DOCKETED

Docket Number:	16-BSTD-06
Project Title:	Updates to the 2019 Time Dependent Valuation of Energy
TN #:	212612
Document Title:	Transcript of 7/15/16 Lead Commissioner Workshop on 2019 TDV
Description:	Certified transcript of the 7-15-16 Lead Commissioner Workshop on Time Dependent Valuation of Energy.
Filer:	Adrian Ownby
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	8/3/2016 3:51:28 PM
Docketed Date:	8/3/2016

CALIFORNIA ENERGY COMMISSION

LEAD COMMISSIONER WORKSHOP

In the Matter of:	) Docket No.) 16-BSTD-06)))
2019 Building Energy Efficiency Standards	) WORKSHOP RE:) 2019 Time Dependent) Value of Energy

LEAD COMMISSIONER WORKSHOP ON
2019 TIME DEPENDENT VALUE OF ENERGY
AND LIFE CYCLE COST METHODOLOGY UPDATE

CALIFORNIA ENERGY Commission

THE WARREN-ALQUIST STATE ENERGY BUILDING

CHARLES IMBRECHT HEARING ROOM

(HEARING ROOM B)

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

FRIDAY, JULY 15, 2016

9:00 A.M.

Reported by:
Peter Petty

APPEARANCES

Commissioners

Andrew McAllister, Lead Commissioner, Energy Committee

Robert B. Weisenmiller, Commission Chair

Pat Saxton, Adviser to Commissioner McAllister

CEC Staff

Adrian Ownby, Building Standards Office

Bill Pennington, ED Administration

Garry O'Neill-Mariscal, Supply Analysis Office

Christopher Meyer, Building Standards Office

Contractors

Tory Clark, Consultant, E3

Snuller Price, Senior Partner, E3

Others Present(* Via telephone and/or WebEx)

Marc Esser, NegaWatt Consulting

Meg Waltner, NRDC

Jon McHugh, McHugh Energy

Robert Raymer, CBIA

Michelle Sim, SoCalGas

Rob Hammon, BIRAenergy

Rachel Golden, Sierra Club

Ted Tiffany, Guttmann & Blaevoet Consulting Engineers

I N D E X

P R O C E E D I N G S

JULY 15, 2016 9:06 A.M.

MR. OWNBY: My name's Adrian Ownby. I'm the Contract Agreement Manager for both our Standards and Development Office technical support contracts and the Work Authorization Manager for the work being done in developing the 2019 TDV.

We'll start off with some housekeeping and then I'll turn it over to the Commissioners briefly. Bathrooms, for those here in attendance bathrooms are outdoor to the left and to the right. Up the stairs in the atrium there's a small cafeteria, so if you need some refreshments it's up there.

In case of an emergency what we'll do is exit through the double doors here, turn right, exit through the doors at the end of the building here. And we'll reconvene across the street in Roosevelt Park.

So I think with that before we start the presentations I'll turn it over for introductions to Commissioner McAllister and Chairman Weisenmiller.

COMMISSIONER MCALLISTER: Great. Thank you, Adrian.

(Colloquy off mic regarding microphones.)

So my name's Andrew McAllister. I'm a Commissioner, mostly overseeing the Energy Efficiency among other things, and the forecast is certainly of deep interest to me. And the TDV is a core piece of how we developed -- well within Energy Efficiency's Building Standards and the TDV certainly is a core resource for the Building Standards and many other things that the Commission does.

And I think TDV has its complexities. It is a very -- so it's not actually the most accessible product to the public, but it is a very, I think, rational and policy-wise very defensible and very robust way to approach the cost effectiveness analysis that we do at the Commission.

Also, I would say, TDV is changing faster than probably at any moment since its inception, in terms of how it has to change to reflect the realities out there is the marketplace and our generation mix and our investment needs. And we're going to hear some of that today. So we really need to make sure that it is updated and adapted as quickly as possible to reflect those new realities.

And so this cycle I think is really important, not least because the 2019 Building Standards are pushing the envelope on the possible. And so we really need to get that right and thread the needle on the cost-effectiveness, evaluations. And understand that the issues that may remain unresolved, so that we can appreciate them going forward in not just in the 2019 cycle, but beyond that.

So this update on the TDV is especially important. It's always important to get it right, but this one has been particularly important. So it certainly is not on autopilot. We've got to bring our critical thinking skills to this and ask the questions and make sure we're heading in the right direction.

And I think so far so good. I think their work has been good quality. And moving it forward, I'm happy how it's going so far. So, with that I'll pass the mic to the Chair.

CHAIRMAN WEISENMILLER: Good morning. I'm Bob Weisenmiller. I'm Chair of the California Energy Commission.

As you know one of the key issues for California is dealing with climate change in terms of our ways of dealing with climate change or reduce greenhouse gas emissions. A key tool that we're using to reduce greenhouse gas emissions are the Building Standards. And the Governor has set an aggressive goal of ZNE by the end of this decade in the Standards. So this is part of that process.

As Commissioner McAllister indicated, that goal fits within the context of the legislation where our Standards have to be cost-effective. And our tool to really address the cost effectiveness is the TDV Analysis today.

And as he indicated the Utility Grid is changing in ways or being transformed in ways, which it's never really seen. And so that has implications as we go back through the evaluation. So this is a good opportunity to kick off the discussion and make sure we get this right so that people can basically start seeing how this affects building designs.

So again thanks for your participation today. And I'm certainly looking forward to a lively discussion. But again, in spite of all the acronyms and complexity of the modeling this stuff is really important to get right. So thanks for helping us on that.

MR. OWNBY: All right, so we can start with presentations.

I have a very short presentation that I can think of as the, "What happens to the people who just wander in here off the streets?" sort of presentation. So they'll figure out whether they want to stay or go. (Laughter.)

COMMISSIONER MCALLISTER: That's a tough, very difficult choice, really.

MR. OWNBY: This isn't just something you discuss over the dinner table at night.

COMMISSIONER MCALLISTER: No, no. There are probably a couple of dozen people who do, but they probably don't actually want to admit that. (Laughter.)

MR. OWNBY: So, anyway I'm first going to start off with what is TDV? What is the TDV Value of Energy? And it really is sort of a meta-time of use rate or value curve for the State of California.

The TDV values energy differently based on the hour of the year to reflect costs to consumers, to the utility system and to society.

TDV is a flexible tool. It varies by utility type, by location reflecting the cost of different climate conditions, and by type of construction: residential and nonres. So essentially we have 8,760 values for 16 climate zones and the residential and non-residential buildings.

The Energy Commission uses TDV. Its functionality comes from its integration into our software, the California Building Energy Code Compliance Software: CBECC-Come and CBECC-Res. Within the software it's the basis for setting the maximum energy budgets for buildings and value in the energy performance tradeoffs in building designs. By itself TDV sort of doesn't designate anything until we put it into the software.

So for the 2019 TDV Update all of this is going to be covered much more in depth by our contractor, E3. But for the 2019 TDV Update all of the data inputs have been updated to the latest and best available date.

The transmission and distribution data in previous iterations of the TDV, we had used heat as a proxy. We were able to get a hold of actual substation data for transmission and distribution to distribute those costs. And that had a very interesting impact on TDV. It's much more accurate now I suppose you could say.

And then finally we base on what we're calling SB 350-friendly assumptions. And the only thing I want to cover any further here with SB 350, is just to remind people what that is. That's the Clean Energy and Pollution Reduction Act of 2015.

And for our purposes we've had two core pieces in it. One is a 50 percent Renewable Portfolio Standard by 2030. And the second piece is a doubling of the achievable annual energy efficiency, again by 2030. Those are the two big targets; I guess you could say, in SB 350. There are other targets and there are other provisions, but those are the two that concern us the most.

So we previously held a workshop, a staff workshop on TDV, on May 12th. And that workshop generated seven different comment letters. And all those written comments have been reviewed, parsed out to sort of get the essence of the various comments and any comment letter may have multiple comments. And then we do the initial draft response, we review and then we drafted the first draft of a response to every one of the comments that we received.

It's important to recognize that in an actual -- in the recently initial stages here (indiscernible) it's important to recognize that in an actual rulemaking proceeding there's a further review of comments that frequently involves the Legal Office. And then the finalization of a response to comments that becomes part of the rulemaking package.

So this is just to say to you, your comments have been heard. And we have thought about them to them and responded to them. And really, if you would like to make further comments as part of the record, on TDV, you will probably even make those comments during our regular rulemaking proceeding for the 2019 Standards.

So since the main workshop we have had three iterations of the TDV that we've published, where we've continuously have improved it and made some adjustments. And we've also published a draft of the Final Report on TAD.

So looking forward the schedule for this has largely been driven by the need to get a research version of our compliance software into the hands of a case team, so that they can begin to use it, they and others can begin to use it to analyze potential measures for the 2019 Standards.

Docket -- I'm sorry to step back just a second here. We do actually already have a research version of the residential software. Bruce Wilcox is our contractor on that and he's produced a residential version of it. We may need to update that, but it's likely that that will be available next week to the public.

Docket, our docket for this is Docket 16-BSTD-06. It's open now. I intend to leave it open through the end of January -- or sorry, January -- July and close it at that point. Presentations that are made here and other materials including for instance a recording of this WebEx and a transcript ultimately will be posted, when we post it to the docket on our website, of this proceeding.

And so at this point what I'd like to go ahead and do is introduce Tory Clark with E3. And she's going to proceed with the presentation here in just a moment.

(Microphone prepared prior to presentation.)

MS. CLARK: So I might be a new face or a new voice to some folks here, but I'm a consultant at E3 who's been managing our TDV efforts on this project. Also here with me today is Snuller Price who everyone in this room I think knows. And some other folks that I wanted to just recognize who've been helping out on our team: Zachary Ming, Brian Conlon, and Hilary Staver. There's been a lot of folks working on this piece of the project.

So today what I want to do is kind of go through a little bit of TDV methodology background and history. There are some questions that we get pretty commonly, so I want to hit those up front so that we're all on the same page. Talk a little bit about our considerations for SB 350 that Adrian started cueing up and the sensitivities that we did around SB 350.

And then I'll walk through the updates to TDV since the last cycle, the 2016 cycle. There are some updates that I'll highlight that are specifically new since the draft workshop in May. And so I'll highlight the differences that are new compared to 2016 and the updates since May.

And then we'll walk through results and compare them back to previous cycles. And then what will be brand new in this workshop is that we'll have Snu run through kind of our very preliminary look at electrification based on the new TDV results. Next slide?

Okay. So Adrian already kind of cued this up pretty well. But when we talk about TDVs or Time Dependent Valuation we're really kind of doing a long-term forecast of our hourly energy, electricity, and natural gas and propane to building owners. And this is used mainly for cost effectiveness under the Title 24 Building Code.

We're trying to answer what is cost effective in the long term. This is required under the Warren Alquist Act. And we kind of create this almost layer cake of energy, kind of differentiating marginal costs for production and delivering energy. And then we also do an area correlation based on the 16 climate zones in California. Next slide.

And so the two main uses for the TDVs are cost effectiveness analysis under our case studies, which are about to kick off here pretty shortly, as well as our alternative calculation methodology, the ACM, when a buildings want to vary from the prescriptive building compliance. And because of this the TDVs do get embedded in the CBECC-Res and CBECC-Com software.

So now let me get to a few kinds of FAQs for TDVs. One question that we get fairly often is why we use statewide average retail rates for electricity and natural gas? And though it seems appealing to have a different retail rate based on specific utilities, because those do vary, we want to have -- the Code wants to have a similar overall stringency statewide. So that we can also have similar construction practices at least within a climate zone across the state.

And then the second FAQ that we get is why we don't use actual retail rate structures. So there's been a lot going on at the CPUC on the residential and retail rate reform. We could scale everything up to the equivalent to these retail rate practices. However, we know that because of this changing, and we're talking the lifetime of a building and we're updating the Building Code every three years, we want to kind of maintain some consistency cycle-to-cycle and over the lifetime of the buildings that we're modeling.

And the last FAQ that sometimes trips people up are the units that we talk about. So we typically report TDV kBtus per kWh for electricity and kBtus per therm for propane and natural gas, which feels pretty counter-intuitive or unintuitive at least. And if you actually open the TDV model, for those of you that are digging into the weeds, you can output results in dollars per kWh and dollars per therm since that's actually how we're calculating these numbers, which will make more sense as we run through the different components.

But for Building Code compliance we convert these using a standard factor, the same adjustment factor that we've used in previous cycles, to be in these energy kBtu per kWh and kBtu therm. And this is so that we can kind of distinguish between what we're doing in the Building Code and what you might see on your bill. Next slide.

So one of the things that's new for the 2019 Building Code cycle is SB 350. And since we're not entirely sure how SB 350 will be implemented all we know is we're shooting for 50 percent utility procured renewables and a doubling of energy efficiency by 2030.

We created a base case that we're calling SB 350-friendly. This hasn't changed since the May workshop. But what we're using is the 2015 IEPR mid-case load forecast, which includes electric vehicles, CO2 price forecasts, behind-the-meter PV forecasts that are consistent with the CEC IEPR. We are using a 50 percent renewable build-out by 2030, which is different from what's embedded in the IEPR, so I'll walk through the assumptions that we made there.

And then for the energy efficiency assumption we're assuming a doubling of the CEC's projected additional achievable energy efficiency.

(WebEx recording interrupts presentation.)

MS. CLARK: Okay. We're picking up where we left off on Slide 9, so back to the SB 350-friendly assumptions. Again, these are the same as what we presented in May, so our mid-IEPR load forecast 50 percent renewables, a doubling of the IEPR Additional Achievable Energy Efficiency by 2030. And the assumption that Diablo Canyon will retire after its license. Next slide.

(Audio issues during presentation at this point.)

We also created a couple sensitivities, just to bound our analysis and see how much a few assumptions would affect the results. We focused on this assumption of energy efficiency and the assumption of CO_2 price.

So our base case we just talked about, our energy efficiency case is assuming that we don't achieve a doubling of energy efficiency, but rather that we only achieve what's defined in the IEPR, which could be considered a high electrification case rather than a high energy efficiency case. And then third, we assumed a case with a high IEPR carbon price. And we'll show how much that affects the results a little bit later in the presentation.

CHAIRMAN WEISENMILLER: Keep going.

MS. CLARK: Okay. So on to Slide 12, so first I just want to highlight a few of the things that have changed since May if we can go back to Slide 12?

Okay. So we got a lot of great feedback in the last couple of months, both written and from those that dug into the model really deeply, some specific comments on deep in the weeds modeling assumptions. And so we've been make some changes also based on availability of data and our own vetting. So there are kind of some key changes that have changed the results a bit more and then just some bug fixes that haven't really changed the results very much.

So the biggest ones that we've been able to include -- the transition and distribution allocation factors using real utility load data -- we did present on this? Let me take one small break for a moment.

(Off mic colloquy to handle technical issues.)

CHAIRMAN WEISENMILLER: Okay. Keep going.

MS. CLARK: Okay.

So the first few changed since our draft TDV values that we presented on May 12th, is that we've changed the TDV allocation factors with real utility load data. We did present on this in the May workshop, but we didn't have full permission to use the data. So there will be some repetition. Basically we have gotten the ability to use this data that we were hoping to use, changing from this temperature proxy that we had in 2016, to now more sophisticated regression that also includes real feeder data.

The second is that we kind of changed one of the temperature thresholds in our generation capacity costs. It's just a small tweak that smoothed out values.

We've changed a little bit to what we're doing on the emissions adder for natural gas and propane. There was kind of an old carryover from a previous cycle where we've been using NOx rather than CO2, or in addition to CO2. And so we've changed that to not include this NOx adder, but rather to have kind of CO2 to be consistent with what we're doing with electricity.

And then finally, we got some feedback from the propane industry about the seasonal shape that we've been using for how the TDVs for propane vary over the course of a year. And we've been using some factors from previous cycles. They were able to get us some improved data and so we'll show you how that changes the shape for propane over the course of the year.

And then a few other bug fixes that have to do with kind of just very in the weeds, but our dispatch logic for calculating combustion turbine energy reserves. We've included carbon and variable O&M costs. And then finally we just kind of changed the units for our CO2, but neither of those have changed the results very much.

So now, I'm going to walk through both -- kind of our big change to methodology and then our changes to inputs. And I'll flag which of these are different from May.

So this is this T&D updated methodology. Previously, we'd been using this temperature proxy to allocate transmission and distribution capacity avoided costs, which turns out to not be as good of a predictor for when we're actually using our transmission and distribution lines whereas using real feeder data is a much better predictor.

So this much more accurately reflects usage patterns in each climate zone. We can now allow for local PV, distributed PV affects to be included, which is especially important as we're using the IEPR's forecast for behind-the-meter PV, which gets quite large. And it's more consistent with our industry view of peak demand. And as I'll show in the effects this actually makes the value more accurate for dispatchable -- for valuing dispatchable options.

And so one of the things that Snu had mentioned in our workshop in May, is that we were waiting for approval to use some of the feeder data that we've gotten from PG&E and SCE and this was released as a part of the CPUC Avoided Cost Interim Report that was released in June. And so we were able to use the same regression factors that we used in the CPUC avoided cost, so there's additional documentation of this in our draft report as well as in the CPUC Avoided Cost Report that was released in June. Just if anyone's curious what the process was to get us here.

And then for the allocation method in a bit more detail, so now in addition to the temperature data that we had been using in the 2016 cycle, we're adding the hourly load data, distribution computer load data, to a regression with many other variables including dry-bulb temperature, cooling degree hours, heating degree hours and others, which pretty accurately reflect what we would actually see on the feeders.

Then we're applying this regression to our weather files, to predict hourly loads. And then we're adjusting for additional solar PV adoptions through 2030 allocation factors.

So next slide will start to show how this is looking in just a moment. We're going to pause for just a second.

(Off-mic colloquy regarding slides.)

MS. CLARK: So the past few slides haven't included any charts, so maybe I'll kind of repeat what I was saying in front of the charts on the next slide since those do more justice to the results. So let's jump ahead to Slide 16.

So what we start to see when we use the new kind of feeder load data instead of the temperature proxy is that we concentrate our loading of the allocation of T&D capacity to fewer hours. And so on our graphs on the right, the red dotted line where our T&D allocation loadings from the 2016 cycle, where kind of later in the day we only ever get up to about 20 percent loading. Whereas in the 2019 cycle, which is our new and improved feeder load data T&D allocation, which is the dark blue line, spikes. So we're concentrating into fewer hours.

And it's shifting it to later in the day.

You can also see our titles are representing the amount of distributed PV in that particular climate zone. And again in year, these graphs are from 2020. And maybe just to walk through in a bit more detail these graphs, because there's a few different axes, a lot of information.

So our left-hand axis is telling us the total loading, kind of the total T&D allocation in each hour, on that average hour. So we're kind of summing up the total TDV, or T&D loading in a given hour, so the average or the sum between hours 6 and 8 kind of giving us that spike.

And then on the right-hand axis we're showing the allocation by month. And so we're seeing kind of -- and that's just for the 2019 numbers, which months are getting the allocation.

UNIDENTIFIED SPEAKER: So the peak shifting from like 2:30 to (indiscernible) --

MS. CLARK: Yeah, so our red dotted line is showing the peak in the 2016, based on the temperature proxy. And now when we shift to using our regression with temperature and the feeder load data, we're really predicting more accurately, but it does shift the peak pretty substantially by a few hours.

And we can show that in a bit more detail I think on the next slide.

COMMISSIONER MCALLISTER: When people talk, try to remember to turn your mic on, so that people outside can hear.

So let's see, your change in analytical tools has sort of pushed the peak back and raised it. And I think that's reflective of reality.

When -- so the Chair just had a comment and its making me think about this. So you're taking the forecast and incorporating it into this analysis to the extent that the forecast also makes that change going forward based on updated analysis in our PV penetration, for example.

MS. CLARK: Right.

COMMISSIONER MCALLISTER: Is that going to exacerbate this effect or (indiscernible) --

MS. CLARK: That's in here. And actually that question about how the distributed PV is incorporated, I think the next slide compares two different penetrations of PV if we look at the same climate zone in 2020 and 2030.

COMMISSIONER MCALLISTER: Okay. So we're having -- in the last forecast, in the last year's fall forecast, there was a discussion sort of toward the end of, "Hey, you know PV penetration is going to really affect this and how do we model it correctly?" So now there's been an ongoing discussion about, "Okay, we're going to update that modeling. The 8,760 is going to look a little bit different during those late day hours."

MS. CLARK: Right.

COMMISSIONER MCALLISTER: So how have you incorporated that in here, I guess is my question.

MS. CLARK: Yeah, so we're scaling everything up to the IEPR mid-PV behind-the-meter PV forecast. And so what we've done is we've distributed it across the climate zones kind of starting with the current distribution of PV and then kind of we're projecting it going forward in a couple of different ways.

I think we've assumed about half of new behind-the-meter PV is distributed in the same proportion that current PV is distributed, so the same places the (indiscernible) behind-the-meter PV are going to get more. And the other half of the new behind-the-meter PV is getting distributed across all climate zones equally -- kind of peanut-buttered across.

COMMISSIONER MCALLISTER: One of the question, though in the PV piece of the forecast was the peak coincidence factor and so I guess -- and there was some discussion about whether we had gotten that right and how we could make sure we did better in the future or at least that we reflected what looks like it's going to be reality as the peak moves sort of kicking in that, but as the peak moves later.

Like the temple issues around PV penetration, have you reflected sort of -- have you thought about where that evolution is going and what we're going to be doing here?

MR. PRICE: Yeah, I mean --

COMMISSIONER MCALLISTER: This is not amplifying? Oh, sorry.

So I'm just asking you about the peak coincidence of PV and how that is incorporated into this analysis.

(Colloquy regarding microphones.)

MR. PRICE: So can I jump in on that?

COMMISSIONER MCALLISTER: Yeah, sure please.

MR. PRICE: So the chart that we're seeing here really has to do with the peak coincidence factor of the solar PV to the local loads. And I think further in the presentation we've also incorporated the coincidence factor of the solar, both rooftop and central station to a system peak. And so both factors are in play and implemented in the T&D.

What this chart is showing is if you take the actual feeder load data from the utilities for a whole number of feeders, do a regression of that load time each (indiscernible) temperatures and the dry-bulb and other type of things, and then adjust by the IEPR penetration forecast of local.

COMMISSIONER MCALLISTER: Okay. I've got it.

MR. PRICE: Yeah, so it's like how does it exist today plus the PV that we're expecting in the forecast. And then calculate peak capacity allocation factors. That's what you get, that's what gives you the blue line on this chart.

COMMISSIONER MCALLISTER: Okay. So you're calculating the peak coincidence rather than taking what was done in the IEPR forecast process?

MR. PRICE: Correct. We have power (indiscernible) coming up with our own factor and then the loads. And the thing that's important about that is that the peak coincidence really depends on where in the system you're talking about, and different parts of the state peak at different times, different climates, different -- so this is just two examples.

The top one is Sacramento, Climate Zone 12. So you see that the weight in the summer and it's very peaky here on distribution in Sacramento. And then if you look at the Climate Zone 3, which is the Bay Area and San Francisco -- the chat bar is over the top of it -- but the weight is really there's some winter in there too, because there's not a big air-conditioning. There's almost no air-conditioning, but there is some space heating. So it's much more sort of spread out and a lot more hours in the

Bay Area. And so that all sort of translates through.

MR. OWNBY: Before you start speaking when somebody in the audience asks a question could you please repeat it, so the people online can hear?

Jon?

MR. MCHUGH: Okay, so just to be clear what we're looking at are peak capacity allocation factors for T&D? This is not in terms of capacity of power plants and serving loads?

MR. PRICE: Right, that's fine.

MR. MCHUGH: Okay. Great, thank you.

MS. CLARK: That's correct. So what we're showing is only for the transmission and distribution capacity. We'll walk through the other components next.

So this chart on the right on Slide 17 is just showing how much better we're doing at predicting actual loads with our new methodology. So the actuals for 2010 are our blue line on our chart, our yellow or orange line is our new predicted top hours of allocation. And our red line is where our old TDV is in 2016. So we're doing much better at predicting, especially the top hours with our new load data, which is also explaining why we're getting higher peaks.

And so here's the chart that I was alluding to earlier that shows kind of our Climate Zone 2 in 2020 and then in 2030, so we can see kind of with an increase of distributed PV we go from 10.1 percent PV to 24 percent PV in 2030. And again, we're showing the shift between the 2016 and the 2019 TDVs, our red and blue lines. And then we're also seeing kind of it shift even later between 2020 and 2030.

UNIDENTIFIED SPEAKER: For Climate Zone 2?

MS. CLARK: And this is Climate Zone 2. We're seeing the same general trend in all the climate zones and we have the graphs for all of these in our report in case anyone wants to track down a specific climate zone. And of course, you can produce these graphs too from the model.

But the other than thing that Snu had just mentioned is that we're also seeing peaks in other months more often, because when you're just using temperature you tend to mainly get summer months. Whereas when we're using real load data you start to see what we're seeing in the Bay Area where you're actually representing what the loads are. And this will be especially true in climate zones without large air-conditioning loads, cooling loads.

Okay. So now I want to walk through all of the updated inputs, so these are where we haven't really changed our methodology from the 2016 cycle, but we have refreshed with the latest data. And so I'll walk through each of these components of the layer cake for electricity, and then we'll do the same for natural gas and propane. Next slide?

So I'll start with our avoided energy and this is where the last presentation we had a bit of a cameo from Angela Tanghetti and Garry O'Neill from the CEC who have wonderfully done this PLEXOS modeling for us. So they've created this marginal energy price shape from the PLEXOS production simulation model that they used.

And this has not changed since May, but we basically recreated it using our new SB 350-friendly assumption, so that includes the 50 percent RPS we've created focusing on instate resources, using the CPUC RPS Calculator Version 6.2.

And Angela and Garry have created kind our AB 760 price shape between 2020 and 2026. That's how far their model runs out and then we take that out through the end of the lifetime of our analysis. And so what we do is we take the 2026 shape and hold that constant through 2049.

And so here's where you can kind of see what the effect of SB 350 is on our marginal energy crisis. So our 2019 TDVs are in blue and the 2016 TDVs are in orange. And you can see that we're now starting to see those middle-of-the-day dips in prices, because of our higher penetrations of utilities: solar as well as behind-the-meter PV whereas our 2016 TDVs really don't dip during the day.

Again this has not changed from our methodology and results from May.

Twenty-three is a duplicate slide, so now getting to Jon's question on generation capacity rather than T&D capacity, so our methodology for generation capacity hasn't really changed although we have updated a few key things.

The first thing that we've updated is our resource balance year, so kind of the first year in the analysis where we think we need to build new capacity for serving load as well as our planning reserve margin. And the key thing to take away from this graph is that we really are pushing out our resource balance year, because we're forcing in a lot of the renewable capacity. So there's no need to build up new capacity until 2032.

And we did have a decision to make about which year to choose and there's a bit more of an explanation of this in the report, but the short answer is that we're kind of using our load including PV, but not the embedded energy efficiency and our resources. Next slide.

And the second piece that we've updated is our capacity value allocation, so we've used the E3 RECAP model again, kind of updated to be consistent with SB 350 which will be the theme of a lot of these updates. And so we've run the E3 RECAP model to calculate the loss of load probability and allocating to hours within the year.

And the big update here since May is that we have set a temperature threshold for this allocation that seem to be just slightly too low at 90 degrees. When we updated it to 90.5 we got rid of a temperature spike in the middle of September. And so now we have smoother results.

So our T&D capacity, we've already talked about kind of our methodology, but we have refreshed the avoided costs of transition and distribution that we are allocating using the new methodology. And those come from the latest rate cases and we're using a load-weighted averages for transmission and distribution from the IOUs. And then we're allocating them using our new heater load based regression.

On ancillary services, emissions and losses, these are all relatively small wedges in our layer cake and haven't changed very much. Our ancillary services and losses of voided costs are just in there as a percent. Ancillary services are just a percent of energy, so the energy has been updated. But the percent that we're using for ancillary services hasn't changed, so it's been indirectly updated.

And then our emissions trajectory has been updated based on our 2015 IEPR GHG forecast. This graph on the right is just showing our 2013 Mid and our 2015 Mid, the two solid lines are quite similar out through 2030.

And then we also have our sensitivity with a high CO2 price forecast, which is our dotted line above.

This is a slightly larger slice of our layer cake, are the avoided costs of procuring additional RPS or renewables for our RPS requirement. And so here our costs of renewables have gone down since the last time we've updated the Title 24. So since 2016 our renewable costs went down and then for our avoided costs went down.

And another thing to note about this is it doesn't vary over the course of the year. It's just kind of a flat adder, so in the end we're kind of grossing everything up to the retail rate. So it really doesn't effectively change the overall TDV, so it's not changing the shape, it just kind of changes a portion of the TDV when we look at kind of the different components that build it up.

And so the retail rate adjustment or the retail rate adder, you know, of one of these large drivers of the overall synergy of the electric TDVs. And so here we're just trying to gross up our other components of avoided costs, kind of the equivalent to the consumer retail rate.

And with this modified participant cost test we were really trying to figure out what is the effect on the homeowner or the consumer. And so this was a bit tricky too, because in past cycles we've used just the IEPR retail rate forecast, but again that wasn't really consistent with what we were trying to for with our SB 350-friendly assumptions. So we tried to create a proxy using the RPS Calculator, which again the CPUC RPS Calculator has a revenue requirement component where we can calculate retail rates based on what it would cost to utilities.

And in order to do that we kind of started with our mid-demand IEPR retail rate forecast, which the colors are hard to see on this graph, but it's the very bottom line here. And then we tried to modify it with the 50 percent renewables and doubling of energy efficiency. And so we kind of recreated those two scenarios in the RPS Calculator, one that was most similar to the mid-case IEPR and then another one on top of that that doubled energy efficiency and went to 50 percent renewables and basically created kind of an adjustment factor that we then applied back to the IEPR mid-case.

And so what we end up getting -- stay on that slide just for a second longer -- so on Slide 29 the resulting retail rate forecast is this middle line, the third line up, this aqua blue turquoise color. And then our sensitivities on either side, we used the same approach. So the lower energy efficiency is our orange line and our high carbon price is the higher line.

But all three of these are still lower retail rates in mid-2050 than the low demand retail rate forecast. And that's just because the low demand, which is the high rate scenario still has lower demands than our doubling of energy efficiency. But just to give a sense of scale we're still lower in terms of retail rates than the low IEPR forecast.

And there's a lot of focus on electricity, because there's so many different components. But we also do the same time of approach for our natural gas and propane, same kind of layer cake. And so for natural gas, we do have natural gas transmission and distribution, emissions, and then our commodity costs and retail rate.

And so we've updated the CO2 price for both natural gas and propane to be consistent with electricity. And then we've updated our -- refreshed our natural gas and propane costs.

We'll walk through natural gas first. So these were a little more straightforward. We're pulling rates and commodity prices direct from the IEPR and kind of our commodity prices in our graph and they're quite similar to what we had in 2016. And then our retail rates are a bit higher than 2016 and there are a lot of lines on here, but all of our blue lines are 2019 and all of our orange lines are 2016. And it's just showing our base and high cases for both res and nonres. And if you track each of those that's kind of apples to apples; it's just a bit higher although similar if you kind of start at the same start year in terms of growth rate.

And then for propane the IEPR does not have kind of a forecast of propane rates. So again we try to use kind of a proxy and then benchmark it back to the IEPR. In this case we used the EIA Annual Energy Outlook and they have a Pacific Region forecast for propane. And then we normalize that back to the IEPR through the natural gas rates.

So we kind of take the EIA propane price and then use the proportion of natural gas prices from the IEPR and EIA to get it back to a benchmark that's similar to what we use in the IEPR.

So we've just walked through a lot of changes. I think it would be a bit more interesting to walk through what those actually mean in terms of the new results.

MR. RAYMER: Could I ask a question?

MS. CLARK: Yeah, so there's a question. Turn on your mic.

MR. RAYMER: Yeah, Bob Raymer with CBIA. If you could for a moment, go back to Slide I think it was 23? Okay, that's apparently the long slide.

MS. CLARK: What's the --

MR. RAYMER: It's the one where you were showing the dollar per megawatt hour.

MS. CLARK: Energy prices, go back up. That one?

MR. RAYMER: That one right there, okay.

If you could speak to a moment to what's happening in July and August with the red line being 2016, been there a moderation of that cost to the tune of about $20. And this is because of, and if you explain that, and the impact you see happening on the development of the 2019 Regs from that. Because usually July, August and September have heavily driven our peak load issues in the Standards.

I mean, how did this happen? How did such a staggering stage? I mean, to me that's a significant change.

MR. PRICE: Do you want me to take that?

MR. RAYMER: Okay.

MR. PRICE: So this the analysis that Angela and Garry did with PLEXOS and I think Garry's here, but I'll try to answer it.

I think what we're seeing is that in our forecast for most of the forecast period we actually have more excess generation capacity in the system. Currently the reserve margins are like 30 percent plus, so when you do that you basically end up -- and we're introducing a 50 percent RPS.

So basically when you do that then you -- this production simulation, what it basically does is to least cost dispatch. So basically we end up with more efficient generators even in the summer operating, which is through the production cycle and calculating for all the costs, will end up with lower wholesale prices. So basically the effect we're seeing here is higher RPS means lower wholesale electricity prices in the market.

MR. RAYMER: But I'm looking at the -- I'm trying to visualize the impact that alone could have on the 2019 Standards.

MR. PRICE: Oh, so the next step, so what does it matter?

MR. RAYMER: Yeah, yeah.

MR. PRICE: So what it means is the energy value is basically flatter. So what that means for Building Standards is where in 2016 we had a Standard that was a little -- from an energy system perspective -- a little bit more tilted towards peak reduction. As we introduce more renewables we have more reserve margin and the standards are going to tilt more towards energy savings. So less important when you save energy relatively in 2019 to 2016 from the wholesale energy market basis.

MR. MCHUGH: So this is Jon McHugh with kind of a question, so but aren't you shifting some of your cost from energy to capacity, because your T&Ds are more peaky, they're later in the day. They're peakier, so are you really getting flat or I mean when (indiscernible) --

MR. PRICE: Well the energy --

MR. MCHUGH: -- all this built up, when you actually built it all the way up it appeared that you're actually more peaky rather than less peaky. But the energy component is less peaky?

MS. CLARK: Right, so I think the key -- what we're looking at here is kind of the average day in a given month, which is kind of different than what this is going to end up looking like in our TDVs for energy. So our TDVs for energy do end up looking flatter, but then when we do show the whole layer cake we do end up with kind of peakier generation capacity and T&D capacity.

COMMISSIONER MCALLISTER: So we know exactly what this data is, is this average costs or like average monthly or average midday costs or what actually is the data (indiscernible) here? Because before you were talking about well the peak is a later and higher, which is sort of against this. Correct?

MR. PRICE: Yeah, so this is energy pricing. Oh, sorry, so this was a question about the wholesale energy prices?

COMMISSIONER MCALLISTER: Right, so this is sort of the average pricing versus the peak -- this is nothing (indiscernible) peak is.

MR. PRICE: This is like one layer of that layer cake in the wholesale energy prices. And I think what this chart is really showing you is the average day: hours 1 through 24 in each month. So it's just sort of a way to look at the whole year on one chart and so what we're seeing on the wholesale energy side is generally flatter with these dips, even in the middle of the day during like spring and fall, which is less peaky than the wholesale energy prices we were using in 2016.

MR. MCHUGH: Okay.

MR. PRICE: And the question is why is that and that's because you have more excess generation capacity and you also have the effect of the RPS, which concentrates the solar in the middle of the day.

MR. MCHUGH: Yeah, yeah, I got that. But is this an AB 769 representation or is it something else?

MR. PRICE: Well, this is an average over each month.

COMMISSIONER MCALLISTER: This is like an average day, so if (indiscernible)

MR. PRICE: So it's like if you take all the midnight to 1:00 a.m.'s in June and average those and put a dot on there, just to kind of get (indiscernible)

CHAIRMAN WEISENMILLER: Okay, but again just to be clear it says, "mid-day energy prices." So is that over the day or is that in the afternoon?

The other question is just the observation is obviously as you have more and more zero or marginal cost renewables, wholesale prices are coming -- you know, they're really down. So that part is just trying to understand exactly what --

MR. PRICE: Yeah. Oh, yeah, yeah. So what this is trying to say is to begin to show lower midday energy prices. So what that is referring to is those blue dips and that is that price suppression from the large-scale and rooftop solar. But these are 1 through 24-hour averages for each day.

CHAIRMAN WEISENMILLER: Sure. Got it, okay.

MR. RAYMER: Bob Raymer, CBIA once again.

What I'm finding out is not just the substantial differential there between July and August, but if you look in September that you don't have something similar. And the blue -- I understand the moderated blue peaks, but that you don't have a rather significant change in September simply because the cooling loads are so similar in July, August and September. You know, these are just the things that kind of jump out at me, how to explain it.

The red line in September doesn't have the same pronounced differential from -- it's weird. Anyway, I trust you. (Laughter.)

CHAIRMAN WEISENMILLER: Yeah, trust but verify. Right.

MS. CLARK: The other thing to add is that this is across climate zones.

MR. PRICE: Is Garry around?

MS. CLARK: Oh, we can also let Garry respond too. He's a lot closer to this.

MR. PRICE: Since he calculated these.

MS. CLARK: Yeah.

MR. O'NEILL: So part of what you're seeing is the RPS building in July and August, and then you're seeing the peak in PV that's being added. We get a lot of that information from the RPS Calculator. The RPS Calculator chooses allotted PV, which feeds its generation in July and August.

There's also a lot of customer site solar tapped into the mid-case demand forecast. We have actually changed our approach in modeling that. It is no longer modeled as just a peak reduction in the load for a peak day. So that changes our shape in the forecast period of our load, which is what we would actually expect. So we're actually modeling it as a load modifier on a daily basis.

And so that ends up also shifting our peak demand out to September, which is why you don't see such a pronounced difference in the prices in September, because you're actually seeing less of an impact of that demand site. So you're also seeing less of an impact of the RPS solar as well. So our peak is actually shifting farther out into September as opposed to July and August.

MR. RAYMER: Sure.

MR. O'NEILL: So what you're seeing in the 2016 T&Ds (indiscernible) probably more correct from our results. So it's more accurate looking at it this way. Does that make any difference?

MR. RAYMER: Yeah, just for awhile it seemed counterintuitive. But I'm also trying to -- how is battery usage going to impact all of that, but that gets way ahead of where we're out.

MR. O'NEILL: There's a lot (indiscernible) go into it. It's a very complicated model, so there's a lot of things that go into it. But the biggest change, the biggest effect is mostly just going to be all that PV that's added into the system in 2026. And that's what you're seeing, the impact of that right now.

MR. RAYMER: Right, right. You bet.

MS. WALTNER: I wanted to --

(Off mic colloquy.)

So Meg Waltner from NRDC, so I wanted to get back to the question of what happens when you roll this all up, include in the T&D and what's the overall effect to the Standard? And whether it looks like from the graphs there was actually more rated value peak savings rather than overall energy savings. Is that an accurate understanding, more?

(Off mic colloquy.)

MR. RAYMER: So Adrian, I think that was Slide 23, that might help us out.

MS. CLARK: Well, so that's the 2016 example. If we run back to -- you keep going forward to the (indiscernible) of result section, we showed a comparison between what we had in 2016 and 2019.

So before I kind of dive into the different components of the layer cake, let me just make sure that we understand what we're showing in these two graphs. So our left-hand graph is our 2016 electricity TDVs. And the right graph is our 2019 TDVs. And we're showing kind of the average day again, so kind of the average of all of our midnight to 1:00 a.m. hours. And then we're showing this in our kBtu per kWh present value over the 30-year lifetime of the building.

So it's a lot of things embedded in here, but the main thing that we can see is that if we kind of overlay our 2016 outline, the black line on the right-hand graph, we are shifting kind of the peak later. Both based on our red T&D capacity and our yellow generation capacity lines.

The overall level has also gone up and that's because of this kind of light blue retail rate adjustment piece.

A couple of other smaller things that might be worth flagging: our orange RPS procurement, RPS adder bar has gone down a little bit due to decreased renewable costs. And our emissions lines, our kind of green bar has decreased in size a little bit. And that only has to do with kind of our accounting of where emissions are included.

And so I think the main things that we wanted to grab on this slide are that the increase in the retail rate doesn't drive our TDV values higher.

And then we also have kind of our average TDVs and this is all for the Sacramento Climate Zone 12 results. But we have seen kind of an increase in average TDVs for electric by 27 percent and gas by 20 percent and in propane by about 40 percent.

We have a couple of questions here in the room.

MR. MCHUGH: So, just to go back to your -- don't move the slide, but the prior slide we were looking at is representing your dark blue in this one -- is that right?

MS. CLARK: Yeah.

MR. MCHUGH: So that really flat thing that is here, even though they're showing them wiggling over the course of the year, that's a relatively flat component.

MR. PRICE: Over the course of the year.

MS. CLARK: Yeah, over the course of the year.

MR. PRICE: Yeah.

CHAIRMAN WEISENMILLER: Or another way of expressing it is that the retail rate adjustment is a much bigger change than some of the other factors we could dig into?

MR. PRICE: I think the other thing I wanted to point out with this is, you know, is it more energy or more capacity? It's kind of both, right? The energy value is higher, that's why it's over higher and the peak is higher. So yeah.

MS. WALTNER: So, this is not a very big part of this chart, but one thing that I find surprising is how flat the emissions adder is over the course of the day. You would think there would be times when marginal resources were zero emissions in a 30-year timeframe. Can you talk about why that is so flat? Obviously it's a small part of the overall picture, but --

MS. CLARK: Yes, our marginal resource is pretty much always natural gas. So if you're looking at your marginal emissions it's pretty flat.

CHAIRMAN WEISENMILLER: Yeah, which has

implications in electricity, the electrification discussion obviously.

MS. WALTNER: Yeah, I mean just I think just as we're thinking about what are the emissions that are going to be -- or sorry -- the resources that are going to be built over this timeframe to actually meet that load? I'm not sure that's the right assumption. Obviously, it's not a big -- it wouldn't really affect the results here.

MR. PRICE: So, this is actually a interesting question. So what we're trying to reflect here with emissions is the impact on the wholesale electricity crisis. And the marginal unit has to buy allowances. This is different than the GHG of the total electricity production, so even if we go from 33 percent RPS and it's a third zero carbon to 50 percent we've obviously reduced a lot of GHGs from the electricity sector footprint.

But if we have a combined cycle with the same heat rate running on the margin in 33 versus 50 we'll end up with the identical emissions component here, because that unit, basically that marginal unit, is buying an allowance. And that's affecting the market price.

So this is basically a picture of the total marginal costs by hour. And I think where you were headed with your question was more around lifecycle GHG emissions, which we're going to get to when we talk about electrification. But that might be also creating some of the confusion.

MS. CLARK: So we can go ahead to the next slide. We can always come back here. We do want to talk about how this change is based on climate zone and the building type.

And so each climate zone will have a different shape, so there's graphs of all of these in the report. But we do see the same basic trends. We're still shifting both our kind of T&D capacity and generation capacity later in the day. There's our Sacramento and San Francisco shapes and again kind of the average day.

And then if we look at res compared to nonresidential we have the same overall shape, but different kind of retail rate adjustment factors. Because we have different rates associated with our residential and nonresidential buildings, but kind of different components aren't being changed as we go from residential to nonresidential.

And one more thing to note on Slide 34 that is a little counterintuitive is that if you look at the bottom two graphs -- our res and nonres charts -- so our nonresidential rate is lower. But it kind of looks like our overall wedges are higher in that right-hand graph. That's only because we're reporting this in the kBtu kWh units. So if we were looking at this in dollars per kWh, our right-hand graph would be lower.

But our kind of adjustment factor is different, is higher for our nonres and so that makes it look larger. So don't read into the fact that our bottom right graph is overall taller, it kind of has an overall lower retail rate adjustment.

So we did want to kind of start teasing a little bit what the impact of the new TDVs would be on particular end uses. And so here we have a couple of different kind of overall shapes for cooking and lighting. And we just wanted to show if kind of we run those through with our 2016 compared to our 2019 TDVs what do we see as the big differences? And I think the big one for us is that cooling is now getting a lot more value, just because of the shifted peak. So it turns out --

MR. PRICE: Residential cooling?

MS. CLARK: Yeah, this is residential cooling, right. So people are coming home and turning on their AC units, not a commercial cooling.

But basically our cooling shapes are now a lot more coincident with our 2019 TDVs. And so that's why we see this giant red bar on our 2019, but there's also kind of an increase in our retail rate adjustment. But the large increase for cooling is the T&D. And so we're shifting -- and also a little bit in capacity, so the shift of generation capacity value as well as T&D.

We have another graph that shows that by climate zone, but that is for Climate Zone 12 where the shift is pretty large.

MR. SAXTON: Pat Saxton of the Energy Commission, so there's a visually very complicated graph that could have been made that would also show this hourly. There's going to be some hours of cooling, going back to the conversation we just had, where the orange and red bars are not tall. And then there's going to be some hours that are late day summer that are going to look like this.

MS. CLARK: That's right.

MR. SAXTON: So it's not consistent over all hours of the yeah.

MS. CLARK: Yeah, that's true. Right, we're simplifying this down to show the effect. But obviously we have a lot more detail in the modeling effort.

And so here's the same type of treatment for lighting. And so here we show that kind of all the different components of our avoided costs don't change very much. There's a little bit more of our red T&D capacity and a little bit more of our generation capacity. But the large increase is due to the retail rate adjustment for lighting.

And so this next slide, Slide 37, kind of just shows us this kind of cooling TDV. This is lifecycle TDV consumptions in units of energy kBtu by climate zone. So this is kind of the total TDVs for cooling, specifically.

And we're showing in the blue bar is the 2016 TDVs and then the orange bar is the 2019 TDVs. So there are a couple of things being shown here, the overall height has to do with the amount of cooling that you get in each climate zone. So the ones where we can't really see the bars are areas where we don't have a lot of cooling load.

It makes sense that we're seeing the most cooling in Climate Zone 15. And for those of you that don't know the climate zones by heart, just a quick map reference, but kind of our southern and climate coastal zones get a lot of cooling. But then you can also look at the difference in proportion between the 2016 bar and the 2019 bar.

And so if we look at the Climate Zone 12 column that's consistent with two slides ago where even though there's kind of a smaller overall level of cooling in Sacramento compared to some of the other climate zones there's a big jump between 2015 and 2019.

And we still have a jump, for example, in Climate Zone 15, but the percent increase is smaller whereas the overall amount of cooling is large. But across the board we're seeing kind of an increase in cooling value from the perspective of TDV with the new layer peak in TDV.

So now coming back to our scenario analysis -- so we've been showing results for our base case that we described up front -- but we also kind of ran all of these through with our two kind of bounded sensitivities: one with a higher CO2 price, which will drive up your retail rate. And our smaller amount of energy efficiency, which will give us a lower retail rate.

And so we can kind of see almost air bars around our total, so this is the same kind of Climate Zone 12 shape that we're now becoming a bit more familiar with. So you can see that these two sensitivities don't change the overall level of TDVs very much, just kind of a little bit of above and below throughout the course of the year.

On to the results for the natural gas and propane TDVs, so the level of natural gas and propane have increased since 2016. That largely had to do with our retail rate forecast for natural gas, which for the 2016 Standards, which were based on the 2013 IEPR, had lower natural gas forecasted retail rates.

And so kind of the overall level when compared to 2013, which is here in pink and 2016, which is here in orange we've gone up. But the overall level has entirely kind of scaled up to our retail rate for natural gas and similar for propane.

So kind of in 2013 we were pretty high. In 2016 we went down and now we're back close to where we were in 2013.

MS. SIM: I have a question?

MS. CLARK: And one more thing I just wanted to flag on this graph --

UNIDENTIFIED SPEAKER: You had a question?

MS. SIM: I had a question about the natural gas rate forecast. There was a slide back in -- I believe 31, Slide 31? And you looked at natural gas forecast, and I understand that the content of it was derived from the 2015 IEPR, but that only goes up to 2025. So when you forecasted after that, I'm assuming you took the trend and continued that trend.

But we have published a 2016 Natural Gas Report, which feeds into the IEPR that shows starting 2024 it actually kind of levels out. So that forecast that increases at some point before this is published for use by the public, is there going to be a revisit of looking at that as the most up-to-date information prior to publishing that, because it's so important that people use it? Or is this going to be the constant, because we're developing it now and improving (indiscernible) is the question.

CHAIRMAN WEISENMILLER: The current IEPR is not really doing an update of the price forecast. The next one will get into more of that and just the reality is there's a lot of the assumptions at some stage in say on solar tax credits. And then there's a lot of things that will come together later in the process or there's uncertainties about those.

And so one of the key questions on this stage is always how much will one of these conclusions be affected by potential changes?

MS. SIM: So, I think the question is at this point if this gets approved before release in 2019 will there be another revisit with the most up-to-date information?

CHAIRMAN WEISENMILLER: Well, again I think the notion is to -- this is going out for people to do their modeling at this stage. You know, certainly within me working with Bob and others on what does this mean at some point. And at some stage along the way if we can then -- obviously you've heard about the (indiscernible) assumptions in this thing. But if it's possible at some point to understand what the three or four most significant assumptions are then as we get closer to the adoption date I'm sure there'll be a discussion of those particular assumptions.

MR. OWNBY: Can I chime in too and say that I think over the next year we're going to be using this to analyze (indiscernible) And I think that we have to recognize that we can just kind of continually update this TDV as we go. You know, we have the best numbers that we have (indiscernible) and make decisions based on that, because what we don't want to do is (indiscernible)

(Audio issues - background conversation drowns out speaker.)

MR. ESSER: I have a question. This is Marc Esser with NegaWatt Consulting. This goes back to gas prices as well. We were looking at your (indiscernible) costs. And the prices there for the 2016 base case move from about $6 to $8, 2019 from 7 to 0. And we tried to match that to the actual reports that this figure comes from and we saw a difference by about $2 there. And I wonder if there's a unit issue that we're not catching?

The reports there show prices between $4 and $6 versus 6 to 8. And I could find an exact reference to try and point that out in the comment, but I was --

CHAIRMAN WEISENMILLER: Yeah. Well again, you've got real (indiscernible) questions too, but it's probably better -- this Bob Weisenmiller again, for those listening on the phone -- it's probably better at this point to walk through the electrification discussion, which I'm sure will raise a lot of these issues along with issues on the POUs. We use an average retail rate forecast and they can be significantly lower, so anyway I'm sure this whole topic will be a hot topic.

MR. PRICE: Yeah, right.

CHAIRMAN WEISENMILLER: So let's get it all out on the table. And certainly you guys can talk back and forth later on about the specifics of the gas price forecast.

COMMISSIONER MCALLISTER: And mainly the purpose of this is by doing -- or sort of tailoring some scenario analysis in specific climate zones or specific case loads instead of sort of trying to deal (indiscernible)

MR. PRICE: Yeah, and we try to do that electrification thing. And if we have like a unit (indiscernible) I'm happy to talk about a real nominal burner tip, city (indiscernible) what have you on gas prices. There's a myriad of ways of getting out of alignment, but Adrian if you can go through the electrification section?

If it's okay I'd kind of like to just sort of walk through this like six slides? I know there's going to be a lot of questions on it. I'd like to kind of hold questions if possible.

COMMISSIONER MCALLISTER: Should we do questions on what we've heard up to now that are not related to --

MR. PRICE: It's up to what you guys want to do.

(Multiple speakers talking.)

MR. OWNBY: If you'd like we can go on to some questions that we've had so far.

CHAIRMAN WEISENMILLER: Actually, I would -- at least for the workshop we had on Wednesday that for online questions instead of unmuting and getting us back to the cacophony, what you need to do is ask people to email you questions.

MR. OWNBY: I've asked them to chat (indiscernible)

CHAIRMAN WEISENMILLER: Oh, chat? So that you've got the list, great. Thanks.

COMMISSIONER MCALLISTER: Maybe we should just pause and ask non-electrification related questions. So we don't get swamped and (indiscernible) asked earlier?

MS. WALTNER: I have one in the room first, if that's okay? Meg Waltner from NRDC, just two sort of logistical questions.

The one, I think toward the beginning you mentioned that a research version of the residential 2019 software is, or is going to be available. And is that the beta hot water heater model software version as well, so you have that new Ecotope model in that 2019 research?

CHAIRMAN WEISENMILLER: Yes, who is on the (indiscernible)

MS. WALTNER: Yes, okay. And that's available now?

MR. PRICE: It doesn't work on the phone?

MS. CLARK: Yes.

MS. WALTNER: That's exciting, yes.

MS. CLARK: It will be available as soon as next week.

MS. WALTNER: Okay, great.

And Adrian you had mentioned that the docket will close at the end of this month. Will there be a formal approval of the 2019 TDV values?

MR. OWNBY: The TDV is essentially approved when we approve the ACM and any time we approve a new version of the software for compliance (indiscernible).

MS. WALTNER: Okay.

MR. OWNBY: So it will be part of the 2019 Standards.

MS. WALTNER: Okay. So it'll be officially approved much later in the process?

MR. OWNBY: Yes.

MS. WALTNER: Okay. Thank you.

(Colloquy between speakers off mic.)

MR. OWNBY: Okay. So the first question we have here is, "What renewable percentage is assumed after 2030 since the SB 350 target of 50 percent is for 2030?"

MR. PRICE: It's just maintained at 50 percent after 2030.

MR. OWNBY: Okay. And similarly, "What efficiency level is assumed after 2030 in the SB 350 target of 50 percent better than (indiscernible) useful also for 2030. However, the 30-year TDV calculations go to 2050."

MS. CLARK: Yeah, it's a similar type of answer, so we kind of have our doubling of additional achievable energy efficiency that's kind of -- we take a wedge off of our mid-case load forecast. And the doubling of energy efficiency only goes through 2030. But then we kind of extrapolate our load forecast beyond that with the same energy efficiency wedge held constant at 2030.

MR. OWNBY: The next question here is, "Hourly energy crisis (indiscernible) gas components, (indiscernible) that in no hour just your model have curtailment. Is this correct? You have curtailment today, but -- " Or containment?

COMMISSIONER MCALLISTER: Yeah, curtailment.

MR. OWNBY: "Yeah, today so it seems this would be something we expect from you as well, which has implications for energy pricing (indiscernible)."

MR. PRICE: Yeah, I can take that and if Garry's still here he can too. But I think that observation is right. I don't know if it's no curtailment, but basically limited and that's because of the way that the PLEXOS modeling was done and basically allows exports out of state.

It doesn't pick up some of the curtailment we're seeing today that's more about local within state constraints and CAISO operations. This is a statewide production simulation or actually (indiscernible) and we're looking at California's ability to export. So the observation is correct and the reason why is the way that the energy system was modeled in the state.

MR. OWNBY: Okay. So the next question is, "What renewable percentages -- " I think, didn't we ask this question?

MR. PRICE: Yeah, but there's a part two to that question.

MR. OWNBY: Okay. Let's see here. So I'm not seeing a question here that wasn't already answered.

"Regarding the doubling of energy efficiency, is the cost of new additional energy efficiency programs incorporated into the base RRQ? If so was there any attempt to look at whether the doubling of energy efficiency was cost effective per SB 350?

MR. PRICE: Yeah, we did not do any assessment of the cost effectiveness of doubling, but doubling the energy efficiency does impact the rate levels. You know, particularly because there's a lot of fixed costs on the system, (indiscernible) and it's delivering fewer megawatt hours. And so increased efficiency does raise the rate levels and you see that in the sensitivity analysis. And that's why the 1 x AAEE has a lower rate forecast than the base case.

COMMISSIONER MCALLISTER: Yeah, so this Andrew McAllister. I want to expand on that as well.

So kind of implicit in the question is an assumption that there's some ratepayer funding going to increasing energy efficiency levels. And I don't think that's necessarily the case. You know, the marketplace is going to do a lot of that and so certainly cost effectiveness on the individual investor and project level is relevant to and programmatic in sort of the results level, you know, getting results.

But I think whether and how much that would affect rates due to the ratepayer participation in that investment, I think is an open question.

CHAIRMAN WEISENMILLER: This is Bob Weisenmiller, to give a more direct quote this is not the forum for those conversations. Commissioner McAllister and I with President Picker, Carla Peterman, Stephen Berberich and Michael Gibbs of the Air Board had a workshop on the doubling of energy efficiency as part of our IEPR last week.

COMMISSIONER MCALLISTER: This was actually, was it Monday?

CHAIRMAN WEISENMILLER: Monday, so anyway you're all welcome to show up in that forum, comment, you can -- happy to see you there, but that's certainly well beyond the scope of this particular proceeding.

And similarly on the renewable flash terms, that's certainly part of the IRP process, which the Energy Commission is dealing with POUs, the PUC is dealing with the IOUs. And again, that's a huge complicated proceeding, which people should really address those issues there as opposed to in this proceeding, which is complicated enough without dealing with the same ACA (phonetic) issues.

MR. OWNBY: So, it looks like we have one last question which is, "Why not allocate the rate adjustment in proportion to marginal costs consistent with general rate making principles rather than a constant adjustment?"

MR. PRICE: So that's a good question. And I think the first thing that is really important to note is that the shape that we're seeing in the TDVs are exactly (indiscernible) well to the marginal costs. It's like our best forecast of the marginal cost in every hour, so that difference between the peak and the trough, that absolute difference is the difference in the marginal costs.

And that the flat adder that you're seeing in there is one way to look at a collection of all of the embedded costs, so the fixed sum cost of the system and of the grid. And basically in order to preserve the difference in the marginal costs, the value of energy from the highest to the lowest. And the only way to keep all of those deltas sane basically is to have a flat adder. So if you think about doing energy efficiency and the difference between two cases, the difference that you'll end up with is the difference in the marginal costs.

So that's been the way we've done it for a long time. I know that there's a lot of different remaining constructs and other ways you could calculate those, but I don't think we would say that the TDVs are inconsistent with the marginal cost remaining principle. The differences are exactly the best we can calculate on commercial costs.

MR. OWNBY: Okay. So before we get into the electrification thing, would you like to take about a five or ten-minute break here? So it's up to you.

CHAIRMAN WEISENMILLER: I think there's one more question.

MR. HAMMON: One more, if I may?

COMMISSIONER MCALLISTER: Okay. Let's get through the questions.

MR. HAMMON: Rob Hammon, BIRAenergy, two

comments.

The first is early on in the slide deck you had a slide that referred to Climate Zone 2? I would just recommend that you not use a climate zone like 1 or 2 or 16 in your demonstrating the analysis, because they tend not to represent most of the state.

And then in Slide 7 you make the point about the units, the units being kBtu per kWh or kBtu per therm. I strongly recommend for reasons that I'll bring up probably later, that you have TDV in that label. So that it does not downstream become confused with what I'll call real energy units. (Laughter.) Thank you.

MR. OWNBY: So I think we have other questions?

COMMISSIONER MCALLISTER: One more question.

MR. ESSER: Yeah, Marc Esser with NegaWatt Consulting. I have another question about the SB 350 scenarios, I think it was Slide 10. And we also had this discussion just now about doubling energy efficiency or not doubling energy efficiency. I just wanted to ask for some clarification there.

As I understand it at some point you will have to select a scenario to determine the final TDV values. And can you elaborate a little bit on that decision-making process? Like which scenario do you think is the most realistic or most representative of the best one?

CHAIRMAN WEISENMILLER: Well certainly, stay tuned. Yeah.

MR. ESSER: Okay.

CHAIRMAN WEISENMILLER: Please, go ahead.

MS. GOLDEN: Hi, this is Rachel Golden from the Sierra Club. I have a question about the CO2 emissions input in the scenarios. I'm wondering if you included methane leakage at all, because it's fairly significant and not just on the production and electricity generation side but also in distribution and end use side for gas?

MR. PRICE: No, there's no gas system, methane leakage in the -- and again remember we're doing a retail rate for -- this is like a consumer cost perspective. There is a CO2 component where the gas company is paying for allowances to get passed to the customers. So I think what we've done reflects what they're currently required to do for allowances.

MS. GOLDEN: Okay. Thank you.

MR. SAXTON: So this is Pat Saxton from the Energy Commission, just maybe an extra piece of clarification. You are reflecting the current price of emissions allowances, not trying to capture actual quantities of emissions or absolute emissions?

MR. PRICE: Right.

MR. OWNBY: So, what was the decision? Do you want to take a brief break or do you want to continue on?

(Colloquy about break off mic.)

COMMISSIONER MCALLISTER: Okay. So let's take five minutes or so just to stretch our legs then come back.

(Off the record at 10:45 a.m.)

(On the record at 11:01 a.m.)

MR. PRICE: -- gives those a sneak preview on what happens when you take these TDVs and you look at a question that we've gotten a lot of interest and comments about. So what we're going to do is take I think about 20 minutes or so to look at the question of switching fuels in buildings and going from these fuel, electric and gas buildings to all-electric buildings. This is a question that we got from a number of stakeholders in comments.

A few caveats that I wanted to throw out there, this is really on our agenda in order to sort of start a discussion and give people sort of the latest view of where it falls out in terms of both carbon and cost effectiveness when you look at electrification of buildings. But this is by no means definitive or the end.

You will notice as we kind of walk through this what we really did was just take three prototype buildings. We didn't play around with a lot of different measures or any, really, and just applied the TDV values that we were all just looking at. And sort of just see, well what does that give us and what does that result in? So we thought it would be of interest and we thought it would spark a lot of discussion.

The CBECC or at least the CBECC-Res version of the tool, with the 2019 factors, is going to be released within the month. And we fully expect that people will be using that to do a lot more than just our prototypes and just our specific technology and our specific example. And that will give us a much richer view overall, but at the same time we've had our views (indiscernible) sort of see what it looks like in sort of the initial work.

So what we did was to work with Bruce Wilcox and Ken Nittler to take the new version of the CBECC-Res and calculate three -- the energy use for all-electric and mixed-fuel buildings, same identical buildings, 2,100 square feet, 2,700 square feet, and a multi-family. And just move them basically through all the climate zones. And so we could get a sense of what the difference are in TDVs, what are the differences in GHG emissions? And we wouldn't ever pretend that this was anything more than just sort of an initial look at what it is when you take the current values and you do that type of an analysis.

So if you go to 42, the basic approach, I'm going to pick on a 2,100 square foot Climate Zone 12, so Sacramento example, just so we can kind of look at what it looks like and what it does for one building. And then we'll look at the charts that sort of blow that out by all the different climate zones and so on, on the parametrics. And that way it'll just be a little bit easier, hopefully, for folks to kind of follow along.

So the first set of questions that we look at are to compare the CO2 emissions to a print of buildings and a consumer bill tradeoff, so these are the two things that we're looking at. Step 1 was to simulate the building and energy consumption and again, Bruce Wilcox and Ken Nittler did that for us. And that was a really easy step for Adrian (indiscernible) them across.

Step 2, we calculate the consumer bills and when we say consumer bills what we're really doing here is applying the TDV methodology. So TDV is a consumer cost-effectiveness test at its core, so what we've done on the highlighted consumer bills is the dollar value implicit within the TDV framework.

Step 3 is to calculate the lifecycle CO2 emissions of the buildings. One interesting thing to do is to calculate the change in cost and the change in carbon to do some sort of carbon value, implied carbon price, whatever you want to call it. And that will be of interest to those.

And then the other thing that's interesting to do is to look at the difference in life-cycle energy costs and then translate that to well what would that mean for a difference in construction costs, so that when you add the two together you end up with the equivalent life-cycle total costs for the mixed-fuel and all-electric homes. So those are the three things that we're going to walk through.

So from step 1, simulate building energy consumption, and again we're talking about a 2,100 square foot home prototype Climate Zone 12. The mixed-fuel home is the 2016 prescriptive standard appliances: tankless gas water heater, gas central furnace space heater, stove, clothes dryer. Okay. So that's good there.

And then in all-electric we've got electric heat pump water heaters and the way CBECC-Res works, you need to pick a specific one, so we did. And a split heat pump space heater, stove, and clothes dryer in all-electric.

So if you do that and you run the analysis for Climate Zone 12 you find out your mixed-fuel home, 4,000 kWh or so, 348 therms, your all-electric home is something like 7,800 kWh.

MR. RAYMER: Which is almost doubled?

MR. PRICE: Which is almost doubled, because 7,800 is almost doubled from 4,000, right?

And then if you look at the TDV units, TDV kBtu, there is a difference. And the all-electric has a higher energy use, a higher TDV value use, one more (indiscernible) across. So if we take then step two and take that delta that we were just looking at in kTbu and talk about it in terms of dollars. We can look at dollars from a number of ways, but under the mixed-fuel you end up with a total lifecycle energy double for the building over the 30 years with something like 38,000. For an all-electric it's something like 43,000, so that's a difference of about $5,700 over the whole life of the building.

If you look at dollars per year that gives you an annual difference of something like $283 and if you look at a dollars per month difference it's something like $23. In other words, if you use the TDV methodology, you run identical buildings, you end up with the all-electric home energy bill is something like $23 more a month, okay?

I'll take questions at the end, okay?

So then that's not the whole story, so then if you do -- calculate CO2 emissions. Okay, so we're going to carry on that basis as well. And for natural gas, calculating the GHG emissions is relatively straightforward. It's a constant.

For electricity emissions it's quite a bit more complicated, because remember we're implementing a 50 percent RPS, so a new electrical load will be met in part by our existing system that's already built and in part by new renewables up to 50 percent, so it's increasing. So we developed a methodology to get at that. And when you apply that to electricity and to the gas you end up at the lifecycle CO2 emissions of a mixed-fuel buildings, something like 92 tons of CO2. And for an all-electric something like 60 tons, so the bill went up a little bit to 23 bucks a month. The carbon went down and how much is in the eyes of the beholder, but it's substantial.

Yeah, so one thing to do is to take a look at this from a load, one by the other kind of perspective. We didn't do the analysis exactly like that, but we basically entered an allowance price and let it flow through our whole TDV calculation engine to see well what's sort of carbon price would I get per unit? And you end up with this between $200 and $250 per ton for a unit price for switching from the mixed-fuel to the all-electric.

And we put on here the 1x AAEE case, which has lower electricity and with low electricity rates that by cost is less, because electricity is not as accessible. (phonetic) So when you switch to it, it doesn't cost you as much.

And then if you go to this and you add up the differences, there's a number of things that -- well before we go to this, so if you go back to -- I want to address one of the questions I know we're going to get, which is well could you make it on a performance standard? So if you want to look at a performance standard and use ACM could you get an all-electric building pass? And that's a question that I don't know the answer to, and that's in part why we're releasing the CBECC-Res and people can go and do more efficiency measures, so --

UNIDENTIFIED SPEAKER: (Indiscernible)

MR. PRICE: I'm sure people will, I don't know, I don't but if you just fit these prototypes into identical buildings this is the kind of thing that you get. So this is a feedback question off of the table.

And the upfront costs of the building don't factor into that performance tradeoff. That's just really a lifecycle energy calculation, lifecycle energy bill in the performance calculation. But we thought it'd be interesting to look at more of a lifecycle total cost that includes construction costs as well and construction cost differences.

That type of analysis at the Energy Commission and the Building Standards is really only used in the case studies, so you look at the lifecycle benefits and (indiscernible) incremental costs and you do a total cost analysis. So we want to take a look at that, so this would be sort of to the hypothetical question would you require all-electric and would it be cost effective, okay?

So in order for that to be the case you go to the construction costs. And again, this is just the Climate Zone 12 example, 2,100 square feet, you end up with this lifecycle higher energy cost of something like $5,700. There are higher appliance costs. We think there's higher appliance costs for all-electric really because the heat pump electric water heater is a more expensive appliance, something on the order of $1,000; there's probably a little bit higher electric panel costs. We don't know exactly, we just sort of put it down as something that would have to be considered.

And then on the gas side obviously there are savings on construction costs too. There's no gas plumbing within the building. Depending on the situation there may be developer costs of the horizontal infrastructure of gas in the development, but that doesn't always fly. Sometimes it does.

And so if you add these two up the question is would it be about -- it'd have to be about $7,000 less to build an all-electric home in order of the total costs. I don't know the answer to that question either, but that is the order of magnitude of what we're talking about that's implied by the TDV values.

So, so far we've just been looking at Climate

Zone 12. I think folks would be interested in the parametrics kind of just looking all across and this is really the tradeoff that we're talking about with electrification. So the chart on the left shows the lifecycle emissions of the mixed-fuel and all-electric buildings, so mixed-fuel is blue. And so the emissions are higher. Really, this is a pretty consistent trend. The climate drives the total level of energy use up and down depending on the zone and what have you. So kind of across the board we're reducing CO_2 emissions and in some cases pretty dramatically.

And then on the right-hand side we've got the TDV, lifecycle TDV consumption. And in all cases the all-electric has a little bit higher TDV energy use for the identical home. And again, they're sort of depending on the ratio of gas and electric use to the differences, kind of are varied a little bit across the zones.

So we wanted to break that down for folks a little bit more, so the first breakdown here is on space heating. So the first break down here is on space heating, so here we're talking about a heat pump, electric for space heating versus a gas furnace.

And on the left again, these all have the same format. On the left there's the lifecycle emissions of the space heat function and on the right the TDVs. And when you isolate the performance of the heat pump technology this is the -- as the CBECC model has recently been tuned up to do a better and more sophisticated model in their heat pumps it shows, to us at least, a pretty dramatic performance of heat pumps. And also coupled with the 50 percent RPS, which is really taking a lot of carbon out of the electricity sector we're ending up with quite good lifecycle emissions for space heating.

But electricity is still costlier, so the efficiency improvement in the heat pump is dramatic. But it hasn't overcome, at least through the TDV methodology, the higher costs of electricity. So you have great efficiency, but you're using a more expensive fuel and so on net -- you know. Now I think everyone would agree, those are pretty modest differences for this particular end use in terms of space heating, in terms of the cost side of heat pump versus gas furnace.

So then let's look at water heating. So water heating is more consistent across the state, because people use similar amounts of hot water wherever. There are differences, because the heat pump water heater because the ambient temperature around the water heater appliance itself is modeled. And so that has some differences, but it's pretty consistent kind of across. And that's showing basically similar trends to what we just saw. It's a pretty dramatic performance particularly with the emissions, because of the high efficiency and because we're aggressively developing the de-carbonized renewable level to meet the electricity demand on the left.

And then in terms of on the right it's pretty modest, in some cases almost identical total lifecycle.

And then cooling, so cooling we have a heat pump technology, but we have electric cooling. In the mixed-fuel home we have electric cooling and the all-electric home, so there's really nothing here in this. There's little bits of differences for reasons that I'm sure the building simulation groups can tell us, but basically the same home, same equipment, same result.

And that's it, so I'm happy to -- I'm sure that this probably stirred some questions. But that's an initial look at what happens when you take the most recent TDV factors and do this comparison of mixed-fuel and all-electric.

MR. RAYMER: Bob Raymer, I have a ton of questions, almost all of them not related to T&D, so this will be short. (Laughter.)

In order of design and consumer feedback is it possible to get an idea from the Commission about timeline here? I know there's a desire here to go all-electric. Is there a wish list of how we sort of wean off gas over the coming year or years? Like I know that's maybe not --

COMMISSIONER MCALLISTER: Yeah, I mean this is really a policy question and not related to this particular session. You know, there still though is -- I mean there are lots of stakeholders and certainly many of them feel that electrification has got to be the future. I think, if you talk to the natural gas side of the things, they maybe don't believe that quite as strongly.

And there are some options to clean up our natural gas supply as well, right? So in terms of like the carbon analysis here, make some assumptions. Well, those assumptions may or may not pan out, but the cost trends I think it is clear that whatever the cleaner fuel will push prices up whether it's on the gas or the electricity side sort of with all of the caveats that we've been talking about earlier.

MR. RAYMER: We're looking at design issues, you know, having one or two electric vehicles in the garage. You know, this is 10, 20 years down the road. We're already doing EV-ready design, but I'm most interested in the impact on the housing design for June, July, August and September where the water heater, the dryer and the stove would be adding a layer of electric consumption on top of everything else. And as we're going vertical, as I've repeated many times, we're losing space on the roof.

And so just as a mechanical engineering approach -- and this gets away from TDV -- but we're going to have to have batteries in the future. I'm kind of seeing that as a necessary component to the house with the solar system, because we're not going to be able to have onsite a large solar system.

COMMISSIONER MCALLISTER: Yeah, well so certainly I mean a lot of these discussions are going to have play out in a Title 24 context like once we get down to brass tacks here with this as a context, right?

MR. RAYMER: But none of this has anything to do with T&D.

COMMISSIONER MCALLISTER: Cost effectiveness has to be a case. I mean, you know, if you think about the costs there are some benefits, but there are also costs and so let's take the $7,000 estimate. Well, if your customers are telling you they still want gas for cooking and you have to put in gas anyway, you don't even get the $7,000. And so in some ways that kind of the worst of both worlds, but those are practical market considerations that we've got to hash out sort of in time on that.

MR. RAYMER: It is, yeah. As you all know there's some very exciting stove range products coming online, which are really extraordinary.

COMMISSIONER MCALLISTER: Oh, yeah.

MR. RAYMER: But once again above and beyond costs there is that, and we just got back from PCVs and hey (indiscernible) and so how do we kind of get them to change?

COMMISSIONER MCALLISTER: And much of that isn't even going to be resolved within these walls obviously. So think I'm actually looking forward to having this discussion in the 2019 context, but we're going to have same type of construction. I see Bill back there, he'll be involved in that and Christopher and his team, convening some forums, hashing it out, and basing it on sort of reality and where the marketplace is. How we can and should push and how we sort of need to give some flexible pathways.

So I think that all of that's got to be on the table. And I think part of exciting here also has to do with sort of offsite types of approaches where we're doing more of an entitlement kind of process. And we need to kind of work that out as well and again that's not just necessarily just in this building.

So anyway your questions are going to be -- or are great and are going to be even better, but it's not really TDV-related.

MR. SAXTON: Pat Saxton with the Energy Commission. One timeline I think that we can definitely clarify, Bob, is that the modeling capabilities of voluntarily choosing all-electric will be improved in this cycle.

MR. OWNBY: I'd also like to chime in here and just to give you a little bit more nuts and bolts in terms of timeline and what's going forward.

So right now we have a PV measure analysis, a work authorization that's about to be signed and Wilcox is the contractor for that. They'll be moving forward and it's going to be an analysis that's going to look at a lot of different things, including some of the things that you mentioned like demand response and storage.

We'll also be looking at community solar, how to offset for mixed use, all-electric and both onsite and community solar. And that's with a goal to have something that we can present for discussion beginning next year when we begin our pre-rulemaking phase, just to give you a heads up on that.

MR. RAYMER: They've got a lot to do in a very short period of time.

MR. OWNBY: Yeah, they do.

MS. WALTNER: Meg Waltner from NRDC.

So I just wanted to start by saying how much I appreciate the fact that you've done this analysis. This is an issue that I feel like I've been raising for at least three years now at these proceedings. And, you know, I think the issue we see is that when you look at the long-term modeling to 2050 and how do we reach the 80 percent reductions -- speaking to the people who did the modeling, so you know this -- you either need to de-carbonize the gas that's going into buildings, or you need to provide those buildings with carbon-free electricity, that meet 80 percent reduction goals.

And our primary concern has been the fact that the Code really inhibits all-electric construction, currently. I really appreciate what's been done to reduce the barriers to electric buildings under the Code. I think these results are consistent with the modeling that I've done myself for 2016 and shows that there's still a discrepancy between the CO2 values and what the TDV results give you.

And so I've come to the conclusion that given the current consumer cost framework that maybe TDV isn't the way to solve this. We need to think about how we're setting the baseline for electric homes versus natural gas homes. So I think that's a conversation we should have throughout the Title 24 process. So those are sort of my comments.

I had a few specific questions about the analysis that you guys did for the inputs. Did you use 2016 envelope and minimum efficiency equipment whenever you didn't specify what kind of equipment?

MR. PRICE: I think that's right except for the heat pump water heater. If you pick the generic one it gives you a really poorly performing kind of water heater, so we didn't. We picked a specific model.

MS. WALTNER: Right, yeah. And that actually gets to one of my other comments, which is -- I think this is still the water heating results that are up right now, right? Or oh these are the total, well on the water heating results I actually think the TDV results would look much worse for any non-NEEA certified water heater. That it's only those --

MR. PRICE: That it would, I promise you.

MS. WALTNER: Yeah.

MR. PRICE: Because we did those first and we were like, "Huh?"

MS. WALTNER: Yeah, I've done a few of those in the beta software too. So for the NEEA models it helps, but I think non-NEEA certified models are still hard to install.

And then on the cost side, you know you mentioned the cost of the -- the $7,000 cost of gas infrastructure to the building. I think one thing that's not sort of included in the overall TDV framework is the cost of maintaining gas infrastructure and the cost of gas leaks that are unpredictable, Aliso Canyon-type events.

MR. PRICE: But maintenance of the gas infrastructure should be included in the retail rates for the gas that we're using.

MS. WALTNER: Right.

MR. PRICE: And so I think we -- if our projection's right for gas rates, then we obviously should have that.

MR. WALTERN: Yeah, I guess it was a question of whether those costs are taken into account adequately in a long-term way.

MR. PRICE: Yeah, we used to argue about what's embedded in the buildup gas rates.

MS. WALTNER: Yeah.

COMMISSIONER MCALLISTER: Yeah. I want to just build on that quickly.

So, you know, we probably need to -- and maybe others have thoughts on this -- but in terms of the gas price forecast there are different opinions about that. You know, one of which is the last IEPR demand forecast. But I think some scenario modeling -- I mean, many of the issues that frustrate us all in terms of on the carbon side have to do with oil and natural gas prices, right?

So that drives a lot of your analysis. And, you know, their (inaudible) statutory requirements around Title 24, but they do become an issue very quickly, because you know forcing additional costs on the marketplace isn't anything that will save us like lighting. So anyway I just wanted to suggest that maybe we could talk about some scenarios for different price forecasts or different price scenarios for natural gas.

MR. TIFFANY: Ted Tiffany, Guttmann & Blaevoet Consulting Engineers.

I would encourage you to do this analysis, because I've done something similar to this. When you throw the renewables into these two different scenarios the TDV equivalents are very, very different under the 2016 and 2019. And as that profile moves out into the 7:00, 8:00 o'clock and you've got renewable production onsite that TDV energy is much harder to offset without some technology like battery storage.

The company did that equation, so as we get into that discussion on the backend of what this equation affects those technologies need to be available and integrated. And it can't just be efficiency; it's got to be part of the generation storage strategy to get to the zero 2019 value.

And then one of the other elements that I'll probably touch on later, but that curve will be drastically affected by onsite renewables. So I'll ask you guys to look at that heavily in your next (indiscernible) --

MR. PRICE: And that is indeed the plan. As Adrian said, that basically the next layer of work that we have planned has to do with digging into renewables both onsite and offsite.

MR. TIFFANY: Okay. I will happily lend my study to you. (Laughter.)

MR. OWNBY: Okay, anyone else?

MR. ESSER: Marc Esser, yeah I have a comment under -- if you could go to the slide where you were showing the $7,000 figure there?

MR. PRICE: Just a second, this one?

MR. ESSER: Yeah, "Natural gas plumbing infrastructure costs would be the $7,000 less for all-electric to break even."

I think that may not paint a very accurate picture, because you're only looking at the building performance overall here. But if you have a mixed-fuel home versus an all-electric home there are also some appliances notably in cooking and drying that may have a different first cost. In the electric case it's higher than for the gas case.

So for the consumer that's not a very helpful number there, because it doesn't paint the complete picture

I think. Plus you have some significant issues --

MR. PRICE: We tried to factor that in on the fee, but whether the all-electric appliance costs $1,000 more in that package than gas or it's 2,500 that would take a more robust search than we did by just basically Home Depot, delta costs, going online. So basically --

MR. ESSER: Yeah, no I understand. This is Title 24, not Title 20. But I just wanted to point out that the homeowner may be confused if he looks at a number like this, because it's not the picture, not the full one. Thank you.

MR. HAMMON: Rob Hammon, BIRAenergy.

On this we've done a fair number of zero energy homes, both -- we've done a few all-electric and we've done quite a few mixed-fuel. And the mixed-fuel are almost invariably less expensive to build than the all-electric. We're not taking into account the infrastructure differences, but those are often zero, because they're reimbursed by the Gas Company. So it's difficult to know how to deal with that.

In terms of storage, let's not forget that if we're going to put storage in the homes, there's both electric storage and thermal storage. And I think we need to loop back and look at the opportunity to use thermal storage in place of electric storage, due to maintenance and first cost issues.

MR. PRICE: And to be clear the next step of work that we have does include thermal storage.

MR. HAMMON: Yeah, good.

MR. PRICE: So we've got both.

MR. HAMMON: Okay. Thanks.

MR. PRICE: And we're intending to look at this.

MR. OWNBY: Yeah, broadly we're defining it as sort of demand-response, which would include thermal storage and batteries on the site.

MR. HAMMON: Yeah.

MR. PRICE: So like pre-cooling with a more thermal mass of a building could be a way of getting the (indiscernible)

MR. HAMMON: Right. And it's important how you do the thermal mass and how you control things and so forth. But --

MR. PRICE: We'll leave that to you building this.

MR. HAMMON: -- the technologies are imminent if not here.

If we can look at Slide 30, I think it is, the water heating slide?

MR. OWNBY: This one?

MR. HAMMON: Maybe it's 50? It's hard to read on this thing.

(Off mic colloquy regarding correct slide.)

MR. HAMMON: That one and going backwards three slides, I just wonder about the T&D, what T&D costs are included in there? Because if we go back to the site source multiply, which I know is voodoo or history or whatever, it seems like there ought to be a larger cost for electricity and I just throw that out there. Without doing any analysis it just looks like it.

MR. PRICE: Well, this is actually it turns out really close to source energy for a water heater, because the shape's relatively flat. And so what you're seeing is basically a coefficient performance of the heat pump water heater of about 3.

MR. HAMMON: Okay.

MR. PRICE: And our old source energy multipliers are about 3.

MR. HAMMON: Right.

MR. PRICE: And so you end up with about the same.

MR. HAMMON: Okay.

MR. PRICE: It's really close to source energy, once you do a shape that looks like water heating that's flat. And it's totally different when you do the long peak of use and so on, but because we've got capacity over here, but it's pretty close.

MR. HAMMON: And apropos of that point of a peak, we've got homes that we're monitoring in Southern California that are -- they have heat pumps, they have heat pump water heaters, they're not all-electric, but they're close. And they have batteries. Some do, some don't.

But they've all got heat pump water heaters and we're finding that in the afternoon it's not uncommon for a large demand of hot water creating a spike of up to 7 kW that's totally unanticipated. And it's the heat strip turning on. And I think that one of the things we need to look at very carefully is how those work.

And I myself have personally tested four different water heaters for equal comparison. And we really need excellent controls in a heat pump water heater. And if they're done right and operated correctly you can get rid of the strip heat. But right now the strip heat is, I think a huge looming issue.

MR. PRICE: And are you suggesting maybe the simulation doesn't match exactly what we're seeing in the field?

MR. HAMMON: Absolutely.

UNIDENTIFIED: I think it actually does in Climate Zone 16, because it's (indiscernible) (Laughter.)

MR. HAMMON: I have one last point.

MR. PRICE: Yeah, resistance because it's cold.

MR. HAMMON: My last point is I think that all the things we're talking about today are really interesting, exciting, but they're all policy related. And ultimately this whole thing gets off and goes to the market.

And there's a huge, what I see as a liability issue to the builders, in this process being outwardly -- that is beyond this policy group -- outwardly being labeled as zero net energy homes.

And if the market goes that way and we go from zero net energy policy-driven issues, to calling the products that result in 2020 as zero net energy homes it's going to be a train wreck, because the homes are going to have residual energy use. They're going to have bills and the consumers are going to go, "What happened?" And if we don't be careful and align all of this and hold it in as policy, as opposed to marketing and messaging, we've got a problem.

MS. GOLDEN: Hi, Rachel Golden, with Sierra Club again. First off, I'm very new to both the Sierra Club and this group, so please excuse any naïve questions.

But I was going to ask about including time of use in the demand response capabilities in this modeling, but it sounds like you're going to be doing that in the next iteration. So that's really exciting to hear and see the future impacts on the greenhouse gas on the cost side.

I also had a more like in-the-weeds question about the construction costs for the natural gas buildings. And I'm wondering if you include in there the ventilation costs and other safety costs that are needed with buildings with tight envelopes for gas, in terms of back drafting and other issues?

MR. PRICE: I think probably as everybody in this room knows, on our construction costs it was just a really very rough lining up of factors. We did not try to do it with detail except just like how big would the delta be and could it conceivably be that much difference in costs? I don't know if we're going to do a deeper dive into that element or not.

Probably there are many others in this room that actually build buildings and could do a much better job than we could of like what the incremental costs are of all the factors that are more or less. But we just sort of wanted to cue up the framework of like how you would think about it and then remind folks that really it's not actually part of the performance testing anyway. So it's more of a choice for a developer or building owner and then kind of leave it at that.

COMMISSIONER MCALLISTER: And I would say that in this conversation those issues are probably at the margin, like a very small margin.

MS. GOLDEN: Yeah.

COMMISSIONER MCALLISTER: And really the substantive discussion about modeling and building construction techniques and the costs thereof really takes place when we get all the stakeholders who are in the room in the actual Title 24 Code development process.

So this is sort of a preamble for that, because this is actually (indiscernible)

MS. GOLDEN: And do those construction costs get folded into the TDV or that's just sort of a separate interesting thing to think about?

MR. PRICE: The place they fit is in if there's a case study, so a requirement for a particular -- for a building to have a particular feature you do an assessment like that where you look at how much more does that feature cost versus its lifecycle savings.

But once you've got a prescriptive package in the building then the performance tradeoff is really just based on TDV. And if you end up putting features in the home that cost more to get that energy savings on your tradeoffs then that is a developer choice. That allows the flexibility in the Code and how you comply.

MR. HAMMON: I think it's worth mentioning that gas appliances don't go in conditioned space except for the stove. And back drafting is really not a significant issue in new homes.

MS. GOLDEN: Right, more for retrofits.

And then I guess I just wanted to add one or two more things. I should have made my methane emissions comment with this presentation, rather than earlier. So I still think that's a significant thing to fold into an analysis.

And then a more general comment on TDV is that I mean I'm looking forward the joining and participating in this moving forward. And I'm just hoping that in the 2019 Code cycle that we find a way for -- our current framework for TDV doesn't pose a barrier to building lower-emitting buildings, whether it means establishing a reference baseline that's the same fuel type as the proposed building or a different method altogether.

COMMISSIONER MCALLISTER: I just want to point out that we've got until 12:00 scheduled. So we've only got another 20 minutes or so left and I saw a bunch of questions come in online. And so I kind of want to just implore us to move it along here, but are there any other questions in the room?

MR. ESSER: I have just one very quick one. I just wanted to go back to the question I had earlier about the SB 350 scenario analysis that you did. And I feel that my question hasn't been answered. I was asked to stay tuned to the later part of the presentation.

But I wanted to know how you will end up selecting the scenario to go with this one in order to calculate the final TDV values, and which scenario do you feel was the most representative at this point?

And I can stay tuned a little bit longer if it's on the agenda, but I just wanted to make sure. Thank you.

MR. OWNBY: Okay. So did you want to try and address just the clear questions in this here, first? Since I think -- excuse me -- this is some leftover questions from our previous section here from George? (phonetic)

Did you want to sign in and answer some of these questions, Snu? Did you want to go over these?

MR. PRICE: Yeah, so I think we're going to continue to table that last question from the (indiscernible) --

MR. OWNBY: Oh, okay. And so did you have a --

MR. PRICE: And then --

COMMISSIONER MCALLISTER: So I do have a point, so just to be clear the base scenario that you are using from the forecast includes the policy regs?

MR. PRICE: That's right.

COMMISSIONER MCALLISTER: So we're starting our priority with the policy on the board then we're doing a few scenarios: high, low-carbon, that kind of thing around that base case, so it's sort of in then from the analysis.

MR. OWNBY: Yeah, at this point our base scenario is 50 percent RPS in the 2 times.

COMMISSIONER MCALLISTER: Yeah.

MR. ESSER: Okay, so that SB 350-friendly one?

MR. PRICE: Yeah.

MR. ESSER: Okay. Thanks.

MR. OWNBY: Okay. So questions here from George, he is asking about PV production, etcetera. "Is the time of peak actually changing, is the time of the year of the peak changing, or is the shift only due to PV production.

COMMISSIONER MCALLISTER: Adrian, can you speak up just a little bit?

MR. OWNBY: Okay. I'm sorry, sir.

MR. PRICE: Yeah, I mean I can paraphrase that question.

So I don't think that the weather files that we have, and that we're using for the building simulation, would really show a dramatic change in the timing of when people are using energy. I think that recent years have maybe shown a little hotter summer later in the year, and so maybe in actuality there might be a little bit of a difference.

I think that what's really driving this question though is that what's important for TDVs is really net load. So load consumption minus the renewable generation mix. And then that net load is changing dramatically. And then implicate in the supposition in the question is, is that solar? And it is. It is solar coming in and moving our net load peak later in the day.

And also we get a little bit more solar production in the middle of the year than in September, so it's sort of flattening out across. So into September is about the same as August, is the same as July. So I think that's the big driver there.

Let's see, it's a long question.

MR. OWNBY: Well, I think that those were the clearest pieces of that, that were clearly questions.

MR. PRICE: Do you want to comment on that?

MR. TIFFANY: Yeah, just on that impact of the TDV later in the day?

MR. PRICE: Yeah?

MR. TIFFANY: I think with the first time, and especially for non-res, you're actually going to see different occupancies being hammered by the TDV peaks later in the day, when your traditional office building will be closing by the time that heat cranks up.

MR. PRICE: Right.

MR. TIFFANY: Whereas retail and restaurants will have a huge impact in a huge energy user like a restaurant will have a much higher TDV impact that then we have to try to offset with renewables during the day that have that same peak. So that's going to be a very challenging occupancy now, instead of a climate more for energy, which is different than I've since (indiscernible) peak.

MR. PRICE: Yeah, no, I agree with that assessment. I think that is exactly the effective energy use in the evening will be kind of becoming the target of and key driver. And there's not as much leverage in solar, because its output profile doesn't line up as well just because we've done so much there, really.

MR. TIFFANY: Yeah, as a designer trying to impact compliance with those types of buildings then the strategy is more (indiscernible)

MR. PRICE: Yeah, where do you go?

MR. TIFFANY: And so you can get to a thermal mass. Residential is our first problem, but I see that problem coming down the others too.

MR. OWNBY: So the next question is what year is the weather modeled?

MR. PRICE: I know a little bit, enough to be dangerous on this question, so the letter files are developed from a whole series of years.

Folks may know Joe Huang from White Box, but basically they have a statistical method of sampling weeks from like a whole multi-decade, historical weather system. And then they put them in to be a -- line them up to be a typical year. And the way that is done is it's actually sampling the same week from each climate zone, what you end up with is a state representation where the temperatures are all correlated and we translate that through to energy demand statewide and production costs from their generation fleet statewide and what have you.

And so we try to make a planning year based on snippets from a whole bunch that sort of statistically give us the right distributions and what have you in the letter files.

MS. CLARK: And I'll just add that if you see a year on our weather file it's because of the calendar year. So in our documentation we talk about a 2009 weather year, it's still this typical weather year that's now described, but we have to keep the same calendar year when we're comparing between cycles. So the day of the week that January 1st falls on is consistent with 2009.

MR. PRICE: And holidays and occupancy schedules and everything else lines up with this one year.

MR. OWNBY: Yeah. Just to add in that we're planning to take a look at, and update the weather files for the next Code cycle. We need to do that basically even ahead of development of TDV, because that's going to feed into the development of the TDV whatever the (indiscernible)

MR. SAXTON: So when you say next code cycle, you mean 2022?

MR. OWNBY: Sorry, yeah, 2022, not the 2019.

MR. PRICE: I'm in the 2019 cycle.

MR. OWNBY: So, the next question is, "PV lifecycle may be 20-25 years, is the overhaul cost included in the longer terms?" I'm not sure about that.

MR. PRICE: Well, so if you were to do a case study on PV you would have to factor in the life of PV. But of a TDV assessment, TDV is not a -- it's just a forecast of operating costs, so the capital cost doesn't figure in.

MR. OWNBY: I think the answer to that is that's something that we will certainly take a look at when we're doing the PV measuring analysis.

MR. PRICE: Right. And maybe inverter only lasts ten.

MR. OWNBY: Yeah.

MR. TIFFANY: Ted Tiffany, one more time.

In that analysis please consider like the overproduction of PV, to run the PV equation at wholesale rates rather than retail rates, because that equation is one of the impacts for specifically with the mixed-fuel builders. That you have people who produce electricity to the grid, and so (indiscernible) maybe you're not getting the 12 or 14 cents at retail rates (indiscernible) that really changes cost effectiveness of PV, to overproduce to offset that.

MR. OWNBY: Yeah. I believe the measure proposal, the measure analysis, the work authorization includes essentially a sensitivity analysis regarding then 2.0 and at what point does PV no longer become cost effective?

COMMISSIONER MCALLISTER: So it's good to see a lot of (indiscernible) in the shadow, in (indiscernible)

(Colloquy off mic.)

MR. OWNBY: I'm trying to find another question and actually I am not seeing anything that clearly comes across as a question.

So are there any more questions online? Please chat them to me immediately and any other questions here in the room? Because if there's not I think we're close to being done and we have about five minutes to spare.

MR. PRICE: I think more just came in.

COMMISSIONER MCALLISTER: When are comments due?

MR. OWNBY: A question here, it says, "Figure 18 of the TDV Report is called Henry Hub Natural Gas Commodity Costs, but the values are those shown on the EIA website and higher than shown in the IEPR?"

MR. PRICE: I think that's the same question that you may have had?

MR. ESSER: Yes, actually. That's right.

MR. OWNBY: Okay.

MR. PRICE: So that's something we'll have to look at.

MR. OWNBY: Okay. So the answer to that is that's something that E3 is going to have to take a look at.

COMMISSIONER MCALLISTER: So Adrian, can you remind us when comments are due on this?

MR. OWNBY: Well, essentially we'll close the docket for this by the end of this month. If you want to submit additional comments to the docket until that point you're certainly free to do.

And when we get into the regular rulemaking and the pre-rulemaking periods we will open additional dockets. We will open a pre-rulemaking docket and then we finally get to the rulemaking we'll open up a rulemaking docket and you're free to comment on TDV in any of those dockets as well.

COMMISSIONER MCALLISTER: Great. Okay.

MR. OWNBY: If you want, to be clear if you want your comments on TDV to be part of the official record, that would probably need to occur only in the regular rulemaking proceeding.

COMMISSIONER MCALLISTER: I think --

MS. WALTNER: When is the -- oh I'm sorry.

MR. OWNBY: I think the timeframe is this, which is sometime early next year, say spring, we're going to begin our pre-rulemaking phase. Through to the end of at least the third quarter of next year we're then going to have to finalize a package of measures and start our rulemaking phase in early 2018. And that will run essentially halfway through the year of 2018. We're looking probably at a June 2018 Commission approval of our 2019 Regulations.

COMMISSIONER MCALLISTER: Or sooner.

MR. OWNBY: Or sooner, well yeah. And we'll have to deliver those regulations in the CBSC by the end of 2018 for their approval. So it has to occur a year in advance.

COMMISSIONER MCALLISTER: But so the process though is that there will be a series of workshops about different issues, there'll be a lot of stakeholder meetings. There will be opportunity in the pre-rulemaking phase to try to get to some component of understanding about what the issues are and what the rulemaking more or less is going to start off looking like. And then that goes into the formal process where we really get down to crafting regulations and having a more formal stakeholder interaction to the record that we build.

So I think it's a multi-step process, a lot of issues to work out, and this really is -- the TDV that we've been talking about today is really a foundational resource to help those discussions be on an even keel and on a foundation that everybody kind of accepts as such and work from, so that's why this is sort of the first major activity with the code cycle to make sure we get off the right foot.

MR. OWNBY: And just to clarify, during the pre-rulemaking process we do the same thing that I did for the TDV comments, we do for all comments that we receive. So your comments during pre-rulemaking do have an impact on the proposals that we finally put together.

COMMISSIONER MCALLISTER: Yeah. So Christopher, did you want to say something?

MR. MEYER: Yeah, basically I just wanted to reiterate -- this is Christopher Meyer with the Building Standards Office.

Getting your comments on TDV in as soon as possible, getting them in this proceeding, helps us sort of as they are saying figure out what questions we need to answer going forward. So you may reiterate your comment later in the pre-rulemaking, but we definitely encourage everyone to get your comments on TDV in as soon as possible, so that we can address them in case there's anything else that we need to, going forward. Thank you.

MR. OWNBY: It's very likely we won't open a pre-rulemaking docket until sometime next year, so once we close this we won't have a venue for you to make any comments.

MS. WALTNER: I just had a further question on the overall Title 24 schedule. Is the pre-rulemaking, does that include the IOU lab workshops that you guys did last time or are those in advance of that pre-rulemaking phase?

MR. OWNBY: Those are essentially in advance of our pre-rulemaking phase. The IOUs have their pre-rulemaking where they go through and they hold their workshops and then we hold a separate set of workshops.

MS. WALTNER: Okay. Thank you.

MR. MCHUGH: This is Jon McHugh, and I'm a consultant who's been working in support of the Statewide IOU Codes and Standards Program. So just first off, they're stakeholder meetings held by the IOUs. They're not workshops. They're not part of the CEC process. They're to collect information from stakeholders, so that these case studies can then address many of the issues from the stakeholder meetings.

I'd also like to say we really appreciate that the Energy Commission is really moving swiftly this time to have these TDV files ready, because even though they're very obscure etcetera, they still form the basis of the cost-effectiveness analysis that underpin the case studies. So that's greatly appreciated.

And are we expecting that we're kind of finalizing these files before the end of the month or is there some sort of a timeline?

COMMISSIONER MCALLISTER: What is the timing of this?

MR. OWNBY: I was anticipating essentially that we'd finalize it at the end of this meeting. That is, we would go forward with the TDV values that we currently have, so that we can get the research versions of CBECC-Res and CBECC-Com in the hands of the case team as soon as possible.

MR. MCHUGH: That's great. Thank you very much.

MR. RAYMER: That answers a question of mine, how can you have a Bay (phonetic) version of CBECC for 2019 without having this finalized.

MR. OWNBY: Yeah.

MR. RAYMER: Or one of the many finalized versions.

COMMISSIONER MCALLISTER: Well, great. So we got everybody in the room and online? I didn't see any other questions coming in online?

MR. OWNBY: No more questions online.

COMMISSIONER MCALLISTER: Great, well I'm going to let my comments stand on just why this is important and what we've been trying to accomplish here and everybody is clear on that at this point.

So Christopher is the lead of the Building Standards Office and if there are process questions or just sort of day-to-day questions, interaction is through him. Certainly, my office is accessible through Pat, my adviser, and the Chair's Office also. You know, maybe not quite as much day-to-day involvement in this, but (indiscernible) in this as well.

So I just want to thank everybody for coming. This is a highly-specialized topic, so we note that the level of engagement and understanding here is much appreciated. And I'm really looking forward to getting the 2019 process really, truly kicked off in earnest, because we have a lot to accomplish and a lot of exciting things going on out there in the marketplace.

And we have some goals we really need to push forward and to help make them feasible. And help to work with everyone in a way that makes sense.

So thanks everybody for coming and we are adjourned.

(Whereupon, at 12:01 p.m., the workshop was adjourned)

--oOo—

REPORTER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were reported by me, a certified electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 1st day of August, 2016.

PETER PETTY
CER**D-493
Notary Public

TRANSCRIBER'S CERTIFICATE

I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were transcribed by me, a certified transcriber and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

And I further certify that I am not of counsel or attorney for either or any of the parties to said hearing nor in any way interested in the outcome of the cause named in said caption.

IN WITNESS WHEREOF, I have hereunto set my hand this 1st day of August, 2016.

Myra Severtson
Certified Transcriber
AAERT No. CET**D-852