

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.

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

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

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

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

21 MR. KNAUER: Tom Knauer with the
22 commission.

23 MS. KROLEWSKI: Mary Jo Krolewski with
24 the commission.

25 MR. HOWE: Micah Howe with the

1 commission.

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

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

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

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

10 MR. QUINT: Andrew Quint, Green
11 Mountain Power.

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

14 COMMISSIONER HOFMANN: Sarah Hofmann,
15 Vermont Public Utility Commission.

16 MS. FRANKEL: Deena Frankel, VELCO.

17 MS. WIDMAYER: Amber Widmayer, MMR.

18 MS. ALDERMAN: Carolyn Alderman, VEPPI.

19 MS. ANDERSON: Carolyn Anderson, Green
20 Mountain Power.

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

23 MR. CHARYK: Nick Charyk, AllEarth
24 Renewables.

25 MR. DePILLIS: Alex DePilllis, Vermont

1 Agency of Agriculture.

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

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

6 MR. CASTONGUAY: Josh Castonguay, Green
7 Mountain Power.

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

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

12 MR. DAY: Jason Day, Star Wind
13 Turbines.

14 COMMISSIONER HOFMANN: And we have John
15 Brabant.

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

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

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

24 MR. MELONE: Tom Melone from Allco.

25 MR. FLAGG: Andrew Flagg with the

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.

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

So with that, let me get started here.

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

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

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

24 So first before getting into material
25 itself, I thought I would give a little bit of

1 background on why we are here, virtually here I
2 suppose, and what Lawrence Berkeley Lab's role is.
3 So we were engaged by the Vermont PUC staff to
4 provide them analytic support to this proceeding.
5 This is happening through a program that the U.S.
6 Department of Energy Solar Office is sponsoring
7 called the Analytic Support for Public Utility
8 Commissions program. This is a program that is
9 relatively new whereby states can submit an
10 application to request free analytic support from
11 National Labs.

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

17 So with that, just in terms of the
18 presentation I'll be giving here really the goal is
19 to give all of you just a common factual basis for
20 comparing and understanding some of the different
21 program design options out there with respect to
22 other programs similar to the Vermont standard-offer
23 program. And we did this really just by reviewing
24 publicly available materials, so looking at
25 regulatory filings, and PPAs and RFP documents from

1 programs around the country, and really just trying
2 to synthesize that information into a format that
3 hopefully will be useful and digestible by all of
4 you.

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

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

1 either New England, New York or PJM states.

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

22 Many of these programs really are just
23 focused on procuring the renewable energy
24 certificates, so that's different than Vermont where
25 the procurement is for kind of bundled REC-plus

1 energy product. There are a few other programs out
2 there that we looked at that were focused on bundled
3 products as well, so it's not just Vermont.

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

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

21 You'll see as we go through you may
22 have just sort of noticed in reading over the list
23 that some of these programs really are geared
24 specifically to solar. They are SREC procurement
25 programs or solar EV procurement programs

1 specifically, but some of the others are open to a
2 broader set of renewable technologies like Vermont.

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

15 So I mentioned that many of these
16 programs do have set asides or tiers of various
17 types. Almost all of the programs that we looked at
18 reserve some set aside either based on budget or
19 capacity for small projects. So that might be
20 projects less than 25 kilowatts or 50 or 100
21 kilowatts, however that threshold is defined,
22 something well below the overall project size limit
23 for the program. Some programs even have multiple
24 size tiers. So maybe a set aside for the very
25 smallest, if there is set aside for a medium size

1 project, and then lastly some carveout for the
2 largest projects within this eligible size range.

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

18 Alternatively to having some special
19 set of provisions to allow small projects to
20 participate in the competitive solicitation, some of
21 these programs instead really just deal with those
22 smallest projects by having some standard pricing
23 available. So in Connecticut, for example, the DREC
24 program for the less than 100-KW size systems, it's
25 just a fixed price for all projects on a first-come

1 first-serve basis, and that price in that case is
2 pegged to the weighted average price of the next
3 larger size projects which are competitively bid. So
4 there are different ways of setting that price. But
5 the point being that often these smallest projects
6 are treated a little bit differently, and in many
7 cases are kind of excluded from the competitive
8 process that are given another mechanism for
9 participating.

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

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

1 emission profile.

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

10 So one maybe important point to just
11 note kind of at the outset here is that Vermont's
12 program is relatively small compared to most of the
13 others that we looked at. So in the last RFP, I
14 believe, about 10 megawatts was procured through the
15 standard offer solicitation. In looking at the other
16 programs here we show the number of megawatts awarded
17 through the last annual round of solicitations, and
18 so you can see in both of these other programs it was
19 somewhere in the kind of 15 to 50 megawatt range.
20 Connecticut's programs it was quite a bit more. And
21 so, you know, this obviously on some sense is just a
22 reflection of the relative size of different states,
23 although Vermont is a relatively small state, so it's
24 not altogether surprising that the procurement
25 volumes would be less. But it nevertheless may be

1 important for all of you to think about as you
2 proceed with revising the program and just thinking
3 about how much complexity and effort is necessarily
4 warranted when you're dealing with still a relatively
5 small program.

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

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

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

23 MR. BARBOSE: Yeah, I think I was able
24 to hear enough of it to answer. So we do have later
25 on in the presentation a slide that shows cumulative

1 procurement for each of these programs as a fraction
2 of each state's RPS requirement. So that's kind of
3 one way of scaling it. I don't have in this
4 presentation or, you know, in any ready-made form a
5 version of this that say scales it relative to each
6 state's retail electricity demand. But that later
7 slide, which is one of the last slides in the deck,
8 does kind of help, I think, to get some scaling
9 relative to each state size at least relative to
10 their respective RPS.

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

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

20 So moving along here. So I know one of
21 the issues that's come up in Vermont has just been
22 kind of the dominance of solar PV within many of
23 these solicitations, and that's pretty common.
24 Obviously in many states it's by design. These are
25 solar-specific programs. But even for programs that

1 are open to a broader set of technologies, you can
2 see here that the vast, vast majority of all awards
3 to date have gone to solar PV. Obviously in some
4 cases you've got little bits of wind or hydro or
5 other resources, but pretty much across the board
6 solar PV is dominating these procurement programs.

7 So kind of moving on to the set of
8 topics related to project attrition. So all of the
9 programs that we looked at here do require some form
10 of site control as an eligibility requirement for
11 even submitting a bid into the program. Really the
12 only exceptions here are the cases that I mentioned
13 where a bidder might have -- might be submitting an
14 aggregate portfolio of small projects and some
15 portion of those small projects are unspecified at
16 the time of the bidding. But that's really the
17 exception and not the rule pretty much across the
18 board. Some form of site control is required. I
19 know in Vermont there has been some discussion around
20 what kind of documentation is required to demonstrate
21 site control. We didn't really dig into the
22 specifics of that, you know, of these documentation
23 requirements, but they do vary quite a bit from
24 program to program. Probably most significantly they
25 vary depending upon whether the program is geared

1 towards behind-the-meter or utility-interconnected
2 projects. In the case where programs are geared
3 towards interconnection -- utility interconnected
4 projects there are at least some instances where site
5 control is required, not only for the project site,
6 but that there is at least some level of site control
7 or some kind of substantive evidence that the sponsor
8 is kind of on the path to gaining site control for
9 the interconnection, the land required to actually
10 interconnect to the utility system as well. So
11 that's one sort of slight variation that can
12 sometimes occur.

13 The on-site control, we also looked at
14 whether or not there were any requirements related to
15 the status of a project interconnection application
16 as a condition for submitting a bid. And in general,
17 most of them really didn't have any requirements in
18 this respect. I think the one exception was in Rhode
19 Island where projects did need to have already
20 submitted the interconnection application. And then
21 in Delaware there are some requirements really just
22 that within a certain time frame after having
23 received an award that they submit the
24 interconnection application. But beyond that,
25 usually the programs that we looked at are kind of

1 silent on this issue. I mean I think the implicit
2 assumption perhaps is just that, you know, these
3 projects alters -- it's kind of the onus is on them
4 to do whatever due diligence is needed to determine
5 whether or not they are going to be able to
6 interconnect easily.

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

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

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

17 MR. BARBOSE: So let me actually just
18 go back to the list of programs here. So I think for
19 those programs that are geared towards
20 behind-the-meter systems, and that's not really
21 obvious here, but I think I can probably off the top
22 of my head tell which you which ones they are, and
23 those are Connecticut, ZREC and LREC program. I
24 believe both of the Illinois programs. Delaware
25 program. Massachusetts. New Jersey. LIPA. Really

1 actually I think most of the programs here actually
2 are geared at least in part towards either
3 behind-the-meter systems or systems that are eligible
4 for the state solar carveout. And in either of those
5 cases, the requirement -- the projects do need to be
6 located in state. So I think that is probably most
7 typical.

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

12 MR. KIENY: Okay. Thank you.

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

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

21 MR. BARBOSE: Umm, so I pretty much in
22 almost all cases where there is a procurement, so I
23 mentioned a few of these programs are FIT programs.
24 So California and New York, those are kind of
25 straight feed-in tariff programs. For the others

1 which are at least, in part, competitive
2 solicitations, I think they are all administered by,
3 if not the regulator, some sort of state agency or
4 centralized procurement agent.

5 MR. McNAMARA: Okay. Thank you.

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

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

14 MR. BARBOSE: No problem.

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

20 MR. BARBOSE: Yeah, yeah. No, that's
21 right. That program was -- I think the ZREC, LREC
22 program is geared towards smaller and in-state
23 resources. The 2016 small-scale procurement that was
24 actually -- I think targeting two to 20 megawatt
25 sized projects which is why, as you mentioned, the

1 total procurement volume is so much larger than these
2 other programs. That one really -- it's really
3 geared towards somewhat larger-sized projects than
4 what the Vermont program or any of the others are
5 targeting.

6 MR. QUINT: Thank you.

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

20 And the way that these performance
21 guarantees are determined or calculated can vary
22 somewhat from state to state and program to program.
23 In many cases, like Vermont, it's just some dollar
24 per megawatt value that's multiplied by the nameplate
25 capacity of the project. Some other programs instead

1 do it based on the expected energy production. Or
2 the bid value where you're basically taking the bid
3 price multiplied by energy production, and then take
4 some percentage of that, and that's the collateral
5 that the sponsor has to put up. However it's
6 calculated, the ultimate dollar value can vary quite
7 a bit. Provide some kind of comparability. The
8 figure here just shows in our calculation of what
9 this performance guarantee would be for a one
10 megawatt-sized PV project under all of these
11 different programs. And you can see in Vermont it
12 would be \$15,000. You guys have a \$15 per KW
13 deposit. That's somewhat lower, I would say, than
14 most of the other programs. They are not wildly out
15 of line. I think most of these other programs if you
16 kind of look across the graph are somewhere in the
17 kind of 20 to 30 thousand dollar range. Obviously
18 there is, you know, that one Delaware program that's
19 much more expensive, and then there are a couple in
20 Massachusetts and New York where no performance
21 guarantee is required. So kind of get some general
22 sense of where Vermont's collateral compares to these
23 other programs.

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

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

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

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

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

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

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

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

19 But in any case, pretty typical to have
20 some kind of price cap, whether that's based on, you
21 know, sort of a market-based number or is developed
22 through some more administrative process, that kind
23 of varies from state to state. Notwithstanding the
24 fact that most of these programs are really just
25 looking at things based on price, some of the

1 programs do include adjustors, price adjustors, for
2 certain types of projects that they would like to
3 give some preferential treatment to. So in
4 Connecticut and Delaware they both have adjustors for
5 projects that use either in-state equipment or in-
6 state labor. And Massachusetts has a whole suite of
7 different adders for the various types of projects;
8 brownfield, landfill, solar canopies, et cetera.

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

20 Another way is to actually say, okay,
21 well you bid a price, and for those preferential
22 projects we are going to actually pay you based on,
23 you know, we are going to give you some sort of
24 kicker on top of your bid price. And the effect of
25 that is to then allow this project to basically bid

1 something lower than what they actually need in order
2 to cancel out. So it's kind of six of one, half
3 dozen of another. The effect is more or less the
4 same. So that's why we use this term price adjustor,
5 but the point being there is different ways of
6 mechanistically including this kind of preferential
7 treatment.

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

22 And so this is one way, of course, of
23 incorporating a locational preference for those
24 projects that are sited in areas of the bulk power
25 system that are more valuable. And this actually

1 ties in pretty directly to the presentation that
2 Andrew is going to give where he will basically
3 demonstrate the application of this type of method
4 for Vermont. I think it's worth just highlighting
5 again though, a point that was made earlier, which is
6 that this Connecticut small-scale procurement program
7 was much larger than Vermont. This was a 350
8 megawatt procurement focused on 2 to 20 megawatt size
9 project. So in that case, you know, having a more
10 elaborate bid evaluation process made sense. Whether
11 or not that same kind of procedure would make sense
12 for a much smaller program obviously is a subject for
13 you all to discuss.

14 So in terms of the pricing from these

15 --

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

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

22 MR. BARBOSE: Yeah.

23 MR. KIENY: So if a project in Vermont
24 was awarded a contract in Connecticut, does that last
25 bullet mean that Connecticut is buying it at the

1 point at which the electricity is generated?

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

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

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

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

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

14 MR. BARBOSE: So yeah, I'm not sure I
15 can necessarily answer that question, definitively,
16 but I think the way that it would work is I mean the
17 generator probably -- if there are developers in the
18 room they might be able to answer this more
19 authoritatively -- but my sense is that you sell, you
20 know, and you are paid based on the node that you're
21 selling into, which if you're located in Connecticut
22 is presumably a Connecticut node. And then, you
23 know, if you're selling it to a utility in
24 Connecticut -- I'm sorry. If you're in Vermont, then
25 you're getting paid a Vermont -- the price based on

1 the Vermont node, and then the buyer in Connecticut
2 is then withdrawing energy at their node and paying
3 that price. There is then some settlement based on
4 the difference in price between the two nodes.

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

13 MR. MARREN: Ed?

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

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

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

17 MR. McNAMARA: Okay. Thanks.

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

24 I think the point being though that
25 this is a mechanism to reward projects that are

1 located in higher cost areas of the grid, and
2 basically avoid siting projects in areas with already
3 really depressed prices.

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

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

24 That's shown in the figure here. For
25 the REC-only program, those projects -- these are

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

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

22 And here in the figure we have just
23 divided the total procurement cumulatively for each
24 program by that RPS demand, the overall RPS demand or
25 the solar carveout demand, just to give some relative

1 and to scale. For Vermont we have actually listed it
2 in both sections of the chart just in recognition
3 that those resources do qualify under the DG
4 carveout. But in the end may get -- getting used to
5 meet general RPS obligations just if that carveout is
6 already deemed met through net metering or other
7 means.

8 Should also mention that the Vermont
9 numbers here are really just reflective of what's
10 been procured through the competitive round beginning
11 in 2013. They don't include the 50 megawatts or so
12 that was procured through kind of earlier -- earlier
13 iterations of the program. So adding those in
14 obviously the numbers here for Vermont would be
15 higher. But conversely, you know, this is all
16 awards. It's not all operating projects or all
17 projects that are likely to ultimately come online.
18 So that would then, of course, make the numbers
19 lower. But in any case, the idea here is to give you
20 a sense of scale, you know, these programs may exist
21 sort of either within or in parallel to the RPS, and
22 of course, it's natural to ask as I think has come up
23 in Vermont, you know, why have this separate parallel
24 program when we already have the RPS. And although
25 it's not, you know, always entirely clear, I think

1 the implicit rationale in many cases is that, you
2 know, these programs are intended to support projects
3 that otherwise might have a hard time participating
4 in the RPS either because they are too small, or
5 because their technologies that aren't as cost
6 competitive as other renewable technologies but
7 nevertheless offer some unique value or help to
8 support some complementary policy goals, and
9 therefore the state wants to support those projects.

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

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

23 So with that, I think I'm just going to
24 kind of wrap things up here unless folks have
25 comments on that last slide. So in looking through

1 the kind of this collective synthesis of information
2 there are a few general themes and kind of take-aways
3 that emerge. Certainly there are some other things
4 that you all have also noted in hearing about this.

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

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

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

24 MR. BARBOSE: Yeah. So that 61
25 percent, so the numerator there is the expected

1 generation from all of the projects that have been
2 procured through the Vermont standard-offer program
3 from 2013 to 2018. So most of those projects are not
4 online. And some of them are not solar PV. So it's
5 really -- the cumulative kind of expected amount if
6 all of those projects were to ultimately come online.
7 That's the numerator.

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

13 MR. McNAMARA: 10 percent.

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

20 MR. QUINT: Actually it's June 30,
21 2015.

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

25 MS. ALDERMAN: Wouldn't existing

1 projects qualify for tier one?

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

7 MR. QUINT: July 1.

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

11 MR. MARREN: Okay. Thank you.

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

17 MR. MARREN: Yes. Thank you.

18 REP. YANTACHKA: Yes.

19 MR. BARBOSE: Okay. So just kind of
20 continuing on down this kind of general list of
21 themes and take-aways. So you know, many of the
22 programs that we looked at are a hybrid of some form
23 between a pure competitive solicitation and some sort
24 of standard offer FIT-type program. I think the
25 typical kind of variation that we saw which I

1 mentioned is, you know, smallest projects to instead
2 be offered a FIT contract rather than having to go
3 through a competitive process. But in theory, you
4 know, that kind of separate standard offer treatment
5 might be extended to other types of projects that for
6 whatever reason are kind of deemed to be kind of not
7 appropriate or not worth trying to force through the
8 competitive process such as -- may be something to
9 think about.

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

21 So I mean even if the programs
22 themselves are generally geared towards relatively
23 small projects, you know, a megawatt or two megawatts
24 in size, typically they have some kind of special
25 mechanism that allows participation by either

1 residential or, you know, sub 100 KW size projects.

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

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

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

25 I just had one question to start this

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

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

15 MR. MARREN: Okay.

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

1 of standard offer pricing.

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

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

6 MR. MARREN: Yes, Ms. Smith.

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

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

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

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

21 MR. BARBOSE: Okay. Great. That's
22 what I was going to suggest. So you know what, I
23 didn't notice any other requirements related to
24 public notice. I mean that -- I assume that's a
25 requirement -- it's a requirement that gets imposed

1 during any sort of permitting stage which would
2 obviously be kind of administratively separate from
3 the procurement program itself. I didn't see any
4 provisions within these procurement programs, though,
5 that mandated anything required to public
6 notification.

7 MS. SMITH: Thank you.

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

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

23 MS. SMITH: That's my understanding,
24 which is why I think it should be clarified that this
25 61 percent is sort of a maximum potential, but it's

1 not necessarily what's happened.

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

8 MR. KIENY: One.

9 MR. MARREN: Craig?

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

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

20 Yeah. I mean in Connecticut the ZREC,
21 LREC programming basically they look at two
22 investor-owned utilities. One represents basically
23 80 percent of statewide load. The other 20 percent,
24 and then the ZREC, LREC requirements are more or less
25 divvied up accordingly. But in New Jersey similarly,

1 so yeah, I think it's based on whether it's retail
2 sales or RPS obligation, it's kind of effectively the
3 same. But I think the approach used in Vermont is
4 pretty standard.

5 MR. KIENY: Okay. Thank you.

6 MR. MARREN: Ed?

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

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

22 MR. McNAMARA: Okay. Thank you.

23 MR. MARREN: All right. Seeing no
24 other hands at this point, maybe now is a good time
25 to just take a quick five-minute break and let the

1 court reporter rest her hands for a second and get
2 ready for Andrew's presentation. Thank you very
3 much, Galen. That was great. We'll be back in a few
4 minutes.

5 (Recess was taken.)

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

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

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

13 MR. MILLS: Great. Thanks.

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

19 MR. MILLS: Great. Thank you. I'm
20 Andrew Mills also from the Lawrence Berkeley National
21 Laboratory. An impetus for this portion of the
22 discussion, as we were looking at some of the
23 comments that came in on the program, one of the
24 things that was talked about a bit was trying to
25 avoid situations where new generators are sited in

1 places that might have adverse impacts on the grid.
2 And there is no current way in the evaluation of bids
3 that sort of really accounts for those locational
4 factors, nor is there a way to kind of communicate
5 that to potential bidders.

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

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

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

1 the Connecticut program.

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

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

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

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

19 In contrast, if you're locating your
20 resource somewhere where the grid is relatively
21 constrained, and you're generating at times when
22 there is less value for that power, then you won't
23 bring down your bid cost by as much. That wholesale
24 value number would be lower. So that's the general
25 idea here, and to kind of illustrate that idea, we

1 have got some specific calculations that we have done
2 to illustrate this. And I don't necessarily suggest
3 that this is the way that it should be implemented,
4 but I just wanted to be able to provide some
5 numerical values, so I will illustrate this approach
6 with some particular data that is available to us.

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

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

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

25 Using those profiles I was able to take

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

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

19 We also see August at night tended to
20 have some higher prices during this historical period
21 between 2015 and 2017. So these higher prices are
22 suggesting that delivering power at these times would
23 be of higher value to the overall system. Whereas in
24 contrast if you're delivering power more at say 9
25 o'clock in the morning in June, it's going to have

1 lower value than these other times. And that's where
2 the lighter color is.

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

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

22 One of the things that's different with
23 the wind is we have a higher scale here, so we are
24 going up to over 75 percent of our nameplate capacity
25 is being generated in those summer months, middle of

1 the day. So from this sort of -- that data just sort
2 of illustrates the overlap here, but what we do
3 specifically to calculate this wholesale value number
4 in dollars per megawatthour terms, I'm going to
5 calculate this energy value, and I'm going to add to
6 that the capacity value. The energy value here comes
7 from summing up that hourly generation profile of a
8 particular technology multiplied by that hourly
9 energy price for a specific node. So I'm looking
10 really at that correspondence of generation and high
11 prices at specific nodes.

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

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

23 And so you know, just to kind of throw
24 out rough numbers for wind, that tends to be
25 somewhere in the 20 percent of your nameplate

1 capacity might be counted towards that resource
2 adequacy for the summertime period. In the
3 wintertime period it might be something higher, maybe
4 up in a 40 or 50 percent of your nameplate capacity.

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

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

17 MR. MARREN: We do have one.

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

1 are therefore paying more for power because we are
2 paying sometimes rate for wind?

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

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

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

24 That's sort of the system value is
25 being reflected by these prices, and then the value

1 that I'm assigning to wind is saying how much wind
2 were you generating during those times, and that --
3 aggregating that over the whole year gets your energy
4 value.

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

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

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

23 MR. MARREN: Patty Richards.

24 MS. RICHARDS: And --

25 MR. MILLS: Yeah. And I support what

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

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

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

25 MS. RICHARDS: Patty Richards from

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

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

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

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

1 to three-year period, and that does move around.

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

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

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

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

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

19 I think a take-away for me, a couple of
20 things from this one is that, you know, the solar and
21 wind value under these calculations isn't that
22 different from this flat block of power, that sort of
23 flat profile. There are a few places particularly
24 for the wind where that value can be quite a bit
25 lower. We will see on a map where those locations

1 are. And then on average the solar tended to be a
2 little bit lower than the wind and the flat profile.
3 Although you don't see as much of the extremes.

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

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

17 MR. MARREN: We have one question.

18 MR. MILLS: Go ahead.

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

22 MR. MILLS: So you know, again
23 mechanically just used the same rules that ISO New
24 England would use for wind profile or solar profile,
25 but in that case it ends up being basically the 100

1 percent capacity credit. So basically you get your
2 full nameplate capacity is counted towards the
3 resource adequacy requirement, and then you divide,
4 so that gives you 100 percent capacity credit. You
5 multiply that by the capacity price, then you divide
6 that by all of the energy that that flat block of
7 power has produced over the entire year to get the
8 capacity value in dollars per megawatthour.

9 MR. MARREN: Thank you.

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

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

1 seeing it to be up closer to the \$40 a megawatthour
2 range.

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

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

1 distinguish between them.

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

18 And so I think that this sort of
19 illustrates an approach of doing that. I think there
20 is a lot of questions about whether it's worthwhile
21 doing this, whether it's transparent and fair, and
22 then also if you can kind of refine some of that. So
23 some of the specific refinements that I think might
24 be worthwhile is to think about I was using sort of
25 the ISO New England aggregate profile because that's

1 data that's publicly available and easy to get. It
2 might make sense to have site-specific generation
3 profile. What does the wind in northern Vermont look
4 like versus what does the wind profile in southern
5 Vermont. I don't have that data, so I wasn't able to
6 answer that particular question.

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

17 And then I think some of the discussion
18 earlier too, that this is just a snapshot in time.
19 Using a few years. Does it make sense to sort of
20 think about how prices will be changing in the
21 future. And so maybe you could be augmenting the
22 historical data with projections in future wholesale
23 prices and be thinking about how prices might be
24 changing as the share of different generation types
25 change around ISO New England. How load profiles

1 might be changing, and also if there is any sort of
2 planned investment transmission that might alter some
3 of these LMP patterns. And that Connecticut example,
4 I think, maybe provides one example of where they are
5 using projections of future wholesale prices in order
6 to generate this information.

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

13 MR. MARREN: Any questions?

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

16 MR. MARREN: Yes, Ms. Smith.

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

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

21 MS. SMITH: Good. So I feel like I
22 need to say that while this is showing, you know, the
23 highest wind generation at night, there is a cost, a
24 societal cost, that's not factored into any of this,
25 and some people need to sleep. So when you look at

1 something like this that seems to invite the idea
2 that there should be more wind because it fulfills a
3 need at night, we have to factor in what that's doing
4 to the neighbors. And if those costs were
5 compensated, the pricing might be very different. So
6 that's my comment.

7 MR. MARREN: All right. Thank you.

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

16 MR. MARREN: All right. Any other
17 questions?

18 (No response.)

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

22 MR. MILLS: No problem.

23 MR. MARREN: I would like to invite the
24 group to share their thoughts if they want about sort
25 of the broader purpose of this workshop. You know,

1 for context, the standard offer program's been around
2 for almost a decade now. And it's got -- it has
3 three more years left to run, and they also happen to
4 be, you know, three years of sort of more procurement
5 than we have done in the past.

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

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

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

25 So we would be open to hearing from

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

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

21 The Board's net metering order a couple
22 months back, I think it was the May first order or
23 something along those lines, essentially set forth
24 that with the renewable standard now, it's
25 essentially the governing overall -- sets the overall

1 landscape for renewable policy in Vermont. Tier two
2 of the RES in particular encompasses both standard
3 offer, net metering, also utility-owned projects as
4 well.

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

22 But the Department's view is that the
23 process that we have of every year setting the
24 technology diversity, setting the avoided cost cap,
25 it is a very regulatory burdensome process for a

1 really small amount of megawatts that come into the
2 system. Also the utilities are usually better
3 situated to actually say here's the general ideas of
4 where there is constraints in the system. For
5 example, we looked at wholesale costs, and what
6 Andrew just presented was really useful. It doesn't
7 take into account certain things such as distribution
8 constraints on GMP's system in Addison County. Those
9 are factors that, instead of the PUC doing the
10 procurement, taking comments from everything else,
11 having GMP, for example, know that up front in their
12 procurement, designing the procurement to
13 specifically address those up front would actually be
14 more streamlined, less costly overall, and more
15 efficient process. So some high level thoughts.

16 MR. MARREN: Thank you. Mr. Allen?

17 MR. ALLEN: I'll just --

18 MR. MARREN: Can you identify yourself?

19 MR. ALLEN: I'm sorry. Riley Allen
20 with the Vermont Public Service Department. I think
21 one of the things that I think Andrew's slides kind
22 of pulls out to me is just the way the -- the value
23 is changing even at kind of the energy and
24 potentially capacity markets over time, and so
25 recognizing that, you know, when we are procuring

1 resources, variable energy resources, we are really
2 purchasing a fairly static set of values that will
3 continue over a very long term. And with the kind of
4 increasing opportunities that are becoming apparent
5 through support technologies and other things, it may
6 be that we can create a more flexible product out
7 there that we capture in the competitive bidding
8 process, one that can over time perhaps better align
9 with the -- with the fairly dynamic environment that
10 we have around us. Still pursuing renewables, but
11 recognizing that there are technologies and
12 capabilities that might over time allow those
13 technologies to better match the values, and with
14 respect to time and location that Andrew is pulling
15 out.

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

25 And basically our power supply mix is

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

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

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

20 And so SRECs and other mechanisms that
21 vary overtime, for example, you could have an LMP
22 prediction in the future. These things all introduce
23 uncertainty that make it difficult to get a project
24 built. I have developers who are really challenged
25 to get a biogas project in the ground at 19 or 20

1 cents. And there is enough uncertainty in what they
2 do to -- that the additional uncertainty that might
3 come by introducing other kinds of mechanisms than
4 what we have which is, you know, a long-term fixed
5 price, would make it, I guess, even harder. So I'm
6 concerned about that.

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

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

18 MR. MARREN: Yes, Ms. Smith.

19 MS. SMITH: I was interested in what Ed
20 and the Department said. I like the idea of
21 eliminating the standard-offer project program. I
22 have been struggling with what I see as a need to
23 enable developer-driven development and not the
24 utility. So if that was tied to tier two, that would
25 make sense. I think as we are seeing with the new

1 preferred site letter, joint letter that can be done
2 in net metering, there is a real problem with the
3 lack of advance notice.

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

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

25 So I think that I really like the

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

3 MR. MARREN: Olivia, did you have --

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

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

8 MS. ANDERSEN: Can they hear me?

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

11 MR. MILLS: Me too.

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

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

22 MR. BARBOSE: Yeah. I think that's
23 correct for the utility-scale projects. I think, you
24 know, as I mentioned, many of these programs are
25 geared more towards behind the meter. And so

1 depending on the states, you know, those projects may
2 or may not be required to go through kind of the CPCN
3 type process. But yeah, I mean in general, I mean a
4 grid-connected project is going to need to go through
5 that process.

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

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

22 MR. MARREN: Yeah.

23 MS. ANDERSEN: Okay. Well I had
24 actually a question, you know. There is two other
25 issues that are -- that I wanted to inquire or

1 discuss in relation to, you know, alternatives to
2 renewable procurement if standard offer didn't exist
3 and sort of right now the current standard-offer
4 program has both a provider block, meaning the
5 utilities, and then a developer block, meaning
6 non-utility or third parties.

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

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

1 when you look at the bids that have come in.

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

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

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

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

25 MS. ANDERSEN: Okay.

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

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

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

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

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

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

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

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

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

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

25 MR. QUINT: No.

1 MS. BAILEY: No.

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

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

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

16 MR. MARREN: Yes.

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

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

6 MR. MARREN: Ed.

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

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

25 MS. ANDERSEN: In that type of

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

20 MR. McNAMARA: Yeah. So I actually
21 have concerns with just the how much solar we are
22 putting on with no diversity in resources. It's --
23 especially given wintertime New England constraints.
24 So I think some kind of diversity, what that looks
25 like, I think some diversity can be better achieved

1 for -- through economic development grants rather
2 than through a procurement process.

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

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

23 I'm not trying to put forward a fully
24 formed Department process whatsoever. I'm trying to
25 suggest the potential different direction to take

1 procurement for resources.

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

11 MR. MARREN: Galen, did you catch that?

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

19 I mean I think the unique issue for
20 Vermont obviously is that it's a pretty small
21 program. And so your guys' appetite for adding
22 additional administrative costs or even retaining the
23 same set of costs is going to be pretty limited. So
24 I mean I think to the extent possible just, you know,
25 standardizing the process obviously helps. But, you

1 know, you guys have been doing this for quite a few
2 years now, and I imagine have probably, you know, you
3 know, picked off as many low hanging fruit as you
4 can, you know, in that regard.

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

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

12 MR. MARREN: Yes.

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

17 As we saw here, you know, most of them
18 are pursuing solar. It hasn't necessarily been an
19 issue. I mean to the extent that programs want to
20 get the lowest cost resources, and solar is the
21 lowest cost, that's just sort of the outcome that,
22 you know, that's just natural outcome of the process.
23 So I wouldn't say that for most programs it's
24 necessarily been an issue, you know, a lack of
25 technological diversity. You know, I think maybe if

1 there is a bigger issue, it's just ensuring that
2 there is a diversity in entities that have the
3 ability to participate.

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

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

16 I think the other, you know, maybe also
17 related to this is just sort of ensuring, you know,
18 trying to direct projects towards, you know,
19 applications that provide some ancillary benefits,
20 and so, you know, we see this in some programs that
21 provide preferential treatment for brownfield
22 projects or landfill projects, you know, preferential
23 treatment for projects that are serving low and
24 moderate-income communities. That's not exactly
25 resource diversity. But it is sort of in the same

1 vein trying to, you know, target the programs
2 towards, you know, projects that may not necessarily
3 emerge just purely based on economics.

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

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

1 value if you have a different entity that is
2 essentially operating and conducting the
3 solicitation.

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

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

18 MR. McNAMARA: Are PUC staff thinking
19 that the report to the legislature is going to be
20 just exemptions? And that you might have some
21 further comments? Because what I'm thinking is, for
22 example, overall how do you restructure standard
23 offer if you do so at all is much larger discussion
24 than exemption. You could have comments on exemption
25 in a couple weeks probably. Most people already have

1 pretty well-formed thoughts on that just to get that
2 done. But if you are thinking about potentially
3 presenting to the legislature a wider range of
4 options, that at least from the Department's
5 perspective we would appreciate a deadline sometime
6 in September actually as opposed to a few weeks.

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

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

1 different if the statute wasn't there.

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

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

16 MR. MARREN: Absolutely.

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

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

23 MS. KROLEWSKI: So I think we are still
24 anticipating, you know, sort of the same timeline as
25 in the past. April 1. But this year we would like

1 to at least get the RFPs circulated maybe well before
2 that. So the RFPs would still be due in the May time
3 frame, but we would like to get the actual
4 requirements out much earlier than that.

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

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

12 MS. ANDERSEN: Does it have a number?

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

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

22 MR. McNAMARA: Great. Thank you.

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

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

3 MS. KROLEWSKI: For comments to be due?

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

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

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

25 MS. ANDERSEN: September 14 and then

1 two weeks after that?

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

6 MR. McNAMARA: Thanks.

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

12 MR. BARBOSE: Yup. Great.

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

A rectangular box containing a handwritten signature in cursive script that reads "Kim U. Sears". The signature is written in dark ink on a light-colored, slightly textured background.

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