You can also choose, if you want to be, to be on the stand-by rate. This confuses people an awful lot of times. Sometimes people win going on the stand-by rate. That happens. It depends on your load shape and a variety of factors. So we have actually had customers who we went in and showed them if you went to the stand-by rate, you would actually save money. And most of the time they just are afraid of it and don't do it. But it is possible to save money.

MR. TRAPP: So all the rule really says is that, you know, warning, warning, you could be in a new rate classification by putting in your solar. And we're not making any policy decisions, I don't guess, in this rule one way or the other. We are just saying that your new load characteristics with your generation is going to determine what rate schedule you're in. And there is a whole, you know, list of rate schedules you need to be looking at.

MS. ROSE: Hi, this is Gwen, Vote Solar.

This is our particular concern, and particularly if stand-by rates end up becoming an economic disincentive for installing solar. And what some other states have done through a net metering rule is provide a sort of safe harbor exemption from moving to stand-by fees. And it is difficult to talk about this without assigning some numbers and looking at load factors. But if this becomes an economic disincentive, I would suggest -- I would encourage looking at safe harbor language to protect customers from --

(Simultaneous conversation.)

MR. TRAPP: I don't know what the impact is now, because this is really the first real discussion, I think, we have had on it. But I agree with you that we need to keep our eyes open if it becomes a problem and address.

MR. ZAMBO: And I'd like to just raise or make two points. One is I'm not sure it is 20 percent of generation. I think it is capacity -- I think it is demand. So if you have got a one megawatt load and you install 200 kW, I think that is the trigger.

MR. ASHBURN: Everyone's tariff is different. Our tariff says load, and we've interpreted that as energy in the past.

MR. ZAMBO: Okay. But if it says load, does that mean you are saying --

MR. ASHBURN: We have in the past interpreted that as energy.

MR. ZAMBO: Okay. And the second thing, I forget. Excuse me.

MR. GRANIERE: Bob Graniere. Would it be fair to say that everyone who is on stand-by rates doesn't necessarily pay a kW rate? Because that's what I seem to be finding as to being the situation. Not everybody would have to pay. I mean, merely going on stand-by rates doesn't mean that you must pay a kW rate.

MR. ASHBURN: Right. We have a stand-by -- we have a stand-by application for every level of service. So we have stand-by application for residential and all the way up through, except for lighting, they don't typically have their own generators. But for any of the RS, GS level, interruptible tariffs we have, we have a stand-by application.

MR. GRANIERE: Now, are these kW rates, as I heard you speak of, they aren't hourly kW rates, they're are --

MR. ASHBURN: The stand-by demand portion is a daily demand, but it is measured on 30-minute periods.

MR. GRANIERE: And it doesn't matter if you are drawing demand for 24 hours or only 12 hours?

MR. ASHBURN: Right.

MR. GRANIERE: Okay. So it doesn't make the adjustment that Mr. Toth was talking about or he was alluding to, that there was a time that he put no demand on the system during the day, but on the other times he did put a demand on the system. And I guess what he was getting to, and correct me if I'm wrong, he was saying that he didn't want to pay any demand charge for those eight hours or six hours. Am I right?

MR. TOTH: This is Bill Toth.

No, I was asking the question trying to clarify my understanding based on discussions I had with staff. I was trying to find out exactly how it is going to work.

MR. GRANIERE: So does it bother you that you would pay a demand charge that was a daily demand charge?

MR. TOTH: I don't know. I would have to look at the numbers and see if it looked like it was a fair situation or not.

MR. GRANIERE: Okay.

MR. FUTRELL: Rich.

MR. KEYES: So just to reiterate what Gwen Rose said, that it is almost impossible to go out as a solar installer and try and convince somebody to put solar on their roof, and they say, "oh, am I going to save money?" And you say, "Well, it depends. See, there are these stand-by charges, and here is how it kind of works." If you can't show them that they are going to save money by putting solar up, then they're not going to go for it. And so what is useful to have is the safe harbor language that says you are not going to go to some other rate, you are not going to go to stand-by charges if you wouldn't have been on -- if stand-by charges wouldn't have applied to you otherwise.

It would be very helpful to be able to say you'll save money because you are consuming less energy, but you also might save even more if you're going to a different tariff schedule or something, you know, or a lower demand charge. But the safe harbor language would help a lot.

MR. HINTON: Well, could you all present some potential safe harbor language in your post-hearing comments, not just citing to another state that has done it, but an actual sentence that deals with it?

MR. KEYES: Absolutely.

MR. FUTRELL: Rich.

MR. ZAMBO: I would just comment that with the language as it is, if you are a demand customer you are going to pay a demand charge, and that demand charge is going to be higher than what you would pay as a stand-by customer unless you are very unreliable. My experience with my clients has been the stand-by rate is lower. It's a discounted demand rate, and it's not paid hourly. You pay a monthly charge for it, and in exchange for that you are allowed to use it for a certain period of time. When you go above that amount of time, then you do pay a daily demand charge. But if you have got a reliable system, you need to look at the rates and analyze them. But if you have got to take what is in this rule and take your ordinary demand charge versus a stand-by charge, you may be better off with a stand-by rate. So I'm not sure a safe harbor would solve your problems or your concerns.

MS. ROSE: Gwen here. I think the question is an issue of choice. If the stand-by rate is going to save you money, that's a choice, and that's customer education. But being switched automatically to a different tariff is more my concern.

MR. HINTON: I was going to ask this question a little earlier. If somebody's usage characteristics would change through self-generation, does the utility automatically switch their rate class, the rate class you have them under, or do you approach the customer and say this is where we think you should be?

MR. ASHBURN: That's a complicated question. It depends, as I like to say at work, and they all say, "That's all you ever say." For example, your load shape might change so that you would be better off on a time-of-use rate. The common use rates in Florida are optional. So we will go to a customer and say, "Look, your load pattern has changed. You would be better off with a time-of-use rate." Sometimes they go; sometimes they don't. It's optional.

Some customers have their load grow and suddenly they have moved out of one tariff into another, say, from a non-demand rate to a demand rate level. And we will go to them and say, "Look, your load grew and you are now above 50 kW, say, and you should be on a demand rate." And they will say, "Whoa, it was a one-time thing, and this happened and that happened, and it will never happen again." So we might let them slide. And then they go back down, and we leave them where they are. So it just depends on what the circumstances are whether we make them change or not change on whether it is an option that they have or whether it is a requirement that they move. And it's just every circumstance is slightly different.

MR. TRAPP: I'm a little confused, I guess, by what is meant by safe harbor. And I guess maybe I would like, before we see it in written comments, a little more explanation of that. Is that something that just says the utility has to put the customer on the most favorable rate schedule available, or is that something that says that -- what does it say?

MR. KEYES: It says if the customer didn't have solar on the roof, what rate schedule would they be under? They can either go with that rate schedule or they can go with something better. If the fact of the solar system is up there qualifies them for some other rate schedule, then they have the choice to go to that. But the default setting would be whatever they would have been on if they didn't have a solar system.

MR. FUTRELL: So is the point to give the customer the choice, put in the customer's hands to make the choice as opposed to the utility making some sort of observation of changed characteristics and then it making the change, is that the point?

MR. KEYES: Right.

MR. FUTRELL: To give the customer the authority to make its decision on which rate schedule to go onto.

MR. KEYES: This became a big issue with switching to time-of-use rates in California, and there were a sizeable number of customers that when they went to time-of-use rates which was supposedly going to help the people install solar, some of them were large customers who had fairly small PV arrays, and it ended up on their time-of-use rates they were paying more than they used to or that they would have if they didn't have the array. And so they were pretty upset about that. And you would like to have some sort of language that says you are not going to be worse off because you've put in solar. We are not going to charge you more because you have solar.

MR. ASHBURN: So is that suggesting they would pick the lower of the two? Is that how it works, or no one switches.

MR. KEYES: You would pick the lower of the two up front. It is not like a month-to-month. You have to say, okay, so here is your rate on this one, here is your rate on this one. You would get to say up front.

MR. TRAPP: The rate they otherwise would have had without solar, so that means you have to back out the solar generation for purposes of calculating the demand charges?

MR. KEYES: I would think that you would need to. So then you would need to get some sort of coincident peak, which can be done.

UNIDENTIFIED SPEAKER: That's complicated and messy. I wouldn't know how to do that for a forecasted test year with billing determinants if you have a changing load profile.

MR. TRAPP: I would be interested in seeing the comments.

MR. FUTRELL: Any other comments on the net metering section?

MS. CLARK: Yes, Mark.

As we had indicated in our post-workshop comments, Gulf and Progress suggested the elimination of the waiver of the metering costs. As I said with respect to the application fee, Gulf and Progress continue to believe that costs should not be waived since such waivers result in other customers subsidizing the expenses attributed to net metering customers.

Now, with regard to the changes to Subsection 8(e) through (g), Gulf and Progress had suggested paying for excess energy on a monthly as opposed to annual basis, and this was not incorporated. The rule does change the payment for unused energy credits to the COG-1 as available tariff, but still has the reconciliation at the end of the calendar year based on an average annual rate. This is a move in the right direction, but Gulf and Progress continue to believe that the reconciliation should be done on a monthly as opposed to annual basis.

While the monthly approach still results in a subsidy to net metered customers, the subsidy is not as significant as with the annual approach. Further, from an administrative standpoint, the utility can best reconcile and pay for excess energy on a monthly basis rather than annual, and FPL agrees that from an administrative standpoint, it is preferable.

So we wanted to make those comments with regard to the changes you have made for net metering.

MR. GRANIERE: I have a question. Would Progress, or Gulf, or FPL be happy with monthly excess payments at the retail rate?

MS. CLARK: Let me be clear that in the post-workshop comments it was Gulf Power and Progress that focused in on the rate being at the avoided cost rate --

MR. GRANIERE: Okay.

MS. CLARK: -- as opposed to net metering.

MR. GRANIERE: So the answer would be no. So, basically, this approach eliminates the carry forward benefit of net metering, right?

MS. CLARK: It eliminates carrying it forward to the next month and then reconciling it at the end of the year. And I think there were some net metered customers who preferred that.

MR. HANSEN: I have a comment. I would just like to clarify something I said before, where I was all for the 10 kW as the level for Tier 1. That was only, basically, to help isolate Tier 1 from Tier 2 and 3. If you want to raise it up, that is fine, but in order for the individual to put in a solar system, there has to be an incentive. Right now in Florida, as I understand it, there is only 34 solar systems put in for individuals. And I was talking to a gentleman that sells these systems, and they don't even deal with individuals because it is not worth it. And it's the individual, the homeowner which this net metering was made a law 20 years ago for. It wasn't for the commercial people and 90 percent of our discussions here are for the commercial people.

So, if I put a system in, there should be a way that I can at least pay off this system within a reasonable amount of time. The way the system works right now, it would take me 75 years to pay off my system. If we adopt the way that you are going to do it, with the excess being paid off at the COG-1 rate, it may take 20 or 30 years. So the emphasis for the homeowner must be on trying to get some excess, and if he does, he should get retail price for that.

If that would happen, then the homeowner, you'll see many, many people get involved in this. And if it doesn't happen, they won't because you can't afford it. So my suggestion is, that on Line 24 on Page 8, between the word credits and the little word at, that you just insert this sentence, this phrase, "For Tier 1 at retail rate and for Tier 2 and 3," and that's all. You just insert that between those two little lines, and that will give Tier 1 retail rate across the board. And that is as far as I can understand -- and I am putting in a system now, and anything I've figured out, that is the only way that I could pay this system off within a reasonable time being 6, 10, 12, 15 years.

MS. ROSE: From our perspective the monthly carry over of net excess generation is critical. First, I think that the way you have characterized in here is correct. You basically say it is a one-for-one kilowatt hour swap. There is not really a sale of electricity happening. And if we can carry that over for a year, what happens beyond a year with annual net excess generation, whether it is paid at avoided cost, or whether it is donated to the utility, or in Oregon whether it is donated to low income programs, that's what they do there, is, I think, a separate question. But for a customer -- let me back up.

We talked about the subsidization of net metering, but there is an implicit bias there that forgets to look at what the benefits of net metering or net metered generation provides. So you have a customer that is paying usually a flat rate for their power. When they are producing excess, it's generally going to be during peak times. That's going to be going into the grid, and that's high value peak power that the utility gets to, basically, sell to the neighbor. But then they get to sell power or they get to give power back to that customer at off-peak periods, which is a lower cost.

So it's a benefit to the utility, and, you know, we could run through what the benefits are of photovoltaic generation, but I think preserving the ability for customers to carry over those credits from month-to-month allows them to size their system to take advantage of the seasonal differentiation of the way solar produces power. Without it, you're going to have customers sizing system to meet winter load rather than maximizing it for the course of the year to offset their consumption.

MR. JONES: I was just going to concur with Gwen. As a small system owner myself, it's so nice this time of the year when the air conditioner is off. You can end up with, you know, maybe two months in the spring and two months in the fall where you have a net, you know, negative feedback. I would just like to get that power back again, you know, for the winter or the summertime. And, you know, it really would take a lot of the wind out of the sails for, you know, potential system owners to know that, you know, they put that power out during, like Gwen said, those peak summertime periods when the utility sees a real advantage to having that generation created, and yet is not given consideration for the value of that at other times of the year.

So as a small system owner and certainly as an industry person, I can convey that that's an important issue in a sales process or a justification for a homeowner that they sort of net out on an annualized basis, not, not a month to month to month. And it is a real critical issue, I believe.

MR. TOTH: Bill Toth. I just want to concur with what they said as far as the carry over. I like the gentleman's idea down there. I'm sorry, I forget your name.

MR. GRANIERE: Bob.

MR. TOTH: Bob. Monthly is good as long as it is at the retail rate. That would work fine.

MR. FUTRELL: Jason, you had a comment?

MR. KEYES: One other practical consideration there is that part of the reason why lots of states have gone from monthly to an annual process is because people are sizing their systems to at most meet their own load. And so in any given month they are not exceeding their load by much if they do at all. And so when you have any sort of payout like this, like they're suggesting, you end up with a lot of administrative expense for something very small. You know, cut a check for four dollars kind of thing. And it's just easier administratively to just carry it over month-to-month.

In fact, several states have now gone to saying it is too much of a hassle to keep track of it over the course of a year. You know, they can just keep it rolling it over to the next year. We are never going to pay them much. We are going to pay them avoided cost, or some states don't pay at all, but they let them roll it over on an ongoing basis. So, at least a year makes sense.

MR. HANSEN: One other point is I don't know how many snowbirds would actually put a system up, but if they did, the power company could be using that power for six months out of the year. That would be a direct benefit to them. It would be distributed power and it would allow them to be selling this power for the whole six-month period, and it would also provide the snowbird, when they come back, to enjoy a very low electric bill. But for the period when the generation is at maximum, they are not even here. So if they could get retail price for everything that they generate, it would help the distribution of power throughout Florida and it would eliminate a lot of the line losses and it would prevent the electric utilities from being overloaded in the summertime. This is one of the big advantages of the solar voltaic system.

MR. FUTRELL: If there's nothing else, let's move on to Section 9, the renewable energy certificates, or RECs. We got into this a little bit on the metering discussion. Again, staff is anticipating the possibility that markets may develop in Florida. RECs are being sold in Florida. We are trying to anticipate that. We have done that in the renewable generator standard offer contracts that Bob mentioned earlier. We had provisions there for RECs, and we are trying to be proactive on this and get out ahead. Any comments on the language we have here?

Bill.

MR. TOTH: Yes. Bill Toth. The requirements in -- where is it -- 12, 13, 14, and 15 where it talks about the -- well, it is in direct conflict with -- you have got to go down to 10 -- 24 and 25. Who's going to decide the purpose of the meter that's going to measure those two things, because they are both measuring the same thing, and one is a reporting requirement of the utility and the other is a REC requirement, but it is the same measurement.

MR. HINTON: Actually, did you say Line 24 and 25, is that what you were referring to?

MR. TOTH: Yes, under reporting requirements.

MR. HINTON: Right. That's customer-owned renewable generation delivered to the electric utility. Under Subsection 9 dealing with renewable energy certificates, that's talking about total electricity generated by the renewable energy. That's what is delivered to the utility and what is consumed by the customer. The reporting requirement is just what's going back into the grid on Line 24 and 25. But to get the certificate, the customer will need to be able to account for what their total generation was, even what the utility never knows about because they just consume it.

MR. TOTH: Okay. Then what about Line 21?

MR. HINTON: That's the nameplate capacity of the customer-owned renewable generation system.

MR. TOTH: So if you have got, like, a 6 kW system, that is what that would be reported as? Okay.

MS. CLARK: Mark, this is Susan Clark. We are in disagreement with the provisions in 9. It seems to us that what you are proposing here to the net metering and through the payments you have provided for excess energy as well as the waiver of fees result in net metered customers being subsidized by other customers. And for that reason the RECs associated with them should belong to the general body of ratepayers.

One of the concerns we would like to raise is the notion of addressing this in the rule, the ownership of the RECs. When you have had discussions of setting up a REC system, under what conditions should ownership be retained, if you are paying more than avoided cost, shouldn't the other customers have some claim to those RECs?

I would urge you not to address that in this rule given the fact that I have seen in the past where you make these small decisions dealing with specific areas and don't address the larger policy decision that you should make which is if you were going to pay above avoided cost, what is the fair way to deal with RECs. And I think that should be done as an overall assessment of what the policy should be.

Rather than making a decision here while it's only these small facilities, it would be appropriate as an added incentive to allow them to retain the RECs, and then you go to the next decision you have to make relative to this, and the suggestion is made, well, you have done it here, you have allowed that ownership to stay, why not do it here. I think the better policy is to look at it from an overall standpoint as to what is fair when you have the other customers paying more than avoided cost.

MR. JONES: Just for clarification, are you saying that all of the RECs associated with the production from a photovoltaics system belong to the entire rate base or only that energy that was netted back to the utility?

MS. CLARK: And I think that's one of the issues to me that really needs to be addressed in an overall policy, because I think you can have other instances where the entire ownership of the REC maybe should be split for one reason or another because of -- I don't know how it is being paid for, but I just think that the idea of who has ownership of the REC and when payment in excess of avoided cost by some level should require that ownership to shift should be looked at in a global consideration of an RPS policy.

MR. JONES: Well, I don't know that you are really paying for the RECs, I mean, if you are being compensated for full retail value. I guess you could make a distinction that if I don't have a photovoltaic system and I reduce my energy load in my home, you know, I have created the same effect as if -- if I have reduced my load consumption in my house by two kilowatts or I have a two kilowatt photovoltaic system, the effect is the same to the grid, and I don't know that you deserve those RECs.

MS. CLARK: And I understand that there are some states that attach RECs to what you were talking about, that energy efficiency. What I'm suggesting is I think the whole sort of gambit of what might generate RECs needs to be looked at. And in generating those RECs, if there is subsidization either through tax credits or anything like that, then some thought needs to be what should be the policy of the state with regard to ownership of those RECs. Does the fact that there is subsidization being provided from all the other customers or taxpayers change who should claim ownership and be able to count them as credits towards an RPS.

MR. TRAPP: If staff were to accept your position that it's premature to address this now and, therefore, not include this paragraph in the rule, would your clients commit not to include that paragraph in their tariffs?

MS. CLARK: To not address the --

MR. TRAPP: Not address who owns the RECs in their tariffs until this RPS policy is settled? I mean, quite frankly, that's the experience we have seen is we enunciated this policy in the cogeneration side of the equation, and we had a big fight about it because you all kept putting it in the tariff and we kept having to fight it in the tariff. And then the Commission finally did enunciate policy in that rulemaking that basically --

MS. CLARK: It gives them the right of first refusal.

MR. TRAPP: No, it doesn't.

MS. CLARK: I'm sorry, Bob, I was thinking about the renewable cogeneration rules.

MR. TRAPP: Yes. That's what I'm referring to, too.

MS. CLARK: They are allowed to put in their tariff the right of first refusal, I thought.

MR. TRAPP: No. Rule 25-17.280, tradeable renewable energy credits. Tradeable renewable energy credits and tax credits shall remain the exclusive property of the renewable generating facility. A utility shall not reduce its payment of full avoided cost or place any other conditions upon such government incentives in a negotiated or standard offer contract unless agreed to by the renewable generating facility.

Now, granted these rules are based on avoided cost. I think your argument is based on some above avoided cost consideration --

MS. CLARK: Right.

MR. TRAPP: -- to assign some portion of the RECs to the utility, so I understand the difference there. But I just don't want to acquiesce to a position that is premature to address this now, and then have it come up in the tariffs and have to fight it on a tariff basis by basis. Sometimes you can win the battle and lose the war. And so if we are going to address it, let's address it. If we are not going to address it, let's agree not to address it until the proper time when the RPS is resolved either by statute or by this Commission.

MS. CLARK: I think if the agreement is to address it as some part of the RPS and looking at it from a global standpoint, then we would not put it in the tariffs having suggested that be the approach you take. But I do think that the difference between what you were discussing was the fact that it was based on avoided cost, not paying in addition. And I believe the rule had in there that there was a discussion about not giving the right of first refusal. And as I recall, there was some statement at agenda that that could be included in the tariffs.

MR. TRAPP: Well, I hope you are listening to the comments on the other side of the room, and they strike me as if there is a fairness issue here with regard to you getting all the RECs when we only may be talking about some netting involved here. I mean, some of the proposals I've heard, at least on the RPS side of the workshops we have been having, will assign great value to these RECs. I mean, great value to these RECs. And I'm more inclined to say we are premature to assign that great value at this point in time in the recommendation than I am to just give them away willy-nilly. And you know my longstanding position is that at least based on the avoided cost principles, RECs belong to the customer; they can do what they want to with them.

MS. CLARK: As long as it is based on avoided cost.

MR. TRAPP: I grant you we begin negotiating once we get above avoided cost, determining the balance between subsidy and equity or fairness.

MS. CLARK: And what I'm suggesting is that the same sort of issues will come up in other applications that RECs may be generated and available, and the question is to the extent there is incentive subsidization that are provided to the customers, should there be some allocation of those RECs to those customers/entities that provided the incentives.

MR. TRAPP: I certainly appreciate your arguments, and I hope that they come forward in the discussions before the full Commission because I think they need to hear these and weigh them. They vote, we don't. But I have to also tell you that if you start out with the basis that what we are trying to do here is essentially promote active conservation, and the principal reason for this rule is offset, then I have to side more with the concept that any additional benefits that are generated by that conservation belong to that customer. And perhaps only the net that goes to the grid that gets on our cogen side, maybe we can talk about that, but it seems to me the lion's share of the RECs belong to the customer. That's just my opinion.

MR. BRANDT: Yann Brandt. Just a quick comment on the RECs. I think the way the paragraph is written is right on. We're discussing the value of the electricity right now that we are net metering, and that was one of the previous paragraphs. When we get into renewable energy credits, we can talk all day long about the value of renewable energy credits, and if you think that -- we need to distinguish that there is two items in that energy that we are producing. There is the actual electricity that we are putting back onto the grid that is being resold at a retail rate to another customer, and then there is the intangible renewable energy credit which we are going to use towards the RPS.

I would welcome the utilities to purchase the renewable energy credits at whatever multiplier they propose towards that value, because if we are going to assign a multiplier or an extended value to that renewable energy credit and the electricity from that, then we can't just buy it for whatever little value we are assigning to it by doing what you are asking for. I think we really need to separate the two and discuss, one, the value of the electricity here, and then we are going to assign the value of the renewable energy credit at the RPS workshop or whatever other function. We really need to separate the two and keep it the way it is here.

MR. TOTH: Bill Toth.

I would agree with what he said 100 percent. I believe if we are doing it on a cost avoidance basis, as you said, the RECs belong to the small system or the customer, not the utility. I keep hearing that the other ratepayers are going to be subsidizing the solar customers, but I have not seen any evidence, numbers to substantiate this claim. I would like to challenge the utilities to provide some proof that there will actually be subsidizing going on under the circumstances that we are talking about, including the benefits. And they can't just look at the negative side of this, they have got to look at the positive side of the not lost, you know, in transmission, the on-site generation and not having to build future plants. I mean, I know they don't want to look at this side of it, but I would like to see some numbers to substantiate the claim I keep hearing that other ratepayers are subsidizing the renewable energy purchasers. I have not seen any numbers to substantiate this, any evidence.

MS. ROSE: This is Gwen Rose. I wondered if I could just add a little bit to that. I haven't seen studies done in Florida, but I can point to at least three studies that were done to quantify the value of distributed renewable energy according to peak generation, peak demand, deferred T&D upgrades, or avoided T&D upgrades and then transmission losses, which can run between -- depending on obviously location, you know, between 7 to 10 percent, or 13 percent. Those numbers change, but even during peak periods transmission losses go up even more.

So, anyway, when they looked at this study in Austin, Texas, they found the distributed generation benefit to be 11 cents; when they looked at it in New York, they found it to be 16 cents; and when they looked at it in California, they found it to be 23 cents. And those are all values that aren't being captured when we talk about distributed generation. So, again, just to reiterate, when we are talking about the cost of net metering, let's talk about the benefits provided by that power to the ratepayers and to the utility.

MS. CLARK: You know, I would just point out that's what you do when you develop your avoided costs. You look at those things and you come up with what customers would otherwise pay for the energy to be generated by the utility. And to the extent you're paying above avoided cost, there is some subsidization going on.

MR. TOTH: And I would like to see evidence to substantiate that statement. Based on what she said just down there, I don't know that that's true.

MS. CLARK: That's what we do when we put out the standard offer contracts and do the need determinations as to what the cost is going to be to provide that generation. Those are where you find that information.

MR. GRANIERE: Just an observation on the avoided cost issue. It really kind of boils down at the end as to how you measure it. That's what it finally boils down to at the end. And probably if it went to the avoided costs, then the discussion would be what is and is not included in the avoided cost. And I think that we are talking of the subsidy, it can either occur in one of two ways. It can be the avoided cost way, is that is there a net benefit involved from a traditional economics point of view, or are we talking about a situation of really the potential for lost sales that may have to be made up from someone else.

I would point out that the second argument for subsidy, the lost sales argument, does, in my opinion, carry much more traction in a system that is either losing sales or is stationery. If, however, that system has growing sales, that argument has much less traction because there's people replacing there. So, unfortunately, it seems to me, and this is my personal opinion, that the lost sales argument has less traction in Florida than I would say in a place like Michigan or Indiana.

But the other issue, the avoided cost issue, that's a much more ticklish issue because the discussion really boils down to what is the time frame within which to measure the avoided cost. If the time frame is very short, it's as available energy. If the time frame is kind of longer, it's building a new plant. I don't know which one you want to use, but that is what the argument becomes down the road.

MR. FUTRELL: Let's take five.

(Recess.)

MR. FUTRELL: Let's get started. We have got just a little bit more to go, and if we can get into Section 10 on the reporting requirements. We have made these applicable to all of the utilities, muni, co-op, and investor-owned utilities. We have made one clarification on 10(e) that would be specified about the previous calendar year. Any comments on the reporting requirements?

MS. CLARK: One question, Mark. On Page 9, Lines 20 and 21, when you say the total number of customers and total kW, do you want that reported as of the end of the previous calendar year? The report is due April 1st, and I would presume that the totals you would want are also as of the previous calendar year. Not just for that calendar year, but the total will be run every December 31st.

MR. HINTON: Yes. And it's not for the previous calendar year, but we could set a deadline, as of this date what is the total.

MR. TRAPP: Well, on Line 19, would you like to add the words, "Shall report the following for the previous calendar year by April 1st of each year," is that what you are getting at, Susan?

MS. CLARK: Yes.

MR. HINTON: Well, I don't know if that will get to the total.

MR. ASHBURN: I mean, customers come and go during the year, so --

MR. HINTON: For (a) and (b), if you did that it would just be for the previous year.

(Simultaneous conversation.)

MR. TRAPP: Cumulative totals?

MR. HINTON: Cumulative, a running tally of what we have total.

MR. ASHBURN: So, for 20, for example, you want the number that were connected during the year, but some came on and some came off, or do you want them as of the end of the year, or what do you want?

MR. TRAPP: All of the above sounds good to me.

MR. HINTON: There you go.

MR. FUTRELL: Specify that it would be effective as of the end of the calendar year.

MR. ASHBURN: That's fine; just which, that's all.

MR. HINTON: It would be a total interconnection.

MR. ASHBURN: If you clarify it might be better to say that, particularly for (a) and (b) if you had said as of December 31st of the prior year or something like that, that would help.

MS. CLARK: As of the end of the previous calendar year.

MR. TRAPP: I think that was the intent to capture calendar year data. Now, whether or not we want the end of the year, or average for the year, if we have any additional data requests we will send them.

MR. HINTON: The reason why we have, you know, because you look down on (c) and (d), it does specifically say for the previous calendar year. (A) and (b) were designed to be running tallies, so we can say as of the end of the previous calendar year, but it is meant to be cumulative for all previous years.

MR. TRAPP: No, wait a minute. I don't think so, Cayce. You want to know the total number of customers you had on-line at the end of the year.

MR. ASHBURN: I think you want them at the end of the year, because then (f) is asking for information about each one of them, and I would assume you would want the count as of the end of the year to have the information about what do they use, and what their ratings were, and that kind of thing.

MS. CLARK: I think we're saying that the reporting will be total number of customers on renewable generation interconnection as of the end of the previous calendar year.

MR. FUTRELL: Right. The effective stop date is December 31st, whatever the world looks like on that day.

MR. ASHBURN: Right. And that would apply to (a), (b), and (f).

MR. FUTRELL: And (a), (b), and (f) would be for whatever is accumulated from when they first got on the system to that date.

Anything else on reporting?

MR. TRAPP: Michelle came back. Can I ask my one co-op question that I always ask?

I can't get through a workshop without calling you to the mike.

MS. HERSHEL: I knew I should have left.

MR. TRAPP: We started the workshop with you and we now end the workshop with you, so I have to ask for the record, do you have a problem with the shift to basically reporting that we have done in the rule?

MS. HERSHEL: No.

MR. TRAPP: Thank you.

MR. FUTRELL: Moving on to 11, dispute resolution. We have tried to simplify that. Referring to two processes, one the less formal customer complaint process, and one a more formal process where a party can initiate a formal proceeding with the Commission and give the customer the option of selecting the process they would like to pursue.

MR. JONES: Excuse me, Mark. I just had one comment. Just going back, again, I was just thinking, on the information collected it might be helpful, again, for conveying RECs and identifying a generating ID, or a unique ID associated if we ever go to a registry on RECs, if you are going to collect (inaudible) information, renewable energy, gross power rating, geographic location by county, it might be interesting either to get -- you don't want to have published a person's address, maybe a unique generator ID which could be maybe a meter number, or a meter number that the system is tied to, at least for purposes in the REC reporting that it might be helpful, so that you can facilitate, you know, good accounting of the RECs and you don't end up with double counting for a system. So just a suggestion, you know, if you're going to collect all of that information, maybe, again, a site ID or something along those lines.

MR. FUTRELL: I guess we didn't contemplate getting into -- that that would be more on the order of the RPS and data requirements for the RPS. We just looked at this as more as overall high-level data so we wouldn't get into any kind of confidentiality concerns and high-level data on what has been happening with these as a result of these rules.

MR. HINTON: Sooner or later we're going to have to talk to the legislature about this, so we've got to start gathering the information.

MR. FUTRELL: Okay. I think at the beginning of the workshop -- I'm sorry, Mr. Hansen.

MR. HANSEN: I just have a real simple question. In the overall scheme of things, what is your projection that you think that this will be clarified and enacted into law or regulation?

MR. FUTRELL: And I may need some help from Ms. Gervasi, but as I said earlier, we are going to take a recommendation to the Commissioners at the December 18th agenda conference where they will decide whether or not to propose a rule.

And at that agenda they can take the rule staff gives to them, recommends to them, make changes to it, or make some other decision about going forward. But if they choose to propose a rule, then there will be opportunities for public comment on it. Also there will be opportunities to request a hearing if someone has a concern with the rule. That will determine how quickly a rule becomes final if a party decides to request a hearing, but it's hard to forecast out beyond the early part of the year. It's very dependent upon actions taken by the parties and their level of concern with the rule.

MR. TRAPP: Let me just elaborate, if I may, in a supervisor's position.

We're staff; we don't vote. We just advise and recommend to our Commissioners. Obviously, we are going to have to come up with a proposed draft to put before them, and that proposed draft is not going to -- we haven't reached consensus here on many issues, so staff is going to have to pick a preferred approach.

It is our practice, however, for staff to put forth to the Commission a full narrative of the record, if you would, in the case, and that's why the post-hearing comments for this particular workshop are to me really important because, you know, what I intend to -- I've challenged you throughout the day, what I intend to now challenge my staff to do is to take those written comments and to go through them point-by-point and say we accept, we reject, we propose modification, and here is why to be part of the recommendation that we give to our

Commissioners.

So, I think, you know, the draft that we give our Commissioners will be a working model, if you would, of a rule that we think from a staff perspective would best work. We may not agree. Where we don't agree, there will be alternatives in the REC saying, you know, Bob thinks this should be done this way and Mark thinks it should be done that way, and here are our reasons for it.

But in addition to that, I hope that we are able, and I am going to challenge my staff to go through the written comments from this workshop and say, you know, Party A, B, C, D, E, F, G said this, this, this. We have incorporated it in the rule, or we have not, and here is why. So that is what we will be doing to present to our Commissioners.

Mark is correct, though, we have been told that the December 18th agenda is when that recommendation will be voted on by our Commissioners. Now, when it comes to them, they vote, we don't. They control the docket from then on.

MR. HANSEN: Thank you very much.

MR. TRAPP: Sure.

MS. CLARK: Are you going to reiterate the dates? I think you said the 19th for the transcripts.

MR. FUTRELL: Right. We are looking at the transcript will be available on October 19th, and we'll make sure that it is put upon our website, on the Commission's website. Also, you can contact staff if you would like a copy of it to get that out quickly. We are looking for comments on October 26th. And then, again, the agenda would be on December 18th.

MS. CLARK: Have you set any tentative dates for the public hearing, if requested, or is that too much in the future?

MS. GERVASI: We don't have shadow dates, I don't believe.

MS. CLARK: Okay.

MR. FUTRELL: We would request, again, on the theme, we have heard a lot today, specific rule language and as much detailed justification as you can provide will be very helpful to staff so we will fully understand what you are proposing and why. So if you can do that, that would be helpful.

If there are no other questions, thank you very much for coming. Have a good day.

(The staff workshop concluded at 5:45 p.m.)

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

I, JANE FAUROT, RPR, Chief, Hearing Reporter Services Section, FPSC Division of Commission Clerk, do hereby certify that the foregoing proceeding was heard at the time and place herein stated.

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

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

DATED THIS 19th day of October, 2007.

Linda Boles / for

JANE FAUROT, RPR
Official FPSC Hearings Reporter
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