STATE OF NEW HAMPSHIRE

PUBLIC UTILITIES COMMISSION

June 18, 2009 - 11:08 a.m.
Concord, New Hampshire

RE: DRM 08-148
RULEMAKING:
Puc 900 Net Metering Rules.

PRESENT: Chairman Thomas B. Getz, Presiding
Commissioner Graham J. Morrison
Commissioner Clifton C. Below

Sandy Deno, Clerk

APPEARANCES: (No appearances taken)

Court Reporter: Steven E. Patnaude, LCR No. 52

I N D E X

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P R O C E E D I N G S

CHAIRMAN GETZ: Okay. Good morning. We'll open the rulemaking hearing in docket DRM 08-148. On May 1, 2009, the Commission voted pursuant to RSA 541-A to initiate a rulemaking for New Hampshire Administrative Rules Chapter Puc 900, rules for net metering, for customer-owned renewable energy generation resources of 100 kilowatts or less. The Initial Proposal consists of a readoption, with amendment, of the existing interim rule that was prompted as a result of modifications to RSA 362-A. The proposed rule establishes reasonable interconnection requirements for safety, reliability and power quality for net energy metering. A rulemaking notice was filed with the Office of Legislative Services on May 12. The notice set forth today as a date for a public hearing, and set a deadline of June 25 for the submission of written comments. And, an order of notice was also issued by the Commission on May 15 providing public notice of the hearing today.

I'll note for the record that the

hearing is held pursuant to RSA 541-A:11, under the State Administrative Procedures Act, for the purpose of taking public comments on the proposed rules. I'll note also for the record that all three of the Commissioners are present

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satisfying the quorum requirement under 541-A.

I have a sign-in sheet, individuals who would like to speak. And, I'll just start at the top with Ms. Matthews.

MS. MATTHEWS: Good morning, Mr. Chairman, members of the Commission. Thank you for the opportunity to comment on the rules. I am here on behalf of National Grid. We will submit written comments, but I wanted to take a few moments to outline our primary concern, which is with Rule 905.01, which is the manual disconnect switch. And, under the proposed rule, it appears that a utility could not require a customer to install a manual disconnect switch, in Section (a). In Section (b) of 905.01, there is some options for the utility to disconnect a customer from the grid. But our concern is that some of those options would impact other customers and cause more delays than there would be with a manual disconnect switch.

For example, I'm not an engineer, but my understanding is that isolating the customer could require a bucket truck and rated lineman. Where, if there is a disconnect switch, it could be operated at ground level without safety gear.

We will suggest in our written comments

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a modification and revision to 905.01(a). We would like to see all the utilities have some discretion with regard to whether or not a manual disconnect switch can be required. And, any other comments we will submit in writing.

CHAIRMAN GETZ: Okay.

MS. MATTHEWS: Thank you.

CHAIRMAN GETZ: Thank you. Jason Keyes.

MR. KEYES: Good morning. I'm Jason Keyes. I'm representing the Interstate Renewable Energy Council. I have been working and representing IREC for the past couple years. IREC is funded by the Department of Energy to go state to state working on net metering and interconnection. So, I'm not here on behalf of utilities or on behalf of the environmental community, just to give you some perspective of how things are done in other states.

Over the past couple years I have been active in New York, New Jersey, Florida, Illinois, Nevada, New Mexico, and Utah. So, obviously, New Hampshire has been at this for a while, and I'm not trying to come here at the last minute, a month and a half before you need to get your rule together, and say "you need to overhaul things." I just want to go through and point out some of

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the things that pop out at me as unique.

Firstly, just go over what I think you have done quite right. One is, to say that there won't be an insurance requirement, that's been a game-stopper in lots of states. And, I haven't heard any opposition to that insurance provision, but that's a key thing to keep in there, to say that the customer-generator is not required to carry extra insurance.

Also, rollover, obviously, that came through from the statute, but that's a key component of net metering to be able to have excess generation rollover on a kilowatt-hour for kilowatt-hour basis to the next billing period and to subsequent periods.

And, also, the disconnect switch, in some ways, it even went a little too far. I actually agree with National Grid on the point that she made. In states that have -- there are now about a dozen states, I believe it's up to 14 states, that have some sort of prohibition on a disconnect switch requirement. And, in, I believe, all of them, the utility has the option to require the disconnect switch at its cost, if it sees a need for it. So, there shouldn't be a situation where, for safety, it sees the need to put in a disconnect switch, but it's not allowed to put one in. And, also, in

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all states that I can think of, the disconnect switch is not required for inverter based systems. And, from what I can see in this rule, you're covering all systems. And, so, it would just be for inverter based systems.

And, what -- let's see. Then, stepping down on the things that potentially could use some fixing. First, you can't help with the fact that the statute says that the cap on facility size is 100 kilowatts for net metering. That does -- in the future, that probably will be changed. That's far behind I believe the majority of the states now. There are over a dozen states that have a megawatt or more cap on net metering, and some have no cap at all. And, about three-quarters of the capacity being installed in California and New Jersey and Colorado, the states that are really leading the distributed generation market, about three-quarters of the capacity is in the larger systems, commercial systems. And, I don't know that there's a 100 kW break to that. But, generally, larger systems are most of the capacity. Most of the installations are small homeowner systems, but that small percentage makes up a big part of the capacity.

What could be fixed, and I'm not sure that you want to take on all these, but I'll just go through them, is the -- let's see, there are -- right now,

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there are no screens in the process. So, there is, in the federal rules and in lots of state rules, following the same procedure, there are a series of ten screens, and it's just a single page of screens. And, basically says, "if you pass 1547, and you meet these screens, and several of the screens are in some ways included in your rules, but it's not really a straightforward thing that, if you pass these screens, then you're done. And, in states that have that, it's about a ten day process. You go through, you pass the screens, and there's no question to it. And, any installer that has gone through the process before knows how to conform to the screens and get something pushed through quickly. And, those -- so there won't be any reason for the utility to come back and say "actually, we want to study this more."

The timelines seem to have some confusion. In the 904.02 and 04 and 05, it -- at one point it says that there is a "ten day timeline for inverter based systems". But, actually, there's a ten day window for the utility to tell the customer-generator that

the application is complete. There isn't something in
there that I saw that says that there's actually ten days
in which to say whether the application is approved or
not. So, there ought to be something like that.

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Seventy-five (75) days for non-inverter based systems is extremely long. And, plus screens in the FERC procedures apply to most non-inverter systems and lots of small biomass generators, for instance, or wind systems that are not inverter based, would pass the screens and they would fly through the procedures in a couple weeks, and, under the rules here, it would be 75 days.

In 902.04, there's the definition of an "eligible customer-generator", and it flows directly from the regulation. It defines "customer-generator" as the owner and operator of a system. And, predominantly, especially in California now, the market is being driven by third party ownership, and especially on larger commercial systems. So, if you have a definition that says that you got to own and operate, then you're cutting out a good part of the market, and, in some ways, you're restricting it to the wealthy. Because you're going to have -- the only people who can really go forward with this are people who have, say, for a home system that's going to be 5 kilowatts, they're going to spend $35,000.

Well, it's got to be somebody that's got that much money
to pay in the first place, and have the tax appetite to
take the tax credits to use it.
Whereas, if you've got a company that

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will come in and put solar facilities on low income housing even or schools or churches, all of those kinds of entities don't have any sort of tax appetite, but the owner of the system can have a tax appetite. So, there's a problem there, though, that the regulation says "owns and operates". But the regulation also has, in its first section, has a provision saying that you want to do the best you can to promote renewable energy. And, so, a way to get around this somewhat is just to broadly interpret "owns and operates", to say that "if there's an ownership interest in the system". So, for instance, under this third party ownership, almost always the customer-generator has an option to buy the system sometime in the future. So, they have some sort of ownership interest. Or, another way is a leasing model. So, a third party owner leases it to the customer, and so -- and, at some point, the customer has the option to buy the system. So, if there's -- if that's broadly interpreted, then you're going to allow more systems, and you're going to allow systems on schools, for instance, that there's no way a school can buy a 100 kW system for $700,000. But, if they have a third party owner coming in and saying "we'll install it for you, and sell you the power cheaper than you get from your utility", then it

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does make sense.

CHAIRMAN GETZ: And, just one thing, Mr. Keyes.

MR. KEYES: Yes.

CHAIRMAN GETZ: I think you mentioned a couple times, and you did here, to the "regulation". Were you meaning to refer to the "statute"?

MR. KEYES: I'm sorry, the statute. Sorry about that.

In 905.06, there's a threshold provided there that says that the utility will consider more than 7.5 percent of maximum load on a circuit as a threshold above which it's important to go and study what impact this generating facility will have. The standard in the FERC regulations and in lots of states is 15 percent. And, that 15 percent was derived by looking at your typical circuit, the max -- the difference between the maximum load and the minimum load is -- the minimum load is somewhere around 30 percent of the maximum load. So, 15 percent was just picked as "Well, that's about half of

what we expect the minimum load to be. So, we're pretty
darn sure that, if all the generation is on, and you're at
a period of minimum load, you still will have more load
than generation on the circuit, and so you won't be

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backfeeding to the transformer." And, it doesn't -- that seems like a pretty conservative threshold, that's been working just fine in other states. So, I would suggest that 7.5 percent is unusually conservative.

There's also a provision in there for how 20 percent of the maximum load be on the generator, and I haven't seen that provision in any other state before. I'm not an engineer, I'm not sure that -- that there probably is some sort of basis for that, but, anyway, it hasn't been done in other states.

So, those are sort of the larger issues. I'll point out a couple smaller issues. In your order a couple years ago, you discussed both "interconnection" and "time-of-use metering". And, so, time-of-use is a big issue. It's not addressed at all in your net metering rule. So, if you've got a time-of-use customer, what happens? And, what other states have grappled with there is, well, we would want to have net metering by time bin. So, if you've got three time bins, if you've got excess in your peak in July, then it rolls over to the peak time bin in August. And, then, what happens at the end of the year, if the peak happens to coincide with Monday through Friday during daylight hours, and you may have excess for the year there, but be paying in the other categories.

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And, so, you can have a provision to roll over at the end of the year any excess in the peak to your shoulder, for instance, or from your shoulder to your off-peak.

There, I won't go through, there are some inconsistencies in terms and grammar, and I can put those in my comments. There is -- I'm sorry, I didn't write down the section, but there is a load break test that's, and I would have to look up the section, but the utility has the option of requiring an annual load break test. So, the customer would need to disconnect from the utility and show that the inverter actually works. The inverters are all built to the UL 1741 specification. That's like their main function is, when the grid goes down, it recognizes that. And, I don't know of any reason why, if it worked in the first place, that function would stop working. So, I don't see a need for a load break test. I don't -- Other states do have some sort of provision saying that the utility, with good cause, can require a load break test. I just want to avoid the possibility that that's going to flow into the terms and

conditions, and that it's just going to be a standard that
they just require everybody to do a load break test.

I already addressed, I think, that for
the disconnect switch, it should just be inverter based

systems. And, on sort of a larger scale, lots of rules have some sort of standard interconnection agreement, or, at least for the simplified agreement, there are standard terms and conditions. So, for instance, the SCHIP has a two-page terms and conditions that goes along with the application. So, what you've got now is a model application, and it refers to "terms and conditions", but there are no terms and conditions in your rules. So, it appears that what's going to happen is the utilities are going to submit their terms and conditions, you're going to approve those terms and conditions by utility. But you can either include the terms and conditions from the FERC SCHIP in your rule or you could reference them and say there's a presumption that those are reasonable, and the utilities could modify those as they see necessary.

I'd be happy to answer more questions on it, but I don't want to monopolize your time.

CMSR. BELOW: A couple of questions. You said you're going to provide written comments, right?

MR. KEYES: Right, a week from now.

CMSR. BELOW: And, can you give examples
of how other states have addressed time-of-use, and do you
know of instances where dynamic pricing has been addressed
in net metering rules?

MR. KEYES: Dynamic pricing has not been addressed, because that kind of gets you to the ultimate where there are no bins. Logically, you would say "well, okay, we'll just take the retail price at that time and credit the customer that amount." But that gets you into exactly the territory you don't want to go with net metering, because that involves a payment. Once you have a payment of some sort, then you worry whether that's something that the customer has to record for tax purposes, whether it nullifies his insurance provisions in his homeowner's insurance because he's got a home-based business because he's getting paid for something. Whether FERC has jurisdiction then, because there's a sale to the utility for resale. So, we try and avoid, like the plague, any implication that there's a payment. But it's a really -- it's a sticky issue when you get to dynamic pricing. Fortunately, there aren't a whole lot of dynamically priced customers. But one option is to just say, for those, there could be some sort of standard payment, there could be the avoided cost, plus some basis for the other benefits of net metering.

For the tiered approach, California has a time-of-use provision. And, they're currently looking over that. And, the recommendation that I just said of

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taking any excess at the end of the year and transferring it over to the next bin down is something that IREC is proposing in California now. Because as it's turned out, in California, surprisingly enough, 10 percent of the customers have excess generation at the end of the year, and that's not for time-of-use customers, but just in general. So, lots and lots of customers went out and they sized their system based on their consumption over the past year. And, what do you know, once they put up a solar system, they get a lot more conscious of their usage, and they put in the right bulbs and they turn out the lights and do all the right stuff, and then they end up with more generation than load. So, there is an issue there for excess generation. And, so, presumably, the same sort of thing would happen with time-of-use and leave some customers with excess.

CMSR. BELOW: I think that's all. Yes.

CHAIRMAN GETZ: Okay. Thank you.

MR. KEYES: Thank you very much.

CHAIRMAN GETZ: Mr. Eaton.

MR. EATON: Good morning. My name is Gerald Eaton. I'm Senior Counsel with Public Service Company of New Hampshire. We support adoption of the rules as they have been written, for the most part. We

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were involved with the process. And, I think the Commission should be aware, there was another process going on at about the same time, and that had to do in docket DE 06-061, the Energy Policy Act docket. And, specifically, the utilities filed either tariffs or standards for interconnections up to -- they were inverter based interconnections up to 100 kilowatts. And, the screens that the previous speaker was talking about are included in PSNH's standards. So, again, the simple inverter based systems would fly through the process, as long as they match those screens, and would qualify very quickly. So, consideration of these rules should also look to some of those filings by Grid and Unitil and PSNH and the Co-op, as far as their interconnection standards that was in docket 06-061.

The inverter is a device, as I understand it, that takes direct current and switches it to alternating current, so it can be used by the customer or delivered to the grid. The UL listed inverters stop working when they lose utility power. So, essentially, the disconnect switch is contained within the inverter, as long as it's working. So, as far as the manual disconnect switch, which is about the closest thing we come to any controversy under these rules, we would like the option to

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explore the manual disconnect switch on non-inverter systems. The ones that we already have the discretion to do a more elaborate interconnection study, because those are the systems that may send power out onto the system when we don't want it.

Under those types of investigations, the rules call for 75 days for a study to be done. I don't know about the other utilities, but PSNH doesn't have a separate department that deals just with interconnection studies. It's the people that are already doing work on system protection. And, that means they're also doing studies for PSNH as to different changes to the system and what protection needs to be involved with that. So, in order to -- in order to be able to handle not only internal work, as well as interconnection studies, it may take 75 days just simply to address the -- to address the study, in addition to all the other work that needs to be done in that area.

The previous speaker talked about standard terms and conditions. Those standard terms and conditions are contained, again, I refer to the interconnection standards that were filed in December of 2008, in DE 06-061. So, there are some standard terms and conditions there that the Commission can refer to, and

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that the customer gets a copy of those.

And, as far as -- I haven't spoken with anyone yet, but, as far as the idea of the owner/operator, I think it's important to PSNH that we have some kind of a contact or some kind of relationship with an entity that knows the system. If a third party, a foreign corporation, out-of-state corporation installs a system on low income housing, we're not opposed to that at all. But, if there needs to be some interaction on how our system operates with that system or whether there needs to be a disconnect or whether there needs to be a test, we'd like someone that we can contact that understands what's going on, as opposed to, if it's simply a building superintendent, who knows nothing about that system, because it was installed and certified by a company that owns it somewhere else, I think we need to have some contact and some way of interacting with that -- with that person who understands the system, as opposed to simply someone who happens to reside or own the building and knows nothing about the system.

I think that's all I have to comment on. If the Commission has any questions?

CMSR. BELOW: I do. On the disconnect issue, your primary concern is the non-inverter based

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system. And, I guess my question is, where pulling the customer meter, you know, seems like it's an obvious option. Would you -- Are you looking for an option to potentially require a disconnect switch, where pulling the customer meter is not an easy option? I mean, would that address your concern potentially? Or, if you can't answer that today, maybe you can explore that in your written comments. You know, the circumstances where pulling the customer meter, you know, seems like an alternative to a disconnect switch, but maybe that's not always accessible or available or there are other circumstances where you would want a disconnect switch.

MR. EATON: Sometimes meters are located inside of buildings, and we have access during normal business hours, but not at a time when there's -- when we may need to operate that. Again, if we ever came to an impasse with a customer, where we really needed the ability to disconnect that, we could install a switch at the transformer, and it would be our switch, and we would interrupt the customer that way and interrupt the flow of power out from the generator.

CMSR. BELOW: Okay. Thank you.

CHAIRMAN GETZ: Thank you. Is there anyone else that would like to make a public comment

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today?

MR. EPLER: Yes, Mr. Chairman. We had indicated that we didn't have comments, but Mr. John Bonazoli, who is the Manager of Distribution Engineering for Unitil Services Company, which provides engineering services to Unitil Energy Systems, is here and would like to make a couple comments.

CHAIRMAN GETZ: Please.

MR. BONAZOLI: Good morning. As Mr. Epler said, I'm John Bonazoli. I'm the Manager of Distribution and Engineering for Unitil. I've got a couple comments. One of these is on the disconnect, which has been spoken about. I just want to add a couple things. In the past, when the utilities got together with the Staff on the original 900 rules, we had agreed that below 10 kW a disconnect was not required. One of the main reasons for this was that, up to 10 kW, the crews are fairly confident with pulling the meter, because there's not that much current that they're disconnecting. Over 10 kW, they're not very comfortable with -- in pulling the meter. So, then, they would have to go and remove taps at the distribution transformer. And, as the attorney for National Grid had said, this is going to require more time and more cost and, of course, that all goes to the

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ratepayer. So, we would -- we'd recommend that we bring that back to the original 900 rules, that up to 10 kW it may be required, but over 10 kW it is required for any generating facility.

CMSR. BELOW: Would you include inverter based ones over 10 kW?

MR. BONAZOLI: Well, as previously said, an inverter by design, if the line -- if the line goes dead, by design, the inverter is supposed to open up. We have a couple concerns with that. One, just safety, that we've got to trust the inverter, that the inverter is working. There is no maintenance testing that you can do for an inverter. So, there's nothing that we can require that requires us to test the inverter periodically. So after a few years, we don't know if the inverter is working.

Secondly, there are some inverters that, if you lose your -- if the customer loses their main service, there are some inverters that, say, that they will go into a backup mode, which will still allow the

generator to be generating, but it will open up a contact
or something between the invert and the incoming line.
One -- There was one inverter that did get their UL 1741
listing with that feature. But, then, that listing was

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removed, because the inverter was tested again, and so they lost their listing. So, that is the concern that we would have, even with inverter systems.

And, I know, in the past, some people were saying "a disconnect switch would add cost to the customer's project." The cost would really be minimal. I mean, you're talking about $1,500 installed for a disconnect switch, where these systems are tens to up to hundreds of thousands of dollars to install. So, the cost savings, really, for a disconnect switch for the safety would be minimal.

My second point is on 9.7 -- 907.01. In Paragraph 1.d, it states that "Facilities greater than 35 kW certify that they are in compliance with IEEE Standard 1547 for harmonics." We would recommend that all facilities comply to IEEE 1547. 1547 is the national standard that most states are going by and the utilities use that. So, we would just recommend that all -- that all facilities comply to IEEE 1547.

Any questions? That's the only

statements we have.

CHAIRMAN GETZ: Thank you. Anyone else who would like to comment this morning?

(No verbal response)

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CHAIRMAN GETZ: Hearing nothing, then we will close the public hearing, await written comments that are due in a week, and then we'll take further action based on those comments. Thank you, everyone.

(Whereupon the hearing ended at 11:42 a.m.)

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