STAFF WORKSHOP

BEFORE THE

ENERGY RESOURCES CONSERVATION AND DEVELOPMENT

COMMISSION OF THE STATE OF CALIFORNIA

CALIFORNIA ENERGY COMMISSION

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| In the matter of, | ) | |
| | ) | Docket No. 11-RPS-01 |
| | ) | |
| Developing Regulations and | ) | |
| Guidelines for the 33 Percent | ) | |
| Renewables Portfolio Standard | ) | |

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 9TH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, JANUARY 28, 2013

9:34 A.M.

Reported by:

Peter Petty

APPEARANCES

Commissioner

David Hochschild

Advisor Present

Gabriel Taylor, Advisor to Commissioner Hochschild

CEC Staff Present

Gabriel Herrera, Staff Counsel

Mark Kootstra

Brian McCullough

Gina Barkalow

Participants

Julia Levin, Bioenergy Association of California

Adam Link, CASA

John Pappas, PG&E

Jedediah J. Gibson, Ellison, Schneider & Harris

Peter Harman, Minasian, Meith, Soares, Sexton & Cooper

Stephen C. Kircher, SPI

Diane I. Fellman, NRG

Steven Kelly, IEP

Matt Langer, SCE

Timothy Tutt, SMUD

Jeffery D. Harris, Ellison, Schneider & Harris

Jeremy Weinstein, PacifiCorp

Oscar Herrera, LADWP

Valerie Puffer, City of Glendale, CA GWP

APPEARANCES (CONT.)

Participants

Susie Berlin, City of Redding, California

Anthony Andreoni, CMUA

David Branchcomb, Sierra Pacific Industries

Jane Luckhardt, Downey-Brand

James E. Hendry, SFPUC

Andy Schwartz, Solar City (Via Telephone)

Scott Tomaschefsky, NCPA

INDEX

P R O C E E D I N G S

JANUARY 29, 2014 9:34 A.M.

MR. KOOTSTRA: My name is Mark Kootstra. I work in the Renewable Energy Division on the RPS. We're going to go through a little bit more information about how this workshop is going to run but, first, I'm going to let Commissioner Hochschild say a few words, if he'd like.

COMMISSIONER HOCHSCHILD: Good morning, friends and welcome. I gather we're having some technical difficulties, which it wouldn't be a true Energy Commission workshop without some technical difficulties.

But I'm David Hochschild. I'm the Lead Commissioner for Renewables here at the Energy Commission.

To my left is my advisor, Gabe Taylor, and to my right is Gabe Herrera, our attorney, and Mark Kootstra.

I want to welcome all of you here this morning. And just to be clear, you know, the RPS is, as we know, touches three agencies, the ARB, the Energy Commission and the PUC.

And what we're dealing with here is the RPS Guidebook. The goal is really to collect information on some of the outstanding issues in the RPS Guidebook. We're not going to deal at all with the enforcement issues and we're not going to deal with station power, which was the subject of a dedicated workshop in September.

But we want to solicit detailed input from you on all the rest of these questions and have a healthy dialogue.

If we could just take a minute, I'd be grateful if we could quickly go around the room and ask everybody here just to stand and identify yourself so we know who else is in the room.

(Whereupon, the entire audience introduces themselves.)

COMMISSIONER HOCHSCHILD: Did we get everybody?

Thank you all for being here. And we are going to stay here as long as it takes to get everyone's input, and we want you to not hold anything back.

I will report a small victory in my life which is that my daughters, after I got this phone I had loaded all these games onto my phone, it turns out, and they've -- and these kids like send text messages like I'm getting in the middle of the meetings like, you know, your princess needs a new dress and time to put -- so, I figured out finally how to disable that so I'm feeling very pleased with myself. So, one technology victory this morning.

MR. KOOTSTRA: So, thank you very much for coming. This is the first time we've tried a scoping workshop on the RPS Guidebook in recent memory, for at least as long as I've been here.

So, we're going to be doing a very special workshop order, so bear with us as we go through this.

As you can see, our workshop agenda, we're going to go through the discussions, topics identified by the Energy Commission. There are six of those.

We'll break for lunch sometime around 12:00 to 1:00, depending on how the discussion flows. And then we'll continue the discussion of topics identified by the Energy Commission if we still have more to discuss. If not, great, we can move on.

And then we'll be discussing topics provided by you, the stakeholders. I now of a few already and I'll let you know how to propose some additional ones, if you'd like.

Last, we'll go into next steps on the process.

So, for housekeeping we have handouts at the front table. The restrooms are located on the first floor right behind you and there's a snack bar on the second floor.

There's also a list of restaurants on the front table, we well as distances and price ranges for everyone.

And emergency evacuation procedures, please just follow us.  We generally meet out at the park across the street.

For WebEx, there's interactive participation. You'll be able to raise hands.  For phone-in users, only, you're just going to be able to comment at the appropriate times.

For the WebEx, again, you can view the slides, raise hands and chat.

You're going to be muted on entry for WebEx and we'll unmute you at the appropriate time.

Unfortunately, WebEx and phone-in participants aren't going to be able to participate in the standard discussion because we're going to be talking back and forth a lot.  But we will have a comment period after discussion dies down here.

And also, if you are on the phone and you haven't already downloaded the slides, the slides are posted online at the same location as the workshop notice.

So, generally how this process is going to work is for each of the six topics that we've presented, we're going to ask any interested parties to come to the table and join us for a discussion.

There will be a short presentation on that topic, as well as identifying the questions that we laid out in the workshop notice. Then you'll be able to go through the discussion and participate however you see fit.

I ask that when you do come to the table you fill out an ID card so that we can know who it is, and to make it easier on the court reporter that you'd also give him your business card.

And as we move through process when you speak, please try to remember to identify yourselves to make things easier, so we can have a full record.

For in-person participants, if you want to propose additional topics we have green cards. There are some on the entry table. Brian McCullough also has some, in case you haven't grabbed one. And we'll be collecting those before lunch as long as we have some time left, and we'll be compiling that information and then putting it in order of how we're going to discuss your proposed topics.

For WebEx and phone-in participants, please e-mail your topic to "rpstrack", with "RPS Scoping Workshop additional topics" in the subject line. We'll review these at lunch and try and include as many as we can. And we'll apologize if we can't get everybody in there, depending on how our e-mail system decides to work.

Again, due to time constraints additional topics provided, we need to have those at the earliest possible convenience. This says before the fourth topic or lunch, whichever’s earliest. I think at this point that’s going to be lunch, so just be prepared to have those before you head out for lunch.

Again, going through this, sorry I’m duplicating, we’re going to be rearranging seats in a minute so everybody can come to the table.

Please, if you don’t have interest in a topic and there are people that want to sit at the table, please head into the audience so that we can get everybody who wants to participate at the table.

If you aren’t able to get a seat at the table, we do have some portable microphones, as well as the podium, for you to come and talk out. We don’t want to exclude anyone, but we want to be sure everybody who wants to discuss in a major way is going to be at the table.

After we discuss internally here, in the hearing room, we’ll extend an invitation to the WebEx attendees and then the phone-in participants.

So, hopefully, you’ve all read the notice. The purpose of this workshop is really to get directions on the next set for the RPS revision process by getting stakeholder input on what’s going on, get your thoughts, as well as any additional topics that need to be, in your mind, addressed.

We’ll then be going to Commissioner Hochschild to work with him on what topics should be addressed and how the initial direction should go.

Our hope is that this workshop will not take the place of a workshop on the actual draft language, but it will help us flesh out what topics we need to address before we get to that stage so that we don’t have to delay the process after we’ve gone through a draft. We can comment on the draft and move on. And any topic that’s not covered we can look at in a future workshop.

We also want to provide you with an opportunity to raise any proposed changes that you see fit.

Again, we are looking at these six topics in particular, as well as any stakeholder-presented items. I do want to remind you that we will not be covering these items, which include station service.

We had an entire workshop dedicated to this in September of last year. You will have full opportunity to comment on that in the guidebook workshop when we have draft language.

We aren't going to be discussing the POU regs or CPUC decisions, which includes portfolio content categories, portfolio balance requirements and historic carryover.

There is one set of questions on energy storage which kind of straddles this a little bit, but we're trying to grab scope on how energy storage should be incorporated.

We also don't want to discuss future legislation today. We recognize that that's a very valid topic, but we're trying to confine our discussion to stuff that we can actually accomplish now.

And then we don't want to discuss any specific facility application reviews. If you have specific questions, please feel free to e-mail myself, my contact information is at the end of this slide, or talk with us after the fact. We can give you specific information there.

So, in preparation for the first topic, Repowering: the definition of Prime Generation Equipment, if there's anybody in the audience that would like to come to the table, please come forward now and we can start our discussion.

So, for those of you that aren't aware, repowering a facility allows a facility to change its commercial operation states for the purpose of the RPS Program. This mainly an advantage for facilities that have time constraints on when they have to start an operation to be RPS eligible and this is generally restricted to facilities that are physically located outside the state and not interconnected to a California balancing authority.

There's two requirements that must be met in order to have a facility be considered repowered and that is replacement of the prime generating equipment, and a capital investment in the facility so that 80 percent of the repowered facility is considered new -- or is from new capital investments.

Specifically what we have questions on is digester gas and landfill gas definitions.

When we revised the Guidebook for the 7th Edition, both digester gas and landfill gas fell under the definition of biomethane, but for repowering they're still called out separately.

As you can see, they're very similar definitions except that digester gas facilities are required to replace the entire digester unit in addition to the internal combustion engine or certificating engine; whereas, landfill gas facilities are only required to replace a combustion engine or the turbine as applicable.

So, we have three questions. What is the appropriate definition of the prime generating equipment for a facility using biomethane from digester gas, from landfill gas, and should the definitions be the same?

Should the definition be different for a biomethane facility receiving gas from either a dedicated pipeline, including on-site, or a common carrier pipeline, and why?

And should any distinction be made for separate ownership of the gas collection or processing equipment and the electricity generation facility using biomethane? If so, how?

So, if you could identify yourselves and fill out the cards, especially if you’re going to be here again, so the court reporter can see that, that would be wonderful. And thank you very much.

MS. LEVIN: You want us to do that before we talk?

MR. KOOTSTRA: No, I think you can talk.

MS. LEVIN: Okay.

MR. KOOTSTRA: As long as you state your name, please.

MS. LEVIN: Okay, thank you. Good morning, Julia Levin with the Bioenergy Association of

California.

MR. LINK: And I'm Adam Link with the California Association of Sanitation Agencies.

MS. LEVIN: So, thank you very much for putting this on the agenda. It's a very important issue for both of our members.

Just to say a few words about the Bioenergy Association, we represent about 50 local governments, public agencies and private companies in the waste management, energy development, technology, investment and other fields, including many of the companies that develop dairy digesters, biogas facilities at wastewater treatment facilities, landfill biogas and other sources of biogas.

So, this is very important to our members and many of the local governments that are developing bioenergy projects to address solid waste issues, water quality issues, and other important environmental and climate change issues.

The role of biogas is extremely important in California for meeting both our clean energy and our climate change goals.

A recent report from E3 really underscored the importance of diversifying renewables in California, especially as we move beyond 33 percent to reduce costs and maintain reliability of the grid.

The 2012 Bioenergy Action Plan found that bioenergy could provide about 10 percent of California's total electricity demand, more than 1,000 megawatts just from biogas, alone.  So, this is a really important source of renewable baseload energy.

Biogas can also provide energy storage and it's a very effective form of energy storage.  If you size the lagoon at a wastewater treatment facility or a dairy digester larger than you need for immediate biogas production, you can store the gas for several hours or up to several days which, when you look at the duck curve and other reliability issues as we increase intermittent renewables that gas storage is going to be very, very important.

But that kind of brings me to the issue with the current definition of repowering.  We strongly support the RPS.  Probably many of you know I've been very involved in it for a long time and we strongly support having a definition of repowering that will stimulate new projects, but it should be new power projects.

Digesters can be built for many reasons that go beyond electricity generation and so requiring the replacement of a digester, as well as the prime generating equipment goes well beyond what's needed for a new power project.

And as I mentioned, digesters can be built for other purposes, for energy storage. Adam will talk about the role that digesters play in the wastewater treatment field. They can be built to reduce odors from dairies and for many other reasons.

There also can be digesters that are built to produce gas --

(Background noise)

MS. LEVIN: Or that create background noise.

So, we will, in our written comments, propose a definition, but it essentially will look like the definition for all of the other renewables. We don't see a reason to distinguish the definition of repowering for biogas from other sources of renewables, landfills or, for that matter, small hydro, geothermal. None of the other forms of renewable are required to replace the equipment that's needed to produce, or clean, or process the fuel.

It's not about the -- the digester is not about the power generation. It's about the fuel source. And it could have multiple roles.

Requiring projects to replace both the digester and the power generator could also triple the cost of the projects, which was demonstrated in a recent Black &

Veatch report produced for the PUC.

So, for all of these reasons we urge you to make the definition of repowering for biogas consistent with the definition for other forms of renewable energy.

And in terms of the three questions, we don't see any reason to distinguish whether it's biogas that is from a common carrier pipeline or a dedicated pipeline. We don't think that ownership issues, any of those other factors are relevant.

What's relevant is the power generation and the focus should remain on the power generation only. Thank you.

MR. LINK: Good morning, again. My name's Adam Link with the California Association of Sanitation Agencies.

I want to thank Julia for coming and expressing support for this issue.

We, too, support a revision of the definition of repowering in the RPS Eligibility Guidebook that's consistent with the definition of repowering for other renewable energy sources.

Just as some background, CASA, my organization is a statewide association of municipalities, special districts and joint powers agencies that provide wastewater collection and treatment services to more than 90 percent of the sewer population of California.

Many of our members are actively involved in anaerobic digestion activities that produce biomethane, biogas, clean bioenergy and low carbon fuels for use here in California.

The current draft, as you saw in the presentation, as Julia mentioned, the definition of prime generating equipment is defined as the entire digester unit and internal combustion engine or combustion turbine, even though the digester, itself, may serve multiple purposes beyond just power generation.

In the case of wastewater treatment plants this is particularly true where the anaerobic digesters on site are a necessary part of the wastewater treatment process in reducing solids, as opposed to purely generating energy.

In fact, a number of our facilities utilize digesters solely for the purpose of wastewater treatment and actually don’t produce power with the resultant biogas.

But for those that do and for those that are interested in repowering, they wouldn’t necessarily replace the digesters, it would just be the generating equipment.

And so, in addition to being simply more consistent with how our facilities view repowering in practice, changing the definition in the Guidebook would be critical to allowing wastewater facilities to participate in the SB1122 Program, which is currently being developed at the CPUC.

As you may know, 1122 created the 250-megawatt renewable feed in tariff procurement requirement for small scale bioenergy projects.  110 megawatts of that is set aside for wastewater facilities and other urban waste.

A Black & Veatch study that Julia mentioned relied upon the CEC Guidebook definitions for commence operation, commercial operation date, and most notably as it applies here, repower and prime generating equipment.

And they concluded that wastewater -- at least as it relates to wastewater facilities, requiring replacement of the digester and the power generation equipment could triple the cost.

And this is effectively prohibitive for wastewater facilities that might otherwise be eligible for the 1122 Program and might want to participate. This would exclude them.

And we think this is contrary to the State's policy of encouraging renewable energy at wastewater facilities.

So, we would respectfully request that the CEC modify the definition of repowering for these facilities to be consistent with the other types of requirements. And that we'll be joining Julia's comments, written comments on the issue that will propose a definition similar to that.

MR. KOOTSTRA: Thank you very much.

Does SCE or PG&E have anything they want to share?

MR. PAPPAS: Great, John Pappas from PG&E. I just wanted to say that we support the definition of prime generator equipment that's been offered today.

There should be consistency between the definition with respect to digester gas versus landfill gas. Neither definition should include the digester unit or the landfill and it should be exclusively based on the power generating equipment.

And we think that's consistent also with, you know, the treatment for other generating facilities, so we support that.

MR. KOOTSTRA: Thank you.

SCE, do you have anything to add?

Okay, Commissioner Hochschild, would you like to say anything before --

We'd like to take this opportunity to invite the WebEx participants. If there's anyone that would like to participate, please raise your hand and then we'll open the phone lines before moving on.

We're going to open the phone lines real quick. Christina, could you unmute the phone for us?

The phone's been unmuted. If anybody has anything to add on the topic of prime generating equipment we ask -- we ask that if you're on the phone line that you mute the phone on your end, unless you wish to speak.

We're going to try unmuting our line one more time to see if there's anybody out there, otherwise we'll be moving on. Christina?

All right, thank you very much. We look forward to reading your written comments.

We're going to move on to the next topic. Anybody who's interested in the eligibility date revisions, please come forward to the table.

I'd like to add a couple of things that I forgot to mention before. While we do want to have a robust discussion, please be courteous to each other and not try and interrupt too much. We are trying to get a court reporter to be able to actually record this, so that being clear helps.

In addition, we ask that if you agree entirely with someone, moving forward, especially as we get a bigger discussion, it’s okay to just say we agree. That’s going to go a long way to moving our discussion. And please feel free to submit written comments in support of what you say here.

So, thank you very much and we’re going to open discussion. We’re going to start with Jed Gibson on this side, if that’s all right with you.

MR. GIBSON: Oh, were you going to go through the slides first?

MR. KOOTSTRA: Thank you. Sorry. So, the eligibility date, it’s assigned to facilities when they apply for precertification or certification for the first time. Generally, it’s the day on which we receive the first application for either precertification or certification for a facility.

Sometimes this date does change for a number of reasons. Two of the main reasons why it’s been changing recently is a failure to submit a certification application within 90 days of commencing commercial operations if the facility was precertified, or a failure to submit an amended certification application within 90 days of requiring an amendment. And this would include utility-certified facilities that have had their contract terminated, or it's ended, or been revised in some way, shape or form.

Previously, for utility-certified facilities they were required to apply for RPS certification before the contract ended. But with the adoption of the 7th Edition Guidebook that was extended to 90 days after the end of that contract.

There are several other reasons for the eligibility date changing, almost exclusively relating to us denying the facility for some reason, or us finding out that the facility does not meet the RPS eligibility requirements, and that generally hasn't been an issue.

As you can see with this table, we've received more and more precertifications. The light blue line is the number of precertifications that we currently have on the books with expected commercial operations dates in the past. The blue line is how many we have for each given year.

We currently had over 700 precertified facilities with commercial operations dates that are in the past. This is one of the reasons why we wanted to put this 90-day requirement in the Guidebook to be sure that we have solid data when we're basing off decisions of determining what we're looking at coming forward in the future.

We've noticed most applications, for whatever reason, don't get back to us when they decide not to pursue a facility any longer, and this includes companies that just disappear. So, it's hard to get a hold of that information.

And when you have approaching 300 facilities in the year that are supposed to come online, but don't, it's hard to follow up on that and have good information for the public to see.

As many people here will be able to attest, this has created some issues. We've had some facilities that have received alternative online dates because they barely missed that 90-day window or were unaware, despite staff's best efforts to contact everyone.

Possible alternatives that we have discussed internally, which is not saying that we endorse any one in particular, but the potential to extend the deadline from 90 days to 180 days; allow the deadline waivers for good cause if it can be demonstrated; and also just complete removal of the requirement, but just requiring a facility to be certified before any verification reports are made.

This is an option that we've had in the past.

However, it generally runs into us having lots of people come to us saying we need to have a certification done now so we can report claims.  And that slows down the verification process.

Given that we now have 45 POUs to work with in that process, we want to take every avenue we can to make sure that goes smoothly.

And having facilities coming to us at the last minute, requiring this, will slow things down again.

Specific questions we have is if, having a requirement to apply for a specific date is reasonable or not, and why?

And if there’s a reasonable timeframe, what would that timeframe be?

Is there another approach that we can use to ensure that we have valuable information in a timely manner, in addition to the topics that we -- or the possibilities we identified?

And should a facility remain precertified if the estimated commercial operations date passes and the facility does not submit an application either for certification or amended precertification within a reasonable timeframe?

This is to ensure that if a facility is delayed by a few years, or months, that we’d have that information as well.

So, we're going to open up discussion. Again, please be courteous. And I don't want to say be short, but just keep in mind that we want to be sure that everybody has an opportunity to speak.

So, we'll start with Jed Gibson.

MR. GIBSON: Good morning, Jed Gibson for Ellison, Schneider & Harris. Thank you for taking the time to discuss these important issues.

Just to begin with, we appreciate the Commission's need to get timely and accurate data for the certification process. That's certainly something we support.

As the Power Point presentation mentioned, that sometimes the -- some of the 90-day deadlines have resulted in negative consequences that can, you know, cost thousands of dollars and result in the loss of RECs that would otherwise be counted for the RPS Program.

And often this will be from a facility that had previously been certified as RPS eligible and would subsequently be certified as RPS eligible. There was no change to the facility in the interim, you know, so effectively it's the same renewable power that's being produced.

So, we just think that there should be some method of either relaxing the interpretation of the current Guidebook to allow adjustments to that eligibility date or to revise the Guidebook to allow a waiver process. Effectively, where if there is good cause for changing the eligibility date that either the Executive Director, or staff, or the Commission would be allowed to go back and revisit that question to, you know, retroactively assign eligibility in appropriate cases for good cause.

So, that’s kind of my short pitch on that. I’m happy to go into more details, but it may be better to discuss offline, as we have already. And we’ll be following up with our written comments to go into more detail.

MR. KOOTSTRA: Please feel free to jump in when somebody’s done, as well. I can’t ready your name; Peter?

MR. HARMAN: Peter Harman. I represent Nevada Irrigation District.

For now, you know, we stand behind Jed’s comments and we plan on submitting written comments soon, but I don’t have anything further to say at the moment.

MR. KIRCHER: Hi Mark, Steve Kircher with SPI Solar. And I’m not sure if I should get into specifics but I thought the comments were certainly right on the mark with regard to trying to find some form of waiver of the deadline in specific circumstances that allows the Commission some flexibility.

Obviously, you know, the intent in any of these programs is not to harm small business or any businesses that are out there trying to participate in this environment. And the solar industry’s clearly been a tumultuous environment over the last few years.

So, the responsibilities of management to run companies, and try and run them efficiently in a rule-changing environment has been difficult for some of us, so some things do get lost in the shuffle.

And when there is no victim in one of these particular situations, in our particular case, you know, we have a project in Palm Springs, with Southern California Edison, where they signed a power purchase agreement. We’ve moved several times in our company and, unfortunately, we’re not on top of the ball with regard to filing. We filed a precertification but not file the final certification in time and got billed by Southern California Edison, who was apologetic about it and didn’t want to do it, but they were the beneficiary of the power. They weren’t the beneficiary of the RPS standards.

So, consequently, it's the small business, which is us, that has to take that hit or that is being required to take that hit.

To allow some form of waiver, appeal process that gives some flexibility to the Commission to go ahead and reinstate the certification will be incredibly helpful.

MR. HERRERA: Good morning, Steve, just a quick question. So, in the case of small businesses that lose kind of track of obligations to file applications on a timely basis what would be a good approach that the Commission could take to make sure -- I mean what could we do to be proactive there to inform --

MR. KIRCHER: I'm trying to think. It's so difficult, it really is because there are so many people who do want to participate, who do want to get involved.

But there's clearly -- you know, every day in the paper you read about another solar company that goes out of business. And my job has been to try to make sure we don't go out of business.

So, we've done everything we can and now we're, hopefully, back in the upstream. But the amount of money that we're talking about in this particular case is $700,000. A small business can't -- yeah, how do you survive in that kind of environment?

The waiver process would be the best, notification process, proactive notification process. It’s encumbent upon, I think, us. We’re clearly not denying responsibility for missing deadlines. However, I do believe there’s not a victim, other than us, in the whole program.

Maybe multiple notifications via e-mail, some -- you know, our e-mail addresses haven’t changed but some of the people who are on the notification changed.

Maybe there’s a different process we can go about for notification that we’re closing in on a standard.

MR. GIBSON: And I would just echo Steve’s point that for some of the smaller entities that may not have the resources to follow the Guidebook, and all the revisions, and come to these meetings, they may be unaware of some of these 90-day windows requiring that a new application be submitted. And upon learning of that, you know, it may be too late, they may lose months of eligibility which could cost hundreds of thousands of dollars.

MR. HARMAN: And I might add that especially facilities that were formerly utility certified, they may not have been dealing with the Energy Commission in the past until this deadline arrived. And so there’s, you know, some form of notification could certainly help smooth things along.

MR. KOOTSTRA: And if I could just ask real quick, before we move on, if you could turn your notecards so it’s -- or your nameplate so it’s easier for the court reporter to see that would make things a little simpler. Nope, never mind, he’s okay.

Yeah, so we’ll continue on, sorry. SCE?

MR. LANGER: Yeah, I’m Matt Langer from Southern California Edison.

So, looking at the suggestions I think that were a few slides back on slide -- I think it’s slide 20, unless it changed. Yeah, I think, you know, we -- but anyway, the concept of extending the deadlines, potentially, or allowing some sort of waiver process for reasonable cause, Southern California Edison’s supportive of that.

You know, in light of some of the challenges that we’ve had with generators getting online for certification on time, I think a longer deadline would definitely be helpful.

And there are definitely cases, the case of previously utility-certified facilities that didn’t even know they were certified, let alone having the CEC have contact information to be able to reach out to them, I think it’s a big challenge for everybody involved in the process in those cases.

So, I think that would be an example of a great case for cause for a waiver if someone didn’t know they were certified, no one had the contact information to reach to them and they somehow lost their certification.

But I think in general we’re supportive of that flexibility.

And I will say that one of the lessons learned for Southern California Edison in this process is, you know, we do have the resources to monitor the Guidebook fairly closely so we’ve been much more proactive, having learned from some of these challenges we’ve encountered, in reaching out to our counterparties and encouraging them to meet the deadlines.

But again, it’s still a challenge. We have several hundred generators that are RPS eligible that need to remain certified. So, trying to make sure that nothing falls through the cracks ever is a real big challenge for us.

So, working together, between the Commission, and the industry, and the utilities, and whoever are the other off-takers I think is a good direction.

And then one other item, slightly shifting but within the same topic, that I think we’ve seen a big challenge in is the requirement for a hardcopy submission on top of the e-mail submission of the certification document. We've seen this on a number of occasions where maybe a week ahead someone went ahead and got the e-mail copy in, so they thought they were pretty much done, but there's the requirement that by the deadline that the hardcopy also be received.

And we've run into all sorts of challenges with, what was it, the postmark date, was it received, was it in this building somewhere bouncing around and didn't get stamped on time?

You know, it seems like -- and I just filed my taxes and I was able to -- you know, for whatever small amount of money it was that I make, but I was able to submit that with an electronic signature and it was perfectly acceptable to the Federal government.

So, I'm not sure if that's just a dated requirement or if there's something we could look at for that because it seems like surprisingly often that ends up being one of the hurdles that generators are facing. It seems, sometimes, these are really simple things, but everyone does a lot of stuff by e-mail these days. So, just another thing to consider.

But like I said, our position generally is trying to be proactive and supportive to make sure that whatever the rules are that folks are abiding by them, and that we don’t have any of these unfortunate situations.

MR. KOOTSTRA: Yeah, I just want to point out, so there’s clarity on the receive date, it is when we receive the hardcopy application and it’s in our hands. Generally, when that comes to there being a deadline, we’re -- we try and be as gracious as we can if there’s reason to believe that we received it the day before in house, but it didn’t make it to us until the next day. We do our best to confirm that and then we generally try to allow it.

But that is something we can look at, receiving electronic application. Our legal counsel can speak more to that, if he’d like.

But we’re -- a step at a time for us at this point.

MR. LANGER: I mean, frankly, I know it’s an additional burden on the CEC staff. You’re already tracking, I’m sure, an enormous volume of precertifications and certifications that are being received by e-mail, and to add to that a hardcopy requirement and I’m sure you’ve got someone date-stamping stuff as it comes in. I can imagine, we’re tracking those exact same dates and I can only imagine the orders of magnitude more it is for the CEC staff.

MS. FELLMAN: May I? We were going this way. I'm Diane Fellman from NRG Solar.

And I don't want to repeat what's already been said, we support that. We have a slightly different twist on this.

We understand that the Commission is attempting to balance the interest of knowing when projects come online and also allowing the project to go forward. Whether or not there's certification, the kilowatt hours generated, especially if a facility is -- especially if a facility is precertified there's acknowledgement that the output is going to be eligible.

But even if it isn't, a kilowatt hour generated by a photovoltaic system, solar system, or a CSP project -- well, let's put CSP on the side because Ivanpah's a special case.

But the PV projects are always -- each kilowatt hour is going to be deemed eligible. And so the stamp of certification, when that comes or how it comes is really key for meeting our obligations under our PPAs. However, it doesn't change the nature of that kilowatt hour.

So, we would suggest -- may I have the questions up again, please, and I'll give you some -- our answers.

Thank you, Mark.

Number one, we think it is a reasonable requirement to have some timeframe. However, what we would suggest, rather than going through a waiver, or a good cause, attaching a reasonable financial penalty to that where if you miss the deadline there's something at stake, and there's some -- there's a financial obligation at stake.

Because, you know, we heard from you, I don't know how large your facility is. Can you tell me how large your facility is?

MR. KIRCHER: It's six megawatts in Palm Springs.

MS. FELLMAN: Okay, six megawatts, over half -- $700,000 that's --

MR. KIRCHER: Unfortunately, our certification date was in the prime generating -- that we missed was in the prime generating hours. So, you're looking at May, June and July where we weren't certified and so that cost us, obviously, more in terms of dollars for not getting paid.

MS. FELLMAN: Well, and we would like to put on that would say -- that would be something having -- I don't know how -- I'd like to hear from the other generators how they would feel, but $10,000 to $25,000 is certainly different than $700,000 at stake.

And with PPA, provisions for financing could affect your lenders because failure to be eligible, it's not only a consequence of the PPA payment, but also a consequence of our financing and could be considered a default under out loan agreements.

So, when you start going down that path, something that is -- where the Commission has a public interest in knowing when the facility comes online, the unintended consequences of that could be quite severe, including all the -- if someone wanted to be very rigorous about it, as a lender, to default.

So, that's our answer to number two.

And then number three we would say, yes, and that's the completion of my remarks.

COMMISSIONER HOCHSCHILD: Before we leave this topic, just so I understand, you're basically, Diane, arguing against doing waivers but having a penalty instead.

But if, just Steve, with your suggestion of having a waiver process, I mean we're trying to obviously balance the principles of being fair and reasonable, and having a real coherence to the rules.

Under what circumstances, precisely, would you suggest the Energy Commission, if we were to have a waiver process that you're suggestion would be reasonable? I mean, what's the threshold that would have to be met to grant a waiver if we were to have this process?

MR. KELLY: You know, if the -- again, if there was a pre- -- in our case we filed the precertification and the two individuals who were in our company left that were involved in our regulatory compliance.

I don't have all the right answers. I try and think about the right answers because I always put myself, say, in the shoes of everyone else and go, you know, guys, that's a shame but, you know, tough break.

And yet, at the same time that's not the right answer. So, how do we come up with a fair way to figure out deadline certifications that could be -- I think notification is prime.

I appreciate Matt's comments. You know, they have the resources, the utilities have the resources to maybe help and be proactive to the generators, if they're signing the PPAs, and say, guys, here's your deadline date, you're missing the deadline. That would be helpful.

You know, you can only, as you're trying to grow a business you can only hire so many people, have so much fixed expense because this is still a development industry.

And these projects, as we've all found out and you see on your chart, they take much longer to finish, to develop and there's no certainty that they ever will get built or developed.

And, you know, the groups that pay those prices that continue to develop them are sitting here at the table. And it's just -- it just gets, sometimes, overburdening and onerous for small businesses to even be able to participate.

COMMISSIONER HOCHSCHILD: All right, and then, Diane, for your suggestion was there a specific amount of money, I may have missed it, that you were proposing as a penalty for being late or --

MS. FELLMAN: Again, I mentioned something in the range of $10,000 to $25,000.

COMMISSIONER HOCHSCHILD: $10,000 to $25,000, yeah.

MR. KIRCHER: Which is enough to make somebody stand up and pay attention. It would be -- if I could pay $10,000 and have this go away, I'd do it tomorrow.

I wouldn't even know, though. It still doesn't solve the problem because we didn't know until after, you know, 90 days after the final certification date that we were in violation of not filing the certification.

MR. HERRERA: Steve, this is Gabe Herrera. Isn’t the, you know, consequence of not being certified potentially being in default in your PPA? Isn’t that a financial incentive enough to encourage the applicants to kind of keep track of deadlines and whatnot?

MR. KIRCHER: You know, again, you know, PPAs are written by lawyers for lawyers, and I’m not a lawyer. I believe that the PPA just says we have to be compliant with all regulatory agencies.

There’s a myriad of regulatory agencies out there that we need to be compliant with. So, if we miss one, forget one, one falls through the chute, you know, and subsequently the cracks that’s an unintended consequence of this.

MR. HERRERA: And just one more comment, just with respect to Diane’s comments about a potential penalty. I mean, we haven’t look at a penalty but I do know that there’s no expressed authority in our statute for the Energy Commission to charge an application fee for certifying facilities, let alone the ability to assess a penalty.

I mean, that’s something we could explore but there’s nothing in the statute that contemplates that right now, just throwing that out there.

MR. KELLY: Yeah, this is Steven Kelly with IEP and I'm not going to pretend I know all the details of individual certification processes, but I -- it's not clear to me that a penalty is necessary because I think that there are processes not only in the PPAs and the ISO interconnection queue that drives development as fast as it can possibly come.

The reality is in today there are a lot of things that arise, that were not contemplated, that cause delays, and I don't think we'll ever be able to specify on a list what those all are.

I'd like to step back a sec and talk about a couple principles and remember why we actually had precertification to start with. I happened to have been around during those years.

First, a couple principles that I think I'm going to articulate during the course of the day is one, you know, really, on this issue, you know, no harm/no foul. I think that's important.

The goal in California is to get RPS-eligible energy delivered to the grid. And there's a lot of reasons why that may be delayed, you know, or plans get upset. But if there's no harm, I think we ought to kind of think of this as no foul.

The second is that the commercial world that is the catalyst to developing all these resources is highly dependent on regulatory certainty. And that if that regulatory certainty gets undermined, then the commercial world becomes a little bit less stable, and the costs go up, and the complexity of building these projects goes up concomitantly. And I think that's something that we probably don't want to do.

Now, let's think back about why we started this. Precertification, among other reasons, one of the core reasons for doing it was to facilitate the procurement process. Projects could get precertified and that aided them in the procurement process that the utilities conducted, or bilateral negotiations, because people had an expectation that this project they were talking to was highly likely to be certified as eligible when it came online.

That was why we were kind of doing it, it was sending those advanced market signals.

The reality of today is that delays in project development are highly probable and the causes are unknown today. You know, you'll never be able to predict what they are, but they are going to arise.

From a counting perspective, in terms of the RPS compliance obligation for the utilities or the ESPs, they're still reliant on WREGIS certificates which are third-party verified. So, you have a mechanism to prevent ineligible projects from actually being counted in terms of the RPS compliance, which I think is an added benefit for the program as a whole.

The precertification should be a relatively simple process. I think, actually, I'm not necessarily convinced that fines are necessary for this mechanism to work. I think you can actually have a mechanism that allows people to move through the process.

I understand that companies are very busy today. But a statement of reasonable cause why you missed a deadline, in my mind should be suitable for the Commission to work out the status of the project vis-à-vis the program in terms of final certification.

It baffles me why that process wouldn't work because it would be flexible enough to account for all the things we don't know.

And it is encumbent on the generators to come to you with a statement of reasonable cause if there was a missed deadline, I think.

But I deal with a lot of companies and it amazes me how often they fail to respond to my e-mails about something that I think is critically important to their business and usually the answer comes, we're swamped. We've got too many people in the companies to do everything. We get a bazillion e-mails all the time so things get lost through the hoop.

And it’s not because of malfeasance or anything else, it’s just the complexities of the world, and developers actually out in the field trying to develop projects.

So, I think we ought to recognize that reality and try to develop something to provide you the information you need in a timely manner, but provides enough flexibilities for these projects to come to fruition also in a timely manner, without additional costs.

MR. HERRERA: So, a quick question for you, Steve. Do you know if in utility agreements, typical PPAs, if there’s a requirement on the generator to provide proof that they’ve been certified by the Energy Commission, or do they typically rely on the precertification that they may have applied for?

Which, by the way, I don’t necessarily agree with your statements regarding precertification, but that’s a topic we’ll discuss later on.

But I’m just saying, if there was something the utility imposed on the generator to make sure that they were double checking that they had in fact sought certification, rather than just rely on a precert that they may have obtained.

MR. KELLY: I don’t know. So, in the PPAs, I don’t see a lot of the details of the PPAs. But my understanding is that most of them have a clause that basically says, you know, you are going to be an eligible, certified eligible resource in order to facilitate the payment that we’ve agreed to in this contract, basically.

MR. HERRERA: Right.

MR. KELLY: So you’ve got to be, at the end of the day, an eligible renewable resource.

There is a change in law provision I think in some of the contracts. Most of them I suspect have that.

But it’s still -- that creates a problem, too, because that’s -- my goal is to try to eliminate risks of change in law as opposed to relying on a contract term that is relatively vaguely stated on that regard.

MR. HERRERA: Good.

MR. KELLY: But I think there are provisions in the contracts that give the utilities some certainty about the online date, what happens if it doesn’t occur, and that you’re going to be eligible to get an RPS payment that was negotiated for an RPS-eligible resource.

MR. HERRERA: And my other point regarding precertification, which I think we'll get into later when we discuss that topic, is that, you know, an applicant can apply for precertification before they even have all the information or documentation to support, you know, a claim.

So, really, precert is just a snapshot at the time based on the information we have. It doesn't provide any assurances that the generator will later become certified.

And I think that's something we need to discuss in the precert section of this workshop.

MR. KIRCHER: We actually didn't find out about our failure to file the final certification for probably 90 days after that failure. And we didn't find out from the California Energy Commission. We found out because Southern California Edison called and said, hey, guys, you know, we just found this out and didn't know, and we want to advise you of that, and it's a problem.

And that's what kind of jumped, you know, and got us running through hoops to quickly get it certified.

But unfortunately, you know, it was poor timing.

MR. KOOTSTRA: I want to address that and one other point real quick before we move on, this is Mark

Kootstra.

I want to thank SCE, and PG&E, and the other utilities for stepping up on that side of things. You guys have been very helpful with that and helping to coordinate with the small developers.

In terms of notification, I know your situation's special where there's a lot of movement and change in people turnover.

We did our best to notify, I believe that there were at least two to three notifications sent out via the renewables list server, which notifies of Guidebook changes, and adoptions of Guidebooks, and letters.

So, I agree that your situation is slightly different.

We are trying, if you have suggestions for ways that we can better notify folks in your situation, that's great. We have a limited resource and the capacity to contact. If we don't have your information, we can't contact you.

MR. KIRCHER: I totally understand that. I'm not here placing blame anybody, I just --

MR. KOOTSTRA: Exactly. I'm not assuming you are, I just want to be sure nobody thinks that this was fully out of the blue. For you, it absolutely was.

MR. KIRCHER: Yeah.

MR. KOOTSTRA: But in general.

The other point, to Steven Kelly, your -- and it’s been talked around, no harm/no foul. I agree that there’s probably little harm in allowing people to come in.

But I think SCE, and I’m not sure if either of you have worked through this process, and possibly PG&E, have had delays in their verification report because facilities have not applied for certification.

We’ve had facilities in the past that have waited two years. All of the sudden we find out the facility’s online because we get a verification claim and that pushes back the verification process.

That may not be a big issue for most people, but we have to ask ourselves is a two-month delay because certifications aren’t getting done okay in the verification process, or do we need to have total compliance data done sooner because we -- and so we need to get those certifications in sooner.

So, I’m not saying that’s a big harm. All I’m saying is it’s a question we need to ask ourselves. It’s a balancing act. Is it worth allowing delays in knowing what verified numbers are in order to get some of these guys in that weren’t in before, or do we need to just draw a hard line and have that certainty, even if it's not positive certainty.

So, not something I need you to respond yourself, just consider it.

MR. KELLY: I can't help myself. Let me ask this question, so let me flip the logic there. I mean, how many precertified projects come online and are counted for RPS that it turns out were not RPS eligible, or CERT?

MR. KOOTSTRA: I only know of a handful of facilities that have applied and have not been eligible in some way, shape or form. So, there's not a lot. There's a difference between eligibility and certification. There's only a handful that I know of that have been certification that should not have been certified.

And I believe that once that information came out there were no problems in moving that. It was an unknown.

Very valid point, it's just it's all a tradeoff of timing. Is it worth delaying two months for one person or one company, but everybody sees the delay? So, it's just a tradeoff we have to consider.

MS. FELLMAN: One suggestion on notification is a lot of the projects, you know, there is a development business in the solar industry and there's an acquisition business in the solar industry.

NRG Solar has been primarily an acquisition business, where we take the projects from the developers and then invest the capital to bring them online.

With the precertification we could create a project e-mail box that could be put into a list serve where there's -- as long as you're precertified, there could even be like an automatic monthly e-mail, you're precertified, remember to certify, kind of just simple.

And then it would be our obligation, when someone has responsibility for the project, to make sure that the asset manager, or whoever is designated in a company, reads that e-mail.

And I think that could be, you know, automatic until it's finally -- you know, has its final certification.

MR. TUTT: This is Tim Tutt from SMUD, and I wanted to go back to Steve's bringing us back to the bottom line here that the intent of this program is to get additional eligible renewable energy online and generating in California, and contributing to the RPS.

And it's, I think, reasonable to have an administrative tracking system. We've set up WREGIS and other systems to try to make sure that that eligible renewable energy is only counted once, not counted twice.

I think it's almost equally important to try to set up the system so that eligible renewable energy is counted at the first time. And so that you should try to minimize any administrative opportunities or structures where that energy is deemed to be not counted, even though it's generated and it is eligible.

So, for this particular case, it's reasonable to have a 90-day requirement, but the consequence of missing that requirement is much too dire, not just for the companies, but for the RPS Program overall. You're losing the energy.

So, you need to have a different consequence. And I don't know whether it's a penalty or something of the sort.

I think what I would recommend is something a lot more similar to what you guys have been doing with certifications where if am application is incomplete, or an application doesn't have all the information, or has some other issue the facility goes on suspension, and there's contact and communication between the parties to try to get that information complete so that you have that accurate information you need.

But as that's going there's no change in eligibility date. There's no change in the eligibility of the generation. It comes into the picture once everything is completed and to your satisfaction.

Something like that seems like it makes sense to me because what you're really doing, it seems with these changing of eligibility date, is causing significant economic harm to small companies and reducing the amount of renewable generation that you should be counting for the RPS.

And I don't see why you'd want to do that without a really good reason.

With respect to communication, I mean companies like PG&E, and Edison, and perhaps even SMUD can help these smaller companies, these generators comply, potentially.

But as many have said, there's a lot of information out there. The Guidebook is pretty complicated. The main purpose of these businesses is not necessarily to deal with the Energy Commission's Guidebook and so these things can fall through the cracks.

I don't know about a good cause kind of structure because, to me, if somebody says, well, I just messed up, I forgot about it, or somebody left my company, I don't know what's a good cause.

I would say that any time you have an eligible generation structure you should be trying to get it counted, not trying to not count it by an administrative point of view.

And I would say a lot of these -- I mean you know have, as you mentioned, Mark, the POUs involved. and some of these POUs do not have the resources that Edison, PG&E and SMUD might have to help their counterparties understand what to do to comply with the RPS. They're very small.

With respect to notification, if you know there's a counterparty to a deal, if that's done, then notify the counterparty as well.

Maybe if Edison had found out, you know, at the very time when the facility came online that you had -- you know, 30 days before the 90-day requirement was up that the facility hadn't met that obligation, they could have notified the facility then, rather than three months later. I don't know if you have that opportunity. But you need a lot more notification.

MR. KOOTSTRA: Yeah, just so you know, we generally do not have information on who or which utility a facility is selling to. Oftentimes it can be multiples but we just -- we don't collect that information for certification purposes.

MR. HARRIS: If I could join in, Jeff Harris. I want to echo a couple of things that have already been said. I think it's important, the no harm/no foul to me really relates to whether the renewable power was generated and delivered to the grid. And if that happened, in my opinion, there's no harm/no foul.

This is obviously a problem right now. I've heard some very good suggestions about how to deal with it in future Guidebooks, but I want to suggest to you a couple things.

And one of those is that I don't think you need to wait. I think you ought to do two things. The Executive Director of this Commission already has the authority to extend the deadlines.

And I've very carefully picked the word "extend" as opposed to "waive". I think that's an important distinction. But it's very clear to me that the Executive Director today, without any changes to the Guidebook, has the authority to extend the 90 days to 180 days, or some other date.

The reason I know that's clear is that the Executive Director currently has the ability to waive regulations.

So, as one specific example, the bid adequacy regulations, you're supposed to get your full Commission bid adequacy determination within 45 days.

Applicants regularly agree to waive that Title 20 requirement that the 45-day hearing be held and push it to the next business meeting.

So, if the Executive Director has the ability to extend a deadline on the data adequacy regulation, he certainly has the discretion to extend a deadline in the Guidebook.

It may not say that clearly in the Guidebook and I think maybe one of the things we need to fix in the next iteration of the Guidebook is to clarify that scope of discretion.

But he clearly does have, and I'm saying "he" because I know it's Rob. He or she clearly has the authority to extent those deadlines today.

So, Commissioner, back to your princess, I don't see any ruby slippers, but you already have the power in your existing regulations to make these changes today.

And so I think it would be useful to make these changes in the next Guidebook, but you're hearing from a lot of small utilities and small businesses that are -- hearing a potential for severe financial, you know, penalties, with no benefit to the environment whatsoever. The power was generated, it's clearly qualifying, and it was delivered.

And I think the utilities have been remarkably cooperative and restrained here. And that's me saying that, so that, hopefully, that says something.

You may have a contract provision but you don't have to enforce it. You might give someone the opportunity to cure something down the road and I think you're seeing a lot of cooperation among folks in that regard.

So, I guess I'd recommend two steps, and the first step would be, you know, now. Either the Lead Commissioner or the Executive Director go on the record and say there is discretion to extend these deadlines for good cause. We don't have to wait for the next iteration of the rulebook. People like Steve don't have to wait for that, you know, six-, eight-month period to know that they're going to have some certainty that their RPS-eligible renewables are going to count.

And then the second step is to formalize those in the next step of the Guidebook.

So, you know, good cause, penalties. I don't think penalties are required. Good cause ought to be that the power was generated, that the utilities will be able to count it towards their RPS, and the only result would be a financial penalty with no environmental benefits.

And I can -- I'll write down those three for you and send them to you, if you'd like. But some kind of good cause standard like that, that basically says, you know, it was power, it was generated, it was eligible, it's going to be counted and that the only result would be a financial penalty.

So, those are my thoughts and suggestions.

MR. HERRERA: Jeff, this is Gabe Herrera. So, I'm looking forward to receiving your written comments on that point.

I'm not aware of the provisions in the siting regulations that you reference, but perhaps there is something explicit in those.

But in these guidebooks, the RPS Eligibility Guidebook, there's nothing that gives the Executive Director that discretion, or one of the Commissioners independently, when the Commission as a full body --

MR. HARRIS: And nothing that deprives them of that discretion, either.

MR. HERRERA: Well, proving the negative here --

MR. HARRIS: That's the issue.

MR. HERRERA: I look forward to receiving your comments on this one, specifically. I mean, it seems like one of the quick fixes, potentially quick fixes for this that would address this issue across the board would be to make some Guidebook revisions that specifically allowed that and under what conditions. And I think your input on this would be extremely valuable.

MR. HARRIS: Okay, well, that was clearly my second step of my two proposed steps. I do think you have an interim problem that’s real, and immediate, and serious for a whole lot of small utilities and for small business that we can, you know, quickly clear up.

You know, one of the things we want to avoid is if you get a negative determination do you have to ask for reconsideration, and then you ask for reconsideration and that’s appealed to the full Commission and then that, potentially, is appealed in a court of law.

We can completely eliminate that type of a process. It’s wasteful and nobody wants to go through that. It’s going to waste resources for people who are already resource constrained. It’s going to waste staff time. Frankly, it’s going to make you mad. You like me well enough now, but you wouldn’t like me then, and it’s important that you like me, Gabe, so --

MR. HERRERA: Thanks, Jeff.

MR. HARRIS: Anyway, I think there is an opportunity to solve these problems now and in the future.

MR. HERRERA: Yeah, I think just a quick point on that, you know, if the Commission does revise the Guidebook to allow for this then what’s going to happen is, you know, a Steve situation is going to be addressed because then it will allow the Commission to go back and retroactively, you know, modify the certificate of eligibility for your facility, and the same with other facilities that have fallen in the same situation. So, that’s certainly one way to move forward.

MS. FELLMAN: Just to follow up from a company point of view, the process -- I want to support what Jeff is saying about the timing on that, Gabe, because certainly the Commission in the past, and I have no doubt in the future, has had a commitment to be rational, and be very open to these suggestions in problem solving.

However, the gap in timing, again I go back to my point about the consequences on the PPA. We would need to work with the utilities on patience during that. And, you know, they’ve been very accommodating in terms of treating the PPA, but the provisions in the PPA are -- there’s discretion, but they are there.

And I’d like to hear -- I’d like to invite, you know, the -- I think John was going to say something about the PPA earlier. I’d like to hear their view on how to approach this and what -- how they would look at this timing issue.

MR. PAPPAS: Well, as far as the PPA, there are -- there is a requirement to have both precertification and final certification, so that was in response to Gabe’s question.

But, you know, in terms of this overall topic, you know, PG&E would support flexibility. You know, similar to Edison, we have a very proactive program to try to monitor the certification and to follow up with counterparties. But it’s still -- you know, things still fall through the crack. We’ve seen it a lot less than there used to be, but it still occurs.

You know, one thing to keep in mind -- what we’re actually observing is that most of the larger players don’t seem to -- and more experienced parties don’t seem to have a problem meeting the deadline, whatever it is. But, you know, it’s usually the smaller outfits that maybe this is their first project, you know, they just don’t have the staffing and so on.

And there’s a lot of things, keep in mind that are occurring during the first 90 days of a project. I mean, you’re trying to get the thing online, you’ve got metering, you know, maybe resolving final interconnection things, start-up testing, you know, all kinds of stuff, getting the new staff on board.

That, you know, maybe the certification is not exactly in the forefront. Probably the forefront is just trying to get electricity generated. So, we have to keep all that in mind.

So, we would support some kind of -- you know, there's been various ideas here in terms of waiver, or some way to address the situation so you don't actually, you know, lose these valuable RECs, if you will.

And just sort of stepping back in terms of, you know, what is the objective here? I mean, I think there's a big focus, there seems to be this sort of emphasis on not double counting. You know, there's a lot of that, you hear that all the time.

I know from my own personal experience in WREGIS it's a big focus there.

But, you know, really I think under-counting is, I think, just as serious a problem as over-counting, and I think we need to really focus on just getting the number right.

You know, and I think the State really deserves it. I mean, you know, we're trying to show what our progress is in terms of renewables and, you know, who's going to want to say that we're at 33 percent, when we're actually at 34, or we're at 25 when we're actually at 26, that kind of thing.

So, we should really try to figure out solutions to this that allow us to really get the right number out there.

MR. WEINSTEIN: So, this is Jeremy Weinstein with PacifiCorp. And I'd actually suggest an approach that's quite different than what's been floated so far.

First of all, I don't think fines are remotely appropriate and I don't think adding another bureaucratic process is remotely appropriate, either.

I think staff has -- there's three prongs that I think need to be discussed. I think staff has put one of them in this workshop that we'll be discussing, which is the dividing line between certification and precertification for your application.

I think this is part of that discussion, you know, gee, when do you apply, what is the part of it?

I think rather than focusing on putting together an appeals process, or giving discretion to a Commissioner, or saying that deadlines can be extended, I think people should be held responsible for the deadlines that are in the regulations, but I also think that there needs to be a better communication process between the Commission staff and the applicant when an application is pending.

And I’ve certainly seen some horror stories in that regard and staff has come through. In my experience, they’ve all worked themselves out.

But certainly in terms of, you know, what I’ve seen and where those could have gone were they not handled the way they ended up getting handled, you could have, gee, the fine gets incurred because you missed the deadline. And, well, wait a minute I didn’t miss the deadline, I sent the application. Well, you know, the e-mail address was wrong so, you know, you didn’t actually submit the application.

And, okay, I just don’t think that there should be a heightened bureaucratization.

I think what should happen is there should be some sort of communication process and staff has got to weigh, you know, how it can handle its scarce resources. But I don’t think that the staff resources should be spent dealing with people who aren’t following the written rules.

I think if you’re following the written rules, the staff resources should be allocated. If you’re going to allocate, then you allocate towards favorable communication towards the people who are following the rules.

The sitting back and when you allocate, looking at communication, when you're looking at certification versus precertification, when you're looking at this rule of filing when you reach COD, I think it's very important to be thinking about the reality of project development and what is actually being developed, and when is it actual commercial, and when is it online.

And, you know, in kind of my practice and, again, I don't know whether it actually follows the rules and maybe I'm missing something, confessing to something, but my practice would be, hey, when you've got test energy coming from the facility it's okay to send in the certification, even if you don't have like the final COD because there's a risk of, okay, what if there is something else that's wrong? What if there's something else that's missing. You want the information from the Commission as soon as possible. You want that feedback. You want to know if you're complying.

Compliance is extremely important to almost everybody in this room, so you want to be sure that you're in compliance.

And as has been pointed out, it's in the PPAs.

So, you know, we kind of have commercial operation, which is like it's operating but, you know, does that mean that you've actually met everything that's in the COD? Does that mean that you're commercially operating under your connection agreement? There’s not really -- these are just factors to be thinking about when you’re setting the certification versus precertification. I’m sure I’ll repeat myself when we get to that part of the program.

But, you know, the -- I really do reiterate, echo and really appreciate the comments that were made here that, you know, the goal is to maximize the renewable energy that’s available to California purchasers.

MR. HERRERA: Cool. Oscar Herrera with LADWP. I’m hoping I’m not jumping on a tangent here, but I think it’s a related issue.

Now, let’s suppose the utility actually submitted the certification application, the precertification application, actually, was diligent in following the process. For DWP, we followed the process, we submitted the certification applications October of 2012.

We followed up with additional certification applications for AB 2196.

Now, the holdup is not the 90-day requirement to submit a certification application. Now, the holdup for DWP is receiving the certification and we’ve submitted these applications a long, long, long time ago and we still haven't seen anything just yet.

Now, what I would like to see moving forward is also a requirement for the CEC to submit a certification application -- a determination on a certification application within a specific timeframe.

Because I think it's -- I mean, I think it's reasonable to have us, the POUs, IOUs, et cetera, submit a certification application and submit it on time to not further delay the process, but another thing that also delays the process is when you actually receive the certification application.

COMMISSIONER HOCHSCHILD: Actually, let me just comment on that for a moment. I share that concern. Actually, this is one of the first issues we dealt with.

One of the challenges is that because there's so many precertifications that, actually, that takes a lot of staff time and it delays certification. There's a limited amount of staff available.

But we've actually made quite a lot of headway on the certification processing time.

Mark, maybe you could share a little bit?

MR. KOOTSTRA: Yeah, we've -- and this isn't covering from when we receive it, necessarily, but the vast majority of applications over the past six months that we've received, once we've been able to deem them complete it’s been taking less than 10 days for most solar and wind, approximately 30 days for others.

You’re alluding to, I believe, the biomethane applications --

MR. HERRERA: And small hydro.

MR. KOOTSTRA: -- and small hydro. Some of those have some significant other issues that are not necessarily due to your application.

I believe in LADWP’s case, for the biomethane, most all of those went back and then we received additional applications. And I think the additional applications are what’s still under question. And we can talk more about that offline.

But I agree, that’s what we want as well. Sometimes there are just circumstances outside of what staff can do. Not necessarily staff resources, but other questions that need to be answered which is delaying some of this stuff.

I agree and I’d be happy to talk with you more. But you’re right, it’s a little bit of a tangent for this particular topic.

MR. WEINSTEIN: So, do my applications got a special pile because I’ve never really experienced --

MR. KOOTSTRA: Yes, they do.

(Laughter)

MR. KOOTSTRA: Oh, that’s been for more recent stuff submitted around July. Commissioner Hochschild directed us to change some priorities around those and so we were able to move them a lot faster.

To be honest, I haven’t seen a lot of applications from you, outside of the ones that need additional review in the recent few months. So, maybe that’s just I’m not seeing your name, but we are making headway.

MR. WEINSTEIN: Because everybody knows it takes forever to --

COMMISSIONER HOCHSCHILD: Speaking of moving things along, it’s 11:00 and we’re still on item two out of seven.

Is there anything else, anyone who hasn’t spoken on this question?

If not, let me just thank everyone. These are great comments. I will definitely address this. And I just want to stress to everybody we are going to do everything we can to be a reasonable agency and to be fair, and to make these decisions as quickly as we can. This is great input so thanks, everyone.

MR. KOOTSTRA: Before we move on I’m going to open it up for the WebEx. Is there anyone on WebEx that’s hoping to make comments? Please keep in mind that we are trying to move things along, so if it's been said before, please just iterate your comments written.

And we're going to open up the phones in just a minute. So, if you're on the line please mute your phone unless you have something to say. Thank you.

If anyone's on the line, the phones are unmuted, so please begin.

We're going to close the line, there's some major feedback. We welcome written comments, but the feedback's been continual. If everyone on the line could take a look at that and try and solve any problems they might have, but we're -- unless there's anybody on WebEx?

MS. FELLMAN: Mark, I just wanted to comment that that was a statement from Solarin, the space solar project that is the contractor with PG&E.

(Laughter)

MS. FELLMAN: They're saying they support everything the generators are saying.

MR. KOOTSTRA: Right. We're going to move on to the next topic, biomethane, the definition of a dedicated pipeline.

And anybody who has an interest in that, please come forward. And if you have made a nametag and you're planning to speak again, please grab that just in case you don’t get the same location as before.

But if there’s nobody else, I’m going to get started with the presentation to talk about this one.

So, as we all know, Assembly Bill 2196 was passed at the end of 2012 and the 7th Edition Guidebook incorporated those changes in late April of this year.

There are three classifications for biomethane facilities under the law.

Biomethane produced on the generation site and these are traditional digester gas facilities and landfill gas facilities.

Biomethane transported via dedicated pipeline. These are very similar to the on-site, except there’s a pipeline running from the production of that biomethane to the end users.

And biomethane transported via common carrier pipeline. This is a gas that’s generally mixed with natural gas in the pipeline system and delivered through the pipeline system contractually.

Currently, the definition of dedicated pipeline in the RPS Guidebook is for purposes of RPS eligibility of biomethane and refers to a gas conveyance pipeline that is not part of a common carrier pipeline system that conveys biomethane from a specific biomethane producer to a specific electrical generation facility and to no other end users.

The intent of this definition is to ensure that if biomethane is delivered via dedicated pipeline that it is consumed at the designated facility and there's no even potential possibility for it to be burned somewhere else.

As you can see -- so, the questions are does our definition meet up to that requirement or to that objective?  And if not, please let us know where that's lacking.

And also, is the definition too narrow?  Are we missing the point of the law?  And if so, how could it be expanded while still achieving the objective in ensuring gas is burned at the proper location?

Go Tim.

MR. TUTT:  This is Tim Tutt from SMUD.  And we do understand the differences between the different types of pipelines that are in the law.

We've gone back and forth with the CEC on definitions, so I think we've provided alternative definitions.

I'll just sort of explain the situation from our perspective.  I mean, we have a pipeline that serves only our power plants.  It serves no other end users. And we think of that as a dedicated pipeline.

It may not meet the specific definitions that you’ve adopted, but we don’t think that those definitions are necessarily required by the law.

Our pipeline is certainly not a common carrier pipeline in the common sense of the term.  If you look at definitions in legal structures, in Wikipedia, in a variety of places, we don’t have a common carrier pipeline where we are required to accept gas for transport to other users.  We’re not required to do that and we don’t do that.  That’s what a common carrier usually is and does.

We’re so close to a dedicated pipeline in your own definition that we’ve told you that the only place that this biogas that we’re injecting into the pipeline can be burned is the power plant where we’ve designated that it will be burned.

And yet, there’s some chance because it’s moved -- it’s not a pipeline that goes only to one user, in your minds there’s some theoretical chance that it might be used somewhere else.

I guess our request is and remains that because we’re that close to your purest definition of a dedicated pipeline that you should expand it a little bit to cover our situation.

And, certainly, that will remove several issues of -- or problems in the future for us. If our pipeline continues to be considered a common carrier pipeline, it raises a variety of reporting and compliance obligations, and transactional possibilities in the future that, really, we don't believe are at all intended by the law.

I don't know that in this public setting we need to go into a lot of detail. I mean we've worked on this offline. We just want to encourage you to broaden the definition of the pipeline or add some other definitions which we feel like you have the authority to do.

I mean, we effectively have a private carrier pipeline. There's not part of AB 2196 that defines a private carrier pipeline. But you could, under your authority, define that term and indicate that you are going to be treating that as if it was or like a dedicated pipeline situation.

There's other solutions we've proposed. We just want you to listen and work on taking care of this situation with us. Thank you.

MS. PUFFER: Valerie Puffer from the City of Glendale Water and Power. And I support Tim.

We want to make sure that -- okay, Glendale has a landfill that goes -- it has a dedicated low-pressure pipeline that goes inside the city, directly to our power plant, and it is considered a dedicated pipeline.

But we want to make sure that you don't put the regulations in that -- that it doesn't get in the way of the benefits of using landfill gas, using biogas, and making sure that it's -- everything's so onerous that it doesn't meet the guidelines for the RPS eligibility. Thank you.

MR. KOOTSTRA: Thank you.

Does anyone else in the room have comments or, Tim, did you have something additional to add?

Commissioner Hochschild, did you have any questions?

Is there anyone on the WebEx who's raised a hand or has indicated?

We're going to try the phone one more time. If we have the feedback, we'll probably move on from there.

Theresa, could you unmute the phone for me? Thank you.

Okay, I believe we're unmuted. If anyone on the line -- I apologize if you're on the line and you wanted to comment. Please submit written comments.

We're going to -- we'll see if we can fix that during lunch, but we'll have to move on from there.

If you do have access to a computer and you can try and log in via WebEx, that would be great, you can type your questions to the person via WebEx, as well. If you’re just on the phone, I encourage you to try and log into WebEx, if possible.

We’re going to move on to the next topic of energy storage. So, please, if anybody’s interested in this, please come forward and I’ll get the presentation started.

So, currently in the RPS Guidebook energy storage devices that are metered and operated as part of a renewable generator may be included as part of that electrical generation facility and be used as -- be used in that certification.

Those facilities that store electricity, that are not operated as part of an electrical generation facility are not currently eligible for the RPS.

And this includes stand-alone energy devices or facilities that are not electrical generation -- they’re just generally not electrical generation facilities. Sorry, I’m jumbling my words.

Energy storage devices, their purpose is to take in energy from one source and then provide their energy. Most good connected electricity storage devices, such as batteries or pumped hydro stations, that accept electricity in and then put electricity out, they’re not truly generating renewable electricity unless the renewable electricity came in, in the first place.

So, we have a long list of questions for this, but should we be looking at energy storage facilities not directly connected or metered as part of electrical generation facilities that are renewable for California's RPS and for certification?

Given the inherent energy losses in storing electricity, is there a benefit for utilities to procure renewable energy that has been stored in energy storage devices rather than directly procuring it from the renewable generator, and allowing generic grid electricity to be stored? And please explain that?

Do those benefits remain if the energy storage device requires firm transmission or another delivery arrangement similar to electric generation facilities not interconnected with California Balancing Authority to provide portfolio content in one category product?

This is the one place where we're kind of broaching into where the POU regs come into play. We're not necessarily looking for extreme specifics. We're just looking for the general concept is this something we should be considering?

And as well, should energy storage devices be allowed to shift deliveries from one portfolio content category to another? Why or why not?

So, we have a few people at the table here. Please go right ahead, Steve.

MR. KELLY: Steven Kelly with the Independent Energy Producers Association.

And I think you've basically got it right, at least from my perspective. And let me describe why I come to this conclusion.

For many years we've been working in developing an accounting procedure that was transparent, clean, and minimized the likelihood of double counting. So we adopted the WREGIS approach which basically said that we're going to read your meter at the delivery point onto the grid and that's going to be the basis for determining the REC creation and so forth.

And in that light, when I think of storage, I think of storage -- if you've got storage essentially within the fence, behind the meter then you've got a single meter read onto the grid and you've got consistency with the status quo today, and I think that makes sense.

So that's saying, basically, storage that's behind the meter or within the fence is probably a very useful tool in actually moving energy from a renewable generator onto a time-of-use delivery period that has higher value. And that is what we want and that's a good thing to do, but they do it through a single meter read.

On the other hand, storage that’s outside that fence or outside of that meter I think creates tremendous complexities and is not the direction that we can go.

It raises two big problems, not the least -- the first is just the problem of how are you going to count this stuff?

We have a WREGIS structure that is designed to count it at the meter read from the generator and now you’ve got a new entity, outside that environment, that in theory is, as I think you’ve correctly pointed out, is simply moving power from one point to another point, and time of day for delivery. It’s not really creating new energy. So, you have a double counting problem.

And the second thing that concerns me related to including what I’ll call out-of-the-fence storage as a potential renewable resources is it strikes me that kind of sales where a renewable generator is selling energy to a storage facility, for use for pumping, is a retail sale, not a wholesale sale.

And I think that creates a complexity that we haven’t thought through, yet, but is potentially quite important. And if you were to go down that path of counting these resources that are outside the fence as considering for eligibility, we would need to explore that.

I'll be raising it because I do think it sounds like a retail sale.

So, I think you've got this right and I support the direction you're going here. And it creates a mechanism, if you're behind the fence, to use storage, to get higher value products onto the grid through the storage facility, and that's the way it should be.

MS. BERLIN: Thank you, Susie Berlin for the City of Redding.

As a practical matter, I agree with part of what Mr. Kelly has said and that's that we have something in place now that addresses storing electricity that comes from renewable resources, but I think it needs to go a step further.

And I think some of those issues that Steve Kelly has specifically stated should be avoided -- should not be avoided. They should, in fact, be explored further and we should try everything we can to ensure that we're maximizing the benefits of energy storage, including exploring ways in which we can have energy storage count as RPS.

There are a lot of benefits to energy storage, we know about that. But I believe that some of those benefits should fall under the category of RPS. And that's something that Redding would really like to see the Commission look at in more detail.

And I'd like to read a statement. There are individuals from the City of Redding on the line right now and they can answer questions, if there are any further inquiries. But I'm going to read the statement regarding Redding's position.

So, the City of Redding's Electricity Utility; "Of course, we appreciate the Commission's consideration of the role of the energy storage in the context of the State's Renewable Portfolio Standard Program.

The current inquiries that were raised in the workshop notice regarding the use of energy storage are a sound basis to begin this discussion. And Redding urges the Commission to take the broadest possible interpretation to the 'requirements' associated with the use of energy storage for RPS purposes.

However, we believe these inquiries do not go far enough and fail to recognize the ways in which some entities, such as Redding, are already utilizing energy storage technology.

Redding believes that the current discussion regarding energy storage and its role, vis-à-vis the RPS

Program, significantly discounts the renewable energy and greenhouse gas reducing potential that energy storage can contribute to the market and, more especially to the RPS Program, itself.

While the benefits of energy storage for load management and grid reliability are being explored in other venues, it is imperative that the direct link between energy storage and RPS be recognized as part of the RPS Program and RPS eligibility.

Doing so will allow not only the expansion of energy storage technologies but will enable the State to maximize the usefulness and efficiency of the existing transmission system, reduced RPS costs for ratepayers across the State, and eventually allow for the time-differentiated value of renewable energy to be recognized."

So, we would like to see the discussion of energy storage, if not in the context of the workbook revisions, but in the context of the entire RPS Program be expanded beyond just the inquiries presented here.

And with regard to the inquiries presented here, we think that the Commission's approach should be one that looks at trying to find a way to include them, rather than using these inquiries as a starting for what should be excluded. Thank you.

MR. KOOTSTRA: Tim?

MR. TUTT: Yeah, this is Tim Tutt from SMUD. And I think that, you know, it’s clear, Mark, as you’ve said, that off-site renewable -- or energy storage probably is not renewable unless all of the energy that is used to put electricity into that storage facility or energy into that storage facility is renewable in and of itself, already.

And that poses some questions about whether or not it even makes sense to claim the RPS credit after the conversion loss of the storage facility.

But given that storage is a potentially significant beneficial technology as we move towards a highly variable renewable grid, I think it is reasonable to explore ways of considering that benefit as an RPS -- in an RPS structure.

And the one thought that I had is that you could use WREGIS to prevent the double counting of renewable generation if you knew the conversion efficiency of the storage facility and you required that a storage unit registered in WREGIS would have input equal to the amount necessary with the conversion efficiency to provide the renewable output from that facility.

In effect, it would be kind of like retiring the input through that storage facility. So, you would retire those initial or input RECs and the output RECs would then become RPS eligible if everything met the conversion efficiency requirements in required generation.

It’s just a thought. It’s a way to perhaps explore this.

The economics and the losses in storage, I think, would lend a kind of natural resistance to misusing this, but it’s something to explore, in my mind. Thanks.

MR. KELLY: I have a thought, too. There is a distinction between RPS RECs, storage used to create RPS RECs and storage that is used to avoid GHG emissions. They are very different in the way that we’ve got programs set up.

They both are valuable and I support storage. But there are two different outcomes that we need to be mindful of.

We have a structure that creates a REC that imbues all the environmental attributes of electric generation in that REC. And we have a whole legal structure designed to deal with that. WREGIS is the mechanism for accounting for that.

One of the original purposes of creating that structure for WREGIS, or something like WREGIS, was to provide a measure of comfort to the public, who was funding the renewable development, that they were getting what they thought they were getting, i.e., a renewable attribute.

The risk of undermining that public's confidence by meddling with the identification of what a REC is, in order to recognize GHG, avoid GHG benefits, is in my view too risky to take, a path to take, and isn't warranted.

We should figure out a way to make sure that storage is credited for avoided GHG emissions, but we can do that outside of the RPS Program, in my view, and without too much difficulty, in my view, because that's what it's doing.

And we need to figure out a mechanism to recognize those values, but I'm really worried about trying to do that within the RPS structure because of the unintended consequences and the mess it's going to create by doing it that way.

MS. BERLIN: This is Susie Berlin. I'll just make, I think, I think one last point, because I don't want it to be a debate back and forth.

But I don't want to say that I completely disagree with what Mr. Kelly is saying. There is a distinction. There are benefits to energy storage across the board.

What we're saying, and which might sound a little odd coming from a public agency, is that we shouldn't avoid the risk of at least looking into it. You know, we're usually risk adverse, but in this case I'm going to say that it's worth the risk to look into it.

Redding's been doing a lot with energy storage and we believe that there are ways to expand upon the benefits of energy storage strictly for the RPS, and to distinguish that from the energy storage benefits that are inherent in reducing GHG overall.

And what we're asking is for the Commission to take up some kind of a process to allow us to embark on this discovery, this further investigation and before we move forward and say, oh, yeah, you're right, let's go ahead and do it. We're not saying this should be rubber-stamped right now.

We're saying that it is, we believe, very worthy of consideration for purposes of the RPS Program.

MR. KOOTSTRA: Is there anyone on WebEx that's raised their hand or wishes to speak?

All right, then we're going to move on to the next topic of precertification.

Just as a reminder, if you've filled out an additional topics card, one of the green cards, please turn that in as soon as you can, we're getting closer. It looks like, given the next topic, we'll probably still have a lunch break before we get into those, but we'd like to have those in our possession just to be safe.

If you haven't filled out one of those cards and you want to, please raise your hand and let us know. We have a number of extra cards floating around.

Our next topic is precertification. Yes, it is precertification. So, if you have any comments you want to discuss on this, please come forward and sit at the table.

We do have some additional nameplates. If they've all been filled out in the area you sit, we'll be happy to pass those out.

So, precertification is for facilities that are not currently commercially operational, that are not using renewable resource, but hope to use one in the future, or do not meet one or more of the operational requirements of the RPS Guidebook, but plan to make a change so that they are in full compliance with the Guidebook and can move forward to certification.

Precertification offers an eligibility date prior to COD. It offers an evaluation of the expected potential to certify the facility once operational, as described in the application. And this is only under the Guidebook in place when the precertification application has been submitted.

So just to be clear, if you receive a precertification under one Guidebook and the Guidebook changes, you would still be required to apply for certification under the new Guidebook, as the program currently stands.

And this goes through -- it does not guarantee that the facility will become certified, will be certified under the same Guidebook as the precertification, that it will receive any kind of shortened review, or expedited review, or the review will be quicker and simpler, and that the facility will ever produce renewable energy.

So, we have a lot of questions for precertification. We have discussed this topic at prior workshops and gotten a lot of information.

Most parties have commented in the past that they want precertification to mean something more, to be a guarantee, to be solid, to be guaranteed that you'll be able to be evaluated under that original Guidebook.

That's not something that we've moved forward with at this point.

We've only had a few parties say either make it stronger or get rid of it altogether.

As Commissioner Hochschild has said, precertifications take up a fair amount of staff time and resources, and eliminating precertification could speed up the review for certification facilities. But we need to know; is this something of value?

We want to know if the market participants are aware of the intent of precertification and whether or not that precertification is being represented in a way that it shouldn't be.

Could the renewables market reasonably adjust to the elimination of precertification; why or why not?

Could test energy, energy generated before commercial operations, be make RPS eligible without precertification? Such as saying if you apply within 90 days or some other timeframe for certification, as of coming online, we'll count test energy going back.

What should the Energy Commission do to ensure applicants for precertification fully intend to complete the development of a facility as planned?

And can the precertification process be revised to provide greater assurance to developers and the renewable electricity market?

And can this greater assurance be provided without providing a guarantee, as well?

So, it looks Steven Kelly, you have some comments.

MR. KELLY: Just thank you. This is Steven Kelly with the Independent Energy Producers. And I spoke on this issue on the first topic, so I'm here for the record, I guess, to say similar things.

You've asked the general question about whether precertification has value. And I think I indicated earlier today and I will reiterate, now, that there is value in a precertification process. In terms of developing projects, the procurement process, working with the counterparties and so forth, having precertification seems to provide some value.

When I've chatted with my members about the process in place today, the one thing that came back was more not eliminate it, but is there a way that we can streamline it a bit?

I think somebody mentioned that there was like eight pages to precertification or something like that, and is there any way that we could make this a little more streamlined recognizing that it was just simply precertification?

So, I'm here to say that I think there's a general value for this in the world, and people are utilizing it. And the one thing that I heard is can we streamline it?

MR. HERRERA: Just a quick question. So, Steve, why is there value in it?

I mean, because we're thinking that there's a perceived value because people who receive precertification think it means more than we think it actually does.

And so that's why I'm wondering what is the value?

MR. KELLY: The comments that I've heard on this, which go back some time, and so I've talked about this recently. But when I heard about this issue and when it came up originally, it was more in terms of if I have precertification then I'm in -- I'm going to be taken more seriously in negotiations for a PPA, for example.

I mean, we have a couple structures for developing PPAs, the RAM and a standard offer contract structure, the RPS RFO, which has kind of a standard contract and is subject to all sorts of changes, and then pure bilateral discussions.

And I think generally developers think or believe that with precertification there's -- you're in a better position to approach the utilities with your project.

COMMISSIONER HOCHSCHILD: Can I just follow up on that? I mean, maybe a different way to ask the question, I think, I get that there’s value if you have a precertification process. I get that there’s value in seeking a precertification.

But I sort of think about it as like the preadmission process for college, right. If you apply early admission and you get into Harvard, that’s great. But if the early admission is actually not binding, you know, how -- which is our situation here, right, you don’t -- the precertification doesn’t guarantee certification. How valuable really is it?

I mean that’s -- because the staff, and correct me if I’m wrong, Mark, but I mean probably, what, half the staff time of certification -- how much --

MR. KOOTSTRA: I would say about half the applications we receive are for precertification in some way, shape or form.

COMMISSIONER HOCHSCHILD: Yeah. So, it’s actually a significant amount of time and it slows down a lot of the other --

MR. KELLY: But does it speed up the process at the end?

MR. KOOTSTRA: Not substantially because we have to check and be sure that the facility's operating as described in the application. We can't assume that nothing has changed because things typically change.

MR. TUTT: I think there's two values for precertification as it's set up, David and staff. The first is the market value for financers. I mean, I think the market understands that it's not a guarantee, but for a financer, to me, it's at least an indication that the agency overseeing, the CEC, the RPS, has looked at the characteristics of the project and said if it were built today, it could be certified.

We don't know what will happen in the future, necessarily, but it gives that kind of sense that it's in the right ball park.

COMMISSIONER HOCHSCHILD: Yeah.

MR. TUTT: And that the second value clearly is establishment of an eligibility date.

And so if you do away with precertification, I think you certainly have to do something about that second value. You cannot have a structure where the eligibility date is dependent on the day-to-day immediacy of getting a certification application in.

You want that to cover the test energy and you want to be able -- you can't file a certification application before the facility is online. So, you're going to be setting up -- if you don't have some kind of early eligibility date cemented in, a structure where there's kind of a race, an hour-to-hour race to determine is the facility online? Okay, push the button to submit the certification application and get down there, and put the hardcopy in because we want every kilowatt hour of generation to count for the RPS.

MR. TAYLOR: So, this is Gabe Taylor. So, would it possible to incorporate some of those benefits into the actual certification process?

MR. TUTT: I think that if you had a certification process where the eligibility date could cover the test energy, could go back before the commercial operation in some fashion that would take care of that value.

MR. KELLY: Real quickly, to respond to your question because you had said you'd thought this was kind of like a pre-notification from Harvard that you're in.

I actually think of it as slightly different. I think it's more that, gee, I've got the 4.2 to apply, to get in line to even talk to Harvard about whether they would consider bringing me in or not.

MR. TUTT: I thought it was 4.7.

MR. KELLY: 4.7, see, I'm older than -- it could be 4.7, now.

But it’s actually, and I think from a developer perspective, an early signal to you and to your counterparties that you can pull a project together and get the financing because you’re going to fit into this box.

And I totally agree with Tim, the world knows that the box may change a bit, the project designs may change as they go through permitting and siting, and the world may change a little bit, but it’s an early signal that seems to provide some comfort to the marketplace and value.

MR. WEINSTEIN:  So, the thing is that it’s there, right.  I mean, I think there’s a lot of things in life where you can have a lawyer look at the rules and tell you, and give you a legal opinion, oh, yeah, this is a wind facility.  CEC certifies wind facilities.

And maybe the approach is to, instead, you know, ditch the certification, precertification process, not have it bifurcated and, instead, have some sort of reasonable trigger for when you do the activity that is the certification.  Site control, substantial completion, something that is pre-COD where the Energy Commission can be assured, yes, this is indeed a wind turbine and no gas turbines were installed, you know, while you weren’t looking.

Some sort of way for -- because I agree with Steve that there’s a fetishistic attachment to the precertification because it’s there. And banks, being banks, and banks are completely unreasonable, and bank lawyers make an awful lot of money making other people do their work, and charging the borrower for it. And if the bank attorney knows, gosh, you have this precertification process available to you. I’m going to make you do it.

Instead, the bank attorney can simply say to the project borrowers, or project’s equal borrowers, lawyer, look, just give me -- you know, sign a legal opinion as part of it, that this is going to satisfy as part of it. And remove some of the burden from the Energy Commission, remove the dual process, and kind of find some sort of date that predates generating energy, but allows the Commission and staff -- because like I said before, we’re hyper-compliant. Everyone in this room is hyper-vigilant on compliance.

We want to be compliant. We want the earliest possible signal that we’re in compliance.

And I think, you know, for people to take the better -- to something that really works and does guarantee.

COMMISSIONER HOCHSCHILD: Great, that's a great point.

A question, actually, for Mark because I'm very interested, obviously, and we want to do the right thing for the market and for the program, but also we want our staff to be, you know, working in the most efficient manner.

And I guess one question I have, what portion of the precertification applicants that we're processing are for obviously renewable projects, the wind and solar where there's not really a question, it's just a need for -- and what portion are for the more complicated, you know, some of the small hydro projects or something where there's actually a sort of a finessing? Mark?

MR. KOOTSTRA: I don't have a percentage offhand. I think the vast majority of stuff we get is simple. It's pretty simple and easy to process. It's just a matter of processing those. If it only takes half an hour to process an application but you have 300 of them, it's as bad as getting two that take a long time but you only have two.

It's a very small amount that have the heightened requirements. But even with the heightened requirements we have to completely evaluate them and be sure the operation has occurred.

Honestly, I like Jeremy's suggestion of having something beforehand. I don't know if legally we can do that.

The question is when a facility commences operations, if they came to us after they received site control saying we're PV, but all of the sudden they're biomass, what amount of changes make it a new facility?

And what amount of changes, even if they're minor allow us to say that we can treat the facility the same way?

If it changes technology, is it still evaluated as if it was the same facility or not, those kinds of questions.

MR. WEINSTEIN: Well, I'm just wondering if there's a way to push it onto the developer, and a way to say, okay, we've got site control. It's solar, or it's wind, it's -- I've given you the certification and basically there is -- before Gina accounts the RECs, the CEC must be in receipt of an independent engineer's -- you have a list, just like the CARB has verifiers, the engineers have -- there's a list of licensed professional engineers, who are independent, and you've received a letter from them that you stick in your file that says, yeah, it's solar. Yeah, I went out to the site and visited and I don't see a gas turbine there.

MR. PAPPAS: Mark, this is John Pappas from PG&E. I'd like to make some comments on this.

Yeah, first of all I agree with the points brought up, you know, particularly Tim's here in terms of the value of precertification.

I mean, there's probably two of them. One would be certainly indicating progress towards final certification. So, I think a lot goes into filing a precertification application.

And as well as, you know, guaranteeing the eligibility of test energy, so getting that eligibility date nailed down.

If you were to do away with precertification, I mean you would certainly want to, you know, have at least the benefit of the eligibility date.

And I think that's a tricky question because as it is now if you were to take your chance and just, you know, not file for precertification, which wouldn't be allowed, say, under PG&E's PPAs, but maybe under some, and just go with the final certification, and the project came online, you know, the 29th of the month, you'd have like one day to get the application in if you wanted. Of course, you'd only have one day of generation you'd lose.

But you'd have to figure out some way to be able to count all the generation and then that doesn't even include, you know, all the test energy.

But in terms of the burden, you know, that it has, and I'm very respectful of the burden that this poses to the CEC staff, but I think you also have to kind of look at there are a lot of, you know, sort of steps that has a project has to undergo to develop a project.

I mean, you're talking about air permits, you've got financing, you know, working with the planning board. There could be a PPA, you know, at the Commission, where you have an advice letter.

And, you know, any one of those things could derail a project. And I guess each of those agencies could come back and feel like they've been wasting their time on a particular project.

But that's just sort of part of this overall process. And, you know, the CEC with the certification, in some ways is part of that.

And then just from a standpoint of a party filling out the application, and PG&E has done that for a lot of our solar projects, where we've done precertification applications and final certification.

And what I've found is that at least from our perspective a lot of work goes into preparing the precertification application but then, you know, you're finally done and the final one is pretty straight forward. You know, you're just updating things and the location should be the same, and WREGIS ID, and so on, and so forth.

So, there is some benefit, at least from the applicant's standpoint and, hopefully, that benefits somewhat translates to you in terms of since you've already reviewed the project once, if it hasn't changed too much, hopefully, for the second time for a final certification won't be too much work.

Now, that doesn't address those that never filed a final certification. But in terms of the ones that do complete the project, I think there's some benefits there.

MR. KOOTSTRA: Absolutely. And I don't want to make it sound like we're upset that we have to review tons of precertifications that don't come online. We fully understand that that's part of the process and not everything's going to come to completion.

Just keep in mind that some folks come to us before they even have an idea of what they really want, a location, or before they started achieving site control, or more forward with that process.

We get people that have certifications that are

10, 20 years out. Twenty years might be a little bit far, but I've seen some that are about ten years out. And you have to ask, is this a really good use of our time or are they trying to leverage this precertification to mean something more.

We do get a lot that are within a year and those look great. We still know that they might not succeed.

So, I just want to be sure that you know that we're not trying to just get out of work. We understand that there's a value.

MR. PAPPAS: No, I understand.

MR. KOOTSTRA: We just want to be sure that the value that is there is properly represented. And if it's improperly represented, then we're making sure we can try and fix that.

And if there's truly no value to the industry, then let's get rid of it and get your certifications and other stuff done faster.

MR. TAYLOR: Also, you bring up a good point. I mean, it's an incredibly complex process. There are a lot of steps. Why do we have two steps when we can consolidate that into one?

There has to be a significant increase in benefit to justify bifurcating that step of certifying to the Energy Commission.

MR. PAPPAS: Yeah, I'm okay with consolidating it, as long as we can maintain all the value that you get from the two steps.

MR. TAYLOR: Okay, let's be sure to get all the value stated on the record today so that we can -- and in the comments, written comments.

MR. LANGER: Could I add a couple things for Southern California Edison?

I think, you know, there's been some comments made about streamlining. I'll echo those.

You know, I think one of the problems with the precertification process is it's almost exactly the same as the certification process except, as you pointed out it comes much earlier than the online date.

So, it might be worth considering really reducing the requirements needed for a precertification so that really could minimize the burden for the CEC staff.

And again, there's questionable value add when facility site designs change all the time and you're submitting that information.

COMMISSIONER HOCHSCHILD: Can I just -- if the purpose of precertification is to send the message that, yes, this would in fact be certified, how can it be anything less than the certification process?

MR. LANGER: Well, I think you would have to look -- one of the suggestions that we may propose is that for certain technologies it’s effectively a foregone conclusion. So, I think you could look at maybe looking at certain different technologies differently.

I think if you have a solar PV plant, and someone mentioned this much earlier, but I think there’s very little doubt of its eligibility status.

COMMISSIONER HOCHSCHILD: Right, so that’s a great -- can I just throw that out? What if we had limited precertification or excluded wind and solar, for example, from precertification?

MR. LANGER: I think that would save probably 98 percent of your workload.

MR. KOOTSTRA: The vast majority of our precertifications are wind and solar.

COMMISSIONER HOCHSCHILD: Right.

MR. KOOTSTRA: But they’re also the quicker applications to review.

MR. LANGER: Yeah, I mean you could even -- even if you didn’t eliminate that step completely, you could just say, hey, I’m building a solar plant on this site. Assuming it’s still a solar plant when I come back with my full application, we’d like to have the acknowledgement that we’ve at least established that eligibility, because that is an important point that has been made a couple times.

And one thing I will point out about that is especially we’ve seen it with some of the very large wind and solar projects, where they have multi-year construction build outs, where they’re actually syncing certain parts of a facility.  And so that’s test energy that can go on for years.

And sort of as a buyer of power, and a buyer of renewable attributes, green attributes, I’d be pretty concerned to have it hanging out there that not even an application or first contact with the CEC had been made about the eligibility for, you know, perhaps two years’ of generation before we can reach that final COD.

So, some way, I mean, to generate some real assurance around that, I think that’s one big piece that’s, in my mind, a real value add for the buyers today.

MR. WEINSTEIN:  Well, this goes back to the theme that I brought up earlier in terms of allocating resources to communication with developers.

And certainly, I think rather than have staff do 300 precertification applications, it would be a lot easier for developers to know, hey, you can call staff and say I've got this weird project, you know, what do you think? You know, can you walk me through the Guidebook and show me what's going to happen and how they get this certified.

And that could be the way that that person could understand, you know, whether or not it's going to be a compliant product or not.

And I think it's just a much better allocation of staff time than 300 precertification applications.

And I also think on a big picture policy basis another reason to eschew the precertification as a separate process, especially when it's available very early, as opposed to, you know, a combined application that has some sort of trigger point is that the utilities, and the CPUC, and the Energy Commission are already very significantly burdened by project failure, by the fact that anybody can show up and say, well, okay, I've got a project and I'm sticking my project in the interconnection queue. And I don't know whether or not I so need something from you in order to have it treated as a renewable thing in the certification queue. If not, maybe we need to talk to the ISO, but I don't know.

But to the extent that administrative resources can be allocated away from project failure risk to communicating with developers that are actually developing projects, the better.

MR. KOOTSTRA: Is there anyone else that would like to add comments to this topic?

MR. TUTT: I'd just add that the streamlining, as long as the value can be preserved, if there's a way to do that and then preserve the values that have been mentioned today, to the market and to the eligibility date, it makes sense to look at that, to me.

MR. KOOTSTRA: Absolutely. I'd just like to iterate that staff has looked at preserving the value, especially for the eligibility date. And if, in big picture discussions, the idea of removing precertification, we have always accompanied that with some way to account for test energy and still keep that eligible.

So, that's not something that we're proposing to get rid of. That's something that we've always looked at and considered.

But it's the other values that need to really be what defends precertification, not that eligibility date because there are other mechanisms for it. And we agree that should be preserved and that's out hope.

MR. KELLY: Can I ask a clarifying question? So, you get the precertification, what does the Energy

Commission do with that? I mean, does it trigger modeling efforts in the planning process or what happens when you've given somebody a precertification?

MR. KOOTSTRA: Our office does not do anything with those precertifications outside of fulfilling questions from outside, or of other government agencies looking at what's proposed to be built.

We do have other departments that use those and use that for estimation. I don't know how heavily they use those. We always caution them to be very careful when using that information.

I do believe that those precertifications are, as stated before, used for PPA compliance purposes. And I think that the Cal-ISO is requiring precertification for the expedited review for interconnection.

So, that's some of the stuff that we know is going on, but we don't always think that our precertification should be the trigger point for those things.

MR. KELLY: right, right. See, the reason I raise it is because my observation is that -- or I had always thought the precertification was simply, from the Energy Commission's perspective, if the developer develops a project as they've just described, then it's more than likely going to count or it will count, right.

If the project developer develops something else, that risk is on him. Not on you guys, right? I mean, that's his mistake because he's not going to be deemed eligible from RPS, whatever.

So, it strikes me that, you know, there's a lot of resources, wind, a lot of solar, there's a bunch of stuff that is kind of, in my view, kind of pro forma.

If you develop a wind project using wind turbines, blah, blah, blah, you're going to be an eligible renewable resource.

And that ought to be like (blast/blast sound), and maybe you don't even need to deal with it. You know, you just take that stuff off the table because it's obvious that if they do that kind of project they're in.

It seems that would maybe save a lot of your resource time.

MR. KOOTSTRA: Absolutely, and we do move pretty fast on those particular ones.

Just to make you aware, I have worked with folks, developers who know the situation and know that precertification does not carry any solid weight, who have said we will not order parts until we have this, and have made those distinctions that we will not go to our financing folks and they will not approve this.

Which suggests to us that maybe those developers get it, the utilities get it, but those people that we don’t deal with directly don’t understand that precertification does not carry any guarantee, and that’s what concerns us is that it’s being misrepresented.

We’ve done -- we’ve stepped up their game and our qualifications on those certifications, but it doesn’t change the fact that people are telling us we absolutely need this to get approval. They can’t just point and say, look, we’re a wind facility.

We’ve done the exact same thing next door, just to prove these documentations so we can move forward.

MR. KELLY: Yeah and that’s why you should get rid of it because the service can be obtained at a cost by the developer from someone else, like a lawyer.

MR. ANDREONI: I’m Tony Andreoni. I represent CMUA. And I didn’t want to come up and add too much to what was already discussed because I do believe there’s some good discussions going on right now.

What SMUD said and some of our members feel in precertification, whatever you call it, if there’s a way to streamline, I think that’s important.

I think even more important are making sure we get the certifications as soon as possible.

And so, really, the question I had for you, mainly, to focus on what is kind of the hold up or what is the time sync that CEC has in going through the precertifications? Is it just based on pure volume? Is there a process or lack of resources?

And if it is some of those issues, are there ways to consider maybe bringing in external stakeholders, such as the IOUs, POUs, and other developers as far as a panel to go through some of these applications and help the Energy Commission, whether it be expertise or other information to streamline.

I like the idea that was mentioned today of wind and solar can just be rubber stamped and move forward, that's great.

But some of the other projects, certainly the biomethane, are there areas that need to be addressed and is there something that we can do to try to help the CEC in doing that?

MR. KOOTSTRA: Primarily, our issue is with volume. There are a few, such as biomethane, that are more complex situations, but I would say that those are the huge sync. It comes down to volume that we have that comes in and that not everyone who's applying, and submitting has given us sufficient information to make the evaluation.

Sometimes the information we need is miniscule and we generally know the answer, but we have to have them provide that to us. So, it's that back and forth that adds a lot of time and drain on resources.

The biggest thing I can say for a person in your situation, and the utilities, is to try and help those that are filling out applications for the first time to have that understanding.

We want to work to be sure that our instructions are as good as possible, so pointing that information out to us where there's additional questions. So, we're working to develop that type of stuff continuously, but it doesn't change the fact that if people don't know that the resource exists, and we don't know that they're going to be applying, there's nothing we can do to help until they've submitted something that needs correction.

MR. ANDREONI: Okay, so for transparency purposes, I would suggest that there's more information provided on the process. Maybe you do have courses or seminars on what needs to be done in order to streamline, that might be a suggestion.

The other issue is right now we're just looking at a website as far as what's in the pipeline, and that's updated I'm not sure, every couple weeks, or every month. I'm not sure of the process.

But somehow there needs to be some type of interface, whether it’s regular meetings on where you are with precert and certification, where the public can actually participate, whether through the business meeting, or something that allows everybody to kind of understand where some of the high priority projects are. And that’s just a suggestion.

MR. KOOTSTRA: Thank you. Just so you’re aware, we are trying to move forward with improving our database so that it can have access to the public. That’s not a guarantee that it will happen. If it does, it will be years from now. But it’s the State IT process, it just takes time.

We can look, definitely look into doing something, either a webinar or whatnot to give some updates. But as we mentioned before, a lot of these easy precertifications and certifications for wind and solar which makes up a bunch of those, those move really fast. And if they don’t, it’s because we’re already in contact with the applicant for the most part.

MR. TAYLOR: So, I think I’ve heard two different types of benefits from precertification. Benefits that could be put into the certification process, such as the eligibility of test energy, and then benefits that could be handled with a very basic kind of letter of intent type process. So, this is a signal to the banker, to the utility that you've contacted the Energy Commission and they're aware of your project.

Are there any benefits that don't fall into those kinds of classes?

MR. PAPPAS: I think the only other thing might be just experience with completing the form, you know, just getting into the project to that level of detail that you have to do to fill out a precertification.

But that's probably, maybe, second tier compared to what you've discussed.

MR. KELLY: I think I'd always presumed that the precertification would actually speed up the final certification, which I guess is not the case, but I think a lot of the marketplace believed that was the process.

MR. KOOTSTRA: In some cases it can, if we've seen the environmental documentation form, there's that type of stuff we need to do.

MR. KELLY: Yeah.

MR. KOOTSTRA: But it still comes down to we have to be sure nothing has changed. So, if we have to do a review of environmental documentation for hydro-electric facilities, or facilities that have a LORS requirement, we just have to be sure that information is all still the same.

If it is the same, then it can speed it up a bit, but you’re not seeing drastic speed increases because we still have to check all the documentation. We can’t just assume they submitted the same thing the second time around.

MR. KELLY: Well, could you have a formula that would simply say, you know, it has not changed and I’ve got my attorney, and signed it, and boom off we go. And the liability’s attended to for fraudulently filling out a form like that.

MR. KOOTSTRA: We generally allow folks to submit a letter stating that this information has not changed from one application to the next. But when you’re moving from precertification, which could have been done years before hitting commercial state, to the certification there’s just a different set of information available. And you can have actual impact information. You have real data instead of proposed data that you have to look at.

Again, those are facilities that we get less often, but it’s just not as substantial, I think, as a time savings as we all would hope. I mean, we would hope it’s as substantial, as well.

MR. KELLY: I’ve heard that RPS characterizes a jobs program, so here we have -- we’re meeting the Governor’s goals.

MR. WEINSTEIN: Well, I mean I think in context, though, I mean I would only take a page from what Mark just said, which is that the application of certification is the actual accurate information that you feel comfortable standing by. And, you know, putting it in the context of where we started, which was doing a new certification every two years, and the Commission kind of dropping that and saying, okay, no, no, wait a minute, you can still do certification. You know, I think the premises should be given of the certification application. I do like the idea of, oh, gee, I can swear that it hasn’t changed.

But actually, like Mark said, it could be very old, it could be very stale and the temptation to just say, oh, yeah, it hasn’t changed could put the Commission farther afield from where it stated its mission was before when it was saying, look, I want to make sure that this is a really a renewable resource.

MR. KOOTSTRA: Well, if there’s no additional comments in the room, I’d like to ask if there is anybody on WebEx who has initiated that they want to talk.

Then I think we're going to break for lunch. We'll head back at 1:00.

Please turn in any additional topic forms that you have. We're going to be looking at those in the lunch hour. If you want to fill out more, please do so now. We won't be accepting those after lunch, depending on how many we get, so I --

MR. KELLY: Do you expect this last issue to take a long time or could we just plow through?

MR. KOOTSTRA: We could potentially plow through, however there are --

COMMISSIONER HOCHSCHILD: Yeah, I was going to suggest, I mean we only have these two items. I mean, I would kind of be inclined to go for another half-hour.

Do you guys think the changes in law -- who's going to speak on that? So, we have two people, three people, four people.

Honestly, I would suggest we go until at least 12:30 and see if we can knock it out, yeah.

MR. KOOTSTRA: Okay, then we'll hang on through the next topic.

Just out of curiosity, how many additional topics cards have we received? None -- oh, two, okay so we'll get started.

MR. PAPPAS: We have -- PG&E's got some

additional topics, so I don’t know if those are included in yours there.

MR. KOOTSTRA: So, we’ll continue on through the topics that we’ve addressed, or identified, and then we’ll go to lunch and figure that out.

So, our next topic is changes in law and how they will be applied to certifications.

So, historically, the Energy Commission has looked at a facility -- if it’s been certified under one Guidebook and you haven’t received any substantial changes, you remain certified under that Guidebook regardless of future changes.

And essentially this becomes down to a facility that’s become certified generally remains certified.

The following changes in the law have impacted the RPS eligibility. That could suggest that we should decertify or change the certification for some facilities.

Assembly Bill 1954 changes the requirements for di minimis fossil fuel use, eliminated the Energy Commission’s ability to set what that di minimis is, and required us to set it at no more than two percent. It can go up to five percent in some special cases.

Assembly Bill 3048 changed the requirements for hydroelectric facilities. I believe this, and I could be wrong, added incremental hydroelectric generation and it also changed and required a facility to have been under contract or owned by a retail seller, or POU as of July 1st, 2006 or December 31st, 2005. I can't recall offhand.

And then Senate Bill 1X2 changed some additional requirements.

And so we're looking at should this information -- should those requirements, those changes be applied to all facilities that have been certified historically or should we leave existing certifications as they currently stand?

MR. WEINSTEIN: Well, I'd be a strong proponent of leaving existing certifications as they stand. And I think the risk runs on both sides, it runs for the developer and it runs for the utility.

And, you know, one of the problems that California has kind of created for itself, I mean in SBX1-2, where it kind of, you know, changed the online date for resources, and for a period there was like this black hole where there was like a six-month period of a resource online date that there's no way you could have got certified.

You know, a year earlier you start a facility but if you came online during that six-month period you weren’t going to get certification. I mean, they fixed that hole.

But if you have California going through a constant process of if you do it this time, who’s to say you’re not going to do it next time. So, it’s going to really stymy development in California if developers think and enter into PPAs, and utilities enter into PPAs that maybe they’re going to get a resource and maybe they’re not because the rules could change later. And there’s a lot that could happen in terms of the rules changing later.

And it runs both ways. It runs both the developer’s at risk and the utility’s at risk. Because if you look at the standard terms and conditions that the CPUC requires the utilities to have in all their RPS contracts, one of the STCs says that it’s not an event of default if I’ve used commercially reasonable.

In other words I’m certifying, I’m representing that this is going to quality, but it’s not a default if I’ve used commercially reasonable efforts to cure the default. And there’s no way that you could be using “commercially reasonable efforts” to retroactively change the constitution of your facility.

So, the IOUs would be stuck with contracts that were not in default, and which they would have to pay for, which would be for non-qualifying resources. So, that's on the utility side that, you know, if you go back and change certifications the utilities are buying something they can't use at the price that's set forth in them by their own contract, pursuant to terms that are mandated by the CPUC.

The developers who are seeking to bring online resources, you know, in the development cycle, so for example they may not have reached COD. It may be a one-year process of bringing the resource online and the rules get changed midway through development can you do it? Can you move forward with your project? Is it going to be in default? You know, you have an online date what -- that allocation's going to hit differently and unfairly.

So, I really have to urge the Commission in the strongest possible terms not to engage in retroactive changing the rules and facility eligibilities.

MR. HERRERA: So, Jeremy, a quick question. So, you talked about situations where the developer and the utility would be impacted because of the provisions they had negotiated in their contracts.

But what if the Legislature changes the laws and the Energy Commission, for example, doesn't apply those in that circumstance until after that contract is ended?

I mean, in that case wouldn't the parties' interests be protected by the fact that there are assurances that the rules that have now changed in statute aren't going to be applied to their certification during the term of the contract? Would that be one way to address that issue?

MR. WEINSTEIN: Well, I mean, that's an interesting idea. I mean, the contracts are 20 years and kind of how do you know it's a contract? And does that mean that entities that have invested to build merchant lose the protection -- aren't protected, whereas those who had a PPA are protected?

You know, the issue I guess comes to, you know, whether or not -- you know, kind of at what point is it -- at what point can you engage in retroactive rulemaking? And at what point is the Legislature allowed to engage?

And I guess that's another issue. I mean, does it rise to the level of a developer suing California and saying you're not allowed to do it. The Constitution says no ex post facto laws. It's a taking. I mean, you know, you kind of hope that it doesn't rise to that level.

And certainly, what we've seen in biomethane, for example, is kind of like the goal post shifting and the frustration that's happening, and kind of what's happened in terms of biomethane development. And you've certainly seen a lot of the resources that you've had to do for the biomethane and having to deal with sort of the way those goal posts have moved.

And so, you know, the nightmare is the Legislature says, oh, for the Cal RPS, gee, the only thing that can be certified is something that's built in 2015, and that happens in sort of what happens.

But I mean, I think in terms of sort of the small items, I mean I would think that anything that you can look at and say, oh, gosh, I was not told by the Legislature to retroactively change the rules, okay, I'm not going to retroactively change the rules.

MR. KELLY: Yeah, this is Steven Kelly with the Independent Energy Producers. And I want to follow up and echo those comments that Jeremy said.

I mean, I'm not aware of a statutory prescription that's imposed on the Energy Commission that requires you to retroactively apply new regulations.

So, I'm operating under the assumption that you have discretion. And I would just echo the fact that not to retroactively apply new regulations.

California, there are billions of dollars coming to California to develop renewable projects. And there’s two truisms, and the one I started the conversation this morning is that commercial development is highly a function of regulatory certainty going forward.

And the truism of California is it’s highly chaotic. And the risk of legislative, statutory changes or regulatory changes is perceived in the marketplace as being relatively high.

So, your assistance in clarifying that you’re not intending to do retroactive ratemaking would be very helpful, I think, in this case.

And it has a number of benefits. One, it allows development to move forward in a timely manner.

Two, compared to the alternative it reduces the cost of renewables. Because if you were to go the other way then everybody’s going to have to incorporate a risk factor into their development project, in their bid factors, which is going to drive the cost up unnecessarily to California consumers.

And when you multiply that across all the projects it’s a big number and just don’t see the value in that.

So, I strongly recommend that you do not move on a path that has retroactive ratemaking.

Once you've approved a certification and somebody's invested 250 to 300 million dollars in California to develop that project, they should have some certainty that they're going to be able to sell that product in California as a renewable resource.

MR. PAPPAS: This is John Pappas from PG&E. I agree or PG&E agrees with the comments thus far. I mean any -- we do not support any kind of a requirement to recertify a facility, you know, once it's already been certified.

I mean, doing so would result in significant risk of noncompliance, contractual default or other kinds of losses and complications.

It could lead to disputes, litigation, affect a project's viability and, ultimately, its contribution to the State's RPS goals.

And in addition create, I think, a huge burden for the CEC staff, you know, in terms of administering it. But that would -- you know, so for all these reasons, once a project is certified it should remain that way.

Now, you know, that said there are situations where an amended certification is required and that's already in the Guidebook, and I wouldn't expand upon that. And that's at page 83, as you're aware, change of pool, change in the nameplate capacity, change in status, change in fuel suppliers, except for biomass, repowering of the facility, which we’ve talked about earlier, increasing the nonrenewable fuel.

Things like that, yes, those folks would be potentially subject to a change in law.  But not, you know, a project that’s already come online.  I think that’s a basic tenet that we have to really stand behind.

Otherwise, I agree with Steve that you’re going to have to factor that all in the cost.  And, you know, renewables are expensive enough, we don’t want to add this level of risk.

You know, I don’t know how much of this stuff will actually come to play, you know, because it does require a change in law and a lot of stuff goes into changing a law.  But the fact that it is possible will increase the cost of doing business.

So, we do not support any kind of change in that way.

MR. BRANCHCOMB:  Well, I would like to add from a developer’s perspective that we certainly do not think this is a good idea.

I mean, we plan our projects.  It’s a long, painstaking process to plan a new project in California.

You have permitting, you have transmission work you have to try to get done, and you do that based on a set of rules and you make assessments as to whether or not this is something that I can do.

You go forward on a good faith basis that I've done my homework, I've checked all my boxes, I've done my precertification, I'm going to be there within 90 days of online to do my final certification.

And then two years down the line you've got an asset that you've invested in, that has a life of at least 20 years, suddenly it's no longer viable because of a whim of a lawmaker. And that just -- that's really not a way that you can proceed with any kind of viable commercial environment.

And I'll add on something else we heard today, we heard staff talking about how difficult it is to get through the precertifications and the initial certifications. So, if they've got to come back every couple of years and do these all over again, how many more are you going to hire.

You know, so anyway, thanks for the opportunity to weigh in.

COMMISSIONER HOCHSCHILD: Could you introduce yourself, sir?

MR. BRANCHCOMB: Oh, I'm sorry. My name's David

Branchcomb. I represent Sierra Pacific Industries. We're a timber products company in California.

COMMISSIONER HOCHSCHILD: Great, thank you.

MS. BERLIN: Hi again, Susie Berlin for Northern California Power Agency and MSR Public Power Agency.

And I will join in the chorus of stating unequivocal no to question number one. There should not be any recertification. It provides no certainty in the market. It would undermine funding and project development in general, all the reasons that have been stated.

And it also wreaks havoc on resource planning. You have three specific procurement categories that you need to plan for and if you have a facility, and you've got a contract that's going to be providing you PCC-1, even if your contract does have some kind of an arrangement where you can reduce the price if suddenly that facility is not PCC-1, there's uncertainty in your pricing.

But now you have uncertainty in your procurement because you need to go out, you still have to meet the 50, 65, 75 percent requirement from PCC-1 and you could have this facility that you were counting on to do that for you suddenly not be able to.

So, I believe that having to recertify a facility is -- has a lot of pitfalls and would wreak havoc on the development of the market and on the utilities that are relying on these resources to meet the RPS mandate.

MR. TUTT: This is Tim Tutt from SMUD and I will add my voice to the chorus. I think regulatory certainty is extremely important for developers and for the obligated entities, the utilities, and so on under the RPS. We want to be able to comply with the resources we’ve procured and it’s damaging both to the resources and their development, and to the utilities if somehow that something we’re relying on is taken away.

Now, I mean I understand you have to react to what the Legislature does in many ways. And Steve earlier used the no harm/no foul analogy.

I guess I’ll use one that says first do no harm. I mean, if the Legislature doesn’t require you to make a retroactive adjustment in the regulations that will harm the market, then don’t do it.

With, for example, the biomethane legislation, the Legislature saw fit to grandfather existing common carrier biomethane contracts. Those should be allowed to proceed through the end of their life as they were signed and procured by the entities.

Now, the CEC has interpreted some of that law to require additional information from even existing landfills and dairies. And I'm not aware that this has happened, but it seems at least possible to me that as that is implemented by your agency that some of those landfills and dairies will be found wanting because of a change in law. And I don't think that was required by the legislation to find them wanting. I think those should continue to be eligible.

Now, on the other hand, SBX1-2 established a 2011 starting point for an obligation and changed eligibility for things like large hydro and unbundled RECs in California.

So, I think it's not a harm, you shouldn't avoid what you've already done, which is to say those large hydro resources that are now eligible are eligible starting in the beginning of the compliance period established by this law.

And I think you should do the same thing with unbundled RECs.

And so you have to react to the law, but your primary concern should be avoid any regulatory uncertainty and first do no harm.

MR. LANGER: Yeah, Matt Langer from SCE. Certainly, I echo the similar thoughts on not applying changes in law retroactively.

I'm glad that the topic of biomethane came up because I think in a sense that's a dry run and we have other examples of similar dry runs, if we were to approach it as sort of a new change in law paradigm.

But I think every time we have a new compliance obligation and you take a whole category of generators, let's say you can go with the example of biomethane and say, you're already certified, but we need you to now re-demonstrate your compliance with this new rule.

And every single time we have to go through a large swath of the industry and get them to recertify there's fallout.

And I think what we'll find ultimately, somewhere in this room, or somewhere in this State, there's going to be a biomethane facility that actually does company that will miss the deadline, or won't file the paperwork correctly, and is going to end up being declared ineligible when, in fact, they really did comply with the law anyway.

So, you're not really, necessarily, even cherry-picking the folks that the change in law impacted directly, you're taking other folks and you're kind of sucking them into this.

I think we've seen it with that, we've seen it with having to go after new certifications for utility-certified facilities, that that's introduced challenges.

So, I do caution that there's unintended consequences when you start applying these rules where you suck up large population of the RPS-certified facilities and have them go back into the process.

MR. KOOTSTRA: Do we have any other commenters in the room? Yeah?

MS. LUCKHARDT: I just -- I was on the phone and I heard you guys talking about the precertification issues and whether it was valuable or not, and then you guys decided not to break for lunch, so I walked over here.

And I don't know if you guys want an additional comment on that but --

COMMISSIONER HOCHSCHILD: Sure, sure.

MS. LUCKHARDT: Okay, so the precertification, where it becomes really valuable is -- from my perspective is on facilities that are out of state or out of the country.

COMMISSIONER HOCHSCHILD: I'm sorry, could you introduce yourself again?

MS. LUCKHARDT: Oh, sorry. Jane Luckhardt from Downey-Brand.

And I also do a lot of financing work. And when you have a facility that's located out of the country or out of the state there’s an additional requirement on those facilities.

So, I do agree a straight PV, a straight wind in California, with no other fuel is not a big deal.

But if it’s located out of state or out of the country and the Energy Commission is then required to do the additional analysis to review the facility to ensure that it is being constructed and developed consistent with California standards, it is really helpful to have an initial review from the Commission, from your staff to look at that.

I understand and your letters are very clear now that it is not a final certification, but in those situations it is extremely helpful to have some sort of an initial review. To have this Commission take a look at that and say, generally, it looks like it’s okay, because that is a harder call to make and would require a lot more analysis and review from a legal perspective in advising banks or lending institutions that the facility -- you know, that you can reasonably assume that the facility will be RPS eligible once it is up and operating.

So, I just wanted to add that piece to it. And I’m sorry to have come in late.

MR. KOOTSTRA: Is there any more commenters on our current topic?

Is there anyone on WebEx who would like to comment?

While we’re checking that, I’m just going to read off a quick list of comments that have been proposed to us, so you can know before you head off to lunch and just determine whether or not you’re going to come back.

We’re going to look at these a little more closely during the lunch hour and choose the proper order to go through them.

But one was on counting incremental generation from efficiency improvements. I assume this is having to do with hydroelectric facilities.

RPS participation of DG resources.

Allowing postmark instead of received by date for certification applications.

Creation of retroactive RECS and/or allowing the ITS.

Counting previous deliveries for 40-megawatt hydro, which is similar to the one above it.

Biomethane issues, modifications to grandfathered contracts.

And interaction between the RPS Guidebook and the POU regs.

So, just be aware that those are the seven or eight topics we'll be talking about after lunch because I don't think we can get that in on a reasonable timeframe, depending.

Was there anyone on WebEx?

Then unless Commissioner Hochschild --

MS. BERLIN: I just have one comment?

MR. KOOTSTRA: Yes.

MS. BERLIN: I just have one quick point on the issues for discussion this afternoon. On the postmark date, that suggestion was globally to change all requirements in the Guidebook for anything that needs to be received hardcopy to be allowed to be a received hardcopy.

So, not just the postmark date, the compliance filings -- I mean, not just certifications, compliance filings. I mean, it's a global acceptance of postmark rather than received by.

MR. KOOTSTRA: Okay, thank you.

So, if there's no other comments, we're going to break for lunch. We'll head back -- if anyone's opposed to it, let me know, but I would suggest we'll just head back at 1:00, anyways.

And there are some restaurants identified on a sheet out from that most of them are within about half a mile.

(Off the record at 12:11 p.m.)

(On the record at 1:07 p.m.)

MR. KOOTSTRA: Given the number of people here, I welcome everybody to come to the table, if they'd like, or even if they just want to sit, you can have work space. And we can start getting discussions on the additional topics.

So, in the lunch hour we looked at the additional topics and they fit generally into these six categories; certification reviews, incremental generation, retroactive WREGIS certificate creation and the use of the ITS, which is the interim tracking system distributed generation, biomethane issues, and interaction between the RPS Guidebook and the POU regs.

So, for certification reviews we had some additional topics on assigning eligibility dates based off the postmark date, instead of the date we receive it in-house. And also, a set time for certification reviews.

We mentioned this a little bit in previous discussions, but I'd like to open this up to the floor if anybody has anything they'd like to add, in addition to these comments.

MR. TUTT: Hey Mark, I guess -- this is Tim

Tutt. And I guess the one thing I'd add is, and this has come up before, I can't remember exactly where, recently, but the communication question. I many cases, in the certification review, it seems like the CEC staff is sending an e-mail or a notification to one person at a company.

And it may be that that one person is on vacation or even, in some circumstances, has left. And so, I guess I want to again advocate that you establish a process where you have multiple e-mails or notification pathways that you send things to so that the party you're notifying about something really understands, fairly quickly, that something needs to happen about a particular issue.

MR. ANDREONI: And just following -- this is Tony Andreoni, CMUA. Just following from what Tim just mentioned, I believe I've spoken to CEC staff in the past to be able to use the association, as needed. You know, should those contacts or should you not receive a reply in a timeframe that you need a reply in, I certainly will be there to help or, you know, NCPA and SCAPPA, for that matter, I'm sure would also be available to assist to make sure that information gets out.

And I do recall some initial interruptions where some folks were actually moved from job to job, so they weren’t around to actually respond to CEC’s comments or questions. So, we’re there if you need us to assist with getting that information.

MR. KOOTSTRA: Is there anyone on the WebEx with hands raised? I’d like to ask that folks on the WebEx, if you see a topic come up, just raise your hand instantly if you’d like to talk and we can sort from there.

But it looks like we don’t have anywhere there, so we’ll move on to --

COMMISSIONER HOCHSCHILD: I’m sorry, who was it who had suggested the eligibility date based on the postmark?

MR. KOOTSTRA: I believe that was suggested by Oscar Herrera of LADWP.

NCPA, sorry, that was Susie Berlin.

MS. BERLIN: For just all filings in general, and this came up, I believe Mark was on the call with the RPS compliance call, just a preview of the compliance filings for the POUs, the webinar a while ago, and we were clarifying when things had to be submitted. And there’s an e-mail, an electronic copy is due, and there’s also a due date, the same due date that they have to have a hardcopy.

And so we said, we were asking for clarification about when that’s due, and it’s an understanding going through the Guidebook that it’s due when it’s received. So, the due date is received here at the CEC.

But for convenience, I suggested that all the due dates be changed from when they’re received, because that could be a little ambiguous, to postmarked by for anything that’s also subject to electronic filing.

So, you do have the electronic filing already and then it’s just being followed up with the hardcopy. But it seems like a cleaner way to do it and then it also ensures that everybody has those couple extra days to put something in the mail, all the way up to the deadline to submit something.

So, if there is an electronic and hardcopy requirement, I recommend that the hardcopy due date be reflected by postmark rather than received by the CEC. Thank you.

MR. KOOTSTRA: Thank you, Susie. Just so you’re aware, with the RPS Guidebook that’s something that’s in the Guidebook at the moment, but it can be changed. It’s just not something we can change in the here and now to change the requirement but --

MS. BERLIN: Oh, I understand. That’s why I put it as an additional issue because it is something that’s a valid revision for the Edition 8; correct?

MR. KOOTSTRA: Yeah, I can't guarantee we'll do it, but it's definitely something valid to look at.

MS. BERLIN: For consideration, okay, thank you.

MR. KOOTSTRA: All right, if we don't have any more comments, we can move on to the next topic.

Here we go, incremental generation. I'm actually going to skip over this one for the moment. I know the person who's involved with this or suggested it isn't here just yet, so we're going to come back to it.

The interim tracking system and retroactive RECs, so we've had a couple requests for retroactive WREGIS certificate creation in WREGIS, or the use of the ITS, including for water supply main system, hydroelectric facilities that it didn't apply much later in time, even though eligibility's allowed to be extended back to January 1st, 2011.

So Tim?

MR. TUTT: Yeah, I think this was touched on in other contexts this morning. And the concept here is that you don't want to under-count your renewable generation because an administrative deadline has been missed, or some other issue that's similar to that.

We understand that there's a wide variety of participants in the RPS, that they have other focuses;

that things are complicated, and that things will slip through the cracks.

So, there’s some current issues where that’s happened and we’re trying to resolve those through one of these steps, either requesting retroactive creation of a WREGIS certificate so that the generation can be tracked in WREGIS as expected.

Now, the current WREGIS rules require the Energy Commission or a similar body to request that creation of retroactive certifications and require that if there’s any costs that the Energy Commission would pay for that.

We understand that that’s not an easy path, but it’s still, in our minds, a viable path. We understand there’s no current protocol for the Energy Commission to get compensation for or pay for that cost, but that such a protocol could be created. It just would take some legal time to do that.

The other alternative there is to extend the use of the interim tracking system to cover some of these initial generation issues.

And here, as you know when the WREGIS was first set up and the IOUs were obligated to track generation in WREGIS, there were significant problems at the beginning in terms of getting generators to sign up, and a variety of other issues.

And so the IOUs got effectively, I think, almost a two-year extension in using the interim tracking system.

And for POUs where, you know, we’ve been going through the enactment of SBX1-2 and the adoption, and finalization of the CEC regulations regarding that, and the Guidebook, we’ve all understood that the deadline, as it stands in the Guidebook is the end of October 2012 for use of the ITS.

But that’s an alternative way of accounting for and counting this legitimate renewable generation that’s been -- that’s being considered here is to extend the use of the ITS. So that while some of these initial snafus, and misunderstandings and, you know, administrative questions with participating in WREGIS are covered or, you know, have not happened as expected.

So, I don’t know have a specific or particular date necessarily in mind. But just as an example, if the use of the ITS could be extended through April or June of this year, I mean that would cover some of these initial questions about generation that’s happened but, as it stands, isn’t going to be counted just because it’s not in WREGIS.

I think in the longer term these kinds of issues are likely to continue happening. As we’ve talked, Mark, in the past, you many times thought that the Interim Tracking System was going to be ended and it turns out that there's been reasons to extend it.

And I guess I'd open up the possibility of considering keeping the ITS around for special cases like this.

If participation in WREGIS is as constrained as it currently seems to be, and there might be ways to open that up as well, but if that's the case then to count this legitimate renewable generation it might be reasonable to allow the ITS to be used in those cases, on an ongoing basis.

And there would have to be some potential considerations or restrictions on that. I mean, I think, obviously, you couldn't use the Interim Tracking System to go back and pull in generation that came prior to the current compliance period. I mean, that would upset kind of verification and compliance in a way that we don't really want to go down, probably.

Another possibility, in my mind, is that someone could use the ITS or resources which have subsequently completed the WREGIS process, so that you know that they're going to be tracked in the future in WREGIS. That's already set up.

It's just a question of, like counting the test energy, WREGIS doesn’t have an easy policy for counting generation prior to completion of the WREGIS certification process at this point.

So, those are my thoughts and I’m open to others commenting on that.

MS. BERLIN: Hi, this is Susie Berlin for NCPA. And we had also suggested the use of or some process to have RECs retroactively created.

We have a situation where there are RPS -- CEC RPS-certified facilities, so these are eligible facilities, and somewhere between the transition from ITS to WREGIS paperwork is not completed, there’s confusion about which of the responsible parties and multi-party agreements are supposed to submit the paperwork, or can submit the paperwork.

And I can go through some specific examples, if you like, or we can save those for our written comments.

But the end result is that beginning, basically, November 1, 2013 to the present there are a number of RECs for which -- or there’s a great deal of renewable energy for which RECs were not created.

And for the City of Santa Clara, for example, some of these issues have been resolved so now their WREGIS application has been approved, but there’s still a downtime during the last year where there was energy for which there are no RECs.

WREGIS does have a system, they have a rule that allows the creation of retroactive RECs. However, as Tim pointed out, the WREGIS rule says that the State or regional agency needs to request it and then there are costs involved.

So, we understand that the CEC may not have a budget to address those costs so, clearly, if we're going to proceed down that path we need to speak more on that issue, and find out if there's a course we can take. The entity that needs the RECs created pays a percentage, depending on the number of RECs. I'm not sure what that would entail, but we would really like to have that discussion.

In the interim, or in combination with this proposal to allow the creation, to allow the Energy Commission a procedure to request REC creation, retroactive REC creation through WREGIS, that's a lot of R's, is a proposal or a process where we do continue use of the Interim Tracking System, or at least use of the reporting that we do for the Interim Tracking System.

Continue to fill out the CEC's reporting form so that you know how much generation is at issue, and then you either track them in the ITS or we just have those forms, and as soon as everything is straightened in

WREGIS we can have the retroactive certificates created.

So, kind of a combination, any combination thereof would work. But the most important issue for us is being able to have something in place that would allow us to be able to count the electricity that was generated by our CEC-certified facilities during this process where we were switching over to WREGIS.

MR. KOOTSTRA: Does anyone else have any comments on this topic?

MR. PAPPAS: This is John Pappas from PG&E. You know, this is an issue that I know that we've experienced over the years. And having the ability to use the Interim Tracking System has been useful, particularly for some of those projects that -- and this is kind of similar to the certification issue where, you know, maybe they just didn't get their project registered quickly enough in WREGIS, and it gives them the ability to be able to get that done.

And, unfortunately, there are limitations in terms of retroactive REC creation in WREGIS. So, I would support some kind of accommodation here so that, you know, you can count all of the RECs that are created.

MR. KOOTSTRA: Thank you.

MS. BERLIN: And I don't want to beat a dead horse, but I do want to emphasize a couple things here. It’s that we’re talking about eligible facilities. So, this isn’t a new facility. This isn’t something that was, well, maybe it’s not going to count in the future. They were counting and then it’s just a paperwork -- all of these end up being paperwork, administrative snafus between the transfer from ITS to WREGIS.

And we’ll reemphasize points raised this morning about the no harm/no foul. And a point that Mr. Pappas made this morning about the fact that we should not be under-counting our renewables, any more than we should be over-counting them.

And at least for Santa Clara there’s quite a few megawatt hours at issue and so we would really appreciate being able to work with you through a resolution. Thank you.

MR. KOOTSTRA: If there’s no other comments, is there anyone on WebEx that has indicated they want to speak -- or Gina Barkalow.

MS. BARKALOW: I’m Gina Barkalow, RPS verification. And I guess one other concerns I have about using the ITS is the new legislation allows 36 months to retire the RECs. And so, we’re really trying to phase it out and have everything in WREGIS. It’s just so much easier to not have to worry about double counting if we don’t have the Interim Tracking System.

And so, if we were to consider something like this, I just know if we would have the ability to restrict it to it can only be -- the Interim Tracking System could only be used for generation reported for the year that it was generated in, rather than seeing an ITS claim coming out three years later. So, that’s just my concern with that.

MS. BERLIN: I appreciate that, Gina. And we were talking about trying to present possible solutions, not just presenting our problem and asking you to fix it.

So, that was why one of the issues that we came up with is to track it in the reporting form, but not necessarily have you register it through the ITS where sits on the reporting form perhaps during -- for a set period of time until WREGIS goes and creates certificates for them.

So, eventually they will have WREGIS certificates, and if that would make a difference to -- I think it would alleviate the concern you’re raising, but I’m not sure. But we’re certainly looking into different options that would take care of that concern and still allow us all to comply with the 36-month retirement requirement and related stipulations.

MR. TUTT: And this is Tim Tutt from SMUD. And I’d just add that I understand that concern, as well. And I think that what we’re talking about is accommodating, in the short term, some of the understandable initial snafus in all the POUs, and their generation resources moving into WREGIS and getting all that straight.

So, there could be kind of a initially, a one-time you can use the ITS for a little bit longer, with some restrictions as I mentioned.

Again, in the longer run, if there’s a lot of discomfort about keeping the ITS around for these cases, I think that the alternative is getting established a change in the WREGIS rules, in part so that the State entity is not the only party that can ask for retroactive creation of certifications, or pay for that.

I mean, it seems reasonable if the generation is happening and, actually, in our case the generation is in WREGIS, they just won’t create RECs for it, then why shouldn’t we or our counterparty facility be allowed to ask WREGIS to create those retroactive certificates?

The only reason right now is that the system was set up with a particular concept of it’s being driven by California RPS and other RPS programs. And if those programs required retroactive creation, then they would allow those programs to ask for it and pay for it.

But we're in a more mature market now and I think there's a reasonable accommodation that could be found in WREGIS to allow even counterparties, you know, other stakeholders to apply for that retroactive certification.

It might take some time to change the WREGIS rules and that's why I think in the interim maybe, you know, an accommodation with the Interim Tracking System makes sense.

MR. KOOTSTRA: All right, thank you very much.

We're going to head back real quick to incremental generation, so the appropriate method for determining incremental generation from both hydroelectric facilities and other resource types.

We current require the applicant to establish an historic baseline of generation from that facility. For hydroelectric facilities that's 20 years of generation data based off of monthly data.

For most other facilities it's three years.

And in particular, for hydroelectric facilities that don't meet the initial 30-megawatt cap, large hydro facilities over that cap are allowed to expand if it's related to efficiency improvements, and in then in theory their capacity can grow, and only that increment can be eligible.

So, John Pappas, I know you have something on this.

MR. PAPPAS: Yeah, thanks for that background. So, you know, basically right now if you have an incremental hydro facility and if it gets certified, the amount that you get to count would be the amount each month that's over and above the 20-year average for that month.

So, let's say if we're talking about a hydro facility here, so let's say we're in a dry year more than likely you will probably get to count nothing in that entire year, assuming that you're below the baseline.

And then the opposite might occur in a wet year, where you get to count a lot more than the efficiency improvement.

And then maybe in a normal hydro year you would probably count, basically, what was in the efficiency improvement that the FERC license had.

But that may not necessarily be the case because you'll have variability from one month to the other.

So, instead of having that kind of feast or famine, you know, some years you may count some generation, other years you may not, what we'd like to see is the ability to be able to count each and every year and to have some fixed percentage.

And in the FERC license and, in particular, the project that we have, and I won't get into the specifics, but there is -- in order to get an efficiency improvement approved by FERC, there's a lot of different showings, and there's tax benefits, and so on, and so forth.

But as part of the FERC decision you actually have an approved efficiency improvement for that particular project, whatever the percentage is, four percent, five percent, six, ten.

And so our proposal would be to basically allow -- count whatever that FERC-approved percentage is each and every month. And so whatever the generation is, you multiple it by the FERC-approved percentage and that would be your RPS-eligible generation.

Instead of, you know, comparing it to some 20-year baseline that would vary from year to year.

MR. KOOTSTRA: Thanks.

MR. PAPPAS: We'll write this up in our comments, but I wanted to at least introduce it and let folks know what we were thinking in case they had -- I mean, we're certainly open to other ideas, but we thought that this would be pretty logical and you would get a contribution, again, each and every year, and each and every month for that matter.

MR. KOOTSTRA: Out of curiosity, I don’t know if you are aware if FERC issues those similar documents for your situation for a variety of technologies, so they would signify that this percentage is incremental or is new generation. Do you know if that’s something specific to hydro?

MR. PAPPAS: Yeah, I don’t know about other technologies, but I know that it applies to hydro.

MR. KOOTSTRA: Okay. Does anybody else have any comments they’d like to add on the situation? Please come forward. We were empty, so we had everybody come to the table.

MR. HENDRY: Thank you and good afternoon. I’m Jim Hendry. I’m with the San Francisco Public Utilities Commission.

I just had one comment on PG&E’s suggestion that for some of the hydroelectric facilities, at least I know for San Francisco, and I believe for Los Angeles, they’re not under FERC licenses. And so if you wanted to craft this proposal, you may want to do it as an either/or proposal where you could use the existing methodology or, if there’s FERC licensing available, you could use that proposal. Something like that just to reflect both options are available.

Because I know for San Francisco, as I said, our facilities are not FERC licensed, there’s no documentation we could provide.

And as I said, I think for Los Angeles and some of the other, some of the older facilities pre-date FERC certification. So, that’s just a consideration we’d like to see kind of followed up on.

MR. KOOTSTRA: Thank you.

MR. TUTT: Yeah, I would support that as well, I mean, having the option, certainly.

MR. KOOTSTRA: All right, if there are no other comments and no one on WebEx, we’ll move on to the next topic.

If you’re sitting not at the table, and you want to participate, please come forward. And if you’re at the table and you want to go back, feel free to as well.

The next one is distributed generation, participation in the RPS as a general question, as well as metering requirements.

And so some background and distributed generation facilities have been eligible for the RPS from the get-go. The question has come into how has that generation been sold or if it’s been sold?

Facilities that meet on-site load, that have not had contracts for both electricity and RECs, have not been historically able to apply for certification because they couldn't meet the requirements necessary to provide and RPS-eligible product.

With the adoption of the May 12th edition of the Guidebook -- sorry, May 2012 edition of the Guidebook that changed and we allowed facilities to be RPS eligible regardless of their ability to sell a bundled product.

And we've been treating facilities as eligible going forward from that date.

With that, we did continue to require revenue-quality metering on these facilities.  Not all facilities have that.  In fact, a lot of rooftop solars don't.  They have inverters with a -- instead of an independently verified accuracy of plus or minus two percent or better, they have a self-verified accuracy of five percent or better.  And in some cases they don't have any metering at all.

So, that's general background on that.  I know that Tim had a general question or statement on that.

MR. TUTT:  Yeah, I think that covers some of the issues that we've seen with distributed solar and other distributed resources participating in the RPS.

I mean, first, there's the question of when they were or are eligible. And we've sort of tried to make the case that as solar technologies they've been eligible as a technology for a long time, if not from the very beginning of the RPS.

We understand that in some cases the Guidebooks have said that if you received net metering or incentives under ratepayer programs you weren't eligible, but that requirement has gone away.

I think in terms of general eligibility, our main contention today would be that it's SBX1-2 that said starting in 2011 you have a compliance obligation, and that compliance obligation includes the possibility of using unbundled RECs up to, in the first compliance period, 25 percent of your obligation.

I guess what we would contend is that similar to the 30- to 40-megawatt hydro issue for L.A., which was also brought into the RPS eligibility in SBX1-2, that the eligibility date for this distributed solar generation should not be when you change the Guidebook to reflect SBX1-2, but from the beginning of the compliance period that SBX1-2 put into place, January 2011.

We think that's a reasonable position and it allows that counting of that generation from the beginning of the compliance period for which we're obligated.

Given that or whichever way that goes, there are extensive transaction costs for participating in the RPS, and they are more significant for these smaller generators.

I mean, first, as you noted there’s the metering costs. And while most of SMUD’s distributed generation does have revenue-quality metering on it, we do think that when you have these smaller systems it makes some sense to at least consider relaxing that metering requirement.

I know that you’ve considered that in the past and I’m not sure of the reasoning why you’ve decided not to do it, I guess. I haven’t really seen the white paper explaining the tradeoff between having these resources participate and some concept of, you know, integrity in the RPS.

I think that we’ve made the point that with these smaller systems, as you aggregate them, the discrepancies between each individual system are going to average out or factor out so that you’re going to get the equivalent to revenue-quality meter accuracy in an aggregated form.

That at least should be explored in more detail. If that conclusion or that proposition is not accepted, let’s actually do a study to determine whether that’s a reasonable proposition or not.

And then the other question is the tracking through WREGIS. I mean, I think we understand that that’s where you want all stuff tracked. And these small systems, the transaction costs of being aggregated and being put into WREGIS can be daunting.

I know in SMUD’s case, we have not taken that step, yet, for our residential solar generation, our solar distributed systems.

Because there are some limitations in how you can aggregate in WREGIS. You can only aggregate up to a 250-kw level. And so you end up getting a lot of aggregated units with a lot of generation added into an aggregated total. And being able to verify that and making sure that all of the things are correct for entry into WREGIS costs a lot.

So, I guess the plea is for trying to find out, find some way of reducing the transaction costs for these distributed solar systems so that they can be counted for the RPS.

Otherwise, I fear that they will just be left by the wayside, even though they’re eligible for the RPS and producing viable, in-State, clean generation.

So, that’s the general issue is let’s explore how we can help these small-scale distributed solar systems be eligible, and count, and participate.

I think we're in a world where the Governor has still a 12,000-megawatt DG goal. We're in a world where the incentives for SMUD and for the IOUs are declining to close to zero, if not zero, so those are going away, or have already gone away.

We're in a world where the question of net metering is being questioned; the idea of net metering, that value is being questioned and how's that going to turn out?

And we're in a world where federally the tax benefits for these systems are also uncertain in a few years.

So, if all of those basic incentives or ways of inducing distributed solar go away, should the RPS value also be limited by the administrative structure for participating in the RPS, or shouldn't that maybe be one way that these resources are allowed to participate.

We're all aware that in some states, in some circumstances they have the concept of solar RECs. That allows these distributed generation systems to achieve fairly significant value in an RPS. We don't have that policy. We don't have that structure.

But what we do have is a structure that kind of allows these resources to be eligible, but then doesn't necessarily accommodate the transaction costs of these small systems in being able to participate.

MR. ANDREONI: And this is Tony Andreoni, CMUA. And I want to just echo what Tim focused on and I do want to add one other point.

And that is when POUs came into SBX1-2, you know, obviously, previous versions of the Guidebook has always forced certain type of metering, but not every member actually had the type of grade meter that's being required by the CEC at this point.

And going back to the discussion this morning where we want to count every possible renewable on the table, it seems like it's just kind of arbitrarily knocking off a few of the systems and not accounting for those.

So, you know, where there may be meters that have plus or minus five percent, for example, there really has never been a reason why not to allow those to move forward in certain -- there's never really been a white paper or something I've seen why it's disallowed.

And it has been brought up and we would like to further discuss that.

MR. KELLY: This is Steven Kelly with IEP. I know why it wasn't allowed.

The reason the California RPS is such a well-developed program is two things; transparency and valid data. And when we were developing the program there was a consensus that in order to maintain transparency and the sense of validated -- primarily avoid double counting, there needed to be metered -- revenue-quality meters or their equivalent measuring the output from these facilities, from all the RPS-eligible facilities.

I have a concern that we would now think about moving into a world where we are either self-reporting or aggregating in some engineering modeling way a certain component of the renewable assets, because I have a feeling that that would have a negative impact on transparency and it will have a negative impact on the public's perception of the validity of the information they're getting out of the RPS Program.

I think it has been and should continue to be important that we have a mechanism that measures this production in a reliable way and in an accurate way.

Now, whether it's revenue-quality meters, I don't know. My understanding is revenue-quality meters cost 20 to 30 thousand dollars over a 20-year lifetime, or something like that, of a facility.

DG ranges from something around zero megawatts up to 20 under the Governor's DG proposal. So, there's a lot of DG that is perfectly -- it’s probably already got revenue-quality meters. So, I think what the conversation is, is on a very tiny subset of that, but it’s an important one, potentially very large for purposes of RPS compliance.

So, while we support those -- IEP supports those technologies, we want to make sure that the production from those facilities, that are counted against the RPS, is actually occurring and is not self-reported and those kinds of things.

So, that’s one of the reasons why early on there was a move to a revenue-quality meter or something equivalent. If there’s an equivalent mechanism to do that for these smaller technologies, or smaller resource technologies that would be fine, but there needs to be something other than self-reporting or aggregation, in my view.

MR. LANGER: Can I add something? I think we have -- you know, we’re talking about a couple of different things. We just went from 20 megawatts and I think we’re talking about net metering, too, which might be two kilowatts.

But it’s I think you have to talk about those a little bit different. But we really have some conflicting policy direction here.

We have AB920 for the IOUs, where we have to pay our net meter customers for net surplus compensation, for any excess generation that they have at their anniversary date of their generation every year.

And then in order to get those facilities registered with the CEC and then -- I’m sorry, excuse me, certified by the CEC and then registered with WREGIS to be able to report a REC, and the fact that most of this surplus is less than a megawatt hour in a year, so you don’t even get a whole REC, the administrative aspects for everybody are just going to be nightmarish for the customers, for the CEC, for WREGIS, for the IOUs, or for whatever other off-taker.

And, I mean, the State’s decided, through this legislation, that it’s important that that net surplus that’s being delivered to the grid be counted somehow, and that the customers be compensated for it. It is part of the picture in, really, the RPS for the State.

And I don’t know if we can get into all the nuances of it here, today, but this has been giving, I think, everybody in the industry fits. And at some point I don’t know what’s going to happen, but it feels to me like it’s going to blow up. Because at some point there’s going to be a lot of, you know, like grandma with her solar facility didn’t get paid for her net surplus because she had to spend $300 to register with WREGIS, and she didn't even have a full REC after four years, and you know, she wanted her $17. And, you know, you can just imagine the stories that are going to happen because this is going to be practically impossible for most folks to navigate.

COMMISSIONER HOCHSCHILD: Well, I think in some ways this is the other side of the coin from your point about counting everything accurately, right. It's like when you get down to this granular a level it is a challenge.

The 920 RECs, though, those -- they do not require a revenue-grade meter, or do they?

MR. PAPPAS: Well, I mean actually, as it turns out for the AB920 REC just for the -- well, let's not call them RECs because it's actually bundled energy, but I know what you're talking about.

They actually are measured with revenue-quality meters.

MR. LANGER: But the utilities are already paying off their revenue meters.

MR. PAPPAS: Right, because we're having to pay sort of the Brown price, anyways, so it turns out we are using those types of things.

COMMISSIONER HOCHSCHILD: That's what I thought.

MR. PAPPAS: So, I share the concerns so far.

MR. LANGER: So, there's a metering question, but I guess there's two questions. There's just the participation in the RPS and then there's the metering requirements. I think if you are a utility customer, then you're going to have something that is basically a revenue-quality meter. It's a little different than what we think of for like an ISO meter, or a net generation alpha meter.

But you're going to have something there that's probably good enough.

But I'm just talking about, now, the other requirements we have that really seem to conflict between the legislation and between what the CEC has going on with the WREGIS that's going on.

I'm sure the staff here is concerned about getting a flood of tens of thousands of applications for certification. I know WREGIS has indicated that they're concerned about having a lot of new registrations to deal with, with these little, tiny customers.

So, again, maybe not the best venue to sort out all these issues, but maybe someone should put a pen on that because it really needs to get sorted out.

MR. KELLY: But just a follow up, if I may. The metering is there. That isn't, in your view, the issue.

It's how do you treat this disaggregated resource in the context of counting, and WREGIS, and whatever?

COMMISSIONER HOCHSCHILD: But hold on, hold on, is the metering there? Because, I mean, a typical customer that's exporting to the grid, let's say, an annual net surplus, right, they have a meter on their inverter and not a revenue-grade meter, to my knowledge.

MR. LANGER: Well, they'll have their retail meter.

COMMISSIONER HOCHSCHILD: So, you're saying the Smart Meter on the home.

MR. LANGER: Right.

COMMISSIONER HOCHSCHILD: Which is sufficient.

MR. LANGER: Effectively revenue grade.

COMMISSIONER HOCHSCHILD: Yeah, okay.

MR. LANGER: I'd have to look at for that particular meter if it meets the --

COMMISSIONER HOCHSCHILD: Well, isn't that going to be the --

MR. TUTT: For AB920 customers, the amount that's tracked is the amount that's tracked through the home's revenue-quality meter. That's what you get, you know, a credit for or what you pay.

COMMISSIONER HOCHSCHILD: Right.

MR. LANGER: That's right.

MR. TUTT: Again, in SMUD’s case, most of our distributed generation systems have revenue-quality meters, so that’s not necessarily an issue specifically for SMUD.

But when the -- I mean, I don’t think anyone’s talking about self-reporting, for example. I mean, what we’re talking about potentially, in the past, would be using the five-percent accuracy meters on the inverters and wondering whether for these smaller systems wouldn’t that be good enough given the transaction costs of adding meters to them, particularly retroactively.

But in the future, I think for SMUD, what we’re talking about potentially is the option of in the new Smart Meter world having a communication between the meter and the inverter which allows us to install these systems, potentially, without the additional cost of a duplicative revenue-quality meter on the system.

Don’t we want to continue trying to reduce the costs of these distributed systems? And shouldn’t we then think, at least think about whether that metering requirement is reasonable in the Smart Meter world?

And I’d add one more thing which is in terms of aggregation I fully understand the IOUs’ dilemma here. You’ve got most of the generation from these system with the RECs owned by somebody like SolarCity, and they could aggregate these units, potentially, into something and put them in WREGIS if they felt the transaction costs were worth it.

My understanding is that these companies that own these RECs haven’t figured out how to do that, yet, because the transaction costs are pretty high.

But for the IOUs, they’d have to aggregate just the surplus generation from the same facilities into another kind of unit, and they have a lot less generation to aggregate per unit.  So, the costs for them are just, you know, impossible to deal with.

MR. KOOTSTRA:  Yeah, this is Mark.  I’m going to step in on that one real quick, sorry.

It’s my understanding that if SolarCity, for example, owns the RECs on a facility that facility cannot participate in AB920 and that surplus compensation for the renewable adder.  Is that correct?

MR. PAPPAS:  That’s correct.  Actually, the tariff that we have filed, which I don’t know if it’s -- it’s soon to be approved or at least dealt with by the Commission, requires that the party, you know, attest that they actually own the REC.

So, if SolarCity owns a REC, then we wouldn’t be paying them for that net surplus, for the green attribute of the net surplus amount.

MR. KOOTSTRA: Okay, thank you for that. Sorry, Tony.

MR. ANDREONI: And this is Tony, again, with CMUA. I just wanted to clarify I’m not -- when I made my statement earlier, I wasn’t talking about any of the CMUA members looking at self-reporting. These are systems that are using meters today.

And it’s just probably a timing issue of when actually grade -- you know, higher grade meters are actually available and used for those particular instances.

So, I’m just saying there are other meters that were used, and they’re probably smaller systems, but let’s not disallow them. And I think that we would certainly like to have that conversation, again.

And I’m sure some of our other members will have additional comments. I know L.A. was in the room. I’m not sure if they’re going to be on the call.

MR. HENDRY: Yeah, no, the San Francisco PUC agrees with this issue with CMUA and SMUD, as well. And it arose when, in part with the Go Solar SF Program, which you initiated, Commissioner Hochschild, and that as part of the incentives we would receive the corresponding renewable energy credit.

And then the issue was, well, we couldn’t really use it because these weren’t the possibly -- the hyper-accurate meters.

And so, I think as Tony’s said, there are revenue-quality meters more or less that are good enough for billing and kind of doing that surplus calculations and whatnot, and plus or minus five percent accuracy, and not the two percent, which is what the current RPS Eligibility Guidebook requires.

And, you know, there’s sort of a benefit of large numbers of, if you start bringing lots of these numbers, the meters that are high are probably offset by the meters that are low and they will zero out.

And one option, for which there’s not unanimity, but is the potential to even, if you really are worried that they may be over-reporting, is you just arbitrarily discount it. That, okay, you take the meter read and you get 90 percent credit.

So, not only are you having the benefit of the statistics of over and under reporting should equal out, but then we take another five, ten percent off of that to be extra sure that what is actually generated actually is renewable energy and has a corresponding credit to it. So, that was an option.

I think there’s sort of a general principle people want full credit for it, but that was an option that was talked about as well.

MR. KOOTSTRA: Okay, does anyone else have comments on this topic?

There is someone on WebEx. We're going to try and unmute you and then, hopefully, that will work. Please introduce yourself when you're unmuted. We should have you unmuted.

MR. SCHWARTZ: Hello?

MR. KOOTSTRA: Yes, please continue.

MR. SCHWARTZ: Okay. All right, sorry. Yeah, so Andy Schwartz from SolarCity, first thanks to -- I want to thank Commissioner Hochschild and CEC staff for the opportunity to speak at today's forum.

So, I don't really have anything to add to the discussion that we've just had, other than to align myself with the comments that have been made by others regarding the need to have a continued discussion to figure out ways to really reduce the transaction costs to allow customer side DG to more fully participate in the RPS Program.

And I think as Tim, really, very comprehensively described, it's a pretty fraught regulatory environment right now for solar with incentives winding down, with uncertainty around the direction of the NIM Program, and with changes in the ITC.

So, I think from an industry perspective there's a lot of value in being able to figure out ways to monetize the value that's embodied by a REC.

So, I would just encourage the Commission, consistent with what other parties have said, to explore options to reduce the transaction costs of participation. Thanks.

MR. KOOTSTRA: Thank you very much.

Do we have any additional comments on WebEx? No.

If there's no other comments in the room, we're going to move on to the next topic.

Biomethane, this is a very general proposal. So, I believe Tim Tutt was the one that wrote this one, so I'm going to let you start.

MR. TUTT: Thanks, it is general. I don't know how it could be made more general, I guess, but you know.

I think that the concept here for me was simply that we've gone through one round of implementing AB2196 and it may be time to sit back and think about whether or not all of the requirements in the Guidebook, as pursuant to that law were really worth it and whether they should be changed going forward.

Not in violation of the law, but just to keep in mind the purposes of the law and information gathered.

And I'm mainly thinking about, you know, the variety of small dairies and landfill gas facilities in this State that, unfortunately, got caught up in the Legislature's decision to say that biomethane consists of landfill gas and digester gas.

Even though these landfill gas and digester gas facilities burn the -- generate the fuel onsite and aren't participating in any common carrier structure, they've been required to go through a series of additional information submittals, which aren't final yet, as I understand it, and back and forth with the CEC to try to understand whether they met the requirements of AB2196 which, in my mind, was not at all targeted towards those small facilities.

So, I think my general question and plea here is to try to see whether the Guidebook can be changed so that the burden on these dairy and landfill gas facilities is not as significant as it has been in the last year.

And maybe that's all going to go away, anyway. I don't really know. But I think it's worth thinking about how the Guidebook can be changed to reflect the fact that most of us, if not all of us, think that those weren't the facilities targeted by the legislation.

And I guess I'd say one other thing, which is my staff tells me that there's another kind of biogas which comes not from digester gas or landfill gas, and it's unclear whether that should be included in the definition for biomethane or whether that would be a problem.

Or whether, if it's not included in the definition of biomethane, whether it would be included at all in the RPS.

And this is -- Gabe, this is the gasification of -- yeah, SIM gas.

MR. KOOTSTRA: The gasification of municipal solid waste?

MR. TUTT: No, gasification --

MR. KOOTSTRA: Or just general biomass?

MR. TUTT: The gasification of biomass, correct. SIM, yeah.

MR. KOOTSTRA: Okay, if there's nobody else I'll just -- I'm sorry, please?

MR. KELLY: The gasification of what?

MR. TUTT: Wood.

MR. KELLY: Wood.

MR. TUTT: Yes.

MR. KELLY: I want to see the list.

MR. KOOTSTRA: So, I'll just address a little bit of your concern about there are some facilities that don't have this information in. I believe the vast majority of those that have submitted us any information, that's been for the most part taken care of there. A few that we're still working on a few items, or that have resubmitted and so some stuff needs to get resolved.

But in addition, there are some of those likely dairy digesters and landfill gas facilities that never submitted anything to us and they are technically standing as suspended, so you're not able to claim any generation from them for a facility -- utilities.

We are gearing up to start contacting them again and let them know that you have these requirements so we can, hopefully, move through that before we get to a year of them being suspended, in which case they can move to disapprove.

We don't want that, either. So, we are engaged in that process, it's just it takes time to contact these folks, as you know.

But if you are a utility and you have digester gas facilities or landfill gas facilities, and you don't know that they've met all these requirements, I recommend that you follow up with them.

We plan to do the same. But just be on top of it. Until we're able to change something, if we decide to change something, and this is unfortunately how we are, and I'd find it very unfortunate if these guys fell through the cracks even further.

So, just please help us stay on top of that. We get a lot better results when they get it from us and the utilities.

Are there any additional comments on biomethane in general?

Is there anyone on the WebEx that wanted -- okay.

We're going to go back to another general topic. This is the last general topic unless -- yeah, the last general topic.

This one kind of borders on out of scope, but kind of not, so I'm going to let Tim Tutt introduce this one a little bit more.

But, obviously, there needs to be some consideration for how the Guidebook and the POU regs work together. And as much as that's part of the Guidebook I'm happy to hear information that you have.

MR. TUTT: Yes, I understand that the POU regs are out of scope for this workshop, so I'm not talking about any changes there.

But I've just recognized that there are some instances, based on the adoption of the Guidebook and the regs perhaps at different times, and that may continue in the future, where there are things in the Guidebook which cover the same areas as the regs and they're not necessarily consistent.

And so, I think the general plea for me is to, when you're changing the Guidebook going forward, make a serious attempt to try to remove anything that's already covered in the POU regulations so that that inconsistency doesn't expand or continue as much as possible.

I also think that generally understanding the history of the RPS Program and the Renewable Program at the Energy Commission, you worked with guidebooks all through this structure until SBX1-2, when you now have regulations for the POUs.

And I'm not sure of the right course of action in terms of how those interact. I just think it's worthy of consideration because, in general, I think what you'd want is to have the RPS Guidebook cover any general eligibility issues for the IOUs and the POUs. And the POU regs cover specific things for the POUs in the RPS.

But I don't think it's quite that clean, yet, and I don't know if it actually can be. But I think you should strive for that because otherwise you're going to get into these questions of how does -- I mean, the Guidebook says this and the POU regs say that, and they're not consistent. What do we do? That's the basic concept.

MR. HERRERA: A quick comment on that, Tim, this is Gabe. So, you recall when we were developing the Guidebook that we were also simultaneously working on the reg development. And we knew that the Guidebook would come out before the regulations and tried to signal, provide some guidance that the POUs and the retail sellers could rely upon, right, until the POU regs were out.

And so that's why, when you take a look at the Guidebook, there are provisions that talk about reporting requirements that are repeated, for example, in the POU regs and are specific to the POUs.

But there are reporting requirements with respect to verification that also apply to retail sellers, as well, right.

So, you need to cover them both in the Guidebook to some degree and in the regulations.

But when we do revise the Guidebook, we will try to remove the duplication in the -- I know there was some inconsistency on reporting requirements and we advised POUs to follow the direction in the regs, rather than in the Guidebook. That was the latest word from the Commission on those particular issues so --

MR. ANDREONI: This is Tony, again, from CMUA. And I'll add to what Tim has said because it just so happens to be that CMUA provided comments on this on multiple occasions during the POU reg development, through the adoption, and through changes with the RPS Guidebook.

And I understand the RPS Guidebook has a different process than the statutory or the APA requirements for the regulations.

So, in the past, and we definitely appreciate the workshop today on discussing the RPS guidance. It would be nice to have some alignment, but at the same time when you do go towards creating a version 8, or whatever version you call it, that the same amount of time on providing written comments by electric entities be considered.

In other words, a 45-day period is certainly a lot better than a 10-day period as we're going through changes with the Guidebook.

We just didn't have enough time to comment. And I understand you all are under very difficult time constraints in getting those documents out to everybody, but we do see it having the same amount of teeth as the regulation. And we would like to have more time to discuss some of the changes, especially at the last minute.

And I do recall there were some last-minute changes that came up and, you know, we do have to spend some time examining what those changes mean to our members.

So, I would just kind of throw out the idea that even though you have different requirements to follow because of the Guidebook coming before the rule, I would just ask that, you know, somehow there's some additional time provided.

MR. KOOTSTRA: On that topic, with additional time, obviously for a business meeting, when we go to adoption, the only additional time you can have is before the business meeting.

But when it comes to a workshop on that proposed language would it be more helpful to have more time after the workshop, or before, or something mixed in between?

I don't know how many people actually read the Guidebook revisions before going to the workshop, or if they want to have the highlights pointed out to them before they decide to make comments. So, that information will be helpful.

MR. ANDREONI: So, there’s two things that you’re bringing up. In one instance, you know, under AP requirements, the rule, you actually have to address all the concerns that were raised.

With the Guidebook, you don’t have to address the concerns. So, we’ll have a workshop and many of us don’t actually see what kind of direction that the Energy Commission may go on some of the suggestions.

So, you know, if you provided a list of changes that you’re making to the Guidebook, and the reasoning behind that before, that would be great.

But if you’re doing that ten days before going to a business meeting, it doesn’t really give us enough time to examine some of the changes that were left out, and we’re not really sure why they may not have been included.

So, to have some additional dialogue before going to a final adoption would be helpful. And that’s almost like providing what you’ve done in the past, a 45-day comment period, a 15-day change under the rule development gives us a little more time.

It would be nice to, you know, be able to see those changes, understand them before we actually make any additional statements as part of the record.

MR. KOOTSTRA: Thank you.

MS. BERLIN: This is Susie Berlin. At the risk of going out of scope, and you can tell me if we are, Gabe, I was hoping, Gabe and Mark, if you can provide some clarification on the relationship between the Guidebook and the POU rules as it pertains to the reporting forms that are POU-specific.

So, I'm hearing that they have to be changed as part of the Guidebook, if they need to be updated, but they're not. Well -- okay.

MR. HERRERA: So, earlier when I made that comment, I do know that there were some dates. I mean, when we were developing the Guidebook at that point in time we thought there was a reporting -- certain reporting dates that we were going to follow in the regs. I think the draft regs had that and then, ultimately, we changed the reporting dates in the regs to provide more time.

And so, the one instance that I'm thinking of, that's in the Guidebook, allows for lesser time to report, rather than more time.

Anyway, in terms of changes to POU reporting forms --

MS. BERLIN: The forms, themselves.

MR. HERRERA: Right. So, if there are changes, you know, formatting changes, or information, as long as those changes are consistent with the text in the regulation, I think we’re okay.

The same holds true with the Guidebook. I’m not sure if we need to -- I’m not sure what changes we might need to make, but we certainly have that discretion to do that.

MS. BERLIN: So, if we do need to make changes, formatting, something in the forms themselves, does that have to be part of the Guidebook process? Or because they’re attachments can you fix the forms?

MR. HERRERA: I think we can fix the forms as long as whatever we were requesting as part of the forms was consistent with the direction of the text in the Guidebook or the regulations themselves.

MS. BERLIN: Okay, thank you.

MR. HERRERA: Yeah. You’re not asking for permission to change the forms yourself, are you? No. Because I do know there’s a --

MS. BERLIN: Is that what you’re granting? Okay, so if that’s off the table, no. No, I’m talking about the CEC making minor revisions as we work through them and find that there are some aspects that just don’t work.

No, not unilaterally this is the form I’m going to use.

MR. HERRERA: Right, right. I think there was a request by one POU, and I'm not going to identify them because Tim would be embarrassed but --

(Laughter)

MR. HERRERA: -- I thought there was a request to unlock the forms that had been -- installed some macros, so that additional lines could be added. I think that would be a problem.

MR. ANDREONI: We actually suggested a group of trial and error. You know, basically, we just sent out your forms and determine are there some errors, and we provide some fixes, just as some assistance.

MR. TOMASCHEFSKY: So, Gabe, I think just in characterizing what you said, I think it's the unfortunate timing of the sequence of getting the regs operating and getting the Guidebook is the fundamental problem here.

So, generally what you wouldn't see is you wouldn't see any changes to the regulations that would occur, you know, as a result of the Guidebook being updated. It would actually be in reverse.

So, if there's any changes to regulations, you would then see subsequent changes to the Guidebook in the future.

And then you still have the ability to tweak things within the Guidebook, going forward, that don't change the intent of what the regs say.

So, if we're talking about forms and you're talking about your interpretation of what the regulations say, you can interpret it in a certain way and then say, okay, based on input from everyone we're making additional adjustments to that, which doesn't change the intent of what was said here on the regs.

So, I think that's the cadence behind it is nothing that gets changed in the Guidebook pushes the changes in the regulations, but regulation changes would then be accommodated in the Guidebook.

The sequence is --

MR. HERRERA: But I think I was speaking generically. If there's a rule in the Guidebook that requires the reporting of certain information, as long as the forms on which that information is reported is consistent with the rule itself, I think the Commission can make those changes.

And that holds true both for forms that are prepared for the regs and forms that are prepared for the Guidebook, as well.

MR. TOMASCHEFSKY: Yeah, I think to Tony's point, as far as the 10-day period, I know that in terms of avoiding APA rules the 10-day rule works well within the Commission. But just in terms of getting feedback from the public 45 days may be too much, but more than 10 days is probably good in terms of having an exchange.

If you want a realistic exchange from stakeholders, when those things come out, it’s probably helpful to build in a little bit more time into the deliberation process.

MR. ANDREONI: Let’s split the different, let’s call it 30 for starters.

MR. TOMASCHEFSKY: Or 27.

MR. HENDRY: So, can I ask another sort of follow-up question to that?

In the regulations, I won’t go into the details, but there’s two ways you can interpret the regulations. And then you look in the Guidebook forms and they seem to have interpreted it one way. And as far as I can tell there’s been no debate about whether -- you know, which interpretation is correct. It’s a new issue and we haven’t really talked through it, yet.

So, what would the forum be for having the discussion about are there forms in the Guidebook, which interpretation is correct and then that, in turn, flows through to how the forms change.

Should that be in our comments, or is that a separate process? Or if we don’t do it in the Guidebook, can we not do it anyplace else? I guess that’s kind of just the process question, where do we raise this issue?

MR. HERRERA: So, you can raise those in the comments that you provide.

MR. HENDRY: Okay.

MR. HERRERA: If you don’t give in the comments, and you still feel that there’s a need to make those changes, perhaps a call to staff, perhaps a webinar.

I mean, if the idea is to communicate the need for change to us, or to raise questions, then just bring it to our attention.

MR. HENDRY: Okay, good. Thanks.

MR. HERRERA: If you know some specifically, James, maybe you can provide those in the comments.

MR. HENDRY: Okay.

I guess I have one final comment on the interaction and this is just a thought that occurred to me this morning, and it’s regarding the storage issue.

And I think there’s kind of two issues. One is I think there’s a technical issue of how you count storage for RPS and make that eligibility.

But I think what will be probably more complicated as it relates to sort of the POU regs and the IOU regs is then what the portfolio content category of that storage is. Is it going to be -- you know, and I think that's maybe a more complicated issue than figuring out how you count whether a megawatt goes into storage and comes out or not.

MR. KOOTSTRA: I would agree that's a very complicated issue. It all depends on what realm we look at it. I mean, if it turns out to be a portfolio content category issue, then it would have to be something we'd have to work with in the POU regs, and work with the CPUC.

MR. HENDRY: Right.

MR. KOOTSTRA: I don't have an answer for you at this point but, yeah, it's complicated.

MR. HENDRY: Yeah, I just raised it as an issue that we need to -- I think it's going to be more complicated, but it needs to be resolved at some point.

MR. TUTT: I guess I have one other general comment on this issue. And I came from the Renewable Energy Program. I'm kind of used to guidebooks. And, you know, they're good ways of doing business in my mind. They are flexible, they allow for changes to be made when necessary, fairly quickly.

As opposed to regulations, and I understand the regulations in this case are necessary.

But in general, if there’s a question as to whether a particular topic should be covered in a guidebook, versus the regulations, I still want the separation where possible, but I’d want to have it covered in the Guidebook.

Because in that case, if something comes up where you want to change it, and for a reasonable and good market reason, you have more flexibility of doing that.

I know there’s one instance where we advocated that a particular topic be kept out of the regulations and remain in the Guidebook so that there could continue to be discussion and flexibility about how that could be handled. And that didn’t happen.

It was actually inserted into the regulations, as well as being in the Guidebook.

So, I would prefer that that doesn’t happen in the future is my point.

MR. KOOTSTRA: If anybody else has any other comments, please let me know. John?

MR. PAPPAS: Not on this issue. Do we still have a few others or --

MR. KOOTSTRA: No, this is actually the last of our issues. So, if anybody has something that they want to bring up real quick?

MR. PAPPAS: Yeah, actually, I had a second issue. I don’t know if I missed it. And this had to do with the counting previous deliveries for eligible 40-megawatt or less generation that are part of a water supply or conveyance system.

MR. KOOTSTRA: I think I intended to roll that into another topic, but I wasn’t clear on that so --

MR. PAPPAS: Okay, can I still talk?

MR. KOOTSTRA: Yeah, go ahead.

MR. PAPPAS: And first of all, I also just want to thank you, and your staff, and Commissioner Hochschild for -- I think this is a great workshop.

MR. KOOTSTRA: Yeah.

MR. PAPPAS: So, really, I’m sure I, you know, echo others’ feelings as well, so really well done.

But let’s get -- so, this really relates to the ITS and this is more of a specific example. But you had mentioned this new category of RPS-eligible resources, which is basically the 40-metawatt unit that’s part of a water supply or conveyance system.

And this came about as a result of SB1X2. And in the 7th edition of the Guidebook there was, you know, the requirement that some of these facilities could be RPS eligible. And that if you applied within 90 days of the adoption of the 7th edition, which in this case turned out to be July 29th, of 2013, that you had the ability, you could count that generation of RPS eligible, if it was approved, all the way back to January 1st, 2011.

And so, actually, we've done that and I noticed, actually on your website, that there's probably around 20 or so projects that have applied, just based on the information I've seen there.

So, we went ahead and we've applied within that 90-day period, and we've also registered the project in WREGIS. However, WREGIS only goes back 75 days, so we're only going to be able to get generation, say, back to June of 2013, maybe May. I'm not sure exactly.

And I think this -- in order to really implement what the Guidebook is trying to implement, as well as what the legislation's trying to implement, I think the only way to really get to count those, that generation, if the projects are approved, is to use the ITS.

So, the solution to the problem is to allow the ITS to be used for that circumstance so that the actual intent of the legislation can be realized.

MR. KOOTSTRA: Thank you on that.

Is there any additional comment that we have? All right, we're --

MR. PAPPAS: And I was going to say, we'll put this in our written comments, as well.

MR. KOOTSTRA: Yeah, I do look forward to reading those. And I look forward to reading everybody's written comments. Believe it or not, I plan on reading all of them.

So, for next steps, once we have all the comments together, as well as the transcript, so we can actually review this in full, we'll work with Commissioner Hochschild to determine what topics we will cover in the RPS Guidebook, and what direction we're going to take in the revision process.

Some topics may be covered in our revision process by doing nothing. So, just because we didn't do anything, maybe as suggested, we identify topics that we decided not to cover because we've chosen not to do anything, and we like the status quo.

But we'll develop draft language of the Guidebook and come out with that information so you can see it.

We'll see about how long of a time we can have for comments. I agree, the longer you have the better comments we get, the better Guidebook we have as an end product.

But it's, again, a balancing act of how long are you willing to let this take.

I strongly suggest you all submit written comments, both to dockets -- and if you do it via e-mail, please send it both to the docket, the e-mail address, as well as the RPS 33 e-mail address.

Things that go to dockets normally take a couple of days to get processed. And if lots of people submit, it takes even longer. So, if it goes to the RPS 33 address we get those quicker and we can actually start our process faster.

Paper copies need to go to the Dockets Office at the address here. Full instructions are in the notice, itself.

The timeline, so we're looking at a draft Guidebook, with draft language and underlined, strikeout in the second or third quarter of this year. It depends on the direction we get for what topics we want to cover and how expansive those changes are.

With adoption either the third or fourth quarter, again based off of how much we decide to change and cover, as well as your comments on the proposed language.

Please keep in mind that we're working to make the Guidebook as clear as possible, and consolidate it as much as possible, so you might see a lot of changes in it that aren't actually changes to what the Guidebook is intending and saying, but will be represented that way because we need to show all tracked changes.

So, just please bear that in mind. We do normally list or provide a list of changes that we have proposed in the Guidebook and we'll try to make it clear if this is a streamlined change, or if this is an actual requirement change.

This is my contact information. Please feel free to get in touch with me if you have any questions on the Guidebook, itself.

I can't help you much on the regs. Right now that's going to be Emily Chisolm which, hopefully, you'll have her e-mail address, if it's not already on the website, and contact information.

But please, let me know if you have any questions on the Guidebook or this workshop, I'd be happy to chat with you.

Otherwise, thank you very much for coming. We appreciate it greatly.

And I think Susie wants to say something.

MS. BERLIN: I just had a quick clarification. You were saying that the written comments need to go and be mailed to the Docket Office, but you're saying that was just in the alternative of submitting -- there's been no change where they have to be submitted in hardcopy?

MR. KOOTSTRA: They only need to be submitted either via e-mail or hardcopy.

MS. BERLIN: Either/or still. Okay, thank you.

MR. KOOTSTRA: Yeah.

COMMISSIONER HOCHSCHILD: Yeah, I just wanted to take a minute and ask -- first of all, thank you, everybody, for spending five quality hours together.

And I just wanted to acknowledge Mark and just let’s give him a round of applause for putting it all together. Thank you.

(Applause)

COMMISSIONER HOCHSCHILD: Are we wrapped up?

MR. KOOTSTRA: Yeah, we’re wrapped up. Hopefully, we’ll see you later, next quarter or early third quarter. And, hopefully, this will go smoothly for everyone. Thank you.

(Thereupon, the Workshop was adjourned at 2:21 p.m.)

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**REPORTER'S CERTIFICATE**

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were reported by me, a certified electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

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Barbara Little

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