STATE OF VERMONT
PUBLIC UTILITY COMMISSION

CASE NO. 17-5257-INV

IN RE: REVIEW OF THE STANDARD-OFFER PROGRAM

August 2, 2018
1 p.m.
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112 State Street
Montpelier, Vermont

Workshop held before the Vermont Public Utility Commission, at the Susan M. Hudson Conference Room, People's United Bank Building, 112 State Street, Montpelier, Vermont, on August 2, 2018, beginning at 1 p.m.

P R E S E N T

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By phone:

Galen Barbose, LBNL
Andrew Mills, LBNL
Tom Melone, Allco
Annette Smith, Vermonters for a Clean Environment
Billy Coster, ANR

MR. MARREN: Good afternoon, everyone. It's 1 o'clock. We will get started now, so good afternoon.

My name is Jake Marren, and this is a workshop in Case Number 17-5257-INV which concerns a review of the standard-offer program. Today's workshop we are going to be listening to some presentations from folks from Lawrence Berkeley National Laboratory, but before we get started with that presentation I wanted to remind people there is a sign-up sheet passing around right now. Please fill it out, if you would. Eventually we will get it to the court reporter who is transcribing today's workshop. When it comes time for participants to speak, please identify yourself before you begin speaking so that the court reporter can identify you in the transcript.

At this point I would like us to quickly go around the room and identify ourselves. We will start up here with the commission staff.

MR. KNAUER: Tom Knauer with the commission.

MS. KROLEWSKI: Mary Jo Krolewski with the commission.

MR. HOWE: Micah Howe with the

commission.

MS. RICHARDS: Patty Richards, Washington Electric Co-op.

MR. KIENY: Craig Kieny, Vermont Electric Co-op.

MR. McNAMARA: Ed McNamara, Department of Public Service.

MR. YANTACHKA: Mike Yantachka, State Rep on House Energy and Technology Committee.

MR. QUINT: Andrew Quint, Green Mountain Power.

MS. BAILEY: Melissa Bailey, Vermont Public Power Supply Authority.

COMMISSIONER HOFMANN: Sarah Hofmann, Vermont Public Utility Commission.

MS. FRANKEL: Deena Frankel, VELCO.

MS. WIDMAYER: Amber Widmayer, MMR.

MS. ALDERMAN: Carolyn Alderman, VEPPI.

MS. ANDERSON: Carolyn Anderson, Green Mountain Power.

MR. BRUNNER: Cyril Brunner, Vermont Electric Co-op.

MR. CHARYK: Nick Charyk, AllEarth Renewables.

MR. DePILLIS: Alex DePillis, Vermont

Agency of Agriculture.

MR. ALLEN: Riley Allen, Department of Public Service.

MS. MARGOLIS: Anne Margolis, Department of Public Service.

MR. CASTONGUAY: Josh Castonguay, Green Mountain Power.

MS. FISCHER: Maria Fischer, Department of Public Service.

MS. GRACE: Sheila Grace, Department of Public Service.

MR. DAY: Jason Day, Star Wind Turbines.

COMMISSIONER HOFMANN: And we have John Brabant.

MR. BRABANT: John Brabant, Vermonters for a Clean Environment, hiding up front.

MR. MARREN: Would people who are participating by teleconference, if you would like to take a moment to identify yourself, that would be helpful.

MR. COSTER: Billy Coster, Agency of Natural Resources.

MR. MELONE: Tom Melone from Allco.

MR. FLAGG: Andrew Flagg with the

commission.

MR. MARREN: Thank you very much. This may not be necessarily worth the effort. If you do want to speak, feel free. Just please identify yourself when you do.

We are going to get started with the presentation at this point. I would ask that folks feel free to jump in with clarifying questions if you have them. But try to save sort of the more meaty or substantive discussion items for after the presentation.

And with that, I'll turn it over to Galen.

MR. BARBOSE: All right. Great. Thanks, Jake. Hopefully you all can hear me pretty well. I will say that as folks in the room were going around the table and announcing themselves, it was a bit hard for me to hear folks. So if people do have questions as we move through this material, I guess I would just ask that either, you know, you try to speak kind of close to the telecom mic, or maybe whoever is sitting near to it can be the relay, just to make sure I hear it. If I don't hear a question, just don't be shy about interjecting yourself.

So with that, let me get started here.

I guess the way that we are going to do this, there are actually two presentations here. I'm going to first present on the topic described on the title slide here. I think we will then have some discussion, as Jake mentioned, after that presentation.

My colleague, Andrew Mills, who is also on the line will then have a separate presentation that's focused instead really on kind of the issue of how to kind of incorporate some aspect of locational thoughts and benefits into the bid evaluation process kind of focusing on the bulk power system. So his presentation is going to really kind of do a deep dive into that particular issue and present one possible approach to doing it.

My presentation, as indicated on the slide here, is really more of a broad review of other programs out there that are in some ways similar to Vermont standard-offer program all in some way targeting small or smaller renewables. And so with that, let me get started here. And just to reiterate again, please don't be shy about speaking up if you have questions as we go here.

So first before getting into material itself, I thought I would give a little bit of background on why we are here, virtually here I suppose, and what Lawrence Berkeley Lab's role is. So we were engaged by the Vermont PUC staff to provide them analytic support to this proceeding. This is happening through a program that the U.S. Department of Energy Solar Office is sponsoring called the Analytic Support for Public Utility Commissions program. This is a program that is relatively new whereby states can submit an application to request free analytic support from National Labs.

And so Vermont PUC submitted an application last year to ask LBL to help out with this proceeding. That's effectively why we are here to kind of give you all some sense for what our role is.

So with that, just in terms of the presentation I'll be giving here really the goal is to give all of you just a common factual basis for comparing and understanding some of the different program design options out there with respect to other programs similar to the Vermont standard-offer program. And we did this really just by reviewing publicly available materials, so looking at regulatory filings, and PPAs and RFP documents from programs around the country, and really just trying to synthesize that information into a format that hopefully will be useful and digestible by all of you.

And in doing that, the focus was primarily on some of the issues that have been raised in this proceeding, program design features that are relevant to issues. So principally we try to look at program design features that were in some ways related to this issue of project attrition, looking at program design issues related to bid evaluation, the process and the criteria that were used to evaluate bids, and then finally issues related to how these programs relate to the broader state RPS or other broader state energy policies.

The programs that we looked at are listed here. There were in total 10 programs other than Vermont that we looked at. Obviously this isn't a comprehensive list, but we tried to at least get a pretty representative set. You'll see that most of the programs here are from other northeastern and mid Atlantic states. These are primarily retail choice states and all states that have an RPS. The one non-retail choice state, though it's sort of a hybrid in some sense, California. But all of the others are either New England, New York or PJM states.

So, you know, these programs, they share enough common features that they were included in this review, but they do differ in many important ways. Most of them, however, like Vermont, were created through some form of legislation. That obviously has implications for how much flexibility the PUCs have in fine tuning the programs along the way. Most of these programs are competitive solicitations, but some have standard pricing on a first-come first-serve basis, often really just for the smallest projects, though there are one or two programs in this list that are kind of broader FIT-type programs, not just limited to the smallest project sizes. Of those that do have solicitation, they typically recur on an annual basis, sometimes more frequently. There were a couple programs in the review that really were just one-time procurement events or were more limited-term programs, but that seemed to still be relevant enough to include in this review.

Many of these programs really are just focused on procuring the renewable energy certificates, so that's different than Vermont where the procurement is for kind of bundled REC-plus energy product. There are a few other programs out there that we looked at that were focused on bundled products as well, so it's not just Vermont.

All of these do procure a fixed price contract. Typically the terms are in the kind of 10 to 20-year duration. But there were a few, I think in Illinois, where the contracts were only for five years. The project sizes, obviously we focused here on programs that were oriented towards relatively small programs, small projects. So, you know, by definition we are going to be looking at smaller project sizes typically capped out somewhere in the one to five megawatt range.

As I'll talk about on the next slide many of these programs do include kind of set asides or tiers for even smaller projects below that cap. Many of these programs, in fact, are focused on behind-the-meter project, though some are also looking at utility connected, and some are actually open to both.

You'll see as we go through you may have just sort of noticed in reading over the list that some of these programs really are geared specifically to solar. They are SREC procurement programs or solar EV procurement programs specifically, but some of the others are open to a broader set of renewable technologies like Vermont.

And then last here is just related to the vintage of eligible projects. Some of these programs are open to pre-existing projects. And so that certainly has implications for issues like project attrition, but others are restricted just to new projects. So there is a lot of information here. There is actually a gigantic text table that underlies all of the bullet points here and kind of describes the various provisions in more detail for each of the individual programs, but for the sake of brevity, I thought I would just kind of boil it all down to these bullet points for you here.

So I mentioned that many of these programs do have set asides or tiers of various types. Almost all of the programs that we looked at reserve some set aside either based on budget or capacity for small projects. So that might be projects less than 25 kilowatts or 50 or 100 kilowatts, however that threshold is defined, something well below the overall project size limit for the program. Some programs even have multiple size tiers. So maybe a set aside for the very smallest, if there is set aside for a medium size project, and then lastly some carveout for the largest projects within this eligible size range.

When you're talking about really small projects, though, obviously it can be challenging for those to participate in competitive solicitation, so where that is allowed and encouraged, the programs will typically have some mechanism to facilitate participation by those very small projects, often by allowing bidders to aggregate those projects into a single bid. And where that's done, in some cases bidders can even include some tranche of unspecified projects where they, you know, they are just identifying the number of megawatts that they will ultimately construct, but haven't yet acquired those customers, and typically the solicitation has some requirements as to the time frame within which those customers need to actually be identified.

Alternatively to having some special set of provisions to allow small projects to participate in the competitive solicitation, some of these programs instead really just deal with those smallest projects by having some standard pricing available. So in Connecticut, for example, the DREC program for the less than 100-KW size systems, it's just a fixed price for all projects on a first-come first-serve basis, and that price in that case is pegged to the weighted average price of the next larger size projects which are competitively bid. So there are different ways of setting that price. But the point being that often these smallest projects are treated a little bit differently, and in many cases are kind of excluded from the competitive process that are given another mechanism for participating.

Aside from set asides related to system size, there are other types of set asides and tiers that are sometimes used in Vermont. Of course you guys have technology-based set asides that are used within the latest set of RFPs. There are a couple other states that also have technology-specific set asides. It's not incredibly common though. There are also a few instances where states rather than doing it based on specific technologies will instead do it based on somewhat more general resource attributes.

So the most obvious example of this is in Connecticut where there is, you know, one program for zero emissions and another program for low emission resources. In either case, RPS eligible but differentiated in this instance based on their emission profile.

The other and last example of set asides that we found within the set of programs are in Massachusetts, for low-income customers or site hosts, and then in New Jersey they have used set asides for brownfield sites. So that's really more or less the entirety of what we were able to find in terms of carveouts and set asides that are used within these programs.

So one maybe important point to just note kind of at the outset here is that Vermont's program is relatively small compared to most of the others that we looked at. So in the last RFP, I believe, about 10 megawatts was procured through the standard offer solicitation. In looking at the other programs here we show the number of megawatts awarded through the last annual round of solicitations, and so you can see in both of these other programs it was somewhere in the kind of 15 to 50 megawatt range. Connecticut's programs it was quite a bit more. And so, you know, this obviously on some sense is just a reflection of the relative size of different states, although Vermont is a relatively small state, so it's not altogether surprising that the procurement volumes would be less. But it nevertheless may be important for all of you to think about as you proceed with revising the program and just thinking about how much complexity and effort is necessarily warranted when you're dealing with still a relatively small program.

I see online that somebody has their hand raised on the webinar. I guess if you've got a question, just feel free to speak up.

MS. RICHARDS: I don't have my hand raised on the webinar, but I have it here in the room. Under slide 7 you have the volumes listed by megawatt. Is there any chance you have that data listed on a -- some sort of scale relative to each of the states? So, as you said, Vermont is small. It would be nice to see this data on a some sort of percent of WEC -- not WEC -- the state peak or some sort of scale relative to Vermont and all the other states the same way so we could see how the megawatts really sugar off relative to the size of the other states.

MR. MARREN: Galen, were you able to hear that?

MR. BARBOSE: Yeah, I think I was able to hear enough of it to answer. So we do have later on in the presentation a slide that shows cumulative procurement for each of these programs as a fraction of each state's RPS requirement. So that's kind of one way of scaling it. I don't have in this presentation or, you know, in any ready-made form a version of this that say scales it relative to each state's retail electricity demand. But that later slide, which is one of the last slides in the deck, does kind of help, I think, to get some scaling relative to each state size at least relative to their respective RPS.

MR. MARREN: Was there a person participating by phone who wanted to ask a question? Because someone actually used the teleconference or the webinar system to ask a question. So I didn't know if we wanted to let them speak up at this point. No. Okay. Sorry, Galen. Keep going.

MR. BARBOSE: Yeah. I'll keep going. It may have just been an errant click somewhere. Okay.

So moving along here. So I know one of the issues that's come up in Vermont has just been kind of the dominance of solar PV within many of these solicitations, and that's pretty common. Obviously in many states it's by design. These are solar-specific programs. But even for programs that are open to a broader set of technologies, you can see here that the vast, vast majority of all awards to date have gone to solar PV. Obviously in some cases you've got little bits of wind or hydro or other resources, but pretty much across the board solar PV is dominating these procurement programs.

So kind of moving on to the set of topics related to project attrition. So all of the programs that we looked at here do require some form of site control as an eligibility requirement for even submitting a bid into the program. Really the only exceptions here are the cases that I mentioned where a bidder might have -- might be submitting an aggregate portfolio of small projects and some portion of those small projects are unspecified at the time of the bidding. But that's really the exception and not the rule pretty much across the board. Some form of site control is required. I know in Vermont there has been some discussion around what kind of documentation is required to demonstrate site control. We didn't really dig into the specifics of that, you know, of these documentation requirements, but they do vary quite a bit from program to program. Probably most significantly they vary depending upon whether the program is geared towards behind-the-meter or utility-interconnected projects. In the case where programs are geared towards interconnection -- utility interconnected projects there are at least some instances where site control is required, not only for the project site, but that there is at least some level of site control or some kind of substantive evidence that the sponsor is kind of on the path to gaining site control for the interconnection, the land required to actually interconnect to the utility system as well. So that's one sort of slight variation that can sometimes occur.

The on-site control, we also looked at whether or not there were any requirements related to the status of a project interconnection application as a condition for submitting a bid. And in general, most of them really didn't have any requirements in this respect. I think the one exception was in Rhode Island where projects did need to have already submitted the interconnection application. And then in Delaware there are some requirements really just that within a certain time frame after having received an award that they submit the interconnection application. But beyond that, usually the programs that we looked at are kind of silent on this issue. I mean I think the implicit assumption perhaps is just that, you know, these projects alters -- it's kind of the onus is on them to do whatever due diligence is needed to determine whether or not they are going to be able to interconnect easily.

And that kind of goes to this next issue on the next slide about timeline requirements and performance guarantees.

MR. MARREN: May I interrupt you for a second? We had one question here in the room. Craig?

MR. KIENY: Yeah. Galen, this is Craig Kieny, Vermont Electric Co-op. Wonder if you have any information on which of these states require the project to be in their state or outside?

MR. BARBOSE: So let me actually just go back to the list of programs here. So I think for those programs that are geared towards behind-the-meter systems, and that's not really obvious here, but I think I can probably off the top of my head tell which you which ones they are, and those are Connecticut, ZREC and LREC program. I believe both of the Illinois programs. Delaware program. Massachusetts. New Jersey. LIPA. Really actually I think most of the programs here actually are geared at least in part towards either behind-the-meter systems or systems that are eligible for the state solar carveout. And in either of those cases, the requirement -- the projects do need to be located in state. So I think that is probably most typical.

I think there are certainly a few examples here where out-of-state projects could qualify as well. But yeah, in general these are geared towards in-state projects I would say.

MR. KIENY: Okay. Thank you.

MR. MARREN: One follow-up question. Ed.

MR. McNAMARA: Yeah. Ed McNamara for Department of Public Service. Galen, while we are still on the slide with all the lists or the list of all the state's programs, can you identify which programs are administered where the RFP procurement is done by the utility versus the regulatory body?

MR. BARBOSE: Umm, so I pretty much in almost all cases where there is a procurement, so I mentioned a few of these programs are FIT programs. So California and New York, those are kind of straight feed-in tariff programs. For the others which are at least, in part, competitive solicitations, I think they are all administered by, if not the regulator, some sort of state agency or centralized procurement agent.

MR. McNAMARA: Okay. Thank you.

MR. BARBOSE: Yeah. I mean now looking, I think, in New Jersey the utilities individually do it, so that would be one other example. Yeah, in general though, it's being done by a centralized agent of some form.

MR. QUINT: This is Andrew Quint with Green Mountain Power. And I have one more question. Sorry. On that slide.

MR. BARBOSE: No problem.

MR. QUINT: Wasn't the Connecticut small-scale procurement actually inclusive of resources outside of the state, and isn't that the largest single procurement that you had on the bar graph on the next slide maybe?

MR. BARBOSE: Yeah, yeah. No, that's right. That program was -- I think the ZREC, LREC program is geared towards smaller and in-state resources. The 2016 small-scale procurement that was actually -- I think targeting two to 20 megawatt sized projects which is why, as you mentioned, the total procurement volume is so much larger than these other programs. That one really -- it's really geared towards somewhat larger-sized projects than what the Vermont program or any of the others are targeting.

MR. QUINT: Thank you.

MR. BARBOSE: Yup. All righty. So we were, I think, here to talk about timelines and performance guarantees. So most of the programs require that a project enter commercial operation within a year or two of when the award is issued or when the contract is signed. Typically there is some expressly stated option for an extension, though that is not necessarily granted automatically, but there is usually some provision for that. And these timelines are generally enforced through some kind of performance guarantee or other form of collateral that is then forfeited if the project doesn't enter operation on time or if the sponsor pulled out.

And the way that these performance guarantees are determined or calculated can vary somewhat from state to state and program to program. In many cases, like Vermont, it's just some dollar per megawatt value that's multiplied by the nameplate capacity of the project. Some other programs instead do it based on the expected energy production. Or the bid value where you're basically taking the bid price multiplied by energy production, and then take some percentage of that, and that's the collateral that the sponsor has to put up. However it's calculated, the ultimate dollar value can vary quite a bit. Provide some kind of comparability. The figure here just shows in our calculation of what this performance guarantee would be for a one megawatt-sized PV project under all of these different programs. And you can see in Vermont it would be $15,000. You guys have a $15 per KW deposit. That's somewhat lower, I would say, than most of the other programs. They are not wildly out of line. I think most of these other programs if you kind of look across the graph are somewhere in the kind of 20 to 30 thousand dollar range. Obviously there is, you know, that one Delaware program that's much more expensive, and then there are a couple in Massachusetts and New York where no performance guarantee is required. So kind of get some general sense of where Vermont's collateral compares to these other programs.

MR. MARREN: We have one question for you, Galen.

MR. KNAUER: Galen, this is Tom Knauer with the commission. Do you have any information on which of those programs that had some kind of performance guarantee have been more successful in ensuring that projects that are granted awards come online?

MR. BARBOSE: We don't unfortunately, and that actually kind of dovetails into this next slide where we present what limited data we could actually find on program performance and project attrition. So I think -- I mean that's a great question. And I think something that we went into this hoping that we would be able to do. But unfortunately there is just not the data at least publicly available that we would need in order to do that.

And that kind of brings us to the topic here where we have just presented what limited data we could find on project delays and cancellations. In Vermont, of course, this has been an issue that's been discussed within the current proceeding. When I looked online it looks like about 6 out of the 22 projects that have been awarded through the competitive solicitations starting in 2013, six of those projects are currently online.

In Connecticut LREC and ZREC program we get about 31 percent of all of the contracts awarded to date over a similar time frame are currently online. And about a third also have been terminated because they have missed their performance deadlines.

The other data point here is from California. This program has a similar time frame. It's also been active since 2013. About 50 percent of the contracts that have been executed since then are currently online, and 30 percent have been terminated. There was a -- some additional information that was submitted in this proceeding from Allco just providing a useful clarification here that actually many of the contract awards within the California program are for pre-existing small hydro projects, and so if you actually exclude those and just look at the new projects that were awarded contracts, these numbers come down and look pretty similar to Vermont and Connecticut in terms of the fraction that are currently online. So not a huge number of comparison points out there. But, you know, if it's any solace to all of you, you know, the issues that you have seen in terms of project delays and cancellations are seemingly not unique to Vermont.

And this is kind of apparently a fairly endemic issue, and is not really out of line with what is happening elsewhere. So that then kind of brings us to the next set of topics related to bid evaluation and whether and how projects might be evaluated on criteria other than price.

So really when we look at the programs in this set, almost all of them are awarding projects solely based on price. So pretty straightforward. Obviously, there are some set asides or tiers that I mentioned, and many of the programs do impose some kind of price cap as you do in Vermont. Interestingly, in New Jersey and Illinois those caps are confidential. So bidders don't know what the kind of upper bound is, and presumably the rationale there is to try to prevent strategic bidding where, you know, bidders are putting in prices that are just below the cap.

But in any case, pretty typical to have some kind of price cap, whether that's based on, you know, sort of a market-based number or is developed through some more administrative process, that kind of varies from state to state. Notwithstanding the fact that most of these programs are really just looking at things based on price, some of the programs do include adjustors, price adjustors, for certain types of projects that they would like to give some preferential treatment to. So in Connecticut and Delaware they both have adjustors for projects that use either in-state equipment or in-state labor. And Massachusetts has a whole suite of different adders for the various types of projects; brownfield, landfill, solar canopies, et cetera.

I should mention I use this term price adjustors as kind of a neutral terminology. And that's just to reflect the fact that there are different ways of doing this. So you can -- one way of doing this would be to say, okay, you know, projects, submit the price that they want to get paid. Then for the purposes of evaluating the bids, these preferential projects we are going to decrement their price just for the bid evaluation purpose in order to make their bid more competitive. So that's one way of applying a price adjustor.

Another way is to actually say, okay, well you bid a price, and for those preferential projects we are going to actually pay you based on, you know, we are going to give you some sort of kicker on top of your bid price. And the effect of that is to then allow this project to basically bid something lower than what they actually need in order to cancel out. So it's kind of six of one, half dozen of another. The effect is more or less the same. So that's why we use this term price adjustor, but the point being there is different ways of mechanistically including this kind of preferential treatment.

The last little bullet here which I think is actually important and particularly relevant to some of the issues that have come up in Vermont, in Connecticut they have a much more kind of elaborate bid evaluation process for the small-scale procurement program where they evaluated bids not simply based on price, but rather on the net present value of projects. So they took the bid price, and then compared that to the projected market value using, you know, essentially the production cost simulation run where they generate hourly prices for different zones and then compare the cost of the project to the market value and evaluate the projects on that basis.

And so this is one way, of course, of incorporating a locational preference for those projects that are sited in areas of the bulk power system that are more valuable. And this actually ties in pretty directly to the presentation that Andrew is going to give where he will basically demonstrate the application of this type of method for Vermont. I think it's worth just highlighting again though, a point that was made earlier, which is that this Connecticut small-scale procurement program was much larger than Vermont. This was a 350 megawatt procurement focused on 2 to 20 megawatt size project. So in that case, you know, having a more elaborate bid evaluation process made sense. Whether or not that same kind of procedure would make sense for a much smaller program obviously is a subject for you all to discuss.

So in terms of the pricing from these --

MR. MARREN: Galen, can I cut you off for a second? We just have one question.

MR. KIENY: Yeah, Galen. Craig Kieny, Vermont Electric Co-op again. The Connecticut small-scale, that allows projects out of Connecticut; right?

MR. BARBOSE: Yeah.

MR. KIENY: So if a project in Vermont was awarded a contract in Connecticut, does that last bullet mean that Connecticut is buying it at the point at which the electricity is generated?

MR. BARBOSE: I'm not sure I heard enough of the question to be able to answer it.

MR. MARREN: We have microphones. We are going to see --

MR. KIENY: I'm not sure it's working.

MR. MARREN: You've got to push the button at the bottom.

MR. KIENY: Yeah. Hey, you know. So for the Connecticut program if there was a project located in Vermont that was awarded a contract in the Connecticut program, is Connecticut buying it at the node in which its generated?

MR. BARBOSE: So yeah, I'm not sure I can necessarily answer that question, definitively, but I think the way that it would work is I mean the generator probably -- if there are developers in the room they might be able to answer this more authoritatively -- but my sense is that you sell, you know, and you are paid based on the node that you're selling into, which if you're located in Connecticut is presumably a Connecticut node. And then, you know, if you're selling it to a utility in Connecticut -- I'm sorry. If you're in Vermont, then you're getting paid a Vermont -- the price based on the Vermont node, and then the buyer in Connecticut is then withdrawing energy at their node and paying that price. There is then some settlement based on the difference in price between the two nodes.

So I think the way that the contracts are structured, I don't know, you know, it probably varies from program to program and contract to contract kind of who is responsible for that basis differential between the nodes. Like I said, maybe if there are developers in the room, they may be able to speak to that more definitively. But it's really a contract issue.

MR. MARREN: Ed?

MR. McNAMARA: So I'll try not to break it. So follow up to Craig's, the same bullet point, about using forecasted LMPs. If the point is that if, for example, Connecticut is partially selecting projects based on low LMPs, because they presumably want to pay lower for those projects, the lower LMPs actually represent the areas you don't want to build projects in because those represent generation constrained areas. So if anything, it seems you're going the opposite direction, you're sending the wrong locational signal by using forecasted lower LMPs. Does that make sense?

MR. BARBOSE: I think the way that this would work is that it rewards projects that are sited in areas of the grid that have relatively high prices. And it deters projects that are located in areas with low prices.

MR. MILLS: I think the idea is that you would be looking -- sort of looking at projects by taking what their bid price is and then subtracting from that bid price that estimate of the value. So if you're -- you would be taking off the value being sold, so if the prices are higher, that's a higher value that you're subtracting off the bid price. So it does, like Galen was saying, it drives you to sort of favor those projects that would be selling into places where the LMP is higher by subtracting it from the bid price.

MR. McNAMARA: Okay. Thanks.

MR. BARBOSE: Yeah. I actually -- I thought that it was basically the market price minus the bid price and that the delta is what the projects are getting evaluated on. But this is probably delving too far into the weeds for this particular program.

I think the point being though that this is a mechanism to reward projects that are located in higher cost areas of the grid, and basically avoid siting projects in areas with already really depressed prices.

Unless there are other questions here, I'm going to continue on. I'm getting to the tail end of my slides here. Just a few more to get through.

So just comparing the pricing that's come out of the competitive solicitations in the last round of each program. So it's pretty challenging to do this. Obviously these programs are targeting projects of different sizes, different technologies. The contract terms and other things differ quite a bit from program to program. We tried to control for that a little bit in the graphic here by first really just focusing on prices for sort of the, quote unquote, larger projects within each program. Notwithstanding that large means something very different from one program to another. But at least kind of cutting out that smallest size category. And then also segmenting the programs into those that are procuring bundled products versus those that are just procuring RECs.

That's shown in the figure here. For the REC-only program, those projects -- these are mostly behind-the-meter projects. So they are also getting compensated typically through net metering or some other retail tariff that would then, you know, be on top of the REC revenues shown here. But you can get some sense in looking at Vermont how it kind of stacks up with peers, and at least among other bundled programs, you know, it seems to be more or less in line. Obviously, there are differences in terms of what's being purchased from one program to another, but not wildly out of line with what we are seeing elsewhere.

And then I think this is more or less my last substantive chart and ties into one of the questions that was asked earlier about how Vermont's program compares to the others on sort of a more of a relative-size scale. So pretty much all of the programs here are intended to procure either renewable resources or RECs that are then used to meet RPS obligations. Either general/class one RPS obligations, or in some cases solar or DG carveout specifically.

And here in the figure we have just divided the total procurement cumulatively for each program by that RPS demand, the overall RPS demand or the solar carveout demand, just to give some relative and to scale. For Vermont we have actually listed it in both sections of the chart just in recognition that those resources do qualify under the DG carveout. But in the end may get -- getting used to meet general RPS obligations just if that carveout is already deemed met through net metering or other means.

Should also mention that the Vermont numbers here are really just reflective of what's been procured through the competitive round beginning in 2013. They don't include the 50 megawatts or so that was procured through kind of earlier -- earlier iterations of the program. So adding those in obviously the numbers here for Vermont would be higher. But conversely, you know, this is all awards. It's not all operating projects or all projects that are likely to ultimately come online. So that would then, of course, make the numbers lower. But in any case, the idea here is to give you a sense of scale, you know, these programs may exist sort of either within or in parallel to the RPS, and of course, it's natural to ask as I think has come up in Vermont, you know, why have this separate parallel program when we already have the RPS. And although it's not, you know, always entirely clear, I think the implicit rationale in many cases is that, you know, these programs are intended to support projects that otherwise might have a hard time participating in the RPS either because they are too small, or because their technologies that aren't as cost competitive as other renewable technologies but nevertheless offer some unique value or help to support some complementary policy goals, and therefore the state wants to support those projects.

So they are, you know, generally aimed at kind of targeting some of these kind of more marginal projects and to do so by providing revenue certainty through long-term contracts. That's, you know, one of the kind of endemic issues that comes up in competitive markets where projects, especially small projects, have difficulty getting financing if they are just relying on, you know, spot REC market.

And in -- some of these programs are either kind of explicitly alternatives to traditional rebate programs, or if not, are kind of filling that same function that traditional rebate programs might have otherwise served.

So with that, I think I'm just going to kind of wrap things up here unless folks have comments on that last slide. So in looking through the kind of this collective synthesis of information there are a few general themes and kind of take-aways that emerge. Certainly there are some other things that you all have also noted in hearing about this.

First and foremost is just that these procurement programs they all exist in states that have an RPS and that have other clean energy policies and serve, as I kind of discussed on the last slide, some kind of complementary role. The design of these programs does vary a lot as we have seen. And as I mentioned kind of early on, regulators' ability to kind of fine-tune these programs have often been somewhat limited just by virtue of the kind of design requirements that are hard coded into the enabling legislation.

MR. MARREN: And apropos of that observation, we have a question from a legislator, so I'll let him interject.

REP. YANTACHKA: Okay. Representative Mike Yantachka. That 61 percent on that other bar graph, what did that represent? Did that represent all of the solar energy being produced? 61 percent of the total RPS or -- what did it represent?

MR. BARBOSE: Yeah. So that 61 percent, so the numerator there is the expected generation from all of the projects that have been procured through the Vermont standard-offer program from 2013 to 2018. So most of those projects are not online. And some of them are not solar PV. So it's really -- the cumulative kind of expected amount if all of those projects were to ultimately come online. That's the numerator.

And the denominator of the 61 percent is the DG requirement within the RPS. So Vermont's RPS has its DG carveout which I can't recall what it is currently. I have some vague recollection that it ultimately gets to maybe five percent; is that right?

MR. McNAMARA: 10 percent.

MR. MARREN: It's 10 percent, Galen. And I know we talked about this yesterday, I may have given you bad information. In that standard-offer program -- projects do qualify for tier two. But only to the extent they were constructed after 2015. So I'm sorry I didn't actually --

MR. QUINT: Actually it's June 30, 2015.

MR. MARREN: June 30, 2015. I'm sorry that I didn't catch that. We may need to refine that calculation just a little bit.

MS. ALDERMAN: Wouldn't existing

projects qualify for tier one?

MR. BARBOSE: Presumably it would be roughly half of that 61 percent. I'm not sure how much was procured the last three years versus the previous. Although I guess -- I mean so they have to be online after June 1.

MR. QUINT: July 1.

MR. BARBOSE: Most of these projects came online after June 1 even if they were procured in 2013.

MR. MARREN: Okay. Thank you.

MR. BARBOSE: So did I answer the earlier question though from the legislator about what this 61 percent even though -- maybe it shouldn't be 61 percent, but some number slightly less than 61 percent.

MR. MARREN: Yes. Thank you.

REP. YANTACHKA: Yes.

MR. BARBOSE: Okay. So just kind of continuing on down this kind of general list of themes and take-aways. So you know, many of the programs that we looked at are a hybrid of some form between a pure competitive solicitation and some sort of standard offer FIT-type program. I think the typical kind of variation that we saw which I mentioned is, you know, smallest projects to instead be offered a FIT contract rather than having to go through a competitive process. But in theory, you know, that kind of separate standard offer treatment might be extended to other types of projects that for whatever reason are kind of deemed to be kind of not appropriate or not worth trying to force through the competitive process such as -- may be something to think about.

I also talked a little bit about different approaches that are used to preferentially favor certain types of projects. I know in Vermont you guys have set asides within each procurement round for non-PV and other technology type. There are other kinds of mechanisms that can be used that they talked about that also serve kind of a similar function. And kind of related to that, you know, one of the common themes that we saw are programs that do have some set of special provisions to facilitate participation by the very smallest projects.

So I mean even if the programs themselves are generally geared towards relatively small projects, you know, a megawatt or two megawatts in size, typically they have some kind of special mechanism that allows participation by either residential or, you know, sub 100 KW size projects.

And then last, but certainly not least, though the available data points are somewhat limited, it is pretty clear that contract failure, project delays and cancellations are not uncommon and are frankly an issue even for larger-scale procurement programs as well. So it's nothing, you know, particularly unique that, you know, you guys have seen in Vermont in terms of having far fewer projects come online than what you had initially awarded or hoped to come online.

So that's pretty much it. You know, certainly we have as much time really as you all want to spend for discussion here. If there are questions or comments that come up after the fact, feel free to comment, or feel free to contact me here or just relay comments via Jake or through other channels. And I think with that, let's, I guess, open it up for discussion.

MR. MARREN: I would like to start off, Galen, by saying thank you on behalf of the Public Utility Commission and its staff. I thought that was an excellent presentation. We appreciate all the research you did for this proceeding.

I just had one question to start this

off. I would like us to take maybe 10, 15 minutes to have questions, but then I do want to give an opportunity for the court reporter to take a break because we have been going for an hour already. So but Galen, you mentioned that these procurement programs are like a rebate program, and I just wanted to make sure we had a common understanding of what do you mean by a rebate program? Do you mean like a general tax-funded type of rebate to stimulate construction of projects like a tax credit or something, or some other type of rebate?

MR. BARBOSE: Yes, so sorry. What I was referring to there would be kind of a buy down program.

MR. MARREN: Okay.

MR. BARBOSE: Where, you know, projects are offered just a fixed, you know, dollar per watt incentive. And, you know, that's been pretty -- I would say was sort of the typical paradigm of how to incentivize especially smaller PV projects for many years. But you know, the PV market has grown, and it's a project that economics have improved, you know, many states have kind of moved away from that programmatic model and have wanted to do more along the lines of competitive solicitations or some sort of standard offer pricing.

MR. MARREN: Thank you. Does anyone else want to jump in? Questions?

MS. SMITH: Annette Smith. I have a question.

MR. MARREN: Yes, Ms. Smith.

MS. SMITH: I'm with Vermonters for a Clean Environment. I have two questions actually. On your 61 percent on your slide 14.

The standard offer bids and projects that are approved can sell the RECs so they can -- they may not count for CRPS. Could someone explain that?

And my other question is about notification, rather public notice or notice to towns at the time that projects are bid in. Do any other states have any public notice provision?

MR. MARREN: Galen, if you can answer the notice question first of all, I'll deal with the other question.

MR. BARBOSE: Okay. Great. That's what I was going to suggest. So you know what, I didn't notice any other requirements related to public notice. I mean that -- I assume that's a requirement -- it's a requirement that gets imposed during any sort of permitting stage which would obviously be kind of administratively separate from the procurement program itself. I didn't see any provisions within these procurement programs, though, that mandated anything required to public notification.

MS. SMITH: Thank you.

MR. MARREN: And Ms. Smith, with respect to your first question, the contracts that standard offer programs receive are for energy and RECs. So those RECs become the property first of the -- or not the property of. The standard offer facilitator allocates all of those RECs to the Vermont utilities. The Vermont utilities turn around, and they have a statutory obligation to retire a certain number of RECs under tier one and tier two of the renewable energy standard.

To the extent they have more RECs than are required by law, they may be selling some RECs, some of which may have been standard-offer program RECs. But the projects are not allowed to sell the RECs.

MS. SMITH: That's my understanding, which is why I think it should be clarified that this 61 percent is sort of a maximum potential, but it's not necessarily what's happened.

MR. MARREN: Okay. Yeah. I just wanted to make sure that it was clear it's not within the discretion of the projects, though, as to what the disposition of the RECs. It's whether the utilities are meeting their statutory obligations or not. Any other questions?

MR. KIENY: One.

MR. MARREN: Craig?

MR. KIENY: Craig Kieny, Vermont Electric Co-op again. In Vermont we allocate the energy from these projects based on each utility's percentage share of sales in a given year. Is that common method of allocation among the programs that are statewide?

MR. BARBOSE: Umm, I think that's more or less how it's often done. I'm trying to think. I mean so let's see, actually probably this slide is the best one to use.

Yeah. I mean in Connecticut the ZREC, LREC programming basically they look at two investor-owned utilities. One represents basically 80 percent of statewide load. The other 20 percent, and then the ZREC, LREC requirements are more or less divvied up accordingly. But in New Jersey similarly, so yeah, I think it's based on whether it's retail sales or RPS obligation, it's kind of effectively the same. But I think the approach used in Vermont is pretty standard.

MR. KIENY: Okay. Thank you.

MR. MARREN: Ed?

MR. McNAMARA: Just a follow up to Craig's question. So for example, the Connecticut program, is it the case where Connecticut DEP, which I think does the actual procurement, they are not actually entering into the contract. Are they then telling the two IOUs these are the contracts that you will enter into? So in other words, is there as in Vermont, Vermont has a single statewide aggregator that enters into the contract. Is that the same case in Connecticut and other states?

MR. BARBOSE: No. So typically what happens is if there is -- a state agency will often run the procurement, but then the contracts that are awarded through that procurement are executed between the, you know, project sponsor and the utility.

MR. McNAMARA: Okay. Thank you.

MR. MARREN: All right. Seeing no other hands at this point, maybe now is a good time to just take a quick five-minute break and let the court reporter rest her hands for a second and get ready for Andrew's presentation. Thank you very much, Galen. That was great. We'll be back in a few minutes.

(Recess was taken.)

MR. MARREN: Thanks everyone. We will get started.

MR. MILLS: Just a quick sound check. I did change phones. Are you able to hear me pretty clearly?

MR. MARREN: You sound clear to me, Andrew. Thank you.

MR. MILLS: Great. Thanks.

MR. MARREN: Now I will start referring to some people by name. Ask them to -- all right. We are back on the record. And we are now going to hear Andrew Mills' presentation about potential bid evaluation methodologies. Thank you, Andrew.

MR. MILLS: Great. Thank you. I'm Andrew Mills also from the Lawrence Berkeley National Laboratory. An impetus for this portion of the discussion, as we were looking at some of the comments that came in on the program, one of the things that was talked about a bit was trying to avoid situations where new generators are sited in places that might have adverse impacts on the grid. And there is no current way in the evaluation of bids that sort of really accounts for those locational factors, nor is there a way to kind of communicate that to potential bidders.

So we were thinking about what are some ways that you could convey that information and then also adjust the way that you rank bids not just based on price, but also based on something else that would account for that locational potential impact.

In the discussions further it sounded like some of these impacts might be on the distribution grid but also if there is some interaction with the bulk power system that might be important in Vermont. We thought as an exercise in kind of exploring this, we would look at the potential of using wholesale prices to inform some of the locational aspect. In addition to the locational aspect of it, wholesale prices can inform something around the temporal profile of different resources and how that (phone interruption).

I just want to make that clear that this is primarily just to inspire discussion and that this also, I think, was really a list of different factors in the other programs including an example of the Connecticut program.

MR. MARREN: Andrew, can I interrupt you for a second? Andrew, it sounds like someone who is using our teleconferencing system has their microphone on. And so we are getting a lot of background noise from someone there, and I would just ask anyone who is not presenting to please mute yourself at this point so we can hear Andrew.

MR. MILLS: Thank you. Great. All right. So I'll go ahead and go to the first slide. So that's our kind of motivating question for this analysis was just whether or not information from wholesale prices could inform something about the bulk power impacts of various resource options, and in particular, how might those impacts vary with different locations around the grid and the resource generating profile. So what I've done in this exercise is I've gone and grabbed a lot of location-specific wholesale prices and generating profiles, and from those I'm making an estimate of the wholesale value of wind and solar, and also just a flat block of power. That means that it's a constant output all 8,760 hours of the year. And that sort of just as a way to provide a reference for the value that we are calculating for wind and solar.

The idea here would be that instead of just looking at the price of different bids that come in and ranking them from the highest-cost bid to the lowest-cost bid, instead you would potentially rank bids based on their net cost where you would take the bid price, and then you would subtract off this wholesale value. Again, that's just for the purposes of ranking bids. It wouldn't necessarily adjust their compensation or anything like that necessarily.

And so that wholesale value means that if you have a resource that's located somewhere where it's more favorable and it's sort of generating more value, meaning that you're inflated to have higher prices or you're generating at times of higher value, then you're going to be bringing the net cost down even further. So it's sort of like suggesting that you have a lower overall cost if you have a high value.

In contrast, if you're locating your resource somewhere where the grid is relatively constrained, and you're generating at times when there is less value for that power, then you won't bring down your bid cost by as much. That wholesale value number would be lower. So that's the general idea here, and to kind of illustrate that idea, we have got some specific calculations that we have done to illustrate this. And I don't necessarily suggest that this is the way that it should be implemented, but I just wanted to be able to provide some numerical values, so I will illustrate this approach with some particular data that is available to us.

So that particular data that I'm using wholesale prices that were observed in Vermont between 2015 and 2017, and I'm taking the value across all of those years. And these are coming from the real-time market prices from all of the nodes that ISO New England has in the Vermont zone. We also have forward capacity prices for the historical years that were specific to the Vermont zone.

And then for the generating profiles I'm using the aggregate of wind profile reported across ISO New England. So I don't have wind profiles from individual locations. Instead I have what ISO New England reports as the aggregate profile across all of ISO New England.

Similarly, we have the solar profile from all the utility-scale solar being tracked by ISO New England. And this corresponds for those same historical years for which we have prices.

Using those profiles I was able to take

the rules that ISO New England uses for calculating capacity credits in their forward capacity markets for wind and solar, and I've applied those rules which essentially are saying what's your production during the times of peak demand. And I've used those rules to calculate the capacity credit that would be assigned to wind and solar both in the winter and summer peak period.

So let me walk through a couple more things just to kind of set the stage a little bit before I go into some of the results. If we just look at the real-time prices from the overall Vermont hub in ISO New England, we get a sense of when electricity during this period was higher priced and lower priced. And so the higher priced periods here are times when the colors are darker here. And so that happens to occur more in the winter months and in particular at night.

We also see August at night tended to have some higher prices during this historical period between 2015 and 2017. So these higher prices are suggesting that delivering power at these times would be of higher value to the overall system. Whereas in contrast if you're delivering power more at say 9 o'clock in the morning in June, it's going to have lower value than these other times. And that's where the lighter color is.

So now we are looking at the same sort of mapping of the average wind production. Again this is the aggregated ISO New England wind profiles over that same historical time period, and the darker periods indicate that's when wind was producing more of its power, and the lighter periods are when winds were producing a lower fraction of power. In this case it looks like there is actually a pretty decent correspondence where we have a higher production of wind in the wintertimes at night and also overlaps to some degree with when some of the prices were higher at least on this sort of monthly averaging that I'm doing with this -- these charts.

We can do the same thing for solar. And so we have solar production being highest in the summer and during the midday hours and then being zero at night. And so we can do the same thing when we have a very high concentration of solar production.

One of the things that's different with the wind is we have a higher scale here, so we are going up to over 75 percent of our nameplate capacity is being generated in those summer months, middle of the day. So from this sort of -- that data just sort of illustrates the overlap here, but what we do specifically to calculate this wholesale value number in dollars per megawatthour terms, I'm going to calculate this energy value, and I'm going to add to that the capacity value. The energy value here comes from summing up that hourly generation profile of a particular technology multiplied by that hourly energy price for a specific node. So I'm looking really at that correspondence of generation and high prices at specific nodes.

And then I'm going to divide that by all of the energy generated over that time frame. And that gets me my energy value in dollars per megawatthour.

The capacity value is sort of a similar approach, but instead what we are using is the capacity credit, again calculated by the rules that ISO New England uses. And this is sort of the what percentage of your nameplate capacity sort of is being counted towards contributing to the overall resource adequacy need.

And so you know, just to kind of throw out rough numbers for wind, that tends to be somewhere in the 20 percent of your nameplate capacity might be counted towards that resource adequacy for the summertime period. In the wintertime period it might be something higher, maybe up in a 40 or 50 percent of your nameplate capacity.

So you take that capacity credit and multiply it by what the resulting zonal capacity price was, and that gets you sort of your capacity revenue. And you divide that again by all of the energy that was generated, and that gets you your dollars per megawatthour. We sum those two up and get the wholesale value. We can get that for each specific node and each generation profile that we did.

So let me just show you those kind of overall results, and maybe I'll pause there to see if there is any clarifying --

MR. MARREN: We do have one.

MR. FITCH: Eric Fitch. I'm with Purpose Energy. I have a question about cause and effect on this. So if you look at these two contour plots, it's kind of interesting that the time that wind produces the most power is the time when energy is apparently the most valuable. And I'm wondering what is the value there. Is it just happen to be that we are producing more wind at that time, and we are therefore paying more for power because we are paying sometimes rate for wind?

In other words, if you subtract the wind purchase price out of that first contour plot.

MR. MILLS: The energy value here that I'm calculating is really sort of saying that generation that you are creating, what was the overall sort of value to the system that's being suggested by the wholesale energy prices. And so it's sort of saying like as if you're sort of taking the prices to reflect what the overall system value is. And then you're just asking the question of, you know, for wind that was generating at that time how much would you sort of have been earning if you were selling your power into that market at that time.

So in this case the prices for power are higher in those wintertimes, and that might be a reflection of things like demands might be higher at those times, or it might be a reflection of natural gas might be more constrained in the winter because it's being used for heating, so that might shoot up the price of natural gas which causes your electricity prices to go higher in those times.

That's sort of the system value is being reflected by these prices, and then the value that I'm assigning to wind is saying how much wind were you generating during those times, and that -- aggregating that over the whole year gets your energy value.

MR. MARREN: Ed, did you want to follow up on that at all?

MR. McNAMARA: I think Andrew already answered the question. Largely it's because during the wintertime natural gas pipelines are constrained, and that's causing the average New England wholesale prices to increase significantly because usually gas is on the margin. When gas gets much more expensive during wintertime when it's being used for heating, it increases the wholesale prices.

The other aspect, too, is that we have added -- New England as a whole has added, I think, over 2,000 kilowatts of behind-the-meter solar which is -- acts as a reduction in the amount of load that's being served on the wholesale level, so that also acts as a reduction in wholesale prices during the times that solar is producing as well, so which is the correlation with nighttime higher prices.

MR. MARREN: Patty Richards.

MS. RICHARDS: And --

MR. MILLS: Yeah. And I support what

you just said. I just want to sort of be careful that I haven't gone in and really been able to tease out exactly why those prices are higher, so that's speculation on my part. But it sounds like that sort of is similar to what your understanding is. So -- and then on that last part about solar potentially depressing prices, one way to think about this too is that these value calculations that I'm coming up with are sort of -- it's -- the idea that it's what the value of that next increment of power that you're going to be delivering it.

So the fact that you've already -- this doesn't say anything about what the value is of all of that solar that currently exists, but it's more about what would be the value of adding more on top of what we already have, I guess. And that's sort of what the prices, because they are marginal, are telling you about what that next increment of power is worth. It doesn't necessarily tell you about all the power that's already been provided what the value of that is.

MR. MARREN: I think we have one more comment, Andrew, and then we will get back to your slides.

MS. RICHARDS: Patty Richards from

Washington Electric Co-op. Just to point out on the slide I think the label says it, but this is -- you're taking the wholesale price for the real-time Vermont zonal price which is an aggregation of all the nodes across the State of Vermont; correct?

MR. MILLS: Yes. Exactly. So yeah. Just mechanically I'm taking what's being reported by the ISO New England for the Vermont hub, so I don't do any of that aggregation myself. I think you're right that's the idea that Vermont hub is an aggregation of nodes, and that's what's reported.

MS. RICHARDS: Obviously if you're going to put a generator somewhere, the specific location matters, because you get paid at that connection point, the node, whereas the data you have here is an aggregation and average for the entire state.

And then the other thing I just wanted to point out is that this time period you're measuring is 2015 to 2017. If you were to have looked at this 10 years ago or a different data point it would look vastly different, so that is a static snapshot, and over time the kind of the heat map is going to change based on generation and load changes of the area. So this is a snapshot of the past two to three-year period, and that does move around.

MR. MILLS: Yeah. I definitely support that idea too, that like if you look back in time it's going to be different than this particular time period, and it also when we look forward in time. But as the system evolves, this heat map of prices will also be changing as a reflection of that. That's where you sort of have to rely on your model as a crystal ball to understand how that might be happening, and we don't necessarily have anything other than models to help inform how this will change going into the future or models or, you know, market prices.

So let me on your earlier point of that -- so I was using -- that map earlier was recording just the Vermont hub price. In the exercise that I'll be doing here now, we did actually have individual nodal prices that we haven't -- so this is showing if we were to take that wind profile that we had and then multiply it by the nodal price at each of these different nodes, we would get sort of one of these dots. And each of these dots represents sort of the different nodes around Vermont.

And then we sort of create this box and whisker plot around the majority of the data points.

The dots are sort of the outliers from that box and whisker. So for the most part the value is pretty similar independent of which node you're at within the Vermont area, but for some of those nodes the value is quite a bit lower than what we see for the most of them. That's these little outliers that we see.

And so in this case we are using those individual nodal prices to do that calculation. And the difference between the three columns here is that for one of those I'm using this flat profile where again it's just a constant output over every hour of the year, whereas for wind it's the ISO New England aggregated hourly profile that I'm using. I'm multiplying that by the hourly nodal price at different nodes. And for solar it's that hourly solar generation aggregated at the ISO New England level, but multiplied by the individual node price.

I think a take-away for me, a couple of things from this one is that, you know, the solar and wind value under these calculations isn't that different from this flat block of power, that sort of flat profile. There are a few places particularly for the wind where that value can be quite a bit lower. We will see on a map where those locations are. And then on average the solar tended to be a little bit lower than the wind and the flat profile. Although you don't see as much of the extremes.

And I think the intuition behind that the fact that the solar is little bit lower is because of that sort of seeing some of the prices be lower in the middle of the day in the summer, and solar tending to produce most of its power in the middle of day and more of it during the summertime. So there is a little bit of an anti correlation there that tends to drive the value a little bit lower, but again, we are kind of zoomed in here, and the difference between the medians is only about a dollar a megawatthour.

So overall we see pretty similar with some extremes that pop out in particular locations.

MR. MARREN: We have one question.

MR. MILLS: Go ahead.

MR. QUINT: This is Andrew Quint with Green Mountain Power. And I was just curious for the flat profile how did you calculate capacity value?

MR. MILLS: So you know, again mechanically just used the same rules that ISO New England would use for wind profile or solar profile, but in that case it ends up being basically the 100 percent capacity credit. So basically you get your full nameplate capacity is counted towards the resource adequacy requirement, and then you divide, so that gives you 100 percent capacity credit. You multiply that by the capacity price, then you divide that by all of the energy that that flat block of power has produced over the entire year to get the capacity value in dollars per megawatthour.

MR. MARREN: Thank you.

MR. MILLS: Okay. And then so that same data that I had just presented earlier, if we just put that now into a map of where those individual load -- nodes are located within Vermont, we can see that those extremes that were showing a lower value than the majority of them are all happening up in the same area which is in the northern Vermont region. So in these cases this is where the prices at those particular nodes is lower.

And that in particular, it's we see that there are a few cases where the wind profile of wind happens to be that it would be generating more at those real low prices, and we sort of get our darkest dots here which are the lowest wholesale value, and that sort of drops down in the $33 a megawatthour range, whereas for most of them we are seeing it to be up closer to the $40 a megawatthour range.

And so this, to me, I guess is sort of poses a question to you all that know more about the system. But, you know, so this is what the data is telling me, and this sort of mapped to your expectations and understanding where some of the constraints and limitations are. And that was sort of the idea. Can we sort of do in an objective data-driven way get a sense of what the system is suggesting is the more constrained areas in the less favorable regions within the State of Vermont. And from this map it sort of -- it becomes pretty clear in the far north that's where maybe you'll see it.

And then the idea here again just to kind of walk through the mechanics of what you would do with this information, if you had two solar projects that had come in, and both of them had bid a price that was say $75 per megawatthour into the standard-offer program, but one of them was down in the southern part of Vermont, and the other one was in the northern part, more constrained, then this would be an approach for sort of distinguishing between those. They come in at a similar price, but their locations are different, so how would you distinguish between them.

In the south it would have a slightly higher wholesale value in the way that we calculated it over this particular time frame. And then in the north it would have a lower value. So the difference between south would be something like $38 per megawatthour. In the north because of those constraints it would be lower at $35 per megawatthour. So if we were to subtract that wholesale value from the bid cost, then the north project would look less attractive because you're subtracting less off of it. And that you would be going with the south project as being the more favorable one. And unless that north project could bring its bid price down by at least $3 a megawatthour or so, it would continue to be less favorable than that south project.

And so I think that this sort of illustrates an approach of doing that. I think there is a lot of questions about whether it's worthwhile doing this, whether it's transparent and fair, and then also if you can kind of refine some of that. So some of the specific refinements that I think might be worthwhile is to think about I was using sort of the ISO New England aggregate profile because that's data that's publicly available and easy to get. It might make sense to have site-specific generation profile. What does the wind in northern Vermont look like versus what does the wind profile in southern Vermont. I don't have that data, so I wasn't able to answer that particular question.

Also in this particular case, we are looking just at the energy that was generated, and so we don't have an estimate of how much curtailment would occur. So the curtailment would actually be a further thing that would decrease the wholesale value in dollars per megawatthour, if you think about that denominator being the total amount of energy that you could produce, that sort of potential energy that you could produce, you could adjust these results on region or location-specific curtailment estimates.

And then I think some of the discussion earlier too, that this is just a snapshot in time. Using a few years. Does it make sense to sort of think about how prices will be changing in the future. And so maybe you could be augmenting the historical data with projections in future wholesale prices and be thinking about how prices might be changing as the share of different generation types change around ISO New England. How load profiles might be changing, and also if there is any sort of planned investment transmission that might alter some of these LMP patterns. And that Connecticut example, I think, maybe provides one example of where they are using projections of future wholesale prices in order to generate this information.

Might also think about does ISO New England have any sort of standard model that they use for doing projection. I think there is a few ways for doing refinements, but I think that sort of covers the idea. I'm happy to answer anymore questions that you might have about it.

MR. MARREN: Any questions?

MS. SMITH: This is Annette Smith. I have a comment.

MR. MARREN: Yes, Ms. Smith.

MS. SMITH: On slide number four, you want to go back to that.

MR. MILLS: Sure. I think I can jump back here. Go ahead.

MS. SMITH: Good. So I feel like I need to say that while this is showing, you know, the highest wind generation at night, there is a cost, a societal cost, that's not factored into any of this, and some people need to sleep. So when you look at something like this that seems to invite the idea that there should be more wind because it fulfills a need at night, we have to factor in what that's doing to the neighbors. And if those costs were compensated, the pricing might be very different. So that's my comment.

MR. MARREN: All right. Thank you.

MR. MILLS: I think just the additional context, I think, Galen's slides were also helpful in that he sort of talked about various ways that you have non-price ways of ranking bids or adjusting bids, things like that. And this is sort of the system value is one of those. I think there is additional factors like what you just mentioned to incorporate in that price.

MR. MARREN: All right. Any other questions?

(No response.)

MR. MARREN: Well thank you, Andrew. That was an excellent presentation. I really appreciate it. I think at this point --

MR. MILLS: No problem.

MR. MARREN: I would like to invite the group to share their thoughts if they want about sort of the broader purpose of this workshop. You know, for context, the standard offer program's been around for almost a decade now. And it's got -- it has three more years left to run, and they also happen to be, you know, three years of sort of more procurement than we have done in the past.

So the commission wanted to take this opportunity to see if we could, you know, make some tweaks to the program to make sure that it's serving its purpose in the last three years of its planned life span. So that's one set of discussion items, as you know.

Did anything you heard today provoke thoughts about what we could be doing at the commission to make the program more successful going forward within the constraints obviously of the statute and the program that we have to operate.

The other issue that we can talk about is that the legislature has asked us to make recommendations about certain programmatic issues like the exemptions provision that's in the statute. And also the commission's considering whether it should make any other recommendations about distributed generation or the standard-offer program to the legislature.

So we would be open to hearing from

anyone about that -- those topics too at this point. Don't feel like you have to get all of your ideas out right here in front of everyone. We are going to have an opportunity for written comment after today's meeting, and so -- but we have a few minutes, you know, we said we would have, you know, a two-hour meeting, and it's 2:40 now. So we can have a small discussion now about anything you would like along those lines. Mr. McNamara?

MR. McNAMARA: Sure. I'll volunteer. So we did file comments in this docket earlier. We have had some internal discussions, this is not, you know, concrete this is definitely what we are going to recommend. But some preliminary thoughts are standard offer has been somewhat useful on a going-forward basis. We are not sure that single statewide procurement is necessarily the best way to continue given significant changes in the regulatory landscape like the regulatory and primarily statutory landscape.

The Board's net metering order a couple months back, I think it was the May first order or something along those lines, essentially set forth that with the renewable standard now, it's essentially the governing overall -- sets the overall landscape for renewable policy in Vermont. Tier two of the RES in particular encompasses both standard offer, net metering, also utility-owned projects as well.

So the Department's preliminary thoughts are -- some preliminary thoughts, I'll just put it that way, are that you could actually get rid of the standard-offer program entirely and still have a lot of the goals met through relatively minor tweaks to the tier two of the RES. For example, one of the benefits of standard offer is to ensure that there is economic development, it's not just utilities building projects, it's actually third-party providers as well. You could have simply a requirement within tier two that says a certain percentage of tier two compliance needs to be met through non-utility owned projects. And then essentially let the utilities do the procurement. You could still have the PUC, the DPS involvement in the review of the RFP, and the resulting award as well.

But the Department's view is that the process that we have of every year setting the technology diversity, setting the avoided cost cap, it is a very regulatory burdensome process for a really small amount of megawatts that come into the system. Also the utilities are usually better situated to actually say here's the general ideas of where there is constraints in the system. For example, we looked at wholesale costs, and what Andrew just presented was really useful. It doesn't take into account certain things such as distribution constraints on GMP's system in Addison County. Those are factors that, instead of the PUC doing the procurement, taking comments from everything else, having GMP, for example, know that up front in their procurement, designing the procurement to specifically address those up front would actually be more streamlined, less costly overall, and more efficient process. So some high level thoughts.

MR. MARREN: Thank you. Mr. Allen?

MR. ALLEN: I'll just --

MR. MARREN: Can you identify yourself?

MR. ALLEN: I'm sorry. Riley Allen with the Vermont Public Service Department. I think one of the things that I think Andrew's slides kind of pulls out to me is just the way the -- the value is changing even at kind of the energy and potentially capacity markets over time, and so recognizing that, you know, when we are procuring resources, variable energy resources, we are really purchasing a fairly static set of values that will continue over a very long term. And with the kind of increasing opportunities that are becoming apparent through support technologies and other things, it may be that we can create a more flexible product out there that we capture in the competitive bidding process, one that can over time perhaps better align with the -- with the fairly dynamic environment that we have around us. Still pursuing renewables, but recognizing that there are technologies and capabilities that might over time allow those technologies to better match the values, and with respect to time and location that Andrew is pulling out.

MS. RICHARDS: Patty Richards from Washington Electric Co-op. One thing I will put on the record, and we will file comments in the event standard offer does continue relative to the exemption portion, Washington Electric Co-op would advocate to continue the exemption, and certainly from its standpoint relative to a utility that went ahead with renewable procurements way ahead of any legislative requirements.

And basically our power supply mix is

full up for the next 20 years, so any additional resources that are added on are just making us more excess and long over the procurement period of our IRP planning period.

So we will file comments in the event standard offer does continue. Ed's talking about a different aspect to that, so I'm not opining on that at this time. But we will file comments relative to continuation of an exemption.

MR. DePILLIS: Alex DePillis with the Agency of Agriculture. I've read a lot of the comments, and I really value the discussion of the LMP considerations and the value of this type of generation in different locations at different times. I also look at it from the point of view as a developer who would want to build a project and needs to get money to do it. The more the mechanism by which that project would get paid has uncertainty, the harder it is to get money to build the project.

And so SRECs and other mechanisms that vary overtime, for example, you could have an LMP prediction in the future. These things all introduce uncertainty that make it difficult to get a project built. I have developers who are really challenged to get a biogas project in the ground at 19 or 20 cents. And there is enough uncertainty in what they do to -- that the additional uncertainty that might come by introducing other kinds of mechanisms than what we have which is, you know, a long-term fixed price, would make it, I guess, even harder. So I'm concerned about that.

There is a lot of work around. Of course, the policy could be a lot of different ways. But, for example, if you did an LMP and there was some variation over time in what the developer was provided, you could have a floor to ceiling so that the developer still got paid what it costs to produce energy and not set adrift into some unknown future price. That's my concern about not having a fixed long-term price.

MS. SMITH: Annette Smith. Vermonters for a Clean Environment. Can I weigh in?

MR. MARREN: Yes, Ms. Smith.

MS. SMITH: I was interested in what Ed and the Department said. I like the idea of eliminating the standard-offer project program. I have been struggling with what I see as a need to enable developer-driven development and not the utility. So if that was tied to tier two, that would make sense. I think as we are seeing with the new preferred site letter, joint letter that can be done in net metering, there is a real problem with the lack of advance notice.

And so what I've heard numerous times with standard offer from towns and from neighbors is that after the contracts are awarded, that's the first time that anyone finds out about it. And that's sort of different from any other type of development that we have in Vermont that goes through Act 250 or applications to the PUC, and certainly are a challenge for communities that have, for instance, had contracts that are bid into the Connecticut program.

So the whole way that the standard-offer program is being implemented without any advance notice and with the very, you know, few limitations on-site control, I think if it were to be kept going it would need to be extended to actually take a look at some of the grid issues and the public notice issues so that there was more of an opportunity. And then once the site is locked in, that's it. You're stuck with it. And you can't move it. And when there are objections, it's almost too late.

So I think that I really like the

Department's proposal. I think that makes a lot of sense.

MR. MARREN: Olivia, did you have --

MS. ANDERSEN: I had a couple questions. Are folks from Berkeley still on?

MR. MARREN: I believe so. Galen, Andrew, you still there?

MS. ANDERSEN: Can they hear me?

MR. BARBOSE: Yes. I think we are both still here.

MR. MILLS: Me too.

MS. ANDERSEN: Do I need this or no? Olivia Campbell-Andersen from Renewable Energy Vermont.

In connection with the comments that Annette just made, are other states in their competitive, you know, procurement programs, once those projects receive a, you know, a procurement or green light, they still need to go through the permitting process through their Public Utility Commission to get a CPG or whatnot; is that correct?

MR. BARBOSE: Yeah. I think that's correct for the utility-scale projects. I think, you know, as I mentioned, many of these programs are geared more towards behind the meter. And so depending on the states, you know, those projects may or may not be required to go through kind of the CPCN type process. But yeah, I mean in general, I mean a grid-connected project is going to need to go through that process.

MR. FITCH: Eric Fitch, Purpose Energy. I'm a developer, and I'll just say, yeah, we do. For both of our projects there is a CPG Act 248(j) That's where the public comment period comes into play. It's not part of the -- not specifically the standard offer contract, but in order to get grid connected you still have to give an advance notice to the regional planning commission, an advance notice to the town. There is advance notice to all the abutting residents. And that CPG process is on the order of six months. So maybe it's not required for the standard-offer contract to be issued, but there is no way you could say that the project doesn't have to give notice to anybody in the community.

MS. ANDERSEN: Thanks. I had -- can I keep going?

MR. MARREN: Yeah.

MS. ANDERSEN: Okay. Well I had actually a question, you know. There is two other issues that are -- that I wanted to inquire or discuss in relation to, you know, alternatives to renewable procurement if standard offer didn't exist and sort of right now the current standard-offer program has both a provider block, meaning the utilities, and then a developer block, meaning non-utility or third parties.

And so if you were to transition to a different system, and you also, as Vermont's a vertically-integrated state, how would -- and we have the utilities owning and operating their own generation, you know, Ed, you did mention perhaps, you know, amending the renewable energy standard to have a certain percentage of tier two be required to be non-utility third party.

How would that work if the utility -- like is the utility competing potentially against themselves? Like how might the mechanics of something like that work. You know, because it's been very interesting to us as we have looked at the pricing, and I know that there is significant interest in maintaining, you know, competitive pricing and continuing to drive prices down for our electricity. And there is a significant difference in the standard offer bids between the provider project pricing and the competitive bidding pricing when you look at the bids that have come in.

So that was a lot, but I'm just thinking about how maybe we could have some conversation about how something like that would work, what would be the challenges, and so forth. And I know the value -- one more point.

The value that standard offer has brought has been to create greater transparency and to drive prices down, and in REV's opinion in terms of, you know, renewable energy projects. So having these competitive bids where utilities, regulators, the commission, the public can see the costs and the value of the renewable electricity helps in that goal as well. And if standard offer didn't exist, you would not have that -- you would not necessarily have that transparency which, I think, would be a particular value for regulators to evaluate both utility and non-utility-owned projects.

That was a lot. Sorry. It would be good, I think, to have conversation around these issues.

MR. McNAMARA: Okay. I can start with your last question and see how far I can remember back.

MS. ANDERSEN: Okay.

MR. McNAMARA: So with respect to transparency, I do agree standard offer provides transparency, but so does a well-constructed RFP process that was administered by the utilities, especially if it was, and this is throwing out preliminary ideas. If, for example, utilities had to develop an RFP process that was approved by the PUC, and then the results were approved by the PUC as well, that puts everything -- makes everything public, would make prices public, transparency as well.

Standard offer, I agree, helped with transparency. I think standard offer itself, I think the RFP mechanism once we had the RFP mechanism within standard offer, helped bring prices down, but the primary driver in bringing prices down was actually mechanics well outside of Vermont's control associated with declining solar costs.

MS. ANDERSEN: So there are a lot of factors.

MR. McNAMARA: Yeah. I wouldn't say standard offer itself brought down prices. I think you can create a different structure that can actually provide the same transparency and cost pressure as well.

That's about as far as I got in terms of remembering your questions. You can't throw out that many at me at once.

MR. QUINT: Can I throw out, Andrew Quint with Green Mountain Power. And I guess I have a couple of possibly comments to throw in.

The first is that the standard offer RFP is good at showing us what the cost is. It doesn't actually address the value. So there is some transparency, not full transparency.

And I would also say even in this latest RFP we saw a pretty wide range of prices ranging from 8.4 cents up to over 11 cents. You know, so yes, there is pressure. And I would also say that the lowest bid actually dropped out after there was a recommendation to award them a PPA.

I'd also say that the utilities actually haven't had many projects, and they have all been small projects in the utility block, the provider block. So it's kind of hard to benchmark small projects versus 2.2 megawatt projects.

MS. ANDERSEN: But the size of the projects in the provider block and the non-provider block have been comparable, yes?

MR. QUINT: No.

MS. BAILEY: No.

MS. ANDERSEN: So like one megawatt range I thought in the last round --

MS. BAILEY: No. This is Melissa Bailey with VPPSA. We have several contract awards for provider block projects. They have all been under a megawatt, around 500 KW in scale.

MR. QUINT: This is Andrew Quint again. One other thing is that actually the majority of solar that we have seen come on to the grid is through net metering. I mean the vast majority. So, you know, the standard offer projects obviously are adding, but they are adding at a much slower rate. And the utility projects are also a much slower rate than what we have seen with net metering.

MR. MARREN: Yes.

MR. CHARYK: Nick Charyk, AllEarth Renewables. In response to the Department and other suggestions that it might be time to terminate the standard-offer program, the data we saw earlier has shown these and other RFP-type programs work well complementary to other programs. Taking an arrow out of the quiver at this point regarding our renewable energy commitments of 90 by 2050 makes very little sense to me.

I'm also not clear at all with the Department's suggestion what the alternative marketplace for projects between 500 and larger projects would be. And so at this point, removing an incentive program makes very little sense to me.

MR. MARREN: Ed.

MR. McNAMARA: I just want to respond to -- apparently I wasn't particularly clear. I'm not saying there shouldn't be procurements. I'm talking about the method for procuring it, and having an entirely regulatory-run procurement process is unwieldy, burdensome, inefficient. It makes so much more sense to have the utilities run the procurement, you would still be procuring resources, 500 KW to five megawatts. It just wouldn't be the same process.

So I think people need to be mindful of the distinction between the process for procuring, and whether you're actually doing the procurement. The Department still supports procurement. We're supporting it through, in our view, it's the RES tier two that is driving the procurements. And we need to come up with a better system for actually procuring than we have with standard offer.

MS. ANDERSEN: In that type of

procurement system I think another benefit of a standard-offer program is, and particularly when some of the architects in the legislature designed it and then expand it, was the technology diversity. And so, you know, I'm thinking -- actually I thought Alex, when you were speaking, representing folks, the agricultural agency, and I think there may be others here that are working on digester projects, sort of in that procurement, you know, sort of are you envisioning with RES that there would be also some kind of technology diversity component? Because you know, I think the standard offer is particularly significant for newer technologies or technologies that perhaps may offer other benefits, you know, digesters with clean water, small wind, you know, et cetera, where those types of technologies are -- don't work well in other, you know, perhaps some -- in some net metering or other procurement mechanisms. So how would we look at that issue?

MR. McNAMARA: Yeah. So I actually have concerns with just the how much solar we are putting on with no diversity in resources. It's -- especially given wintertime New England constraints. So I think some kind of diversity, what that looks like, I think some diversity can be better achieved for -- through economic development grants rather than through a procurement process.

If you want to develop small industries, for example, using standard offer has not been shown to be particularly useful at developing specific technology types. It's only been shown to be able to sort of push down prices for solar essentially. Maybe there's certain carvesouts. There is, for example, the existing standard offer has a carveout for methane digesters or farm methane projects. That's a legislative direction.

Those are issues that I think can be resolved. Just because it's a utility-RFP procurement the Department is proposing, doesn't mean that all other factors fall by the wayside. Those would all have to be taken into consideration in development. This would also have to go through a legislative process which means anything actually proposed would probably change, and everybody has the opportunity to throw ideas in, both through comments filed here, comments at the legislature, if it gets that far.

I'm not trying to put forward a fully formed Department process whatsoever. I'm trying to suggest the potential different direction to take procurement for resources.

MS. ANDERSEN: And it could be a good question too for the folks from Berkeley as they have seen other states grapple with some of these issues, are there ways to -- what are the best ways to reduce some of the administrative burden, you know, or is that just because literally because of size of the procurements in the other states? And also the technology diversity component, what they have seen.

MR. MARREN: Galen, did you catch that?

MR. BARBOSE: Yeah. I think so. I'm not sure if I'll be able to answer really the first part of the question in terms of how states have tried to minimize administrative costs. Obviously it's an issue. I'm sure it's a consideration that goes into the design of these programs in every case. And it's just a tradeoff.

I mean I think the unique issue for Vermont obviously is that it's a pretty small program. And so your guys' appetite for adding additional administrative costs or even retaining the same set of costs is going to be pretty limited. So I mean I think to the extent possible just, you know, standardizing the process obviously helps. But, you know, you guys have been doing this for quite a few years now, and I imagine have probably, you know, you know, picked off as many low hanging fruit as you can, you know, in that regard.

So yeah, I'm afraid I don't really -- I'm not sure I had any like generalizable strategies that other states have taken that really are applicable for Vermont in terms of administrative costs.

I guess the second part of the question had to do with technology diversity; is that right?

MR. MARREN: Yes.

MR. BARBOSE: Okay. And there -- I mean I think I talked about this a little bit. I mean in general most of these programs are quite solar heavy. Let me see if I can -- yeah.

As we saw here, you know, most of them are pursuing solar. It hasn't necessarily been an issue. I mean to the extent that programs want to get the lowest cost resources, and solar is the lowest cost, that's just sort of the outcome that, you know, that's just natural outcome of the process. So I wouldn't say that for most programs it's necessarily been an issue, you know, a lack of technological diversity. You know, I think maybe if there is a bigger issue, it's just ensuring that there is a diversity in entities that have the ability to participate.

And so, you know, there have been, I think, at least in one or two instances that I can think of, limits on how much any individual bidder could grab from a given solicitation, so sort of, you know, bidder caps, no more than 20 percent, or I'm not sure what the exact percentages are, but some limit on how much of any given solicitation can go to a single entity.

So I think that's maybe been sort of a more, you know, a bigger concern, I guess, that I've noticed is just sort of equity and opportunities to participate.

I think the other, you know, maybe also related to this is just sort of ensuring, you know, trying to direct projects towards, you know, applications that provide some ancillary benefits, and so, you know, we see this in some programs that provide preferential treatment for brownfield projects or landfill projects, you know, preferential treatment for projects that are serving low and moderate-income communities. That's not exactly resource diversity. But it is sort of in the same vein trying to, you know, target the programs towards, you know, projects that may not necessarily emerge just purely based on economics.

MR. MARREN: All right. Thank you, Andrew. Riley, I'm going to call on you also and say we have sort of reached the end of the time we allotted for this workshop. I do want to be mindful that some people have other places to get to later this afternoon. So after we hear from Riley, we will talk about next steps. And then we will wrap up.

MR. ALLEN: Okay. I just wanted to harken back what I had heard from Ed earlier which is in my mind it's not just about getting kind of the lowest cost. But it's trying to get the best match between value and cost. So it's -- and I think, you know, allowing and engaging utilities essentially in the successor process might kind of increase our kind of opportunity with the odds that we can kind of better pursue that match of value whether it's time of day or location or other things. Not to diminish the point about diversity which I think is still on the table, but to recognize that you might have a kind of a better chance of providing more ratepayer value -- a better match of projects and ratepayer value if you have a different entity that is essentially operating and conducting the solicitation.

MR. MARREN: All right. So looking forward from now. Next steps. Obviously we would like to hear from people in writing to the extent you want to put your thoughts down on paper and give us something.

Do folks have a thought about how long they would like to work on that project before they turn it in to us? I don't think we are under a particularly tight deadline at this point. The only hard deadline we have is that we do have a recommendation concerning the exemptions issue to the legislature by December, so that's obviously a little bit of time. But on the other hand, it's good to keep things moving along so I don't want to -- Ed.

MR. McNAMARA: Are PUC staff thinking that the report to the legislature is going to be just exemptions? And that you might have some further comments? Because what I'm thinking is, for example, overall how do you restructure standard offer if you do so at all is much larger discussion than exemption. You could have comments on exemption in a couple weeks probably. Most people already have pretty well-formed thoughts on that just to get that done. But if you are thinking about potentially presenting to the legislature a wider range of options, that at least from the Department's perspective we would appreciate a deadline sometime in September actually as opposed to a few weeks.

MR. MARREN: Okay. Then that -- let's do that. Do you want to segregate, or I think maybe we can just push it all out until September, and people can comment on the topics that they want to comment on. But just to set people's expectations I mean we -- the commission has not given us direction we are going to recommend to the legislature to do something to standard offer. This was just something they wanted to hear from the regulated community about, whether that was something -- whether there were any changes that they should be thinking about.

I know that the commission has spent a lot of time working on standard offer, and I think at various points they have expressed concern about the fact that, you know, projects weren't surviving the RFP process, and so how can we do things better just next year within the confines of the existing statutes and maybe make that work better. And also that led them to think could we do something different if the statute wasn't there.

So it may be the case that after reading all of your comments the commission says, you know what, we can't arrive at a recommendation to the legislature because we have three people who don't agree on what the recommendation should be. But I have a feeling that we will talk to them about it. And hopefully this will lead to something productive.

MR. McNAMARA: One other procedural question is if there were going to be tweaks to existing standard offer, and also just acknowledging that even if the Department pushes forward, comes up with draft legislation, everything, there is still going to be at least another year or two of standard offer at a minimum.

MR. MARREN: Absolutely.

MR. McNAMARA: The Department definitely has some ideas about potential improvements, things like that. What's the timeline for the next RFP to go out?

MR. MARREN: December or January; right? We just opened the pricing docket.

MS. KROLEWSKI: So I think we are still anticipating, you know, sort of the same timeline as in the past. April 1. But this year we would like to at least get the RFPs circulated maybe well before that. So the RFPs would still be due in the May time frame, but we would like to get the actual requirements out much earlier than that.

And we are opening a process to review the price as we are required by statute to do annually. And I think the order might have went out today, or it might go out tomorrow opening the process. You might not have seen it.

MR. MARREN: You may not have seen it yet.

MS. ANDERSEN: Does it have a number?

MS. KROLEWSKI: But we have a schedule outlined in there to have some sort of decision on the prices possibly by the month of December.

MR. MARREN: But that docket is just about the prices, so I would suggest to the extent that people have suggestions about the 2019 RFP and things we should do differently, file them in this case, and the Commission will resolve those issues in this case.

MR. McNAMARA: Great. Thank you.

MR. MARREN: So I'll get a calendar out and pick a date in September, recognizing that we have lots of cases going on this fall. Does

September 14 work? Do you have any comments, team, on the timing of this?

MS. KROLEWSKI: For comments to be due?

MR. MARREN: For comments to be due in this proceeding. Making, you know, recommendations on the gamut; what should we do in the 2019 RFP, any suggestions about the exemptions issues, suggestions about changes to -- recommended changes to the statute. Recognizing that folks like Mr. Yantachka actually get to call the shots on what the statute says. If we are going to give them input about what the commission's views are on it, it's probably good to get that done well before the legislative session begins.

MR. McNAMARA: Could we also have a deadline for also replies? I think there is going to be some relatively new ideas that are going to be popping out, and I think it would be useful for people to be able to respond to that as well. I know, for example, the Department will have some more fleshed out thoughts I'm guessing folks are going to want to respond to, so if we have a deadline.

MR. MARREN: Is two weeks a good enough response period?

MS. ANDERSEN: September 14 and then

two weeks after that?

MR. MARREN: September 28. Is that okay? Okay. I'll issue a memo shortly after we leave here, and I'll record all of the deadlines for everyone.

MR. McNAMARA: Thanks.

MR. MARREN: All right. Well thank you very much. It is -- it was a lot of interesting discussion today, and I appreciate everyone coming to participate. Thank you, Andrew and Galen. That was excellent.

MR. BARBOSE: Yup. Great.

(Whereupon, the proceeding was adjourned at 3:16 p.m.)

C E R T I F I C A T E

I, Kim U. Sears, do hereby certify that I recorded by stenographic means the Workshop re: Case No. 17-5257-INV, at the Susan M. Hudson Hearing Room, People's United Bank Building, 112 State Street, Montpelier, Vermont, on August 2, 2018, beginning at 1 p.m.

I further certify that the foregoing testimony was taken by me stenographically and thereafter reduced to typewriting and the foregoing 97 pages are a transcript of the stenograph notes taken by me of the evidence and the proceedings to the best of my ability.

I further certify that I am not related to any of the parties thereto or their counsel, and I am in no way interested in the outcome of said cause.

Dated at Williston, Vermont, this 5th day of August, 2018.

Kim U Sears