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BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the matter of,	)
	) Docket No. 19-SB-100
SB 100 Joint Agency Report:	)
Charting a Path to a 100%	)
Clean Energy Future	)

SB 100 Modeling Inputs and

Assumptions Workshop

WARREN-ALQUIST STATE ENERGY BUILDING

1516 NINTH STREET

1ST FLOOR, ARTHUR ROSENFELD HEARING ROOM

SACRAMENTO, CALIFORNIA 95814

Monday, February 24, 2020

10:00 A.M.

Reported By:
Elise Hicks &
Peter Petty

APPEARANCES

Commissioners Present

David Hochschild, Chair

J. Andrew McAllister

Karen Douglas

Other State Agencies Present

Liane Randolph, Commissioner, CPUC

Rajinder Sahota, CARB

CEC Staff Present

Terra Weeks

Siva Gunda

Mark Kootstra

Noemi O. Gallardo, Public Advisor

Dorothy Murimi

Chris McLean

Consultants/Contractors Present

Oluwafemi Sawyerr, Energy and Environmental Economics, Inc. (E3)

Dr. Zachary Subin, E3

Panelists

Delphine Hou, CAISO

Jason Rondou, LADWP

Jim Shetler, Balancing Authority of Northern California (BANC)

APPEARANCES (CONT.)

Panelists (Cont.)

Marilyn del Bosque Gilbert, Imperial Irrigation District (HD)

Dan Severson, Turlock Irrigation District
Erica Brand, The Nature Conservancy

Zainab Badi, GRID Alternatives

Matthew Freedman, The Utility Reform Network (TURN)

Michael Wara, PhD, Stanford University

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Public Comment

Julee Malinowski, California Biomass Energy Alliance

Roger Lin, UC Berkeley

Ben Allen, UC Berkeley

Danielle Osborn Mills, American Wind Energy Association of California (AWEA-CA)

Diane Moss, California Hydrogen Business Council (CHBC)

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P R O C E E D I N G S

FEBRUARY 24, 2020 10:00 A.M.

[Proceeding in Progress]

MS. WEEKS: So, where it says supply 100 percent of all retail sales. And so, we've received comments around whether this includes system losses associated with retail sales. And so, this is a point under active consideration and we appreciated the comments that we've received on this point.

Additionally, the bill states that achieving the 100 percent policy shall not increase carbon emissions elsewhere in the western grid and shall not allow for resource shuffling. And it calls on all state agencies to incorporate this policy into all relevant planning.

State agencies must also ensure that steps taken to implement the policies do the following: Maintain safety, reliability, and balancing of the electric system. Prevent unreasonable impacts to utilities and ratepayers. Support efforts to reduce emissions in other sectors and not effect implementation of RPS.

So, as I mentioned, the RPS will remain at 60 percent indefinitely under the statute. And so, really what we're talking about is the 100 percent outside of that 60 percent RPS.

So, more specifically, the statue requires the

Public Utilities Commission, the Energy Commission, and the Air Resources Board to do both of the following: First is to utilize existing programs to achieve the 100 percent policy. And the second is to issue a joint agency report to the legislature. And so, this report is to be done in consultation with the California Balancing Authorities and through a public process. The first report is due January 1, 2021 and then every four years thereafter.

So, the statute requires that the SB 100 report include all of the following: The first is a review of the policy focused technologies, forecasts, transmission, safety, affordability and reliability. Also, a specific section on system and local reliability, which will be discussed during Session 2, with the California Balancing Authorities today. The nature of anticipated costs and benefits to utilities and ratepayers. Overall barriers and barriers to achieving the policy. And lastly, alternative scenarios in which the policy can be achieved. And so, that's really going to be a core focus of our technical section today.

So, now, I'll shift into the report development process so for. So, we've assembled an interagency team which is led by the SB 100 principals at each agency,

who are Energy Commission Chair David Hochschild, CARB Chair Mary Nichols, and PUC Commissioner Liane Randolph. We also appreciate Commissioner McAllister be the lead for the modeling portion of the report.

So, we are still in the process of collecting stakeholder input through a series of workshops, which will help inform the report and, of course, we'll be developing the report over the course of this year.

So, the primary goals of this report are to, obviously, meet the statutory requirements, to provide direction to the electricity market, to coordinate planning processes across the state agencies, including integrated resource planning, RPS compliance, the Energy Commission's Integrated Energy Policy Report, and CARB's scoping plan, among others.

And in this first report we're also working to ensure that we have consensus on interpretation of the statute. So, for instance, around the definition of zero carbon resources.

And of course we're trying to balance many facets of this policy, so including reliability as we incorporate more intermittent generation onto the system, resource diversity and flexibility as key tools to maintain reliability, energy equity, affordability balancing, providing market direction, while still

allowing for flexibility with emerging technologies, and supporting innovation, and environmental impacts including land use, which we'll be discussing today.

So, just to recap the timeline so far, we really launched the report development process last fall with our kickoff workshop here in Sacramento. We then held three regional scoping workshops across the state, in Fresno, Redding, and Diamond Bar to solicit feedback on the scope of the report.

We held our first technical workshop in November, where we outlined the state of the market for both existing and emerging technologies. And we also outlined two proposed modeling scenarios, which were the RPS Plus and no combustion scenarios, which we'll be diving into more detail today.

Following this workshop, the Modeling Inputs and Assumptions, we'll be finalizing the scope of the modeling work for this report and then complete the analytical portion of this report. We're planning to have a draft modeling results workshop in late spring, and then a draft report released with a workshop in late summer. And then, of course, finish the report by the end of the year.

So, just to wrap up, I wanted to summarize some of the key comments that we've received to date on the

report. So, one of the most frequent comments that we received is support for a diverse portfolio of resources, including a mix of both in-state and regional resources and a focus on energy storage.

We've also heard support for specific technologies to fall under the definition of zero carbon resources, including large hydro, small modular nuclear, hydrogen, gas with CCS, and bioenergy resources. Comments around including resilience planning and addressing wildfire risk. Continue to address reliability.

We've heard many speakers and comments on the critical importance of affordability and energy equity as we implement the policy. Also, to address air pollution particularly in disadvantaged communities. And concerns around a narrow interpretation of the scope of SB 100. So, again, this is getting to the question as to whether system losses should be considered under the purview of SB 100.

And so, with that, unless there are any questions, I'll turn things over to Mark Kootstra from the Energy Commission, who's going to dive into the analytical portion of this report. thanks.

MR. KOOTSTRA: Good morning everyone. My name is Mark Kootstra. I work in the Electricity System

Modeling Unit at the Energy Commission. Today I'm going to really talk about the analytical approach we're taking for SB 100, specifically the modeling that we're hoping to do.

So, as you can recall from Terara's presentation a few minutes ago, these are some of the key considerations we're looking at within SB 100. Some of these are easier to model, to analyze quantitatively versus qualitatively and so some of those we're going to try and do quantitatively now, others we're going have to model qualitatively now and look at quantitatively in the future. A subset of these we'll definitely be modeling at this point.

Some of those include the statewide resource scenarios. We'll hopefully be able to provide you guys examples of scenarios that we will be modeling and then what resource scenarios will come out of that. The cost, and benefits of impacts of those scenarios as well. Again, on a limited scope because we're not modeling the entirely of everything, but we can through a capacity expansion model.

The rest, as you can see, we're going to talk about qualitatively and we may do quantitatively in the future. E3 will talk a little bit -- in a little bit about the RESOLVE model, which is the capacity expansion

model that we'll be using this time around.

So, SB 100 identifies eight main analytical requirements. This is kind of a little bit grouped together and simplified from what's actually in the bill language, but it gets the point across. What I'm going to describe next is going to be what models that we could use now and in the future, as well as what we're actually using, as well as describe our general approach and what scenarios we'll likely be -- we're planning to use for the time being.

So, coming out of these disparate eight main analytical aspects that we need to look at, we can take a look at power flow modeling which really looks at the electrical system, how that power flows in particular cases. The current that's used to evaluate current operations, optimize those operations, as well as look at future expansions ore retirements of different aspects of the system.

The demand forecast models, the Energy Commission produces a demand forecast out to 2030. It's really not efficient to review out to 2045. That's pretty obvious. We are going to be making use of E3's PATHWAYS model to give us similar numbers that are provided by the demand forecast, but it's not a forecast. It's looking at what if we comply with this,

what demands we're really going to be looking at. And Zach from E3 can characterize that a bit better down the road.

Fuel price modeling, again, we're not going to be doing any of that here. That's a key input as we look at what the costs are for the natural gas system. The Energy Commission does a NAMGAS model, or North American Market Gas Model, in these price forecasts. We're not updating those here, but that's something we could be looking at in the future of how that is impacted by SB 100.

What we will be looking at is the capacity expansion model RESOLVE. There are a number of different capacity expansion tools out there. These take a simplified version of the electricity sector, as all models do. RESOLVE looks at 37 days and E3 will talk about that a little bit more. It has to in order -- it has to take a small set of the year that we're modeling to allow it to iterate over many different possible scenarios and different options so we can actually identify what could be built. Is this optimal? Is this going to be too costly or expensive given the very stringent set of assumptions?

As will all models the assumptions are really key and if you make a bad assumption, the model results

will reflect what that assumption is.

What we're looking at for outputs here are possible resource builds with basic characteristics such as cost, how much solar is going to be there versus wind, versus storage and other things.

Another model that we could to be looking at and, hopefully, in the future will be able to do is production cost models specifically with some stochastics. The Energy Commission runs production cost models right now and this helps us to evaluate resource builds by looking at the entire year that we're modeling or the entire spread. It gets a little bit more granular and specific, but it has some similar limitations in the fact that it's still a model, it's representing a simplified environment. And it's not a predictor of what the future will look like but, rather allows us to explore what the future could look like based off of different policy decisions that we look at.

Adding stochastics is essentially running many different combinations of possible outcomes, so we can explore what if the sun doesn't shine as much this year, what if hydro is lower or higher, how does that impact the model so you can get a broader view and perspective, as opposed to just a single point forecast or analysis, which can hide different things and you can't

necessarily explain it as well.

Some of the future modeling possibilities we're looking at, and we would love input from folks on this is what models are out there and what are the desired outputs? Not necessarily the numerical values that you get that it's 100 percent to 30, but really what measurements do we want to look at. Especially in the case of environmental protection, affordability and safety. There's some aspects of these that we can do, that we have some identification on what we possibly can do in the future, but we'd like to know what's important to stakeholders as well. Again, this is likely not going to happen in this cycle, but in future cycles, and we're trying to gather that information now.

Our overall inputs for SB 1001, there's a lot. This is a very small subset, already. But it just kind of identifies how different assumptions and inputs that we have feed into the different analytics that SB 100 calls for. So, some of these analytics we have to do before we do the modeling, some of it can flow out from it, but this kind of gives some of that flavor.

Some of the key inputs that we're looking at and we're iterating over, which I will talk about later for our scenarios, is the available transmission. Are we expecting more transmission to be built, both in-state,

out-of-state, and how that works. What energy demands we're looking at, not just what's the energy consumption for the state, but the shape of that consumption. If we continue to have a peak that shifts later and later into the day, solar contributes less and less to those resource needs in some situations, or we have to pair that with storage to make that up. Whereas, if somehow our peak magically goes to solar noon, that's really nice for us. Knowing what that shape looks like is really important.

Different resource availability, so how many resources are there? Can we access offshore wind? Are we making that assumption? Can we access out-of-state resources? Or, are there going to be further constraints in different regions that we currently think, hey, we can build solar forever in this area, but maybe we can't. So, those types of considerations come into play.

And then, resource eligibility. This goes back to what Terrara was talking about as there is no definition for what is a zero carbon resource for SB 100 and we need to look at some different definitions of that so that we have a rationale and reasons for what we're suggesting.

Some of the outputs that we're looking at and

we're hoping to make use of is what transmission is selected when transmission resources are options? What GHGs are there? What resource mix we're looking at? And this shows and points to how the different analytics can flow into actual model results.

For affordability, I want to point out this would be cost per kilowatt served. This would be taking the levelized cost and dividing by the total energy. We suspect, but we don't know yet, that if costs go up, if demand goes up at the same time or even faster, that the total cost per kilowatt hour could actually down despite total resource cost for the system going up. So, it's those types of things we want to look at as well. So, just because the total resource cost goes up, it doesn't mean there is an increase in kilowatt hour served for the energy side. But the converse could also be true, demand could go down, total resource cost could go down, but cost per unit energy could go up.

So, now, I'm going to talk a little bit about the scenarios we're planning to do and what's feeding into those scenarios. As Terrara mentioned already, the eligibility is not defined, so we want to set that eligibility for SB 100 resources and how that fits.

Right now, we're looking at two different options, the RPS Plus scenario and a no fossil fuel

combustion. The RPS eligibility is identified there just as a reference. Hopefully, most of you already know solar has eligibility, wind, small hydro, and other resources such as biomass, and there are some minor resources that don't play a significant role in the RPS at this point. All of those would be eligible in both of these cases. That's what we're proposing. The RPS Plus and the no combustion also add large hydro and nuclear resources. The main difference we're looking at with the no combustion of fossil fuel is that natural gas carbon sequestration would not be eligible, whereas under the RPS it would. That's the only carbon capture resource that we're adding to the dataset or to the possibility for result to select at this point, that we plan to. But as time goes on new technologies come around and whether that's carbon capture or not, we'll evaluate this list and see what's appropriate in future iterations to add.

Our demand scenarios, we're relying on PATHWAYS from E3 for the high electrification case, high biofuels, and high hydrogen cases. These have already been out there in the public. The CPUC's 2045 IRP studies looked at these as well. They should be relatively familiar to some of you.

We're also asking E3 to work with our demand

forecast staff to create a base case that's in alignment with the 2019 California Energy Demand Forecast that was recently released. There's an existing base case that we want to update that with the new information that we have, and we'll use that as a reference case as well.

Looking at different resource availability, these resources options are very similar to what the CPUC put out in their 2045 IRP study. They're framed a little bit differently. The CPUC's base case where offshore wind and new out-of-state were not available or severely restricted, and then they allowed those resources to come into play to test what happens if you add offshore wind or out-of-state resources -- out-of-state transmission that allows a lot of out-of-state wind to get selected in the model. But we also want to look at what happens if we allow both of those things. Just to throw that out there.

So, if we add together the possible iterations that we're looking at, we're looking at the option of 64 scenarios. If we iterate over anything else that could duplicate grow exponentially, that's not going to be helpful. So, we want to narrow down what those scenarios look like. We want to make sure we filter out ones that aren't meaningful, because not all scenarios are going to be meaningful. Some combinations won't

make a lot of sense. And so, we're narrowing them down to eight at this time, with some options to add a little bit more if we need to, if we find out there are areas we want to explore.

And so, these are the eight that we're looking at. The first five are largely the same as what the CPUC did in the 2045 IRP scenarios, with the exception that it's now statewide, and there may be some other minor changes that we can talk about in the RESOLVE model discussion that E3 will do.

These are looking for the three main PATHWAYS demand, and then for high electrification also looking at if you allow offshore wind and if you allow out-of-state transmission to change what the resource mix ends up looking like.

Scenarios six and seven are really looking at what's going to be the difference in outcome if you use RPS Plus versus the no combustion of fossil fuel scenario options. This will kind of say what those costs look like. It could be that there's no cost difference, it could be that they're significant. We don't know. And that's one of the reasons why we want to look at it and find out what the model's going to select.

The last scenario, scenario eight is purely a

reference scenario at this point. This is going to be what if SB 100 was adopted for 60 percent RPS only, but not the zero carbon grid. We know this isn't the case. What this is going to allow us to do is give comparisons between a business as usual and these other scenarios that we're looking at. It will allow us to say, hey, total resource cost is really big, but if you look at what it's going to look at no matter what in 2045, it's not that much different or it actually is different from there, and see how the resource build changes. I can't recall for sure the exact numbers, but CPUC's IRP 2045 study had huge, tens of thousands amounts of new solar on there. Is that because of SB 100 or is that because we're just going to have to do that anyways and that's going to be selected. We can start to answer that question a little bit by looking at this scenario.

that's what I've got for you today. Please, provide us what comments you have, especially on what models and what desired outputs and measurements you'd like us to look at in the future, as well as any comments you guys have on the scenarios or anything else you'd want to analyze.

I'm going to invite Zach to come on up and present on PATHWAYS.

?MS. HERNANDEZGUTIERREZ: We have set up an

overflow room in Imbrecht, so I will ask that any Energy Commission staff that aren't directly involved in the workshop to head over there, and we'll be projecting all of the information.

MR. SUBIN: All right, I'm going to give a pretty brief intro to the use of the PATHWAYS modeling here and then turn it over to Femi to talk about RESOLVE. For PATHWAYS, we'll just overview the kind of model structure and how we pass those over to RESOLVE and what scenarios we're using.

So, you know, the key use of the PATHWAYS model in this study is to provide load projections for kind of the future scale of the electricity system to then test different electricity portfolios in RESOLVE.

So, the PATHWAYS model we've used in a number of California state agency studies. And what the model allows us to do is kind of test hypotheses about if you are going to meet economy-wide decarbonization targets what are possible ways that you could meet those targets and then, you know, what you have to do in each of the sectors. It keeps track of stock rollover in key demand sectors where, you know, it takes time to turn over appliances and vehicles to decarbonized options, model energy flows, and greenhouse gases throughout the economy.

And it sort of allows you to stay honest by adding up a restricted fossil or biomass budget across all the sectors, instead of kind of looking at one sector at a time to meet an economy wide target. And we also develop a reference or a counter-factual scenario so we can have a consistent comparison to what would have happened in the absence of the decarbonization policy.

So, as I mentioned, it's really a -- it's a scenario tool. It's not a forecast or optimization. What it allows you to do is kind of test hypotheses about what you would need to do to meet the economy wide emission targets. So, you know, we call that back casting, kind of starting from assuming we have a decarbonized economy in 2050 or 2045, and then seeing what we have to do in each sector to get to that target. And our reference scenarios are typically aligned with existing data sources from state agencies like IEPR, you know, like from the Department of Finance population forecasts and, you know, some amount of expert judgment establishing current trends.

We represent the energy demand in a kind of broadly similar set of sectoral categories to the IEPR. We have eight demand sectors. And we did a pretty comprehensive benchmarking back in 2016, when we were

building up the modeling for the CARB 2017 Scoping Plan Update.

And as was mentioned, we're doing an updated reference to benchmark to the latest -- the latest IEPR reference. Or, sorry, the latest IEPR forecast.

So, we have three sectors that we look into in greater detail, residential and commercial buildings, and transportation, where we represent these by kind of detailed end uses, with stock rollover. So, we have 11 subsectors for residential buildings. You know, you have lighting, air conditioning, space heating, et cetera, as well as housing stock turnover. We have a similar representation for commercial buildings.

And then, for transportation we have four on-road vehicle subsectors, as well as the treatment of off-road. And then, for some of the other sectors we have kind of a more aggregated treatment of the energy demands across different categories, and we estimate how these can undergo efficiency or fuel switching measures as part of decarbonization.

So, an important thing to keep in mind when comparing with a kind of bottom-up forecast like IEPR that's closely benchmarked to different policy choices, the PATHWAYS model is really kind of starting from like an end use appliance level. You know, the number of

space heaters that different heating types. You know, in the chart we have gas furnaces, heat pumps, electric resistances. And those will shift over time based on mitigation measures that are input. And, you know, first you calculate sales and then that penetrates into the stock, the full fleet of appliances, and then that allows you to calculate the electricity demand in, you know, terawatt hours for different sectors.

And if you were to kind of evaluate, you know, how much electrification or how much efficiency load is there, you really have to compare two different PATHWAYS scenarios. You know, you have to kind of have a counter factual and then subtract the difference. You know, we don't put in kind of efficiency as a measure, it's more like, you know, you have efficient air conditioners, you have efficient light bulbs, and those all kind of stack up.

So, now I'm going to talk about how we provide the information to RESOLVE and the scenarios we'll be using for this analysis. So, PATHWAYS provides to RESOLVE, the biggest piece of this information, particularly for this study is the annual loads by category in your total number of gigawatt hours. We also provide some load shape information from a variety of sources for key new loads, and load modifiers, and

that's like a normalized 8760 load profile.

And then, we can provide electricity sector GHG emissions that are consistent with economy wide goals, which may or may not be binding. If the electric sector has its own policy that's kind of, you k now, enforcing faster emission reduction, then that will be what takes precedence. And we used this approach for the CPUC 2019 reference system plan. And what we did is we kind of used the PATHWAYS loads as modifiers on the IEPR load forecast, based on forecasts and kind of propagated that through towards 2045 for several different -- several different scenarios for different levels of electrification loads.

So, for this study, we've been asked to use four PATHWAYS scenarios. A reference scenario which is aligned with the 2019 IEPR. And then, the three mitigation scenarios from our CEC 2019 study, with some minor adjustments for the updated IEPR. So, that will be the high electrification scenario, the high hydrogen scenario, and the high biofuels scenario.

And then, each of those four scenarios will provide load inputs to RESOLVE, and to the extent relevant to the study PATHWAYS would cover sector assumptions for outside the electricity sector.

So, in our initial look at benchmarking the

updated PATHWAYS reference scenario, we align well with the IEPR mid demand scenario, moving through the 2020s through 2030. And then, the PATHWAYS reference would extend beyond 2030 with, you know, kind of extrapolating the trends built in, with some additional assumption about, you know, continued vehicle electrification being likely the biggest driver for load growth after 2030.

The three scenarios we're using were selected by the CPUC and we're choosing the same three to be consistent here for the study. So, the three scenarios that I mentioned. The high electrification scenario includes electrification of buildings and transportation, high energy efficiency, high use of renewables, and limited biofuels. The high biofuel scenario includes imported purpose grown crops and that means that there's fewer direct GHG mitigation measures, such as electrification in other sectors.

And then, the high hydrogen scenario tests a higher level of hydrogen electrolysis loads with more heavy reliance on hydrogen fuel cell trucks and lower reliance on all-electric vehicles.

So, to kind of look by sector, those three scenarios that were chosen have high electrification buildings in common. The light duty vehicles have very high electrification in the high electrification/high

hydrogen scenario, with a little bit lower in the high biofuels. And then in trucks, the biggest difference is we have kind of lower electrification in the high electrification/high biofuels scenario, with increased use of biofuels in other sectors or other measures to make up the difference.

In the high hydrogen scenario, there's much deeper decarbonization of -- a direct decarbonization of the trucks with increased use of hydrogen trucks.

And then, the scenarios have a relatively high electrification of off-road transportation, but minimal electrification in industry.

I'm now going to turn it over to Femi to talk about the RESOLVE modeling.

MR. SAWYERR: So, we're going to be doing a bit of a deeper dive into the RESOLVE modeling than we've just done with the PATHWAYS. And then, we'll look at some of the assumptions we're making different from the CPUC IRP 2019-2020 modeling.

So, RESOLVE is E3's capacity expansion model that does a linear least cost optimization. It combines investment decisions that you would typically make in your traditional capacity expansion modeling with operational dynamics that you would look at in more like production cost simulations. And so, by doing this

combination of optimizing your operational dynamics with investment costs, you come up with a least cost portfolio over a long time horizon that meets your policy needs which, in this case is the SB 100 policy, in addition to some other constraints that we'll be looking at. For example, like GHG emissions from the PATHWAYS modeling.

RESOLVE is primarily a zonal model. And the implications of that is in in the IRP modeling we've had the four California balancing areas represented, and then we also have California's connections to the Northwest and the Southwest.

In this modeling, we're going to be looking at the State of California, rather than the four Balancing Authorities. And so, what you're going to have is a situation that will be looking at a statewide representation of the model.

Generally speaking, flows may be impacted by the transmission you have between zones. It might also be impacted by the amount of resources you have available that can be transmitted between each of the regions.

So, to that regard, there are a few limitations with the existing RESOLVE modeling. One of them is the fact that for your RPS constraints, for your planning reserve margin constraints, and for your GHG emissions

constraints you can only have one overarching constraint for each of those. And so, this sort of lends itself to a more high level analysis that we're doing in this first stage of our analysis of SB 100.

What that means is that even though the BAAs may have different constraints, when we're looking at a statewide analysis we're only going to have one constraint for that. And the same applies for our GHG scenarios and our planning reserve margin.

In addition to that, the IRP analysis did an optimization that was strictly looking at the CAISO area. And for the other Balancing Authorities we had some considerations of meeting their policy constraints. In this case, we're going to be looking at an analysis that is statewide for California.

And what that means is that each of the Balancing Authorities may not necessarily have results that meet their individual targets, but if we're looking at California as a whole we would meet the policy constraints we're analyzing.

And by implication what that means is our results for resource build, for example, are going to be reported at a statewide level and not to the individual local Balancing Authorities.

By implication as well what that means is

contrary to what was done in the IRP analysis, which was looking only at the CAISO, we're going to be scaling up some of the numbers. So, for example, the GHG trajectory at 46 million metric tons at a statewide level would actually represent that, if we were using that for example. Whereas in the IRP modeling that number came to about 38 million metric tons.

Okay. I'm having some blank slides. Can I get some help with this?

(Pause)

MR. SAWYERR: Thank you. So, one of the things that the RESOLVE model does pretty well is it provides a framework for valuing flexible resources. The challenge when you have a high renewable system, or high renewable penetration system is the fact that on the one hand you have in your analysis a need for renewable overbuild to be able to meet all your capacity and energy needs.

And on the other hand, if you're trying to minimize curtailment and over generation, you have high integration costs.

And so, what RESOLVE does is it finds that sweet spot in between where you're optimizing the delivery of every megawatt as much as is beneficial to the system, considering your least cost options.

And so, flexible resources is selected when

they're benefits, which primarily we're looking at reducing renewable generation over build are greater than their cost. And so, by that we could also analyze things like energy storage, as well as other zero-carbon resources as is done in this analysis.

And so, like I mentioned initially, RESOLVE does a co-optimization of both investment and operational decisions. And doing that, it basically does it over a long time horizon, like Mark had mentioned before, and I will talk in a few other slides. Because of the computational difficulties in doing this over a long time horizon, in addition to modeling only a sample, a select representative sample days, we also model only a certain number of years. And then, the information is pretty much interpolated within the years that aren't modeled.

And so, RESOLVE combines operational detail that directly informs your economic decisions, addressing both your existing resources, as well as future resources. And it is able, using data on your fixed costs for the existing fossil generation, to economically retire some of these resources if they're deemed not necessary, as well as make investments in new infrastructure.

And in doing this analysis, the optimization

considers certain constraints like hourly load, meeting RPS targets, or an RPS Plus target, and planning reserve margins and GHG emissions.

To do this, in our analysis of several scenarios what we end up doing is a situation where you have certain base inputs. What you have as your load forecast, what you have as your generation resources available, as well as what you have as transmission inputs and assumptions on availability and access.

And then, you look at certain scenario-specific inputs, which might be, for example resource costs or land use availability affecting resource potential. Or, forecast loads, as we will be doing in this scenario, for this analysis where we're looking at electrification loads, as well as alternative technologies available to you.

And then, what you have is we run this through the actual optimization in RESOLVE. And generally, when I speak of RESOLVE here we have the RESOLVE optimization which is done in Python, but we have a toolkit that has both a scenario tool, as well as a RESOLVE tool based on Excel. And so, when we talk about inputs and viewing results, we're dealing mostly with those output tools and input tools.

And so, ultimately, we will be looking at some

base scenarios, but also looking sensitivity analyses that we will be changing certain inputs and assumptions. And Mark has already spoken about those.

There's a lot of data on this slide. The key takeaway is just the fact that RESOLVE, in its generation capacity expansion has several resources available to it, both conventional and renewable, as well as storage resources. And there are certain cost considerations that are considered in such a way that each resource is assessed on an apples-to-apples basis. And so, we're looking both at your capacity value, as well as your energy and ancillary services value for each of the resources.

And finally, on this set of inputs and assumptions one of the things we're considering is the fact that there's several policy lenses that you can view your constraints from. With the RPS and your GHG constraints, while both of them may get to the same results they're using different perspectives to view the question of what portfolio you want to have.

And so, in RESOLVE we can assess both an RPS or clean energy standard, as well as a GHG constraint. And depending on which is the binding constraint, your resources meet both of these needs.

And why this shines in the RESOLVE model is

because it has the ability to androgenize the reliability and economic aspects of these variable resources. Something that Mark had alluded to earlier is the fact that when you have a constantly moving a constantly moving system peak as you add more solar into the system that also reduces the capacity value that solar is able to contribute. This also affects resources like wind and energy storage as well.

In previous capacity expansion analysis, we used to have four-hour storage be equal to the same capacity value as a perfect capacity resource. But in our analysis, we're starting to see that that is not entirely the case, especially as you have more renewable resources on the system.

And so, we are able to do these kind of deep dive analyses of not just renewable resources, but also resources like demand response and energy storage, as well as look at transmission constraints in our analysis of the optimal portfolio you need on your system.

And so, RESOLVE does this and we will be using the same inputs that we used in the CPUC IRB model in this analysis, even though it's a statewide level analysis.

This slide just gives you an idea of the way resources are represented in RESOLVE. There's a lot of

information here. One thing I will say is that ultimately we have tried to make sure that in our representation of the resources we're looking at real world applications of each of the resources we have modeled in RESOLVE.

And, finally, this deals with our operational metrics and the sample data that we have in RESOLVE. And so, it uses a linear dispatch formulation where you're looking at the hourly operations in each of the modeled sample data that you have in RESOLVE. And looking at the generation profiles, both for renewable resources, as well as your more dispatch flexible fossil generation, and meeting your daily load in each of the hours you have modeled.

RESOLVE has 37 representative sample days. And in the selection of these 37 days, we did this in an algorithm that is separate from the RESOLVE model itself. And several things are taken into consideration for selecting those several -- those 37 sample datas. They cover three years' worth of load and generation profiles for each of the balancing areas within California. And consideration was taken to the distribution of both the generation and the load in representing which historical days we used.

And, ultimately, each of these 37 sample days

has a weight that gives you one full year of operation in the model.

and with that, I will talk through some of the assumptions we're making in our modeling for the SB 100 analysis and how these are different from the 2019-2020 IRP model.

So, like Mark had mentioned before, we're looking at a host of candidate resources. And in the scenarios where we have full candidate resources availability that is going to include existing fossil generation, as well as the more established renewable generation, like solar PV and onshore wind. But we're also going to be looking at offshore wind as well. Geothermal, biomass, we're also looking at energy storage.

And for some of the scenarios we will have carbon capture sequestration available. In the no combustion sensitivity, we're going to have hydrogen fuel cells being considered as an opportunity for zero carbon flexible dispatch.

And then, in addition to supply side resources, RESOLVE also has some demand side candidate resources, so that includes behind-the-meter PV, behind-the-meter storage, and sheds demand response.

In the 2018 -- in the 2019-2020 IRP, the costs

there are -- the costs there were based on both the NREL 2018 ATB for most of the generation resources, and the Lazard Levelized Cost of Storage 4.0.

Since the inputs and assumptions were locked down for that analysis, two new reports have come out. And so, for this analysis we're going to be updating the cost to the 2019 NREL ATB for the generation resources and the Lazard Levelized Cost of Storage 5.0.

Financing costs are still going to be based on the NREL ATB. And for our shed DR supply curve, that is going to be based on the existing study that was done by LBNL for California's demand response potential.

And then, finally, for resource potential and the land use considerations we're using the supply curve that was developed by Black & Veatch for the CPUC RPS Calculator Version 6.3. What that comes to is a little over 350 gigawatts of solar PV in-state, about 2,000 megawatts of wind in-state, and some geothermal and biomass availability as well.

For the modeling that was done in the IRP, restrictions were placed on the out-of-state wind to the extent that we were basing that analysis on existing transmission between California and the Southwest, and considering one new transmission line built between California and New Mexico and California and Wyoming.

And so, what that comes to is about 3,600 megawatts of out-of-state wind.

And I will hand it off to Jesse. Are we doing the next steps or -- all right, so I'm done.

MS. WEEKS: Great, thank you. So, now, we're going to shift into an interactive Q&A session. So, we're going to invite E3, as well as Mark Kootstra, and Siva Gunda from the Energy Commission to sit on a panel. And so, first, we'll open it up to questions from the dais. And then, if anyone would like to make a comment or ask a question, we ask you to please come up to the podium and we'll have a mic on right there.

And then, following that, I'll also be reading off questions that we're receiving over WebEx.

So, now, just open it up to any questions from the dais.

COMMISSIONER MCALLISTER: First, I just want to say thanks. So, and just the fact that there were -- well, I guess there were 58 slides. You only went through 31 of them so far.

But, obviously, a lot of meat to this. And, you know, always on technical topics like this I have concerns about just accessibility. You know, you shouldn't have to be a heavy duty modeler and really in command of all of these tools to kind of understand it.

And so, I think part of our challenge today and going forward is just making sure that we -- maybe we'll never be able to put this into truly lay terms, but to make it as accessible as possible to the most people possible, so they can kind of understand. You know, if you're interested, you should be able to understand it.

I guess maybe just as a high level kind of coordination question, you know, obviously the -- many -- some of the resources that we're relying on for this are E3, we have staff at all the agencies, particularly, you know, the Energy Assessments Division here at the Commission, and your counterpart, Siva, across PUC and ARB.

I guess, can you, starting with Siva maybe, and Mark, but talk about how the batons kind of get handed off between, you know, across the team and how we're going to avoid having little silos kind of spin off in this discussion?

MR. GUNDA: Yeah, thank you, Commissioner. This is Siva Gunda, Deputy for the Assessments Division, for the record.

So, we have, since last year, been able to double up and innovate better on how to coordinate between the three agencies. So, before I directly answer the question you posed, I just want to thank the

IRP team, specifically for the competence they bring to the table in terms of having done this recently, in terms of how they approach this analytically. And also, to CARB staff for bringing in additional consultations, just such as help and such. How do we incorporate into this broader modeling as they embark on the Scoping Plan?

So, the current status quo on the coordination is that we meet weekly on an interagency call to avoid the kind of siloedness of this analysis. So, the staff from all three agencies meet weekly to discuss emerging issues in a timely fashion. And being able to talk about not just the process and the structure for what we are implementing for a public process, but also how do we coordinate across analytical work, but also across the different proceedings we independently are also doing in terms of IEPR, Scoping Plan, and IRP.

We also currently have an opportunity for the CEC staff from different divisions and I want to thank the Renewable Energy Division, the Research Division, and the Efficiency Division for their participation on this regularly.

So, we have a weekly technical meeting where we are able to discuss a lot of the modeling issues together, in one single forum.

And also, we have the opportunities with the principals to bring up important considerations if we were not able to resolve at our level, at the staff level, bring these up to the principals' level, Commissioner Randolph, Chair Hochschild, yourself, and also CARB with Chair Nichols and Rajinder, being able to kind of get guidance.

So, I think we have a process that meets regularly and discusses emerging issues in the three agencies with our lens, and being able to coordinate on a regular fashion. It also helps that E3 is helping all of us.

CHAIR HOCHSCHILD: Yeah, I just wanted -- did you have a comment on that, Mark? Yeah. I just wanted again to compliment the collaboration between all the agencies, which has been outstanding.

I did have a question just on the demand forecast and just specific to what's happening with housing. Obviously, the Governor has made this a top, top priority for the state to address the homeless problem, and address the affordable housing crisis in the state. And there's some pretty bold goals in terms of new construction.

At the same time, we now have about 30 cities in California that have adopted natural gas bans or

electrification preferences in new construction. We expect about 60 by the end of this year. And just given those trends, I mean how are we assessing the demand from new construction in the state? How much is actually going to get built?

MR. GUNDA: Yeah, I'll take this and I'll pass it on to someone who can give a little bit on the PATHWAYS side.

So, from the demand forecast side, as you know we have an update coming up in 2020. And so, for each of the updates we update the econometric and demographic variables. And that we're looking into getting the latest version of projects for the state to look at some of the new policy goals of the administration baked into our analysis this year.

One of the things that we're doing analytically, with E3's support, is to look at how do we bucket the different times of demand forecast and scenarios we're collectively looking at? One of the key aspects here is, so as we look into for example AB 3232 goals, which looks at 40 percent below 1990 levels in residential and commercial sectors, and that kind of looks at -- that yields a certain demand scenario.

Similarly, SB 100, when you're looking at the PATHWAYS analysis and looking at an economy wide

intersectoral approach, you have one set of demand scenarios. Similarly, when you look at the standards work on 2127 that's looking at transportation you have a variety of demand scenarios.

So, what we're trying to attempt to do this year and we probably will attempt it qualitatively, not quantitatively, is to at least frame how are we going to implement these different goals, as well as changing econometric and demographic goals that we have moving forward into a cohesive framework for future analysis.

So, at this point for the current version we're going to stick with the 2019 demand forecast, which does have some of the ambitious goals that the Governor recently spoke about. Some of them are baked in because we get some of our values from the DOF.

But moving forward we want to create a comprehensive framework on how do we talk about demand forecast, but also the intersection of these different legislations that are coming together.

CHAIR HOCHSCHILD: And I had sort of the same question -- oh, do you want to add to that? I've love to hear your thoughts. Yeah.

MR. SUBIN: So, first regarding the housing stock. So, PATHWAYS models the housing as kind of in equilibrium with population growth. And I think, you

know, the Department of Finance population growth forecast that's baked in the model I would say if -- you know, if we had a lot of new construction, it's probably just sort of closing the loop of consistency so that the housing does actually match the kind of population growth that the state was projecting. You know, this is a little bit of what we saw in some other work on the electrification markets last year. So, you know, I think to some extent that's somewhat included.

In terms of the local policies for building electrification, I'd say the PATHWAYS centers we're using kind of bracket the range because the reference scenario is, you know, pretty closely aligned with IEPR which has, you know, very little or no building electrification in the kind of current trends. And then, the high electrification scenario has, you know, a very high level, likely even more rapid than just targeting new construction. So, I think, you know, if you kind of use those two as the bookends you could get a sense of, you know, the possible range.

CHAIR HOCHSCHILD: Any other comments from anyone else on the Panel?

I had the same question also about transportation electrification. Some major develops obviously happening now in that area. We're adding

about 20,000 electric vehicles a month now, in California. It's a leading export for the state today. It surpasses almonds and a bunch of other things. And you see these big announcements coming up. GM is announcing in two weeks their whole future is electric. VW has made that, right. The Ford F-150 is getting electrified. All this stuff, you know, how quickly this all happens is, you know, a question of great interest.

I'm just curious of your take on that question and how we account for that?

MR. GUNDA: Yeah, absolutely. And I think you continue to raise the important distinction between the demand forecast that we develop for the transmission planning purposes and what E3 support allows us to do in terms of the PATHWAYS to really back cast and understand how to approach the different levels of electrification both in transportation and buildings.

So, as Dr. Subin kind of talked about a little bit at a high level, this current report will be based on the PATHWAYS scenarios that we've discussed in the past. So, that's developed in 2018 timeframe.

But I think looking, moving forward we have an opportunity to continuously revisit the PATHWAYS as these market dynamics, as well as the goals change.

From a forecast perspective, one of the basic

requirements are -- the basic limits that we'll meet is the 5 million goal that we have, the ZEV goal for 2030. But beyond that, most of the exploratory work has not been published or used in the study -- or will be used in the study.

MR. SUBIN: Yeah, so again we sort of maybe bracket the range of the two scenarios. We have the reference scenario gets to about 4 million zero emission light duty vehicles in 2030, which roughly corresponds with the IEPR, and also the 2017 Scoping Plan scenario.

Whereas the mitigation, the three mitigation scenarios reach about 6 million vehicles in 2030, which is above the 5 million that was mentioned in the Governor's goal.

COMMISSIONER RANDOLPH: And I was just going to make an observation based on what Siva was saying that, you know, there's a short time frame for this initial report, and I appreciate that we're using what's available to talk about the issues as much as we can. But there's a lot evolving on the ground with the announcements that are coming out, like Daimler in the heavy duty space.

But we also have a chance, when we look at the 2021-2022 Scoping Plan to get into more of these new details and these new announcements that are being made.

I would like to see it, if possible, if we could in the report identify things that are evolving that need to be considered in the near term and long term when we think about SB 100. That way at least we've put out a marker out there that this isn't the end of the story, but that there's an evolution going and that we need to be cognizant, incorporating that as things get developed, and planned, and put out. Thank you.

CHAIR HOCHSCHILD: Okay, that's it. Yeah.

MS. WEEKS: Okay, great. So, now we'll open it up to comments in the room. And we do ask that if you comment or ask a question that you fill out a blue card. And you can do it after you ask your question.

And so, Noemi, our Public Advisor has them in the back there. So, we just want to make sure we're capturing your name and organization if you speak.

So, now, we'll open up this podium right here. So, if anyone has a question or comment, please feel free to come up.

MS. MALINOWSKI: Yeah, Julee Malinowski on behalf of the California Biomass Energy Alliance. Just a clarifying question. It seems as though you made a distinction between non-combustion in your presentation, Mark, and it was specifically to fossil non-combustion, so we're not talking about other combustion technologies

like bioenergy.

MR. KOOTSTRA: Correct, but I'm going to restate just to be sure we're on the same thing. If it's RPS eligible and it's combustion, it would still fall in the no combustion of fossil fuel scenario, so it would still be eligible. So, we're not expecting to touch the RPS at this point.

MS. MALINOWSKI: No matter which modeling scenario you're working.

MR. KOOTSTRA: Correct.

MS. MALINOWSKI: Okay. Because then you had said something that confused me even more, but I think we're on the same page right now.

MR. KOOTSTRA: I think so, yes.

MS. MALINOWSKI: Okay, thanks.

MR. KOOTSTRA: Yeah, biomass is still going to be allowed for SB 100 given the scenarios that I presented.

MS. MALINOWSKI: Great, thank you.

MS. GALLARDO: Hello, this is Noemi Gallardo, the Public Advisor. We have V. John White from CERT, and then following him Roger Lin from UC Berkeley, Environmental Law Clinic.

MR. WHITE: Thank you Mr. Chair and Members. I'm sorry, I just got in late. But a couple of things

come to mind listening to this conversation. First of all, we are in grave danger of locking in the least ambitions assumptions in some of our plans. We're using out-of-date load forecasts. We have a transmission planning process that is severely constrained by arbitrary point assumptions. And we're in danger, I think, of missing the boat here.

So, I don't want to do too much detail, but there's a couple of things that seem glaring in some of the scenarios. We have an -- we have no offshore wind because it seems it's not feasible, which is not where the direction is. We have a number of proposals moving forward. We have transmission plans being done.

This is partly why transmission planning has to have a longer term focus because if we use, you know, limited assumptions we're not going to have the transmission we need to get to the targets.

Okay, so to me this scenario, multiple assumption thing may be more confusing and complicated, but in fact the world doesn't rely on single point forecasts, particularly in such a dynamic space as the one that we're in.

So, I appreciate this process very much. I appreciate the time that all of you all are putting together, and to see the coordination and the

cooperation between and among the agencies that's been lacking, and it's important because everybody's got a little different vantage point. We look forward to working with you in discussing these matters further. Thank you.

MR. LIN: Good morning, thank you for the time today, and also for the presentations. Roger Lin with the UC Berkeley Environmental Law Clinic. I'm also on the Disadvantaged Communities Advisory Group. And I'll let my colleagues talk in a second about the substantive questions that we have regarding equity.

But from a procedural matter, I think one of the questions that we'll keep coming up with, and probably all of the sessions today are whether the consultants or the staff have baked in public participation to get the viewpoints from disadvantaged communities in particular, integrated into the results that you're performing.

MS. WEEKS: We have Ben Allen from UC Berkeley, and then after that Danielle Mills from AWEA California. And after her will be Diane Moss, Policy Director of CHBC.

MR. ALLEN: Hi, thanks so much for the presentation. Also here from UC Berkeley's Environmental Law Clinic. I had a question for you about the RESOLVE model and how you more specifically

plan to integrate equity issues, including air pollution, water pollution, the location of transportation resources, like electric vehicle charging sort of all on a local. How you plan to integrate all of that into the RESOLVE model for this report?

MR. SUBIN: So, unfortunately, the RESOLVE model doesn't do that level of local analysis. It does more a transmission level analysis. So, we don't do EV charging and all of that in the capacity expansion model.

With regards to equity issues, the level of land use considerations and how that interacts with resource potential is where we look at that analysis. So, for example if you had issues concerning siting, for example, of solar resources or wind resources that would -- that would impact how much renewable potential you had available on your system. But we don't look at local considerations in the analysis. Unfortunately, that's the nature of the model.

MR. KOOTSTRA: This is Mark Kootstra. I think that's the nature with most electricity system models. You can't necessarily say this one point will operate this way. And it's just an inherent limitation. You can only get so small. It depends on what demands -- how small of demand you can get, how well you can model

that system at that size, and even then it's not perfect. So, we can incorporate as we can, but we have to look at a larger scale. We can't go down to individual plants or distribution circuits and still be able to attempt to model what we need to model. So, we're trying to figure out how to do that better and if you have suggestions, we'd love to hear that. But there's just inherent limitations.

MR. GUNDA: Yeah, thank you. I just want to add a couple of thoughts. So, first of all, thank you so much for that important comment. So, equity has been an important consideration for the team. We have been able to engage at the DACAG, but also recently did a working session with the EJ communities broadly on the equity issues to help one understand what the limitations of the current modeling paradigm is, but also help them articulate what kind of metrics they would be looking for, for us to generate in the future.

So, even though the current paradigm of modeling that we have does not take into account equity as comprehensively as we would like to, we are really looking into feedback on those issues. What are some of the models that you might be aware of, that are well vetted, that could be readily used. But also, how can we qualitatively set this up in the report for both

bringing in recommendations, but also setting the stage for the future reports. Thank you.

MR. ALLEN: Thank you.

MS. OSBORN MILLS: Good afternoon Commissioners, thank you for your panelist discussions. I'm Danielle Osborn Mills with the American Wind Energy Association of California.

I just wanted to start with some questions, particularly around the resource availability scenarios. When I'm looking at slide 30, on the CEC slides that you presented, Mark, it looks like there are a variety of technologies that are going to be eligible, but it seems like you're singling out out-of-state and offshore wind as being somewhat more uncertain than other technologies. And I just wanted to get a sense of what the justification for that was and what the challenges you foresaw were.

MR. KOOTSTRA: A lot of those restrictions are coming from the CPUC 2045 study. So, we're presenting those as a way that we can duplicate the 2045 study, or largely duplicate them on a statewide level. And so, it mostly goes back to that.

And I would encourage the CPUC staff to correct me if I'm wrong here, but I believe that offshore wind was restricted in part because it's an unsure

technology, and they're not sure how it's going to play out, what the costs are going to be, or if it's going to be able to be sited. We haven't done anything, yet, in California, so it's a big question unknown.

I'm not sure what it is about the out-of-state transmission versus -- which it's not a restriction on out-of-state wind, it's restriction on the transmission, which effectively -- wind is what gets picked up, typically. And I don't know the details of that, but that's there for -- to duplicate the CPUC 2045 studies on a statewide basis.

For the other scenarios that we've identified that weren't duplicating that, our base case is planned to be all available resources. So, we would be including both offshore and out-of-state transmission with wind. So, we're not trying to prohibit those for the main course of what we're doing, but trying to do that just to stay as true as we can to the CPUC study.

MS. OSBORN MILLS: Okay, thank you. It seems like the ultimate effect of this type of resource analysis is that you're allowing all technologies to compete in all scenarios, except for one of the most obvious and low-cost renewable resources that is available on the system today. So, I would suggest just taking another look at those inputs.

We're talking about planning for 25 years out here, so this is a real opportunity to think a little bit beyond where we are today. Out-of-state wind resources are available. There's transmission getting build on a merchant basis and there's discussions underway on a regional level. I know those aren't easy. Believe me, I know the CEC's been involved in a lot of efforts to better plan for transmission, both in the state and regionally. But this is a huge gap in the report, so we need to think about how to rectify that.

I also want to clarify that out-of-state and offshore wind resources can be upwards of 50 percent capacity factors. So, when you're comparing that to in-state wind resources that's another serious limitation.

And I also just want to note that the feedback that I see the CEC has received to date is to be technology inclusive and to maximize optionality. So, that's a major contradiction in the inputs and studies.

And, lastly, the section which requires this study states a need for a diversified and balanced energy generation portfolio. So, we need to think bigger than the 2019 reference case. Thank you.

MS. MOSS: Hi, Diane Moss, and today I'm representing the California Hydrogen Business Council as Policy Director. And thank you, it's really exciting

that we're here getting to talk about these issues. We've come a long way.

On the part about candidate resources, I noticed that you have natural gas generation, you have hydrogen fuel cells for a flexible dispatch. It's great.

What about zero carbon hydrogen storage and generation in thermal plants? If you're going to have natural gas, you know, there's around the world, and including here, even in Southern California one of our utilities is looking at transition to 100 percent hydrogen generation. So, is that something that would be considered as one of the candidate resources in modeling?

MR. SAWYERR: To respect, is your question considering hydrogen as a drop in fuel in existing natural gas plants or is it as a new resource entirely?

MS. MOSS: It would be as a -- well, it would be as a drop in fuel with an upgrade of the turbines to be able to handle, and the equipment to be able to handle hydrogen combustion.

MR. SAWYERR: It's something we could consider. It's something we have considered in previous modeling. But we would have to talk with the CEC modeling team about that.

MS. MOSS: Okay. And then, what would be the

issues with other --

MR. SAWYERR: There aren't any limitations on that.

MS. MOSS: Okay.

MR. SAWYERR: Your question of which resource options and all of that.

MS. MOSS: Then, I could encourage you to do it. And the second question I had is also, as Terra mentioned, there's a big concern about including long duration and seasonal storage solutions. I know E3 has talked about this in workshops. Energy Futures Initiative has talked about, you know, that solar, and wind, and batteries, and flexible dispatch are all very important, but we're going to need some kind of gaseous fuel to get to where we need to go. And hydrogen is zero greenhouse gas if it's produced renewably. So, just encouraging. Will long duration and seasonal storage solutions to be included, is that something that may -- it may be in your flurry of slides. I didn't actually have the handout with me. You already talked about that. But that's something that CHBC would heavily encourage, also.

And lastly, you know, the RESOLVE model is based on deep decarbonization scenarios. And we've been talking about 80 percent for a long time. But now,

we're starting to talk about carbon neutrality economy wide, and that's an Executive Order. ARB is looking at that. Other places like Europe, New Zealand, you know, are starting to look at that, really, how do we get to zero? How do we get to carbon neutral? And so, is that something that you've entertained the possibility of not just going to 46 million metric tons, but how do we get to real carbon neutrality economy wide, and modeling that, and getting ahead of ourselves on that? Because 2045 is probably barreling at us faster than we think.

MR. KOOTSTRA: So, I think the scenarios that are mimicking with the CPUC, so what CPUC did was they built in GHG constraints.

MS. MOSS: Uh-hum.

MR. KOOTSTRA: In there, and I think we're planning at least for those scenarios build in some more GHG constraints. We also want to attempt to evaluate how SB 100 is becoming the constraint, and what that falls into without necessarily saying we have to reach this GHG, and all of the sudden the GHG is the limiting factor instead of SB 100. We kind of want to know what SB 100 is doing.

So, there is some consideration of how do we get there for sure, but we also want to be sure we're saying this is what SB 100's going to drive, not just what all

our policies together might drive us to.

MS. MOSS: Right, and so there -- so, we're --

MS. SAHOTA: So, I can jump in on the ARB portion.

MS. MSOSS: Great, yeah.

MS. SAHOTA: You know, you've got the SB 100 process here, we've got the AB 74 Transportation Study that Cal-EPA with -- it's a multi-agency effort there on transportation. And what we're trying to do is look at zero, near-zero in all the sectors, looking at the tradeoff for how far we can get. Looking at costs, reliability, consumer acceptance across all the sectors, and technologically feasible across the sectors.

And then, in the Scoping Plan we pull all those sectors together to understand where we're left in terms of emissions in the complete system, and how much we may need to look for compensating for any emissions left in the system.

And so, that's the way that we've been approaching it at ARB. That's the way that we've been engaging with CPUC and CEC on the SB 100 effort. And I think that's why you see that no combustion scenario in there which is, you know, if you get fossil out of the system what are the tradeoffs between that scenario versus an RPS Plus. And what are the reliability

considerations, what are the cost implications, et cetera.

MS. MOSS: And when you say no combustion, I'm hearing no combustion and I'm hearing no fossil fuel combustion. Is that no fossil fuel combustion that you're talking about or no combustion at all?

MS. SAHOTA: So, it depends on which -- and I mix the two between AB 74 and SB 100, so I apologize.

MS. MOSS: That's okay.

MS. SAHOTA: In AB 74 we're looking at no fossil combustion, period. Right, because it's the largest source of air quality issues and --

MS. MOSS: For transportation.

MS. SAHOTA: Exactly. Here, we're talking about no combustion.

MS. MOSS: Okay

COMMISSIONER RANDOLPH: And I just also wanted to follow up on Mark's point, or Mark's response to your question, which is that the 46 million metric ton GHG constraint is an IRP constraint in the IRP process to 2030, and as that constraint.

MS. MOSS: Uh-hum.

COMMISSIONER RANDOLPH: This process of looking at SB 100 is broader than that. It's looking statewide, it's looking at resources throughout the system. It's

looking at how do we get to a zero carbon out to 2045. So, they're just -- they're bearing on each other, but I just wanted to make it clear that the modeling they're doing is not a 46 MMT constraint.

MS. MOSS: Thank you.

MS. GALLARDO: We have Mary Solecki of ADW [sic]. And if I got the name of the organization wrong, Mary, please correct that.

And then, after her will be Sergio Duenas with California Energy Storage Alliance.

MS. SOLECKI: Hi there. Thank you. Mary Solecki with AJW. Just a couple of questions. On the CEC presentation, Mark, your slides 31 and 32, you talk about the possible scenarios and the current proposed scenarios. I guess I was hoping to see a little bit more detail behind, you know, some of the broad strokes of those. So, curious when and how we might be able to see a little bit more of that?

MR. KOOTSTRA: We'll have to talk and figure out when we can release something a little more detailed and what will look like. Almost certainly by the time we get results we should be able to give you more detail. But want to make sure we've got all the details right. As Femi presented, we are updating some cost numbers, so not everything's been fully fleshed out to date. This

is what the input assumptions are. We don't want to say here are the input assumptions and we're changing it three weeks later and have everybody be surprised.

MS. SOLECKI: Okay.

MR. GUNDA: And just to follow up on that, our hope for this workshop is to get some ideas. So, after this workshop is concluded, the interagency team will have an opportunity to kind of read all the comments and develop more scenarios.

And one of the things we are entertaining right now, between the interagencies, is potentially doing a webinar.

MS. SOLECKI: Uh-hum.

MR. GUNDA: Just to kind of provide a little bit more detail between now and the modeling, some of the final take scenarios and interpretations of the bill.

MS. SOLECKI: Yeah, that would be helpful.

MR. GUNDA: Thank you.

MS. SOLECKI: So, the second question, I guess it's a little bit on the process side. As Terra mentioned at the beginning, defining zero carbon is an important part of this, and I didn't really here, hear any additional discussion about how to define that, unless I missed that. When and where does that happen?

MR. KOOTSTRA: It's mostly it was brought up

between the two different scenarios of RPS Plus --

MS. SOLECKI: Uh-huh.

MR. KOOTSTRA: -- which would be the eligible resources under one scenario, which would include natural gas with carbon sequestration.

MS. SOLECKI: Uh-hum.

MR. KOOTSTRA: Or, a now combustion of fossil fuel scenario.

MS. SOLECKI: Got it.

MR. KOOTSTRA: And those are kind of the bookends that we're looking at, at this point. If there are comments on what we should be doing somewhere in between, we can look at that and move from there.

MS. SOLECKI: Great, thank you very much.

MR. DUENAS: Hi everyone, thank you for your presentations. They were very interesting and helpful to understand the point of the process we're facing. Oh, by the way, I'm Sergio Duenas with California Energy Storage Alliance.

I have a couple of questions mainly about resource availability. I heard in the presentation that hydrogen fuel cells are being considered as candidate resource in the no combustion case. Is it only in those scenarios or in all scenarios?

MR. SAWYERR: So, it will be considered in all

scenarios. But like we were having it as a combustion or having it as a candidate resource in the no combustion scenario, so you also have flexible dispatch --

MR. DUENAS: Great.

MR. SAWYERR: -- zero carbon resource.

MR. DUENAS: A bit of a follow up on that one. In slide 29 of the same deck, we have the total levelized fixed costs for resources. But I don't see hydrogen costs there. I guess because it is usually difficult to get this sort of data in the market that you are working on those. Will those be public? When do you think we could take a peak?

MR. SAWYERR: So, first off, let me say if we -- if you do have an idea of publicly available data on that, we will totally welcome it. The resources, the resource costs here are from the two sources that we mentioned, so the NREL 2019 ATB and Levelized Cost of Storage from Lazard, which are both publicly available at the moment.

MR. DUENAS: Well, one of the issues that -- this is a comment mixed with a question. One of the issues that we think RESOLVE might face when trying to do this sort of modeling is that because of its structure, having 37 independent days, it doesn't full

capture the benefits of having a long-term arbitrage of electricity. Via, for example, storage in the form of hydrogen or pumped hydro.

So, I was wondering if you're thinking about one of two options. The first one would be increasing the optimization horizon to have consecutive days, potentially. I know this might be very disruptive for the model, itself. I've used it and it seems that it's not that easy.

Or, the other one, maybe play with the original state of charge, of storage when a new day starts. Would the state of charge begin at zero in an incremental way?

MR. SAWYERR: This is going -- this is going pretty much in the weeds on the actual like operations of the model. What I will say is for certain resources, like hydro for example, we do have the ability to share energy, and then you have a total within -- I have to check this to be sure. But I know you have the ability to share your energy within a certain limit of days.

We don't do that for battery storage at the moment, where what you have is a situation where you need to have a particular closed cycle within each day. And so, I guess that's getting to your point, or the point you mentioned earlier.

With hydrogen storage, I'm not sure we have that modeled at the moment, and so I can't speak to that.

MR. DUENAS: Yeah, we'd be glad to help out in this sort of thinking through these issues in the process of the modeling. And as well, in your answer you just said hydro. Did you mean pumped hydro or just hydroelectric generation?

MR. SAWYERR: Hydroelectric generation.

MR. DUENAS: Okay. So, for pumped hydro that's not the case, either? Okay, thank you. Thank you very much.

COMMISSIONER MCALLISTER: So, I want to just jump in real quick and I know, so you said this is really in the weeds and stuff, but I think the -- I would just encourage us to have these kinds of conversations. Because I think being explicit about what the modeling, you know, can and cannot do, and directing investments to add modules or add, you know, iteration, even, you know, kludgy ways of passing between models and, you know, I think we need to be explicit about that. You know, what our answers mean when we get them, right? Because that's always the problem with models is that you think they say more than they actually say, or vice-versa.

So, anyway, I think these are really critical

because the system issues, you know, I think we need to learn about as we go forward, and we're laying the groundwork for that. So --

MR. DUENAS: And if I may elaborate a little bit on your comment, too. Our main concern, just to clarify is we believe that the system going towards a decarbonized future will need a vast array of resources that are diverse in their applications in order to maintain reliability in a cost effective way.

And generally, some resources here, such as longer duration storage resources would have some costs that are higher than others of their peers, right. But they would have benefits that couldn't be really captured in a simulation that only takes each day completely independent from the next. We know that is not the case in reality. And we know there might be several weeks or several days where we don't have enough sun, where we don't have enough wind, and we don't want to keep burning fossil fuels, naturally.

So, it's a good idea to think how we can represent these complexities in the model without breaking it, without breaking the efficiency of the process, but also capturing this. Thank you.

MR. SAWYERR: One point just to close the loop on that is that we do consider the situation where you

don't have the sun shining, or wind blowing over an extended period of time. It's one of the things we call the dunkle flautea constraint, which actually does address that point. But we will note that the long duration storage is something that we are considered for additional analysis in the model.

MS. GALLARDO: Up next we have Bob Mitchell, Co-Founder of CEDC. Then, Deepika Nagabhushan of the Clean Air Task Force. And after her will be Gregory John Stangl, CEO of Phoenix Energy.

MR. MITCHELL: Good morning and thank you for making this workshop possible, and for all your participation. My name is Bob Mitchell, with the California Energy Development Company.

I was involved in California when we had the energy crisis in 2000 and 2001, with rolling blackouts in the Bay Area, and so on. And was instrumental in putting together a public/private partnership with PG&E and with the U.S. Government Department of Western Area Power Administration. And my company was Trans-Elect.

And we were able to come in, in 2001, and look at what one of the problems was that was causing this energy crisis. And it was a transmission problem on Path 15, an 83-mile stretch of cable, or a transmission line that had not been built back many years before when

it could have, and was planned.

Under the domain today, I don't think we ever would have been able to get that project approved and built, and from 2001 to operation in 2004. It's amazing the process that's been created. I, frankly, don't understand it all that well. I might be the only person in the room who doesn't.

But we now are proposing to build a sub-sea cable from Diablo Canyon switchyard down to L.A. And that line would enable, if it were built today and five years from now, to eliminate 2,000 megawatts of gas-fired generation.

But we're having a dickens of a time getting consideration of that because of an arbitrary setting of LCR prices. And the line has been shown by an analysis of the Cal ISO that it would be economical, it would be a savings to the ratepayers assuming that the cost of the LCRs would be essentially what they are today. But because of rules and regulations, and processes that I don't totally understand, what would normally be a 6 dollar and something or another LCR price, is sent from the CPUC to the Cal ISO, and the price is not what is the price, 6 dollars and something today. But it's cut down so that our line is evaluated on the basis of, I think it was a dollar 37. Which at a dollar 37 LCR

price, it isn't economical. It comes close, but it's not economical.

If it were properly priced, it would become economical and we could proceed to build the line that would enable 2,000 megawatts of power to be transferred into the L.A. Basin. That makes it possible for 2,000 megawatts of gas to be eliminated.

I invite you to reexamine that feature of transmission planning to see why it is that we can't make something like this happen.

I was a little surprised, Mark, with your comment about offshore wind not being understood -- or, what was the phrase that you actually used? Not proven, perhaps.

MR. KOOTSTRA: I'm not sure what phrase it exactly was, but I think it's it hasn't been deployed and shown here.

MR. MITCHELL: But if you're not including offshore wind because. And I'd just point out that, you know, we've had offshore wind in Europe since the late 1990s. On the East Coast today there's 27,000 megawatts of offshore wind that's been authorized, approved as a goal.

Now, you can say on the East Coast it's because the outer continental shelf slopes very gentle and it's

possible to have monopoles put in, or jackets, and have offshore wind built.

We don't have that luxury on the West Coast here. But what has happened and has been proven in Europe and other places in the world is that remarkably, in my mind as a non-engineer, it is possible to do floating platforms in water as deep as a mile deep, and to put a turbine on a floating platform that can withstand waves of 40, 50 feet, and winds well in excess of 140 miles an hour. And a 10 to 12 megawatt machine on top of these towers.

And the wind blows off of the California coast exactly at the time that we have the experience of the duck curve and the high demand in the late afternoon.

MS. WEEKS: Excuse me sir. We have quite a few questions to get through, so if you wouldn't mind wrapping it up shortly, thank you.

MR. MITCHELL: I'm sorry. I'm as old as Joe Biden and so --

(Laughter)

MR. MITCHELL: -- I'm sorry. Well, the point is that power is needed in the late afternoon when the solar's going down and so on, and offshore wind is a fantastic resource that the state ought to get aggressive about. So, with that, I'll close and say

thank you very much.

MS. WEEKS: Thank you. And we also invite everyone to submit written comments, if you do have lengthier comments that you would like to submit, we really appreciate that.

Also, just building on that question, we've also received a number of questions over WebEx on transmission planning generally. So, wondering if the panel can just address that more broadly and how it relates to the TTP process as well.

COMMISSIONER MCALLISTER: So, Terra, do we know if there's anybody from the ISO on the line, or I don't see anyone in the room. Anyway, just by way of reminder, you know, we are actually -- this process does consult with the ISO as well. So, the ARB, and the PUC, and the Energy Commission are the three lead agencies, but ISO's a key contributor to the process as well. So, you know, this is certainly an area that they could opine on.

MS. WEEKS: Right. And we will have Delphine from CAISO on our Session 2 Panel. I don't see her in the room, yet. But we can also punt this question to that session, if it makes more sense to address there.

MS. NAGABHUSHAN: Hi, my name is Deepika Nagabhushan. I'm from the Clean Air Task Force. A

question, two questions and a clarification. This might be a little bit of a repetition, but I think I need a little bit more clarification.

The first point is a question on including climate-related risk in the modeling. Some work has been done that shows that warming climate may reduce wind speeds and hydro reservoir volumes, and there's fire risk to electricity transmission.

So, I just wanted to ask what kind of stress testing are you planning to include in your scenarios?

MR. SAWYERR: So, currently in the RESOLVE model, with the selection of the sample datas we actually look at a variation of hydro years. So, it covers wet years, average years, and dry years. So, that sort of speaks to the understanding that we will have variation of hydro situations in the future.

With respect to the climate impacts on renewable generation profiles, we're currently using historical data in our modeling because there's really no way right now to do an analysis, a proper analysis of what exactly those climate impacts will be. Whether that's with solar generation as the climate warms up or affecting wind generation. So, for now, we're just using historical data.

MS. NAGABHUSHAN: Okay. Well -- sorry, go

ahead.

MR. GUNDA: I was just going to add to that. I think Mark, in his presentation kind of talked about some of the critical gaps in the modeling that we have. One of the things that it's trying to understand, as you're suggesting, is different variations of climate. And that's something we'll be looking into in the future, but also one of the tools we can bring into this. Thank you.

MS. NAGABHUSHAN: Okay. And then, here's the clarification question. I see that in the SB 100 RPS Plus scenarios there isn't hydrogen. But then, we've spoken about hydrogen and so I'm confused in what way hydrogen plays a role in your scenarios. Again, I'm sorry, but I had to bring it up.

MR. KOOTSTRA: That's okay. You're right, hydrogen isn't explicitly put in this stack. If it's produced renewably and it doesn't have any emission combusting out of it, it should be able to qualify, especially under the RPS Plus definition.

MS. NAGABHUSHAN: As a drop-in fuel in a natural gas-fired powered plant, okay.

MR. KOOTSTRA: It depends. If it's a mix of fuels and we have to figure out if the plant wouldn't actually be zero emissions. So, we have to figure those

types of things out.

MS. NAGABHUSHAN: Uh-hum.

MR. KOOTSTRA: Yeah, if the hydrogen's produced renewably and it's running through a fuel cell, yeah, it's going to be fine. It would be something in my understanding should quality for the RPS fill because the hydrogen's renewably sourced.

MS. NAGABHUSHAN: Uh-hum.

MR. KOOTSTRA: And so, that would be fine. If it's other situations, it may get a little sticky. But generally speaking, if it's truly renewable hydrogen, it should be fine.

MS. NAGABHUSHAN: Okay. So, on that note my next point is that we would like for, you know, you all to consider hydrogen power generation as a zero carbon source, as a zero carbon resource. And there are different ways to produce hydrogen in a zero carbon way, which could include steam-methane reforming with CCS. And coming to CCS, I just want to say that with both of these technologies, I would like for the modeling to consider cost reductions based on synergies across sectors. So, because there will be shared infrastructure and so, that would mean higher utilization rates. And so, for both hydrogen production and CCS, we will be very happy to help, you know,

participate in addressing cost assumptions just to incorporate cross-sector synergies.

MR. KOOTSTRA: Absolutely, thank you.

MS. NAGABHUSHAN: Thank you.

MR. STANGL: Good morning. Greg Stangl. I appreciate you guys and ladies laboring in the kitchen here so we can all come and critique your food. It's tough. It's a tough gig.

Is there any scenario in which the CEC is excluding or considering excluding the combustion of biogas or biomass?

MR. KOOTSTRA: Not at this time.

MR. STANGL: I hope I can clear out ten percent of this room with that question. Thank you very much.

MS. GALLARDO: All right, next we have Evan Edgar of the California Compost Coalition. And after him, Jim Shetler, General Manager of BANC.

MR. EDGAR: Evan Edgar on behalf of the California Compost Coalition and Clean Fleets. We're a producer or renewable natural gas and today that is carbon negative fuel as a transportation fuel over with the Low Carbon Fuel Standard.

Plus, as another path that's being considered by dairy to make it a carbon-negative electricity. So, the role of RNG as a resource is not explicitly mentioned

anywhere. And to follow on the question by Stangl, we should not be excluding anything with regards to RNG as a resource being available and the recognition of RNG being carbon negative today. We're talking about deep carbon in 2045 and today, with regards to removing methane from landfills and making RNG, we're carbon negative today. And to miss that opportunity and not to expand on that opportunity is a big miss.

We're keeping our near-zero trucks, the refuse fleet alive with RNG in-state. There's a mandate for 1383 to get organics out of the landfill, and 75 percent organics by 2025. And these methane landfills are a mass emitter today. So, we're doing that by 2025, getting this methane out of the landfill, put in our trucks, be carbon negative. So, the whole refuse industry will be carbon negative by 2030. That's right now, in front of us. And to leap over that to look at carbon neutral by 2045 is skipping over the best opportunity today in front of us.

So, let's preserve a role for RNG as a resource. Thank you.

MR. SHETLER: Good afternoon. Jim Shetler of Balancing Authority of Northern California. Just based on some very quick discussion with a couple of the other Balancing Authorities, I think we do have a bit of a

concern about the statewide modeling and not having a look at individual Balancing Authorities. We'll plan on providing some more specific comments on that.

MS. GALLARDO: Okay, we have Julia Levin or Levin. Is she here? Okay. Last call for Julia.

UNIDENTIFIED SPEAKER: She left.

MS. GALLARDO: She left, okay. All right, this is Noemi Gallardo, Public Advisor. I've been asked to relate a comment from someone who's joining by WebEx. Mark Roest, R-O-E-S-T. I will summarize this because it's very long and we'll put the remainder into the docket.

Mark said, "Please look at the possible extremely rapid growth of BEV sales, and conversions, and concomitant growth of distributed solar energy using both rooftops and solar canopies to meet needs of both building and all the vehicles associated with it. We will be able to support that with a suite of technologies, batteries with 3 to 5 kilowatt hour per kilogram capacity, selling at under $100 per kilogram. Mass production in two years. 48 percent to 50 percent peak solar efficiency thin film. Meet whole sale market price with ample margin, mass production in one to two years. Because the sun and wind are free and the purchase costs while continue to fall while longevity

increase, the point of cost recovery will come very quickly, more so going forward. The levelized cost and purchase price will be lower than BAU after financing is paid off for both on-site solar and BEV conversions or new purchases. This will result in adding circa 20 percent to the income available for use for each market participant from consumers to fleets. Please examine the high distributed generation with an economic motivation of getting to free energy per the above statement. It will be highly attractive when all of the pieces are in production and marketed together."

And those are all the blue cards I have. Final call for any other comments in the room. Okay, Terra, I'll turn it over to you.

MS. WEEKS: Great, thank you. So, we have received a number of comments over WebEx, but I think first we'll go to the phone. We had a couple of folks with comments, so we'll just go ahead and unmute them.

MS. MURIMI: We have Ramon Gaez [sic] -- Gamez, sorry.

MS. WEEKS: Okay, it looks like he may have dropped off. So, I'll go ahead, we have received quite a few written comments. I think I can kind of group some of them together. Again, they will all be docketed and we'll have another public comment period at the end

of the workshop today. So, if we haven't addressed your specific question, we have received it and we'll try to address them throughout the sessions this afternoon and then, again, in the public comment session.

So, there are quite a few questions around specific assumptions around technologies, including solar PV. So, again, maybe you could just speak broadly to how we're gathering the assumptions that we're using for cost of technologies. And maybe, again, Siva, if you want to just talk about opportunities for us to better engage with stakeholders on the assumptions that we're making.

MR. SAWYERR: So, like Mark has mentioned before, we're trying to us as much as possible the CPUC IRP model, so that we can have an apples-to-apples comparison between the CAISO-wide modeling and the statewide modeling.

And for the inputs and assumptions that were used in the 2019-2020 RSP, the generation data for costs was gotten from the NREL Annual Technology Baseline from 2018. For the storage costs, it was gotten from the Lazard Levelized Cost of Storage 4.0, which came out in 2018.

For this analysis, we're using the NREL ATB from 2019, as well as the Lazard Cost of Storage from 2019.

MR. KOOTSTRA: And I think, too, correct me if I'm wrong, Femi, but there is additional detail in slides that were presented and posted as part of the CPUC IRP studies. That's a good source. If we haven't explicitly said something different, chances are it's going to be very similar, if not the same.

MS. WEEKS: And can you also just speak to the specific storage technologies that we're looking at? There was a question specifically around lead acid batteries and whether that's covered.

MR. SAWYERR: So, we're looking at lithium-ion batteries and flow batteries. So, I imagine the lead acid would fall under the flow batteries.

MS. WEEKS: Great. And then, Siva, did you want to add anything else?

MR. GUNDA: Just to kind of reiterate, one of the goals of this workshop is to kind of share our current thinking, where we are going with the scenarios and the assumptions. And we're really hoping that stakeholders will put in some comments on specific recommendations on either the scenarios, or cost curves, or assumptions, or any of that. So, I just wanted to reiterate that point. Thank you.

MS. WEEKS: Great. And then, we also received a question regarding the conversation around retail sales.

So, Jeff Kessler asked: "During the CEC modeling discussion it wasn't clear if within the modeling matrix line losses would be treated as counted under SB 100 requirements or excluded? Without also modeling line loss under SB 100, it will be hard to know the impact."

So, I'm going to turn this over to Siva to respond to.

MR. GUNDA: Thank you for that. We currently are figuring out the best way to think about the supply of retail sales. That's something that the three agencies are deliberating on how best to interpret the supply of retail sales. So, the comments are welcome on that as we continue to deliberate.

One of the -- just to kind of use the words of Commissioner McAllister, one of the hopes of this report, not just for this year but, hopefully in the future, is to draw a boundary around the analysis that really stands the test of time. So, being able to analyze a variety of scenarios and to advance the public conversation on these things.

So, some of the aspects of interpretation are very easy from the bill. Some of them are not, and those are the reasons why we are putting those out there for public comments, so we can get some information as we form our consensus. Thank you.

MS. WEEKS: Great. Unless there are any additional comments in the room, I'm going to propose we end there. I think a lot of the remaining questions will be addressed during the two sessions this afternoon, and we can revisit them again in public comment.

So, I'd just like to say thank you to all of our presenters and panelists this morning. And we'll plan to reconvene in one hour, so just right around 1:10. Thank you.

(Off the record at 12:09 p.m.)

(On the record at 1:13 p.m.)

MS. WEEKS: Good afternoon everyone. I hope you all had a nice lunch. So, we are now reconvening with our two panel sessions for the afternoon.

So, first up we have our Panel on Reliability, with the California Balancing Authorities. So, this session will moderated by Chris McCLean from the Energy Commission.

On the Panel we have Delphine Hou from the California Independent System Operator, Jason Rondou from Los Angeles Department of Water and Power, Jim Shetler of Balancing Authority of Northern California, Marilyn del Bosque Gilbert from Imperial Irrigation District, and Dan Severson from Turlock Irrigation

District.

And with that, I'll hand things over to Chris.

MR. MCCLEAN: Great, thank you, Terra. I wanted to thank you all for your engagement to date and really looking forward to this afternoon's presentations from each of you.

I think if you're comfortable presenting from where you're at, we've got a clicker here. If you prefer to go to the center podium, that's fine as well.

I've reviewed some of the material. I know we're rich in slides and perhaps short on time. So, I don't want to waste a lot of it with a setup. So, I'll just note that the folks you see here on this Panel are really at the implementation cutting edge for how we go about meeting these technological challenges.

We've got a really diverse set of entities that fulfill the Balancing Authority role. Some of them serve no load. Others do have sort of both an operations and planning mandate before them. Some span most of the state, others are focused in some of the areas where the state's disadvantaged communities are really in need of a very well thought out and well discussed solution.

So, I think you'll see that as we go through the presentations today. And, you know, we'll likely hear

about new market opportunities. We'll hear about folks who stick to a good neighbor policy, which is so core to utility operations. And I think we're in for a real treat this afternoon.

Without further ado, I think we'll move through in the order that we've presented in the agenda. So, I think first up we have Delphine from California ISO.

MS. HOU: All right, thank you very much. Thank you very much, Chris. My name is Delphine. I am the Director of California Regulatory Affairs from the California Independent System Operator.

Thank you, Chair Hochschild and Commissioners for having us here, and fellow panelists.

So, we have a couple of slides, but I won't go through every detail on every slide. But I'll start off on the second slide as these were the five main questions that were posed to Balancing Authorities. And some of them, we're really excited that have been teed up because we think they are very important discussions.

So, the first one I want to go through, which some folks have seen this slide before. But as Chris mentioned, we are a Balancing Authority in California, but we do not serve load. Even though we encompass 80 percent of California load, we do depend on local regulatory authorities for resource adequacy, the

largest of which is the California Public Utilities Commission. And that's fairly important to remember because a lot of this will be about California ISO's relationship to those regulatory, local regulatory authorities and providing them feedback on reliability and trends. However, we will not be the entity in the first instance to do any sort of procurement. So, there really is that partnership and that sharing of information that has to happen.

So, the first question that we were asked -- or, sorry, the second question that we were asked was about flexible and dispatchable resources. And we are very glad to be asked that question. Because going back as early as 2012, the CAISO has really been highlighting this issue through our infamous or famous duck curve. As we're wont to say at the CAISO, we never leave home without our duck.

But that's interesting because we've really exceeded those expectations. And I'll show you on this next slide. So, what we've done here is we've mapped out from 2013 the actual kind of quote/unquote flexibility needs.

In hindsight, when you look at the 2013 actual, it basically looks like a flat line today. Whereas before, we were quite concerned about how much ramping

and flexibility we would need. Today, comparatively, it hardly even registers on this slide.

But if you look at 2019, the actuals there from the beginning of the year, we had a maximum three-hour ramp of over 15,000 megawatts. Now, going forward, we took an illustrative -- this was not approved. I just want you to know this was not approved by the CPUC, but it was an illustrative portfolio from the Integrated Resource Plan that looked at a potential build out, with a significant amount of solar and storage. And so, we ran that through as an illustrative example.

And here, we can see that potentially by 2030 our ramping needs could increase up to maybe, approximately 25,000 megawatts. That's huge. That's like over 11 Diablo Canyon's turning on one after the other.

So, those are the things that the CAISO is thinking of as we receive and see these portfolios from our local regulatory authorities, to run that through the reliability analysis to feed that back into the public sphere to say, hey, this is what it looks like. This is what our operators will be dealing with.

And so, how do we rally together to make sure that we have a reliable system for the future?

So, today, in order to meet those needs, we are

using vast amounts of both natural gas and hydro internal, and then imports. Those imports from external entities could also be comprised of natural gas and hydro as well, but those are largely the three types of resources, hydro, natural gas, and imports that we're using today for operational flexibility.

So, one thing that we want to focus on is what are we looking at for the future? And I think we're looking for resources that have those same operational characteristics to be dispatchable. But I think what we're really seeing, especially from the preliminary modeling that we've outlined here is that the models tend to drive towards a singular solution, which is a lot of solar, bolstered a little bit by short duration batteries.

And so, that brings us to the next reliability issue that we do want to highlight. Which is, if you do have that kind of portfolio mix, what do you do when you have multiple days of cloud coverage for example? And I know that's not a new issue. That's been brought to this forum and other folks have mentioned it within the context of SB 100. But we do want to reemphasize it here because part of that is looking at the modeling framework, trying to understand what it tells us, and then trying to find the solution.

And what we're seeing here is that the modeling tends to push you towards a fairly narrow set of solution points. And so, that really makes us wonder, well, if we have large amounts of solar with some batteries to bolster that, what would operating that grid in the future look like? What do we need for reliability?

But we want to maybe step back a little bit and maybe reconsider some of that premises, which is, well, it probably -- we probably don't know exactly what we're going to build out in the future because what we're seeing today is just what that model framework has told 2030 will look like. But we could be building something different. We could be doing something different. New technologies could actually develop differently between now and then.

So, our best guidance would be there probably needs to be a serious consideration of strategically maintaining the gas fleet whilst we try to figure out what those other futures might look like.

In addition, not just maintaining the gas electric generators, but also thinking more broadly about the gas transportation infrastructure. Because just as I showed on the previous graph, if you do have to have, for example gas resources ramping very hard,

that means in a short amount of time they're going to be drawing a lot of gas and a lot of pressure from the system, even if overall across the entire year the uses of natural gas has actually been reduced, as the state policy is driving us towards. So, those are just things that we wanted to think about.

The next few slides I'm putting in there as informational. I think these are slides that we've seen before. But this is the actual production data from the CAISO about the week where we had low solar production compared to a typical week where we did have robust solar production, and then the metrics behind that.

But let me focus on these last two slides. Which is, you know, where are we going and what's critical for the next 25 years. And I think, really, we need to step out of -- not that cost isn't important, but I think we need to step out of just focusing on a few simple metrics. Because it's really critical, as mentioned from prior speakers that we look at diversity, because that's probably our best bet in trying diversify not only the resources we have, but where the reliability comes from.

Right now, the simplified modeling that we have tends to give you more simplified solutions. So, if the model finds that solar is cost effective with a couple

of batteries, it will keep giving you that out of the model, because it's optimizing. It's telling you optimally this is what you should do. But policy wise, is that the best decision to have not a diversified portfolio?

Also, a lot of the easy decarbonization has already occurred. And whether that's everyone switching out to LED lights or perhaps meeting RPS up to a 50 percent level, I think we're in another step function where things are going to get increasingly harder. And so, we need to take very intentional steps to unlock that value.

And we're all for testing new technologies. But rather than, you know, doubling down and getting 30,000 megawatts of that one new technology, maybe mindfully say we're going to commit to X tranche, test that and make sure it works right. And if it's good, let's do more of that.

And lastly, I'll be remiss to not bring up transmission planning. I heard that was the hot topic whilst I snuck off to lunch, so my apologies.

But transmission planning, so what are the needs, the opportunities? Really, the opportunities that we've identified on the CAISO side is that there is

a big opportunity to potentially increase transfer capability into constrained areas. And those constrained areas are not just the local capacity areas, but those could be areas where we have significant disadvantaged communities and allow for thermal retirement.

But in order for us to do that, we do need a policy direction and sort of a mindful policy direction that that is what we want to do. Because on its own, increasing the transfer capability, again it may not be economic. But if we have a policy decision around that is what the state wants to do, we would have a public policy driver.

In addition, there is also offshore wind, there's out-of-state resources, so there are these opportunities for transmission that we're happy to look at. But ultimately, the need is from the policymaker side.

And again, to note that it's quite challenging with permitting and siting because construction and all of those issues could take ten or more years.

So, that is my ultimate slide. Thank you.

MR. MCCLEAN: Excellent. Thank you, Delphine.

I think if there are questions or comments, if there was -- from our group of panelists here, if there

was anything that Delphine touched on that you think would generate some interesting discussion here, I think I'd like to take the opportunity after each presenter to have the collection of panelists engage on that topic. So, pause for a moment and reflect.

Some of things I noted, themes I noted from Delphine's presentation are resource adequacy, ramping, flexibility and reliability in the resource base. Diversity in resource fleet. Policies around disadvantaged communities. Anybody like to comment on any of those?

MR. SEVERSON: Hi. This is Dan Severson with the Turlock Irrigation District. And I appreciate the opportunity, Chris.

I think Delphine touches on a lot of things that we will all touch on in that, you know, a one-size-fit-all approach. Keeping in mind a host of solutions to this overwhelming, but solvable problem is, I imagine, where a lot of us are coming from on these.

MR. MCCLEAN: Great. Thanks, Dan. Any other remarks from the panel?

MR. SHETLER: I'm almost willing to say ditto and let's get on with it. But, no, Jim Shetler with the Balancing Authority of Northern California.

I think you will hear themes here and we did not

compare notes before we got in here, but I think you'll hear some general themes.

I agree wholeheartedly with a need for a diverse resource mix. When SMUD launches its RPS, going on 20 years ago, one of the things we embedded in our RFPs was making sure we had a diverse mix of potential resources and didn't allow just a given resource, just solar, just wind to dominate, but to make sure that we had a diverse mix in there.

MR. MCCLEAN: Great points. Thanks Jim. Any other remarks? And if not, I'd like to welcome our next presenter, Jason Rondou from Los Angeles Department of Water and Power.

MR. RONDOU: Jason Rondou, LADWP. And I'm going to give a quick presentation on kind of the status update on our power planning efforts and how that's really been shaking up over the last couple of years. And what that means for L.A., some of the unique aspects of L.A.'s planning efforts and let's get right into it.

So, just to kind of set the stage here, we're a vertically integrated Balancing Authority. We own or control the vast majority of our generation. We've got significant transmission resources that throughout this transformation we intend to leverage to the degree that we can. Maximizing the existing assets but also, you

know, getting back to Delphine's point about diversity, not just in technology, but geographic diversity as well. Especially when it comes to solar and storage.

Our peak load is about 6,500 and our retail sales have been a little flat, so we're getting a little bit more peaky and that's, you know, obviously introducing flexibility challenges. And that's going to be something that we'll see how that plays out with electrification. We, as a city, we've got fairly aggressive electric vehicle and building electrification goals as well. So, how that unfolds is going to be big.

Just to kind of recap some of the things that we've done recently, we've got over 1,000 megawatts each of wind and solar. We're generally pretty well recognized for our local solar efforts, in part because we've got a lot of, you know, geographic land as the City of L.A. But we also have a fairly robust portfolio of local solar programs.

We just recently launched a 250 megawatt solar and storage facility, with a small, 20 megawatt battery. And we actually signed a new agreement with a very large solar and storage project that -- kind of at a record setting solar and storage price, and so that's something that we're very excited about.

All that's really led to us being comfortably

ahead of GHG projections by getting 47 percent below 1990 levels. And last year, the kind of unofficial numbers were at about 35 percent renewables. And we expect that to -- we're hoping to secure about 55 percent of our renewable resources this year under contract, to be built out over the next several years.

So, our efforts around 100 percent planning started a couple of years ago with our City Council, directing us to look into this in partnership with the DOE. And so, that's been underway for a couple years, now, and we expect to have that completed by the end of this year.

But midway through that effort, and this is something that if everybody could just try their best to read every little word on there that would be --

(Laughter)

MR. RONDOU: This is just a four-year plan of what that looked like and we're into the last year. So, by the end of this year we expect to have results. We have some preliminary results. We've looked at different scenarios. Scenarios where we call it L.A. Leads, where we over comply, where we are very aggressive in securing renewable energy. We have scenarios that comply with what we know about SB 100. And we have different scenarios that take into account

high electrification and, you know, potential, you know, higher temperatures as a result of climate change. So, we're looking at various things like that.

And in the middle of this effort it was announced last year that we would not be repowering 1,600 megawatts of in-basin, so in the City of Los Angeles generation.

And so, we suspended our traditional planning processes, where we update our plan every year, every other year as a public outreach effort. And what we are doing is putting together a ten-year plan to address the lost capacity. And we're also completing our L.A. 100 Study. And those are going to be done at the end of this year, and then we'll get back to a little bit more of a traditional planning process.

I say that but, you know, there will likely be new things that arise in the coming year, so I think that we need to maintain flexibility. Not just in our planning processes but, obviously, in the plans themselves.

So, what does that look like for us? We've adopted a number of guiding principles that we think are consistent with the overall efforts in the City of L.A. These touch on a lot of the things that I think everybody here is going to be taking about.

Flexibility, obviously, reliability and equity. So, equity's going to be very big for us as a municipally-owned utility, and a very diverse one when it comes to our customer base.

So, how are we going to do that? In the near term this is our plan for transmission. So, we've got ten transmission projects. This is really an unprecedented level of investment. You'll see the dates that we need to have these upgrades in. And this is not really new right-of-way, not new corridors, but these are very significant upgrades. These are very important projects that will help us maintain transmission reliability as we lose the in-basin capability, the gas-fired generation capability.

And you'll see the dates of 24 and 29 that align with the once-through cooling dates for our Scattergood generating station and our Hayes generation station.

In addition to that, we are investing even more money and effort into distributed resources. So, we expanded a number of programs or we're in the process of expanding them. And later this week we'll have a workshop on our upcoming DER RFP. This will be the first time that we've done something like that. And so, we're kind of in the process of trying to figure out how we can procure DERs faster than simply just doing, you

know, one RFP after another, after another. So, we're trying to rethink that and trying to modify, potentially, the way, you know, we simply approach it just so we can get these resources in faster.

We're also making investments now in hydrogen. So, at the Intermountain Power Project we have committed to doing 30 percent hydrogen when those projects come online in 2025. In addition to that, the compressed air energy proposed project we have, we intend to have 100 percent hydrogen at some point in the future. And when that point is in the future remains to be determined, obviously, because we've not done that before.

But we say this because this, again, getting back to leveraging the existing resources we have for our clean energy future but, you know, making the investments today in order to get there.

And so, this really doesn't get at one of the chief challenges that we have, which is local long-duration storage in the City of L.A. And so, the makeup of the city is such that we import a vast majority of our renewable generation, our base load generation, and our pumped storage capability through the northern part of our city. And you can't really see it here very well, but we have three transmission corridors that bring in power to the City of L.A. And as we lose

resources in the city, we become more and more reliant on external generation. Which is great, we can get low cost renewables. However, when we do modeling, you know, we can show that we're reliable, we can show that we're resource adequate, but it introduces a resiliency challenges that -- getting back to the qualitative versus quantitative approach this is something that's very important. And it's going to be probably assessed qualitatively, because I'm not aware of a way to address that quantitatively.

So, the case study that we have here is the Saddle Ridge fire last October. It happened the day before October 11th, in the evening, and our peak load was about half of what it typically is. And we lost import capability on all three of the lines. Two were completely down and one was significantly reduced.

And what this resulted in is us being about 135 megawatts away from curtailing customers. So, we had about 135 megawatts of in-basin generation to work with. And so, luckily, we did not. But that's happened before. About ten years ago with the Sayre fire, we did lose customers.

So, again, getting back to planning and looking at securing resources, and maintaining transmission reliability, this is an area that I think we need to

make sure that we don't lose sight of. And try to figure out, if not quantitatively, how can we make sure we very seriously address this and try to make that very much a part of our planning process.

And we intend to do that with our future strategic resource, long-term resource plans where, you know, we have different scenarios that say X percent of renewables by certain dates, reliability, we have cost. And we don't have an assessment of what resiliency is. And we intend to do that, again, as part of our planning processes and we think that would be important here.

So, we've kind of summarized our takeaways and I think a lot of these get back to the questions that we've been asked. So, not just four-hour storage. That's going to be very important, the long-duration storage.

We're looking at interesting things like liquefied air storage that might be able to provide 10, 12 hours of storage, as well as hydrogen. But again, getting that long-duration storage in the City of L.A. to be able to mitigate some of that geographical risk of importing renewables.

So, I will leave it there.

MR. MCCLEAN: Excellent. Thank you, Jason. That was a really full set of challenges that L.A. is

facing and it looks like given the work of L.A. 100, other efforts that you've got, you're well underway. But I think I'd like to hear whether or not any of the other panelists found some commonalities or differences in what they saw from Jason's presentation. Any extra thoughts sparked there?

Hearing none, I think I'll perhaps query this. The L.A. Leads-based work, did that get into much of a transmission expansion consideration or did that leverage sort of existing or planned projects?

MR. RONDOU: I think any scenario is going to call for a significant amount of transmission, whether that's for the next ten years or for 2045 time frame.

There are some -- I'll give you kind of a ballpark dollar figure, and this is very preliminary. This is something that is -- you know, these are preliminary numbers, but it gives you kind of the range of capital investment that we would have to make over the next 20 or 30 years.

Just simply complying with what we know about SB 100 would call for an investment over 20 years of about $35 billion. And again, these are preliminary results. We still have to work with NREL to complete this. Under a scenario where we are very aggressive that doubles.

So, I think it gets back to how can we make the

most impact on GHGs and not chase some of the sort of interim targets as well. So, and then that gets back to -- that translates into rates and how are we going to spread that rate recovery across customers that are very different in the City of L.A. in terms of income, in terms of, you know, climate, in terms of, you know, size of housing, in terms of commerce, and all of that. So, it is a very, very serious challenge, but an exciting one.

MR. MCCLEAN: Great. Really appreciate that insight, thank you. Yeah, go ahead, Delphine.

MS. HOU: I have a question for Jason. This is Delphine from the CAISO.

So, I was curious, aside from the retirement of Scattergood, Haynes, and then the transmission project upgrade, what other -- and I apologize, I haven't read through any of the plans. But what other considerations did L.A. have for maybe disadvantaged communities or environmental justice, in that vein?

MR. RONDOU: Yes. One really interesting challenge that arose after we did some modeling where we said, all right, if we decommission the 1,600 megawatts of combined cycle, and some of it's fairly new, some of it's 15 years old, it's relatively more efficient than some of the other generators that we've got, what would

happen. And we modeled it. And it would require relying on the next most efficient unit, which is at our Valley generating station, which is adjacent to several disadvantaged communities. There's a lot of environmental justice issues in that area. And so, now, we'd be asking that part of the city now to shoulder a greater share of the burden.

And so, what we've done is we said, well, we can't sort of accept that. So, we've added that as part of our planning processes to try to figure out how we can come up with scenarios that do not require us to fall back on that. And that could mean looking at alternative ways to maintain existing resources. Not repowering, but potentially doing things like wet cooling of 15-year-old, again, relatively new and efficient units.

But we also have what we call our equity metrics. And it's an initiative that we have that we run through every investment that we make in our city, whether it's a transmission -- sorry, distribution upgrades, power system reliability, customer programs, solar, energy efficiency, we look at it through the lens of where is that money going in the city? And how is it -- is it concentrated in areas of affluence? Is it not? Things like solar and net metering you could expect

would happen more often than not in middle class and, you know, more wealthy neighborhoods.

And so, we've made tweaks to our programs to help try to promote them in areas that otherwise do not get the same level of participation. So, it's not just sort of a principle of ours, we've actually tried to actualize that in our planning process. It's not perfect and we have a lot of work to do, but it's something that is absolutely on our radar.

And the last, I'll close this out by saying our advisory group for our 100 percent study includes 40 advisory members that span all stakeholders in the city, from universities, from the business community, from environmental justice, and many others as well. So, we never lose that perspective through all of our planning processes.

MR. MCCLEAN: Great. A really valuable discussion. Thank you all.

I think we'll move on to our next presenter, Mr. Jim Shetler. Thank you.

MR. SHETLER: Thank you. And I'm pleased to be here today. Thank you for having me.

Maybe a little quick overview of BANC. Similar to the ISO, we are just a BA, we're not a load serving entity. I have six members, SMUD, Modesto Irrigation

District, City of Roseville, City of Redding, City of Shasta Lake and Trinity PUD. All of them are vertically integrated, publicly-owned utilities, load-serving entities, where they do their resource planning.

We also have within our footprint the WAPA Sierra Nevada Region 230 KV transmission system. And then, the transmission agency in Northern California's -- the California Oregon Transmission Project, one of the 500 KV interties to the Northwest.

We are about a 5,000 megawatt peak Balancing Authority, which is about midsize for the western interconnection.

So, I have a little introduction. Number one, in talking to my members, clearly we are supportive of the goals of SB 100. But I think in the near term, we view that as a net zero carbon basis to get there. My members are very strong in their belief that balancing the carbon reduction, or the reduction has to be balanced with the equally important goals of safety, reliability and affordability.

And into that, previously we also believe that there needs to be a very well thought out transition plan. We need to understand where we're going, how we're going to get there, and that the resources that we are bringing online are proven before we take off

resources that we know can do the job.

And then, we're also, and I'll pick on SMUD on this, over the next horizon here, the next 20, 25 years, we feel when we talk about decarbonization we've got to look at transportation and the building infrastructure where the biggest bang for the buck is.

Certainly, electricity is still at 15 percent, but we have to be careful how we move forward with that.

Referencing, now, some of the questions on reliability and resource adequacy, polling my members, right now if we look at the next 20 to 25 year horizon, thermo and hydro capacity is on the table. I want to make that clear that we are looking at continuing to use thermo and hydro capacity to meet our needs.

Appreciate the fact that the join agencies have included in their RPS Plus large hydro. We view that as a very valuable resource and we want to make sure that continues.

Now, when I say we're going to continue to have capacity from natural gas generation, it is at a much reduced capacity level. Currently, we're averaging about a 70 percent capacity factor on our natural gas generation. Our current forecasts are somewhere in the 20 percent range over the next to -- ramping down to about a 20 percent capacity factor over the next 20

years.

Now, over that time period certainly we'll be adding renewables and we'll be adding cost-effective storage. And we'll also be evaluating other technologies as they come online. And as they get proven, we'll be looking how to include those in the resource mix.

On flexibility and dispatchability, obviously we need resources that can manage real-time fluctuations in the intermittent resources. Similar to the ISO, though right now we're not as big a duck as they are, we do have morning and evening ramps we have to deal with.

And then, into that, or mentioned earlier there needs to be available capacity and energy that can deal with low solar and low wind production periods. And based on my history in California, we're talking not days, we're talking more like -- or talking more days and weeks, not just hours. And so, we need to look at how we do that.

And I appreciate the fact this was mentioned earlier by staff, but we do believe that we need to look at low hydro events when we're talking about studies.

On challenges, obviously coming up with the resources that meets today's capabilities is what we're

looking at. How do we ensure that we have that we have frequency, inertia and voltage support in the system if we do away with thermal units, and then the long duration capabilities.

Considering critical innovation. Again, I'm not going to prolong it. I mean, long-duration resources are key. We also feel that we need to be evaluating alternative fuels, renewable gas. We, too, are interested in hydrogen as a combustion resource.

And then, as we look at this, and this has been hinted at in prior conversations, we have a pretty major R&D investment in front of us, as an industry. And we think this is probably a global issue that needs to be dealt with. These are huge dollars that we need to consider how to come up with and invest.

And then, relative to transmission planning, as we retire the thermal units in their locations, and ramp those down that will change transfer capability within the western grid. We need to understand that. We still have the same import capabilities we had prior, now, or not. And I think it does argue for broader regional planning. I know some may say, well, that means we need to have an RTO tomorrow. I'm not suggesting that. But I do think there can be more consolidation of planning around the regional planning groups and coordination

among them.

And then, on modeling I want to focus on the second bullet, which I know will be very popular in this room. But we feel pretty strongly that if we're going to look at all the scenarios and we're going to look at all the possibilities of what the future may bring to us, we need to at least understand if we have a high electrification penetration, but we're still needing low levels of combustion resources to maintain reliability what does that look like? What is that carbon footprint?

And so, we would argue for at least looking at that with, say, a 20 percent capacity factor as a reference point.

With that, I'm done. Any questions?

MR. MCCLEAN: Excellent. Thank you, Jim. Anyone from the panel have points that they'd like to dive a little bit deeper on with Jim?

MS. DEL BOSQUE GILBERT: So, Jim, I think we echo a lot of the same responsibilities that -- this is Marilyn Gilbert with the Imperial Irrigation District.

And especially when you mentioned about the flexible dispatchable resource needs for the grid reliability, and those are some of the things that our operators are also experiencing. But I think everybody

in this room probably are echoing the same thing. But I just want to say that you touched upon a lot of the things that we would also be concerned as well.

MR. MCCLEAN: Great. Thank you, Marilyn. Any other remarks from the panel? I'll throw one at you, Jim.

Maybe for the benefit of the audience you might be able to maybe offer up a thumbnail sketch of some of the visions of the regional planning, how that might go. So, RTO is one path. Could you maybe pull back the curtain on what some of the alternate paths might look like?

MR. SHETLER: I think there is probably several alternatives. I mean one we're seeing in the northwest right now, where you're seeing Columbia Grid and Northern Tier combining into one regional planning group. So, I think that's an example. Is there potential for the remaining regional planning entities in the west to consider consolidation?

Another one that I have a reference to and some of you in the room may remember this, we used to have a California Transmission Planning Group that was formed by the IOUs, and the publicly-owned utilities in California. And we retained our individual responsibilities, but we opened up to each other. We

did joint planning together and looking at where those projects might be. So, I think there's also an ability to do more facilitated coordination among the regional planning groups. That may be the first step.

MR. MCCLEAN: Okay. And then, so I agree that that may have legs. To the extent somebody was going to lead on that, do you think that ought to be something that arises from a group of peers or should it be more of a directive from, say, a policy or regulatory agency?

MR. SHETLER: Well, I think probably the one problem you would have is the joint agencies don't have a whole lot of authority over the rest of the west. So, I'm not sure a directive would be the approach.

But I'll use the EIM reference. And if you look at the Energy Imbalance Market, you have a very diverse, broad group across the west, publicly-owned utilities, investor-owned utilities, Northwest, Southwest, California, and what's driving those entities together is the understanding and the need for facilitation on managing the intermittent resources and renewables coming at us, and the carbon goal that many states are putting in place.

So, I do think that driver coming from a peer group is probably the best way to go.

MR. MCCLEAN: Appreciate the insight. Thank

you, Jim.

All right, I think we'd like to turn to our next presenter, Ms. Marilyn Gilbert.

MS. DEL BOSQUE GILBERT: Thank you for inviting the Imperial Irrigation District to be part of this important panel. We truly appreciate the opportunity to be here to speak before you.

My name is Marilyn Gilbert and I oversee the Energy Department. And I'll be providing you today a brief summary of IID's service territory area and what IID has done today as a Balancing Authority, and comments on the plans to accommodate those additional renewal resources that we are seeing in our service territory.

IID's electrical service territory area, this is a brief overview of where we are. This slide represents a brief summary and its demographics. IID is a Balancing Authority that serves about 156 electric customers in both Coachella Valley and Imperial County.

In 2001, IID adopted the open access transmission tariff to facilitate the interconnection. Currently, there are about 1,100 megawatts and interconnected resources consisting of small hydro, geothermal, biomass and solar.

IID's service territory has a vast renewable

resource availability, including geothermal. IID's territory is also home to the Salton Sea known geothermal service area, consisting of a potential resource of over 2,000 megawatts that can help our other utilities in the state meet their SB 100 goals. If the state considers providing incentives to provide flexible geothermal and reduce costs, IID can offer a great opportunity to offer some of the core issues that are being discussed today.

About our demographics, the majority of the customers are residential, about 86 percent. We have commercial 13 percent, and very few industrial, .5 percent.

There is a high employment rate in IID's service territory and approximately 15 percent of IID customers are receiving rate assistance.

Last year, IID commissioned a 30 megawatt, utility scale community solar program known as the Citizens E-Green solar to serve IID's low income customers. IID continues to explore the possibilities of another utility scale project designated to serve low-income customers, such as a storage project. And we serve a disadvantaged community and our comments reflect that because of our customers. Because we don't want to do anything as a Balancing Authority that is going to

affect our customers.

So, here in this resource mix where we're at, I wanted to give you a little bit of where we've been and where we're going. So, back in 2008 we were about heavy on the resources that were not meeting RPS compliance. So, IID has met and exceeded all of RPS in Cap-and-Trade requirements and plans to be in compliance and committed to implement the state goals.

In 2008, we were 73 percent of IID generation was from non-RPS compliant resources. By 2030, we'll be approximately at 60 percent.

As demonstration in the progression of the pace over the past 10 years, IID has made drastic changes to the resource mix. We had an early exit of the San Juan Coal, which occurred on January 1st, 2018, and it used to provide about 20 percent of IID's requirements. IID lost about 25 years' worth of equity payments, consisting of about $10 million per year in order to apply with emission rules. Ninety-nine percent of IID renewables are located within IID service territory.

IID retired all burn units with high greenhouse gas emissions. We invested in the Niland Peaker units and a (indiscernible) three repowering to lower emissions for the gas units. And we also made significant transmission system investments primarily

used for renewable energy transmitted to other parts of the state. IID has also incorporated additional emission consideration for hourly dispatch formula.

As a Balancing Authority, we actually see extreme weather conditions. As you can see from this chart here, our summer peak load is -- it's about 1,067 megawatts and IID's winter load is 209 megawatts. Our average winter load is at about 320 megawatts. So, a lot of our generating resources are sitting idle a lot of times of the state. So, we're looking into opportunities to potentially over those resources to other parts whenever they're sitting idle.

IID has recently hired Black & Veatch to model existing generation and options for meeting SB 100 goals, and have previously commissioned other studies that had looked at various alternatives to meet the SB 100 goals. We are committed to providing these.

Other challenges include high potential debt required to meet the plan, high overall costs to meet SB 100. Uncertainty in rule definitions like zero net carbon, and uncertainty in overall rules over the next 25 years. Mandates that are passed through to our customers sometimes don't work well for us because our IID board is very sensitive to the rate increases because of the serving of the 156,000 customers we

serve.

These charts an average representation of the IID load. The integration of renewables has impacted the load profile and the shift and the changes are also due to customers' activities, which are non-controlled on an hourly basis. The actual daily profile is very volatile and we continue to grow in volatility in higher intermittent resources and resource supplies, and the uncertainty of customer programs impacts.

IID has mitigated these challenges by becoming more nimble in operations and we'll continue to look for greater flexibility resources for the next 25 years. We try to optimize the delivery of our resources from the IID system. Many of the decisions made today can turn very costly with us if we don't thoroughly think things out. And I think some of my other counterparts have already mentioned that. That we are very -- we're trying to do the best that we can with the resources today.

We have seen a resource shift and IID has experienced a resource shift, and with that shift there has been a transition from thermal to variable and energy-limiting resources. This shift in resources that do not contain fuel sources that can be controlled is adding another peak load to our service pockets and can

increase or decrease at any given moment. This shift to these resources without (indiscernible) increases reliability to the risk, and this type of supply resource planning is difficult and costly to manage as a Balancing Authority. And since it's adding to an already uncontrollable activities that are occurring on the demand side. A greater percentage of error between the long-time, daily, hourly, are occurring.

The currently lack of cost-effective technology solutions to replace the gas-fired generation is a challenge. And IID's evaluating areas where technology is improving and costs have decreased. IID is risk adverse to new and unproven technologies and we are currently evaluating the EIM (indiscernible).

The resource shift that has identified the need for flexible and dispatchable resources needed for grid reliability.

IID is not alone in managing real-time fluctuations with the intermittent renewable resources and this challenge is specifically seen in morning ramp, as some of my other counterparties have also mentioned.

This is a slide from our 2018 IID study, which shows the difference between the capital investments. When IID's load is more volatile on the supply and demand side of the meter, IID requires greater

investments in generation, and transmission, and distribution.

Currently, Black & Veatch has been hired to evaluate IID's fleet and other energy resources and plan to make recommendations for the IID transition plan for the next 20 years. Their study will be inclusive of alternative fuels integration as part of the generation needs. And the results will not be available until the late summer.

The first of the report has analyzed the historical forecasted performance on O&M cost, CAPEX, and they have already made suggested adjustments to the dispatch parameters where they deemed necessary.

Some of the SB 100 cost challenges. One of the biggest concerns for IID is the retirement of generation that's before the end of their useful life. IID has existing debt services obligation. IID is in the process of quantifying its remaining fleet replacements costs, and preliminary results indicate that the replacement of the existing units with more reactive and flexible resource will result in added costs.

All of these costs will be pushed back to the 156,000 customers, causing rate increases, and IID's low-income customers will suffer the greatest of negative impact. The retirement of these units will

drive the increase for balancing and ancillary services as well.

IID can help reduce these to other California utilities by using IID's willing and resource availability. And we continue to support for geothermal and grant program will benefit the state as a whole and possibly expand to the added subsidies on flexibility for geothermal and geothermal demonstration projects.

Additional long-term challenges that we are seeing is the cost burden of new resources, in transition investments required to build the new resources, and transmission is a factor.

The additional rate increases on IID customers because of where we're located and also our demographics.

Uncertainties in resources procurement and capital investments due to the potential loss of load in the Coachella Valley portion of the IID system at the end of its contractual term is also of great concern for us. The contract ends in 2033 and accounts for approximately 60 percent of the load.

Challenges with the demand side uncertainty and constantly changing landscape is also something for us to -- that we are concerned about.

IID's service with flexible geothermal could

also offer solution if technology improvements and cost risk are reduced.

The timely supply of resources properly can be difficult due to so much uncertainty in load growth, customer program participation, and effectiveness, intermittent uncertainty, and political policy shifts and weather-based impacts.

As far as energy storage and IID's future plans, IID invested in a 20-megawatt hour, 30-megawatt battery in October 2016, and the largest of the battery storage systems at that time. The battery energy storage system provides great ancillary service, such as frequency relation, backup electricity, peak saving and load shifting. However, right now there's only -- we primarily use it for balancing our service system.

Since many of these uses of storage are multiply inclusive of one of those uses, a moment's use of one may create another situation where the storage isn't yet ready to use for another subsequent event. IID storage appears to be helpful, except when adding a Dutch installed technology, or adding storage too soon prior to the intended use in a timely manner.

Careful planning of the storage limitation must occur. IID views storage as a possible solution to solve imbalancing issues with intermittent resources

within its IID Balancing Authority. As part of our studies, IID has had -- if IID had greater capacity for storage, the storage system could absorb the excess generation in the morning as the solar plants come online, and then disperse it as they go offline.

Our ratio of solar to capacity is disproportionate at this time.

Future IID interconnections, to give you an idea of where we are and the amount of interconnection we're seeing of our service territory, interconnection requests processes into IID open access (indiscernible) are approximately 2,325 megawatts. Those consist of 250 solar, 550 geothermal, 1,525 of combined solar and storage. And the majority of the queued projects are intended to export from the IID systems, which will have significant transmission planning for that area.

Because of that, then our transmission planning challenges we are facing with an aging infrastructure. The IID's battery sources experiences about a 10-megawatt hour cooling losses for its 20-megawatt system. High ambient temperatures affect efficiency of all of our resources, started at temperatures above 110. We experience sometimes temperatures up to 120 in most of the summer, so at that time we're already seeing inefficiency, so we need to plan for those resources.

What future technologies can avoid these issues? IID is researching the various technologies to make sure the specifications do meet operational expectations. IID can protect within the cost (indiscernible) to ensure contractual requirements are properly defined. However, we need to make sure that technology performs as intended to avoid reliability issues.

Planning in contingencies are crucial to integrate and maintain the system of reliability. We may consider in the future considering programs to ensure that the batteries do perform how they're intending to perform. And if not, we're going to end up adding double of the amount that we need because of the inefficiencies our system is experiencing.

As earlier mentioned, there is a potential for large-scale structure additions within the IID due to the renewable potential footprint within our service area. Geothermal, solar and storage.

From an operational perspective, as each project achieves commercial operation into the IID system there's a lot more manual interaction with the balancing and load in the generation due to the integration of intermittent resources. Operators have to closely monitor the system balance of solar resource to ramp up and monitor down.

Investments are required to automate the system, this more manual process, and we're looking into doing all of that.

Additional transition challenges. Installed energy storage is key to minimize the impacts for our customers. Energy storage is planned to be used to defer any reliability upgrades. Our challenge is when to trigger those installations to minimize the impact and get the best dollar for what is affordable to the IID.

Additional transition planning challenges consist of maintaining the system reliability when impacted by demand side, demand composition. The desert southwest has a high penetration of single-phase motors, which represents the air conditioners and at that time that's causing issues.

The WECC Phase 2 has composite load showed us that there might be some reliability issues, too, because of that.

We have also looked into low load, high renewable export scenarios, geothermal, solar production, exports increasing from the area. The system has assessed multiple different areas in there and we are looking into adding approximately in the area about anywhere between 1,500 to 2,500 of integrated

renewable energy.

With that, just in the transition of load could be 300 million to 500 million of infrastructure, plus adding remediation action schemes.

Based on the existing forecast, there is an increased activity for geothermal resources in IID's service area.

In conclusion, IID's requesting to add an additional planning modeling scenario for geothermal resources, including the sensitivity scenario for resources within IID's service territory to be exported to the rest of the state out of its Balancing Authority.

Thank you very much and this concludes.

MR. MCCLEAN: Very good, Marilyn. Thank you for that presentation and, again, I think we here at the Energy Commission, staff would extend our thanks for IID's engagement in the IRP process. I think we're pleased with the way things are going. And again, thank you for being here.

Any questions for Marilyn from our panelists? Hearing none, I'll turn it over to Mr. Dan Severson to close us out here.

MR. SEVERSON: Kudos, Marilyn that was impressive. I'm going to try and be brief here. I now it's we're pressed for time, and so I'm going to quickly

run through my slides here.

My name is Dan Severson. I'm the Assistant General Manager of Power Supply. And why they sent the markets guy to speak on behalf of the VA, I don't know, but they get what they deserve.

So, about TID. First irrigation district in California by one week, where we're one week older than Modesto, and we proudly shout that from the rooftops. It's the bane of their existence, but it's very much a source of pride for us.

We are -- similar to other panelists, we are locally owned, like L.A. and IID. We do serve load. We are a small Balancing Authority, so we have a lot of the same challenges that they do. We are -- we were founded in irrigation water. You can see there we were founded in 1887. We provide irrigation water to over 4,500 growers and almost 150,00 acres. And so, our stewardship along the Tuolumne River kind of drives who we are.

We decided to build some generation along the river. In 1923 we put a power plant at La Grange. And that started our journey into the electric retail business. And today, we're just over 100,000 retail electric accounts.

So, like I mentioned, we are an independent

Balancing Authority area as of 2005. That was mainly driven, full disclosure, by the energy crisis. We were subject to rolling blackouts. Our ratepayers took it upon themselves to insulate themselves from that. We invested the money in the infrastructure to become a Balancing Authority to mitigate those issues. Now, has it been perfect? No. Have we learned a lot? Absolutely. And so, in that vein we realized pretty early on we needed to build a diverse portfolio to spread not only the costs around, but the risks around serving load.

It was pretty well recognized early on that the way people were using energy was changing. And so, there's a list of our resources there. And similar to L.A., you'll see a majority of it, and in fact if not all of our -- just about all of our RPS portfolio is external to our BA. And that's both good and bad.

So, you touched on the disadvantaged community aspects of local benefits, and the local air quality, but there's a cost benefit. And so, to date we've taken an approach from our RPS procurements that we were going to find out the absolute cheapest way to comply as possible.

Our most recent acquisition was the 54 megawatts of solar there. That's down in Kern County.

And really, our area is -- it's okay for solar. It's not good for wind. The radiation is just better down in the desert. And there's a huge price break, especially when you get to the utility scale in the further south you go.

So, peak load of about 600 megawatts. Thirty percent RPS eligible, that is not our RPS percentage as to serve load. But I don't want to confuse anybody, that is just our -- that's a calculation on installed capacity and over 50 percent carbon free, again by installed capacity.

We do share a tie with the Cal ISO and with BANC. And we are joining EIM. We've decided to move forward with that. We'll be going live next April.

So, this slide, the takeaway here, customer owned solar. All of these slides have been taken directly from our IRP, by the way, to they're readily available on our website or the CEC website.

This is a projection. The bottom line you see there is capacity and the yellow line is the expected generation, of the customer-owned generation forecast.

And one thing I think I failed to mention about our nature as a BA is we have one -- we don't have an -- we have one large full requirements customer to the south of us. And we don't have any third-party

generation. There's nobody knocking down our door to buy our transmission, yet. It's a hurdle we haven't had to cross, yet. Now, joining EIM we're kind of reevaluating that.

So, to the extent that you look at this slide, roughly 40 megawatts installed as of 2018. About double that projected for 2013 [sic]. And the generation is 144,000 megawatt hours. That's less than one percent of our annual energy needs and less than 7 percent of the installed capacity on our system.

But I guess what I'd like to highlight is this is what it does. And so, this is our take at our load shape and how it's changing. To your left is, I believe an April day. I didn't bring my glasses. And to the right is a July day. You'll see in 2016, on the left, in April the significant -- and even though it's just one percent of our energy needs, it's when that energy comes that's the significant driver of these ramps that we're seeing.

So, the ramping is the takeaway on the left side. The right side, there's a pretty discernible shift in peak from earlier to later. All driven by multi-solar.

You know what, I need to -- so, I'm going flip around. I put these out of order. So, some of the

ramping challenges that that drives. This is our average three-year load decreased by month of 2017 versus 2030. The 2017 is the solid orange bars. 2030 is the shaded area there. And you can see the incremental challenges of our ramping. And that it is really representative of the slide before. And then, these are the challenges up.

It's more tailored to the peak months, whereas the ramps down are more tailored to your shoulder months and the light load areas.

So, our current renewable portfolio is depicted there. The takeaway here, the gray bars that we're filling in, in the early 2020s is based on our early action by buying the wind farm in the northwest, Tuolumne Wind Farm that it has grandfathered status. And that's why I think most of you at the Commission have seen us up here pounding the table for fair regulatory treatment because we were early actors, and it was a significant part of our ratepayers' investment, RPS wise.

The Tuolumne Wind Farm, just for perspective, comprises around 80 percent of our renewable portfolio.

Moving forward, this is our plan. To comply with SB 100, we're going to have to add the equivalent of 100 megawatts of solar in 2025 and 2029. Now, the

600-megawatt BA, there's some challenges with that. We're either going to have to source it outside of the BA, or to be able to source it inside we're going to have to put some prohibitive requirements on them, as far as the developer to come to the table with ramping and storage capability. All of which we're looking at. We're very much focused on having a discernible NBA option to the extent we can.

And it's not say that, you know, RPS is not the only answer. We're not going to hit our goals RPS alone. I think it's fairly well known statewide that utilities have done their share, and beyond in emissions reductions and we're happy to continue that trend.

And like someone alluded to earlier, a lot of the heavy lifting has been done. And so, it's those last increments that are the challenge.

I took a stab at answering these questions, I think. So, the first one, how are you planning for reliability and resource adequacy?

So, with every increment of solar and wind that comes on the system the capacity value go down. And it's counter intuitive -- and I think it's a little bit of an unintended consequences from the policy and a little bit of the unmitigated proliferation of solar and wind on the system.

And I have an example here. That 54 megawatts of solar that we added to our portfolio, in the NQC, the net qualifying capacity, which goes against our RA requirements, was cut by roughly 40 percent from one year to the next, as solar came in.

And so, while it's a small part of our portfolio, it's a large cut for a system that small. And it doesn't mean that we're short capacity, it just means that we are having to procure RA that we didn't necessarily plan on.

As far as flexible dispatchable resources, we do have 200 megawatts of large hydro. It's fast ramping. It's carbon free. It's very much the heartbeat of our BA. And to the extent that the market can recognize the ramping capability, the zero carbon attribution, and unlock the flexibility that we have -- granted, it is somewhat river dependent, but we're looking at some pretty significant investments in not only upgrading those facilities, but upgrading the ability to move. And I think it can be a very much vital part of hitting our greenhouse gas goals.

And we are looking at storage. Storage is, as everyone alluded to here, it is coming down quite a bit. It's really on the cusp of making sense financially to do something that we otherwise would do. And so, we do

plan on adding a storage pilot here in the near future, per our strategic plan.

Twenty-five year view. Available balancing capacity. This is something that we see as a real problem. As more variable generation comes on the system, less base load is around, and balancing capacity there's shortages. I think there's multiple reports here, recently, that have pointed to that.

One example of that is we do -- our wind farm is in the BPA Balancing Authority. There's been a -- quite an effort of wind farm owners up there to move their wind resources out of BPA because their balancing resources are run on the river they're highly seasonal. There are times where we're put on the back burner and we're curtailed. And so, we recently put in motion a project to move that -- move our wind farm dynamically into a more wind friendly BA that is committed to making wind work.

Technological storage, cost and performance. I think there were some skittish people in the industry after the fire. To the extent that they can mitigate that and that lithium-ion can improve their -- or overcome those PR issues would give us a little more confidence.

Smart grid technologies to leverage demand

response and aggregating load to better match generation would be very helpful.

And then, on the transmission front, we do have quite a few transmission assets that are somewhat constrained in that there's differences in -- there's the operational themed issues, where one set of transmission, and I'll just be -- as an example here, we have transmission rights from John Day to Captain Jack that tie into our tank transmission. And those two scheduling paradigms don't necessarily coalesce. And it makes for some stranded transmission. Some of which, and a lot of which we think will be mitigated and improved by EIM.

So, that's all I had. I tried to be short. And I'm happy to take any questions.

MR. MCCLEAN: Great. Thank you so much, Dan. I think as we, you know, get started on this process and we have years ahead, I think working together and leaning on your history with the water/energy nexus, and others similarly situated, I believe there will be tremendous value in that moving forward.

Any follow on from the panel for Dan? Seeing none, I'd like to pose to the dais any exchange or you're interested with the panel here?

MS. HOU: I had a quick question. One of the

RPS Plus resources that we are talking about in this report is gas-fired generation with carbon capture. Are any of those of you who are load-serving entities, have you looked into that at all? Okay.

MR. MCCLEAN: Okay. So, I think there will be an opportunity for public engagement, I think later in the afternoon. But while we've got the panel here, we did have a few questions come in over the WebEx. And I'd like to maybe address those before this panel breaks.

One from Habib Maiga: "Can Delphine expand on what is needed by the policymakers, which is not already available in the IRP results?

MS. HOU: Sure. I can provide a little bit more detail. Sorry, let me get back to a couple points. So, let me start where I think we can -- the last slide that I have about transmission opportunities, for example.

So, first of all, the very first opportunity that I described was looking at local capacity areas. So, that's something that the CAISO transmission planning process has already taken a stab at. And what we've done there is there are certain local capacity areas that we have to protect for. And I think it's very similar to maybe what Jason was saying about L.A. is that, you know, you're trying to reduce some of the

capacity you have in your footprint, and those are older -- maybe, potentially older resources.

So, then what happens is you're dependent on a lot of imports coming in. But you might run into a scenario, like with the Saddle Ridge fire, where you aren't able to import as much as you would like. And so, that leaves you in a vulnerable spot with your local capacity area, you're constrained.

And so, there's various pockets of this within the CAISO footprint where we have local capacity areas that are constrained and how much transfer capability you can get into those areas.

So, then what happens is we say, well, since you can't get enough energy into those areas, then we have to retain the capacity within those areas so that we can serve the load. But some of the capacity in that area are potentially order resources. They could be in disadvantaged communities. There could be other, you know, emissions or environmental justice concerns. But then, you end up in this stalemate where you can't let go of the resources because of liability, but the community there obviously does not want the resources there.

And so, the consideration would be at minimum let's have a conversation about what a future would look

to enable some of those maybe older, you know, heavy emitting resources to retire. But it's not just about going and shutting those power plants off. It's about what does the transition look like? What resources take the place of those existing, let's say, high polluters? What are the reliability services that you might need? It's not just the energy. It could be, you know, as other folks have mentioned you might need frequency response or inertia within those localized -- or voltage support within those localized areas. Or, it might even be, you know, opportunity for a transmission solution.

So, all of those are on the table, but I think we need to start having that conversation. And I think the reason why the CAISO brings that up is because both the IRP and SB 100 are focused at the system level. So, they're -- at this early stage we haven't really delved very deeply into localized areas. And so, that's where the CAISO has, at minimum, taken a stab at doing some analysis in our transmission plan. And we're hoping that with both SB 100 and IRP is that we start kind of moving closer towards each other to bridge that gap, and trying to come to an understanding with that solution.

So, I would say that was kind of the first, I think opportunity that we have to work together.

And for the other resources, offshore wind, out-

of-state resources, you know, some of that is picked up in the IRP. But I'll note that the IRP itself is remaining open to those options. And so, we'd like to have a conversation around those as well.

MR. MCCLEAN: Great, thanks for that color, Delphine.

There was one more set of questions from the line. These were posed by Edward Smeloff. I'll just open it up to the group and then there's a few specifics.

So, this would be to the panel in general. Will the SB 100 report have a specific section to address issues and potential solutions for disadvantaged communities?

And so, I think as we intend to seek consultation from the Balancing Authorities, any comments you care to add on that, whether you expect or require seeing something like that in the final report. Interested in your consultation at this time.

MS. DEL BOSQUE GILBERT: I'll go ahead and respond a little bit to that. I think part of it is we do represent a large of the disadvantaged communities, and we would like to see at least there was something being addressed, and maybe consideration for some of the different resources to also be applied as part of the

solution here.

Either it could be that there was additional ramping opportunities for utility-scale solar specifically for them, or batteries, or other types of solutions for disadvantaged communities. Because anything that we do as a Balancing Authority does affect our customers. And in order to pay that, there has to be a rate structure. And we do not want to have them increase on any of those costs.

So, to answer the question, I would like to see consideration and we would work with our staff to be able to provide some of that information there.

MR. MCCLEAN: Excellent. Thank you, Marilyn.

The next question would also go to the group. The questioner is interested in the panelists' thoughts on what level of transmission planning should appear in the SB 100 report. So, any panelist care to comment on SB 100 reporting as a venue for transmission planning?

MR. MCCLEAN: All right, that's fine.

MS. DEL BOSQUE GILBERT: I can comment a little bit more. I did request for an additions transmissions planning scenario for the, you know, high geothermal area. So, we are requesting a scenario for that, as well, you know, to do for the transmission planning to be able to get at some of those resources out of there.

MR. MCCLEAN: Noted. I apologize, Marilyn, for forgetting that from your slide, but I do recall that. Thank you.

Okay, one more for LADWP. How does possible conversion of the Navajo Generation Station play in California's and Department of Water and Power's plans?

MR. RONDOU: We do still have transmission capacity coming from Navajo. And, you know, we mentioned earlier that to the degree that we can do it, we'd love to use the existing transmission resources, the existing infrastructure that we have.

You know, that said, we need to also get something that's cost competitive, too. So, you know, we have seen some proposals in that area and some proposals that look, you know, very interesting. But it's going to come down to how do we balance best costs -- or, you know, least costs and best fit? And that's definitely a candidate for a best fit because there's transmission capacity for us.

So, it's something that we're open to. It would be great, I think to partner in that area given the impact that that area's had as part of the decommissioning. So, if there is an opportunity to do that that would be fantastic. But again, it also comes down to, you know, the cost as well.

MR. MCCLEAN: Great. Thanks Jason.

This final one is for BANC. Looking for a bit more color on a definition for net zero and perhaps contrasting that with the concept of net neutral. Are those the same thing?

Anything you'd like to clarify?

MR. SHETLER: I think from our perspective it's looking at the total GHG emissions and where we're spending our money on reduction. And if we spend dollars more efficiently in reducing, say, transportation or building impacts, but that does mean we have to use a little bit of combustion generation to get there overall are we still better off on a greenhouse gas perspective?

MR. MCCLEAN: Right, I appreciate that clarification. Thanks Jim.

So, let's see, Terra, if -- I'll let you guide us from here. It looks like we're about a dozen minutes ahead of schedule.

MS. WEEKS: Great. Well, first I would just like to thank Chris and all of our panelists. We really appreciate the close consultation with the Balancing Authorities as we progress in the report development. So, thank you again, all, for making the time to be here and we really appreciate your input.

So, we're going to take a five-minute break and then we'll reconvene with our third session of the day on additional perspectives around SB 100. And then, following that we'll have our public comment period as well. So, if you have other questions or comments that we weren't able to address at the wrap up of this session or this morning's sessions, there will be another opportunity to make those remarks.

So, we'll reconvene here in five minutes. Thanks.

(Off the record at 2:43 p.m.)

(On the record at 2:48 p.m.)

MS. WEEKS: Okay, I think we are ready to reconvene here. So, we are starting our third session of the day which is on Additional Perspectives Around SB 100.

So, we're really excited to have this discussion, kind of looking at SB 100 through a number of different lenses.

So, to lead us in this session, I'm going to hand things over to Siva Gunda, who leads our Energy Assessments Division here at the Energy Commission.

MR. GUNDA: Thank you, Terra. Good afternoon Commissioner Randolph and Commissioner McAllister. Thank you for holding the dais for us. I would also

like to thank everybody in attendance here for your time and participation today.

A special thanks to the panelists for extending your top leadership and expertise in the areas that we're going to discuss a little bit more.

This morning, Mark Kootstra from the CEC kind of provided a high level overview of the analytical capabilities that we currently have for the first report. And he also identified some critical gaps specifically around equity, environmental issues, jobs, land use, and such.

So, what this panel, we're hoping to tackle is, with the top leadership we have here provide some high level perspectives on where we are going with this particular report, but also where we could go in the future years. And translate some of the qualitative assessments we are hoping to do this years into more quantitative metricized values that we could be using in the policymaking.

If I spend a lot of time here talking about all the good things you all do, it will take the whole hour. So, I'm going to try and limit my remarks and introductions to a very high level.

I do have some prepared questions for the panel if we have time at the end, but if not I'm going to just

hand it over to the dais.

With that, I'll call on each one of you individually and then, after your presentation I'll introduce the next person.

Without much ado here, I'd like to start off with Erica Brand. Erica serves as Director of the California Energy Strategy at the Nature Conservancy, where she works on state and regional policies related to clean (indiscernible). In her role, she leads a team that focuses on decarbonizing the electric grid, providing science and policy analysis to the state and federal regulatory agencies that develop and implement clean electric policies.

And Erica will be primarily commenting on the land use, but also might go into other issues as she sees fit. Thank you.

MS. BRAND: Great. Well, thank you for having me here today. Thank you, Commissioners.

I'm going to spend a few minutes presenting mainly on some research that the Nature Conservancy has done around the potential land use requirements of achieving SB 100, but going beyond that and helping the state deeply reduce greenhouse gas emissions through clean power and electrification.

So, why land use? Which is what I'm here to

talk about today. Decarbonizing California through clean power and electrification will require significant land area for new electricity infrastructure. So, we need to think about how we're going to site and build all of the generation and infrastructure needed to help us meet these critical greenhouse gas emission reduction goals.

The path to decarbonization will require resources of all size. So, energy efficiency, demand response, distributed energy resources, but based on research I'll share today it will also require a significant amount of zero carbon resources generation and the electricity infrastructure needed to deliver that power to where it's used.

The path that California takes to the resource build out to achieve these goals will have different impacts and tradeoffs to natural and agricultural land, human communities, natural communities, but the pathways can also have different impacts on the pace and scale of the deployment needed to achieve our greenhouse gas emission reduction goals.

We have done research into siting. Specifically, we recently looked at a case study of large solar projects across California. And found that projects, large solar projects that were sited in areas

of lower conservation value were actually permitted two and a half times after.

So, the good news is that California knows how to make land use and energy work together. There's a number of tactics that are underway, both landscape scale planning and seascape planning that the California Energy Commission has been leading on. But also, long-term energy and transmission planning, which will be the focus of the research I'll share today.

And really, I think what's most important is that the landmark SB 100 gives California a leadership opportunity to move from target to action in creating a thoughtful implementation plan.

So, integrated environmental and land use data as a first step in long-term energy models yields multiple benefits. And so, what we mean by this is taking specific information, spatial information from the ground related to natural resource values, areas of opportunity, areas of constraint, and actually using that information in behalf of the expansion models, like RESOLVE, as inputs to inform how energy resource portfolios are created is an important step.

The reason for that is because it makes opportunity areas, areas of constraints visible much earlier in resource and transmission planning, improving

the projections and the policy decisions that flow for them.

So, in modeling terms, we're talking about creating environmentally informed supply curves. And I'm going to share how we did this recently in a study with E3, an energy reflection called Power of Place. We had a couple of central research questions.

One of them is highlighted here. Can the high renewable builds needed to achieve deep decarbonization in 2050 be done while limiting impacts to natural and agricultural lands across the west?

This research built on a study that E3 had done through the California Energy Commission EPIC, a project called Deep Decarbonization in a High Renewable Future, which considered multiple scenarios for achieving statewide emission targets.

We selected the high electrification scenario. So, all scenarios incorporated high levels of vehicle and building electrification. And all of the scenarios in our study met SB 100 targets as having a hundred percent of retail sales met with zero carbon resources.

The chart on the left is meant to show that achieving greenhouse gas emission reductions through electrification is projected to significantly increase demand, which relates to the amount of land area

required for that generation.

This slide here is an overview of the core scenarios and sensitivities that went into the study that we did with E3. In total, there were 61 scenarios. There's a couple of assumptions that I'm going to highlight here. But all of this information is available in a technical report, if you're interested in following up.

So, we studied three different geographies from within which California may have access to new resources moving forward. We studied a California only pathway. A pathway where there's some kind of regional solution with a few of the states across the west, mainly California's neighbors. And a scenario called full last (phonetic), where there's a regional solution across most of the states in the WECC. And when we get into the results, I'll show that there's some pretty significant differences depending on the geography.

In the center, we explored four different levels of land protection. So, these levels of land protection, as you go through them they increase the emphasis on land protection to reduce impacts to natural and agricultural land.

And then, we explored some sensitivities around rooftop solar deployment, reduced battery cost.

And all of the scenarios were designed to achieve an 80 percent greenhouse gas emission reduction below 1990 levels by 2050. So, we didn't study neutrality.

Now, we'll get into some of the results. So, the 2050 scale of wind and solar across the scenarios is approximately 1.6 to 3.1 million acres. For a little bit of context and reference, I was in Yosemite this weekend. That national park is 760,000 acres, A little more local reference, the combined acreage of Sacramento, Yolo, and Placer Counties is 2.3 million acres. So, two examples that fit right within the ballpark of the scenario.

We found that the 2050 generation capacity differs across the geographic scenarios. So, the grouping on the left is the in-state scenarios. And you'll see that the primary resource selected is utility scale solar.

As you move to the part west and the full west scenarios, RESOLVE wants to pick up as much high quality resource as it can and bring that into the state. And interestingly, as you integrate wind, the amount of capacity and use overall to achieve the same goal goes down.

We did not study offshore in this particular

work because we ran the model -- ran the scenarios in 2018, when the date wasn't quite available, yet.

I do on the in-state scenarios want to highlight one piece. So, I looked up today on the CEC website that the installed utility scale solar capacity through the end of 2019 is about 10 gigawatts in California. The builds in these in-state scenarios for 2050 have over a hundred gigawatts of utility scale solar in them. So, about 10X increase in deployment from today.

The resource used to balance the solar generation is the primary difference between the cases. So, in this slide we're showing battery storage and wind. When the model, which we used RESOLVE in this study, has access to out-of-state resources, it generally prefers them to battery storage.

And then, we get into some of the cost results. And an important finding is that when clean power can be sourced across a larger area, we found in the scenarios that there were most cost effective opportunities to create balanced solutions for clean power and land conservation.

So, another way to think about that, broader geography, more opportunities to think about low-impact siting of generation, more opportunities to have a more balanced portfolio of different types of technology.

One of the things that we did in the study was be able to take those bar charts, which come out of most expansion models and actually visualize them using the mapping model.

So, on the left, it's going to be a little hard to see at this resolution, we have a map of solar build out through the end of 2018. And it's about -- at that time it was about 90,000 acres.

On the right, we have a map of the in-state scenario, level of land protection one, and it's about 1.2 million acres of utility scale solar that were selected for those portfolios.

So, again, potentially a very significant increase in the amount of generation that's deployed across these scenarios.

And then here on this map we're really showing the range of land use outcomes that could be possible as we're thinking about achieving our climate goals in 2050.

Starting on the left we have the in-state scenario, a part west scenario, and the full west scenario. And this under the third level of land protection, which protects lands of high conservation value in California and across the west.

And you'll see some differences. On the left we

move from primarily solar resources over to integrating different quantities of wind, which changes the size of the solar imprint from around a million acres to around a half a million acres.

So, one of the key outcomes or one of the key recommendations coming out of this study is that with planning California can scale up the clean energy infrastructure needed for decarbonization through clean power and electrification, while limiting impacts to natural and agricultural lands across the west.

So, across all scenarios we were able to find pathways that limit impacts to natural and agricultural lands. But there's tradeoffs in terms of which technology is selected, costs, and other variables. But the planning is critical because at the lower levels of land protection we saw significant conversion of natural and agricultural lands to energy.

And in fact, one-half to one-third of all solar was sited on agricultural lands or lands that are designed as agriculture. And so, for us, that really points us in the direction of wanting to find solutions to directing solar to farmland that is impaired or otherwise degraded.

So, a few recommendations teed up by the questions from the CEC. On the quantitative side,

incorporating environmental and land use data into the modeling for the SB 100 report can help improve projections.

On the qualitative side, we recommend including a chapter or section on land use, and really socializing and planning for the land use changes that may be needed to meet this ambitious, landmark policy.

Thinking about solutions that allow us to identify opportunity areas early, think about planning transmission to those areas, especially important given the long lead time for transmission investments. And thinking through policy structures and recommendations that can enable lower impact development pathways.

So, that's what I have. Thank you.

MR. GUNDA: Thank you so much, Erica. I just want to open it up to the panelists, if you have any questions for Erica.

Okay, then I'm going to move on to the next panelist. Zainab Badi is the Workforce Policy Project Manager at GRID Alternatives, which he helps shape workforce development into renewable energy. She holds a master of public policy, with a focus in environmental policy from UCLA Luskin. And previously was a Policy Fellow at Greenlining Institute. And she's going to offer some perspectives and jobs.

MS. BADI: Great. Thank you so much. Good afternoon. Like you mentioned, I'll be talking about some high level workforce considerations that can be taken into account as programs are designed and implemented pursuant to SB 100.

And so, to give some background on GRID, we are a nonprofit solar installer, the largest nonprofit solar installer in the country and makes -- and our vision and mission is really to make renewable energy technology available to under-served communities. And along with that to include workforce training, and to that as well. And so, we advocate for equitable and inclusive policies and programs. And we do a combination of both installation and workforce training.

So, to begin, I want to touch a little on why workforce is important for SB 100. And first, mainly, there will be a need to expand the workforce to meet the needs of a hundred percent renewable energy target. And secondly, we want to make sure that workforce is not an afterthought in programs but, really, is one of the key components from the onset so that communities that are most in need aren't left behind. So, it's really great to be here and discuss these equity considerations in this process.

So, a quick overview. I'll be talking about

some existing research and then highlighting one specific example of a workforce program design that could be considered and then just some general best practices in workforce development.

So, I'm going to be mainly talking about the recent of the UCLA Luskin Center for Innovation and existing research, which has started to do some work on this subject matter in their recent report around building decarbonization workforce needs that I found to be a helpful resource. That might be useful to other stakeholders in this process. It's not GRID's area of expertise, but I wanted to put this out there as related research that exists that might be helpful to folks that are working more on the analytical piece and how to build this into modeling.

So, this is from the report. And it's available online for folks who want to take a look at their methodology. But this estimates job growth from just building decarbonization. So, these are high and low estimates of how many jobs would be created and sustained annually through 2045 in these sectors as a result of building decarbonization. And it ranges from our 60,000 to 100,000 jobs annually.

And this is quantifying jobs by resource mix. And again, I'd really point to the Luskin Center

researchers as the experts on this issue. And as I go along the rest of this presentation, a lot of what I'll be talking about will be more focused on workforce development in general and how it can be implemented outside of this model. But I wanted to highlight that there is some work being done around quantifying job metrics for decarbonization particularly that can possibly be adapted.

So, the main example I wanted to highlight that contains really specific language around workforce development training requirements built into the program is the California Solar on Multi-Family Affordable Housing, which is managed by the PUC.

And it has really specific job training requirements for all projects that are awarded contracts. There's a lot of specificity in SOMAH for job training metrics, which is important for program design and implementation. And it's a program that can be modeled and adopted for other programs.

And so, here listed are some of the key specificities within SOMAH, including number of trainees by project size. And this is all available in the SOMAH program handbook, which is available online for folks as well.

And I wanted to highlight this piece of SOMAH,

which focuses on local and targeted hiring practices, which is something that we recommend. So, SOMAH defines local hire as any individual residing in the county where projects take place. And then, target hiring is more broad and includes lists of individuals meeting any of those different key demographics. And within the program there's a job training portal that assists both job seekers and job contractors. And we've found that this is a really useful model for focusing the needs in the communities that need them most. And then, also connecting job trainees to employment opportunities.

And some best practices on workforce development. This isn't an exhaustive list by any means, but these things should be taken into account when talking about implementation of workforce. And so, equity in hiring and procurement, like the local and targeted hiring policies.

We really advocate for funding set aside within program budgets for workforce development, including paid work and stipends for trainees, and wraparound services. And again, just to ensure that workforce development isn't an afterthought, but is really built into the design of these programs.

And then, engagement number 3 and number 4 engagement with communities is a really key piece that's

brought up often by numerous stakeholders and policy groups. And it's also really important that this collaboration and partnerships as much as possible so that training pipelines are established, and trainees can get hired in the industry once they complete training.

And then, establish metrics for success and data tracking is really important as well. And I link there to the Low Income Solar Policy website, for folks that are interested in looking more at a comprehensive list and different models of programs that exist across the company, specifically in solar around workforce development.

So, I'll leave it at that. And if anyone has any questions, happy to follow up.

MR. GUNDA: Thank you, Zainab. Any questions from the panelists, other panelist for Zainab? All right, thank you.

Moving on to our third panelist here. Matthew Freedman is TURN's staff attorney, specializing in electricity. He has over 25 years of experience working on diverse issues, including renewable energy, utility ratemaking, distributed generation, state legislation and consumer complaints.

Matt is going to provide some perspectives on

affordability and might go into other work as well.

MR. FREEDMAN: Thank you. Again, my name is Matt Freedman. I'm a staff attorney with The Utility Reform Network. And I may the only panelist without a slide deck, so I hope you won't hold that against me.

I'd like to walk through a couple of concerns and thoughts that I have about the portfolio choices that are in front of the Commissions as part of this implementation process, to flag a couple of concerns. And then, to talk about affordability and how to think about it in the context of SB 100.

With respect to what's in the portfolio that agencies are going to be looking at today, SB 100 refers to two categories of resources, eligible renewable energy resources and zero carbon resources.

It's not reasonable, in my view, to suggest that SB 100 prohibits any form of combustion generation, which is one of the options on the table. That's not in the statute. The agencies can certainly decide to prioritize some resources. But to categorically exclude them would, in my view, be a mistake.

We are at the front end of a big planning process. And broader eligibility criteria are really appropriate at this point in time. It's going to

promote the ability to consider all cost-effective solutions that may include combustion resources.

It's really impossible to know right now what we're going to need to get all the way to one hundred percent. And although the modeling that's been presented today is a very high quality, and I have great respect for all the modelers working on these hard challenges, the track record of long-term forecasting is pretty poor. And long-term forecasts are directional at best. We shouldn't place too much confidence in them.

I'll offer a couple examples from history to make this point. In 1975, the Rand Corporation prepared a report for the California Legislature, forecasting that the state would have 18 gigawatts of nuclear capacity by the year 2000. Well, the state actually ends up relying on five and half gigawatts of nuclear by the time 2000 rolls around.

In the early 1980s, the Energy Commission predicted that oil prices by the 1990s would hit $120 a barrel. Oil prices were actually about six times -- that was actually about six times higher than where oil prices ended up being during that time period.

When the Renewable Portfolio Standard was enacted, the conventional wisdom was that geothermal and wind resources would dominate, and that there were

concerns as to whether there would be any space in the portfolio left for other types of renewable resources. Well, obviously, that didn't come to pass.

In 2007 and '08, the conventional thinking was that large-scale solar thermal facilities would be the backbone of the state's renewable energy portfolio. That has not come to pass.

In recent years there's been a lot of emphasis on solar photovoltaics, and now on storage.

My point being that we should be careful about forecasting long-term trends based on what we know at this point in time because the modeling misses a lot of innovation and unexpected developments that are going to come to pass. And right now there are no rules in place for compliance with SB 100, and the agencies are going to be thinking about this for a long time. So, keeping all the options on the table really makes sense.

So, what do we do in the short term? We look for no regrets actions that can be taken over an actionable planning horizon. What would that be? Let's call it five years. In other words, we could spend so much time thinking about the end point of this exercise that we do nothing for the next decade, other than model and think about things.

We have to take some actions. We don't want to

go too fast, too quickly for fear of investing in resources that end up being a bad bet. But if we wait too long, we've missed opportunities to make meaningful progress. So, a balancing of objectives here really does make sense.

One thing that hasn't been mentioned today is another piece of SB 100. I think it was in the initial presentation having to do with resource shuffling. SB 100 also states that the achievement of this policy for California shall not increase carbon emissions elsewhere in the western grid and shall not allow for resource shuffling. This was not an accidental addition to SB 100. It was quite intentional.

And it's based on the recognition that current approaches to greenhouse gas accounting allow in-state buyers to claim credit for purchases of zero greenhouse gas electricity from existing out-of-state resources that have no carbon emissions.

What are we talking about? We're primarily talking about large hydro and to a lesser extent nuclear. For a long time California has been relying on out-of-state hydro to satisfy some of our needs. It used to be call economy energy. And after deregulation it was called unspecified energy. Well, now, it's being called zero GHG imports.

And the problem that we're facing in the near term is that these resources are essentially coming from existing assets that have no ability ramp up to produce more energy. They can change the timing of their energy, but they're energy-limited resources. And they have load they've been serving in other parts of the Northwest and other parts of the West.

So, the idea that you can simply redirect that output on an attribute basis to California and help it to meet the state's environmental goals is problematic. Because in some cases we've seen examples where owners of assets outside the state resell into California, and then backfill to meet their own native loads by going to the market. And what does that do? Well, in many cases it results in the dispatch of thermal units. This is resource shuffling.

The modeling needs to look at this. It needs to consider west wide impacts of different portfolio strategies. And my understanding is the modeling to date has really focused on California impacts. It is hard to model the whole West. It's hard to think about what everybody else might be doing in the future.

But, unfortunately, we need to take a stab at that, otherwise we end up misrepresenting the impact of our state policy choices.

And we also need to look at how we do greenhouse gas accounting, which is a topic that makes everybody's head hurt, but it's really quite important. For example, right now imports of unspecified electricity have a static emissions factor that the Air Resources Board developed a decade ago, based on a study of grid conditions back in 2008. Well, as more and more zero greenhouse gas resources are stripped out of the unspecified mix and sold separately, you'd think the unspecified mix would be potentially changing. You'd think it might be changing on an hourly basis. But the accounting doesn't reflect that.

In addition, we know that the Public Utilities Commission has been very carefully at hourly accounting and there's a lot of emphasis on moving to an hourly accounting approach. These are the kind of innovations that we need to be looking at as part of any statewide modeling exercise. And we think that the Joint Agency Report should identify this as a scope of work for further progress to be made as part of operationalizing the SB 100 goals.

There was an item that was teed up around measuring SB 100 compliance, retail sales versus total supply on the grid. Why does SB 100 identify retail sales as the relevant metric? Because that's the piece

of the system that is clearly state jurisdictional. The state cannot regulate the amount of supply that shows up in wholesale markets. That's federal jurisdiction. And as we all know, the federal government is not a great partner for California right now on the issue of moving forward with these greenhouse gas targets. Perhaps in the future the federal government will be a more willing partner, but for now they are not.

I think it's clear the goal of SB 100 is total transformation of the system even if it's focused on the metric of retail sales. And there may be ways to reconcile these two approaches.

One would be to revise accounting protocols to ensure that retail providers are assigned responsibility for resources that they don't explicitly purchase, but are really needed to meet their retail sales obligations.

For example, a retain provider today that buys 100 percent GHG free electricity may also end up getting a hundred percent of their resource adequacy from gas-fired units. But there is no allocation of responsibility for the emissions from those entity that buys that resource adequacy. So, we have all this missing emissions that sort of drift into the system. There's got to be a way to account for that. And I

think this is an area of study that the agency should look at.

So, how do we reconcile all of these aggressive goals with affordability? Well, there are number of significant near-term pressures on electricity rates that are inflicting huge economic pain on California ratepayers today.

The total system average rate of the three investor-owned utilities historically tracked close to inflation, but it's been deviating in the last number of years. And although California customer bills have historically been lower than the national average due to milder climates and lower usage, we're seeing increases in rates that are threatening this track record. And one of the ways that that's showing up is an increase in customer disconnections.

In 2010, the four major investor-owned utilities, meaning the three electric investor-owned utilities, plus Southern California Gas, 600,000 customers were disconnected for nonpayment. In 2018, that number increased by 50 percent, up to 900,000. So, we have a crisis of affordability that's showing up in customers being unable to pay their bills. We're going to have to take some action on this in tandem with meeting our SB 100 targets.

And the rate increase trends are really driven by two factors, declining sales and increasing revenue requirements. It's a bad combination. Trying to spread more money over fewer sales is going to lead to a very significant uptick in rates.

And that increased spending is due to wildfire mitigation plans, and grid resiliency hardening, transmission additions, and general investor-owned utility initiatives to deploy more and more capital.

Declining and flat sales are due to energy efficiency and behind-the-meter customer generation.

And because SB 100 implementation is going to require a lot of spending on new infrastructure, the state has got to look at some very creative ideas for potentially removing some of these costs from rates and finding ways to bring down the cost of the investments.

One option that should be considered is the potential to deploy the state's general fund money and the state's bonding capacity to reduce the cost of getting to a hundred percent. Moving some of these costs out of rates and into general taxpayer revenues could help to promote affordability of basic usage.

The options include tax credits and using bonding for infrastructure improvements. The public sector cost of debt is far below the investor-owned

utility cost of capital. Investor-owned utilities are getting seven and a half to eight percent weighted average cost of capital. If you look at the transmission investment side, PG&E has been authorized 12 and a half percent. Edison is asking the federal government for 17 percent return on equity. These are eye-popping numbers

When you do public sector bond issuances and you look at publicly-owned utilities in the state, their cost of capital is looking like 4 to 5 percent. That's a big spread. If there's a way to use the public sector capability to issue debt, to substitute for the higher-priced utility investment, there is an opportunity to bring down costs while making big investments.

We know that electrification is another interesting topic. If you increase electrification, you get more sales. More sales should provide downward pressure on rates. But it costs money to do electrification. And there's a way to throw a lot of money at this problem and not get great results.

In particular, you can spend a lot of money to retrofit existing homes, but you may end up in a situation where the savings to all customers aren't that great. Which doesn't mean you don't do it, it means that you mitigate your expectations about whether you're

really going to see huge rate savings.

And when you start moving customers away from gas and there's big declines on the gas system, we're going to see a spike in gas rates that's going to have its own set of consequences. And there's a good report that was done recently by Gridworks, and maybe many of you have seen this, that looks at projected future trends for gas rates. Some of the scenarios are pretty ugly.

Someone suggested rate design can solve this challenge. If we just design rates right, we'll get the affordability problem handled. But rate design just shifts costs from one set of customers to another. It doesn't fundamentally reduce the average rates.

And rate design that's done to assist early adopters of new technologies can have major free-rider problems and widen the gap between haves and have nots. Customers that want to spend a lot of their own money on new technologies, giving them a great rate, they'll be able to save a lot of money. But sometimes those rates also allow customers with just favorable load profiles to save a ton of money. And it means that the loss in revenues ends up having to be collected from other customers who don't have access to these new technologies.

The last thing I want to talk about is behind-the-meter resources. And I think this is controversial one, but it must be said that the assumptions about behind-the-meter resources are likely to be a key driver of overall costs and rate impacts associated with SB 100 goals.

We've seen total average system rates have gone up for the three investor-owned utilities in recent years. But for San Diego Gas & Electric, their rates have gone up a lot faster, about 6 percent per year. Why are they so different? Well, one reason is that they have greater adoption of customer side solar that is eligible for net energy metering. Over 12 percent of residential customers in SDG&E's service territory are on net energy metering.

This tariff is a money loser for the utilities. But shareholders don't pay the costs. Other customers pay the costs. And the cost shifting is becoming significant.

Right now, the investor-owned utilities' programs essentially exempt net energy metering customers from a variety of costs that we would argue represent a shared customer responsibility. It is reasonable for a customer to avoid paying for wildfire liability costs because they switched to rooftop solar?

Or, should they be able to avoid investments in system electrification? Should they pay less towards public purpose programs that support research and development, and low-income programs?

The problem is that the existing tariff treatment for net energy metering, which was critical to getting the solar industry off the ground is simply not sustainable, and it's definitely not scalable to higher rates of customer adoption.

So, the need to reform net energy metering becomes much more important as we look out towards achieving these big goals. And the SB 100 report these agencies prepare really should consider alternatives to the current net energy metering paradigm and assess the costs of continuing the current approach versus alternatives.

And why is it so important to be in this report? Because the state's decarbonization goals are being implemented with a significant focus on behind-the-meter generation.

The Public Utilities Commission is looking at a doubling of customer side solar over the next decade, about on par with the amount of growth in utility scale grid connected solar. That's a one for one. But customer side solar is more expensive to install and

other customers have to pay a much higher premium for that.

Right now, if a customer with net energy metering put solar on their roof, they're essentially getting paid 20, 25 cents a kilowatt hour for that. If the utility, instead, were to go buy central station solar, even with storage, lots and lots of storage, maybe you're looking at 4 cents a kilowatt hour. That is a big spread.

And on top of that we have recent legislative and regulatory focus on microgrids. Are microgrids the solution to all of our problems? Well, distributed resources are more expensive, but they do make sense when a customer can avoid paying for these shared system costs. I would be happy to cut myself off from the grid, if I don't have to pay for everybody else's -- you know, for my share of all of these systems costs that are needed to keep the system going.

And if we're providing net energy metering-like treatment for microgrids, this is going to create an even bigger problem with respect to affordability.

So, the Joint Agency Report should identify scenarios involving different ratios of behind-the-meter and large-scale solar, and should consider the impact of affordability. On affordability of continuing current

tariffs versus alternative approaches. At least look at quantifying the rate impacts. And I don't see that anywhere in the modeling that's being teed up today.

These assumptions may prove to be the most consequential with respect to the overall affordability of achieving SB 100 goals in a cost effective manner. Thank you.

MR. GUNDA: Thank you, Matt. Any questions from the panelists to Matt?

Okay, the next panelist, Dr. Michael Wara, is a Senior Research Scholar at the Woods Institute for Environment, and Director of the Climate and Energy Policy program focused climate and energy policy.

The Wara scholarship focuses on carbon pricing, energy innovation, and regulated industries. Dr. Wara recently served on the Catastrophic Wildfire Cost and Recovery Commission. He's going to offer some perspectives on resiliency.

DR. WARA: Green. Green is good. Thank you very much for inviting me to provide some perspective on the implications of resilience and resilience thinking with respect to the SB 100 goals.

I think it's worth just reflecting on kind of what resilience means. It's kind of a nebulous concept. Before we get into -- or, before I provide some

specifics.

When I think about climate resilience or just plain old resilience in the power system, you know, we typically think about capacity to recover quickly from disturbances, from some sort of ideas about toughness. And maybe in contrast to that or intention with that ideas about elasticity and a flexible system that can be self-healing.

I would add that I think -- and I think I agree with a lot of what was just said, a resilience system is an equitable system and an affordable system. And that the more that we move away from that, the harder it will be to construct a system that's really robust to whatever shocks come upon it.

In particular, when we think about climate change and global warming, I think what resilience amounts to in the power sector context is the ability to withstand shocks that exceed the design basis of the infrastructure when it was built.

You typically build infrastructure today, or in 1970, or in 1920, depending on what we're talking about in the California power system, with a particular idea of the weather-related variables, other shocks that may occur. And what is most challenging about climate change is that it really undermines many of those

assumptions.

That means we need to think ahead. We need to think about where the puck is going to be. And I would just say, you know, there are a number of typical kind of, you know, things, factors that have been considered with respect to climate resilience and grid planning. Sea level rise has been one. Heat has been another. And, of course, lately we've been worrying a lot about wildfire and weather-related impacts on the system.

I would just add, you know, as we think about SB 100 and broader, you know, system energy planning over the time scale of decades, I think it's really important never to forget as earthquake as a potential resilience function. And that whatever we do on a 25-year time scale should factor in the resilience of the system to the major earthquakes that will with certainty occur, both in Northern and Southern California.

So, how does that relate to how these set of concerns, these broad set of concerns relate to the planning that you are charged with accomplishing? No easy feat. I completely agree. And I've written several publications that basically support the view that Matt Freedman just expressed about the challenges associated with long-term energy forecasting. It's a very difficult job.

But I think there are sort of three big take homes that I would recommend that you consider. One is, and this is maybe an intention with what was just said, the relative value of incremental, and I would emphasize that point, incremental residential solar plus storage, and/or hybrid microgrids in the context, the specific context of high fire threat areas. This is not general application. I'm not suggesting that this is a one-size-fits-all solution. But I think this is an area that's received a lot of attention lately, both from you, from the PUC, from the Legislature, and from the utilities themselves. And it's an important one because over the last year we've experienced I think what can only be described as extraordinary reliability impacts in particular areas of the state. Not everywhere. Not even most places, right. A million, I guess 950,000 customers. It sounds like a lot, but it's really 20 percent of the PG&E customer base that were impacted in the major blackouts during October.

And really, when you drill down into the data, you find that there are clusterings of customers that are much smaller than that that have been most severely impacted by PSPS throughout last year.

I think at this point it's very hard to simulate what this impact, what the meaning of this, what the

costs of this are because, really, there's no agreed upon set of expectations for how this situation will evolve over time.

Some people have said that -- the Governor in particular has said that the situation is unacceptable. The CEO of one of the IOUs has said that PSPS may be reduced by a third. That would still leave 600,000 people in the dark in October, or 600,000 customers in the dark in October. 600,000 meters in the dark.

Which to my mind is a substantial reliability problem for both low-income, and high-income customers, and commercial customers, and communities in impacted areas of California that I think we just need to address. And so, I think thinking about how those should be incorporated -- how that reality on the ground needs to be incorporated into planning, both in terms of what we should expect from load when the lights are on in those places, and in terms of the potential value of those resources to the system when the lights are on is worth doing.

But I would argue that that's something that needs some thought, some attention, and probably a lot of consultation and input from the entities that are really boots on the ground when it comes to these questions. The CCAs that are running around, putting

backup generation in place for critical infrastructure. The IOUs that are standing up these temporary microgrids, possibly, and the DER providers.

But we need to be thinking about this and paying attention to how the PSPS situation evolves over time. It's clearly and evolving context, but it's one that I think is potentially significant in terms of the needs and the resources available to comply with SB 100.

Another very important consideration I would argue is the incremental cost of transmission moving forward. There's a very -- I think one of the most important things that was said in PG&E's Wildfire Mitigation Plan, the draft that was filed with the PUC at the beginning of February, is a section that discusses moving from what they refer to as run to condition as approach to maintenance of the T&D infrastructure to preventative maintenance in high fire threat areas.

Typically, the system we have has been run to condition. And what that means is that because the expectation was that system components would fail during winter storms, with very low significance consequences for the broader system or for ratepayer that elements of the system could be run far beyond their useful lives, until they broke.

As the utilities, and I think this is all three IOUs, move toward a preventative maintenance framework for the areas that are high threat that is going to involve much higher costs. And that tends to shift the balance of value between building more wires versus building either storage in load pockets, or facilitating some sort of more decentralized arrangement that minimizes the need for these wires that are now both expensive to both construct, but more importantly to maintain.

We really don't have a good model yet for much this is going to cost, but we do have some examples to look at. One that I would point to is the history of rates in San Diego Gas & Electric's territory. There is a reason that people there put solar on their rooftop. And the reason really starts in 2007 with the Witch, Rice and Guejito fires, right. San Diego implemented grid hardening after 2007. It hit rates around 2012. And I think all of us who have looked at the PUC annual reports know and remember what happens at that point. The SDG&E rates jumped right up above the other two IOUs.

I think that's -- the unfortunate reality is that's the future in high threat areas. That is the impact of preventative maintenance on cost. And to the

degree that the other IOUs have more above ground infrastructure, SDG&E has more underground than the other two IOUs. So, the degree that they have to manage more aging transmission infrastructure, there's wonderful reporting in the *Wall Street Journal* that shows, has a figure that shows the age of at least the publicly available -- well, it's not publicly available. The ages of the transmission infrastructure that PG&E owns, for which we know the age, most of it was constructed pre-1970. Right. So, the new stuff is going on 50 years old.

That implies that we're going to have to replace a lot of it over the time frame of this planning horizon. So, we need to think about what are the costs of that? What are the continued costs of maintaining that infrastructure in a way that will not cause fires, which are catastrophic for ratepayers and for the affordability of everything under consideration today.

And factor that into the planning model, I think. I think we cannot assume that the old assumptions about the cost of T&D are right in the current weather and climate environment.

And I guess the last thing I would say is we have to think about what happens in response to that. As Mr. Freedman said, there are a lot of pressures on

costs right now, and on affordability. And I think it's important to have realism about the cost of grid-supplied power, and likely responses to that higher cost. What do people do when they experience higher cost of power? How do they respond?

And over the time scale that we're talking about, 25 years, what does that mean for higher DER uptake in non-high threat areas? And the San Diego experience was mentioned. I intended to mention it as well, but I'll just skip over that.

I just think we need to be careful not to assume that the customer will always be there. I think that to the degree that we can encourage electrification in cost-effective ways, you know the history of the 20th Century is that costs fell as load grew. If we can keep that pattern going in California, through building electrification, and vehicle electrification that is cost effective and strategic, and it's public investment, there's a way out of this.

But it's also important to factor in, you know, as a number of parties have mentioned that the distributed -- what I think of as the manufactured components of the energy system, things that can be made in factories of small scale, those costs are going to fall. They're going to continue to fall.

And to some degree the costs of storage are really disconnected from what happens in the electricity system because they're driven by vehicle electrification at this point and not deployment as energy storage.

So, we should be attuned to this potential and at least evaluate costs with different scenarios in mind. Different scenarios with respect to customer response to changing energy prices.

I'd just close by saying that I think the experience of the last three years, for anyone who works in the electricity space has been one where it really brings equity to the fore, as never before because of the financial challenges that the utilities are facing. And I know that the folks sitting up on the dais today take that concern to heart, and I would encourage you to continue to do so as you think about SB 100 implementation. And finding sort of a dual path to success, where we ensure that the covenant we all have to make energy access affordable for all California is maintained, even as we reduce the climate impacts of living in this kind of world.

Thank you.

MR. GUNDA: Thank you so much, Dr. Wara. I'm just going to open it to the panelists if you have any comments or questions of Dr. Wara?

Okay, with that, moving on to the final panelist. Phoebe Seaton is a co-founder of the Leadership Counsel and leads the Leadership Counsel's state level policy work.

The Leadership Counsel works with impacted communities to advocate for sound policy and eradicate injustice, just like your equal access to opportunity regardless of wealth, race, income and place. And Phoebe's going to offer some perspectives on equity issues.

MS. SEATON: Thanks so much. I'm just going to say a few words. The other panelists and, hopefully other participants will discuss more of the issues around affordability and access, and making sure that with our pubic investments and other incentives we're addressing that from a community perspective and a household perspective.

I want to focus on I think there has been some conversation in the last panel, and in other panels on environmental justice, but I really want to highlight a few points as we're talking about energy production and procurement. And the need for the SB 100 implementation to take into consideration environmental justice broadly. And there's been some discussion around air quality.

So, I think the three or four things that come to mind for us right now are kind of air quality, impacts on communities, community cohesion, water quality, and general how we're addressing climate change broadly to communities most vulnerable.

On the air quality side, I agree with a lot of what Matt discussed. Do feel that we have now an opportunity to really transition off of combustion fuels. Absolutely critical for the communities where combustion is happening and that we need to develop scenarios where we're not combusting.

There was also discussion earlier today around biofuels and RNG, which again are impacting some of the most vulnerable communities, areas of the most impacted air quality and water quality. And really look to SB 100 as well to look at reducing and eliminating our need to rely on renewable natural gas, which generally isn't renewable. But that can be a topic for another conversation.

Similarly, on the water quality side, I know that the air and energy is a common nexus, but really, really important that we're looking at water as well. Both on the discharge side, and on the surface water, and on groundwater, and how what we're looking at the different inputs in procurement, kind of resources that

we're looking at address water quality.

Again, so much of kind of the energy framework is in some of the most impacted communities. Impacted not just by air quality, but contaminated water. So, we'd really like to see that in the analysis in our report.

And we've had some really good conversation with TNC on kind of their analyses. And one of the things that came up is that solar is one of the obviously preferred resources that we're looking at, but many communities are feeling that they're becoming surrounded by and just becoming kind of solar farms.

And that both the aesthetic and the community impacts of being completely surrounded by utility photovoltaic, and what that means and what we should do to address that, and ensure that communities can maintain their character as we're building out our solar framework.

I would, of course, like to see much, much more rooftop, and how do we invest in rooftop and how do we invest in the homes that need rooftop and community solar more than anyone else?

I think on the vulnerability side and on the affordability side we can address a lot of our vulnerabilities there.

And kind of lastly, as a general matter, I think we do want to see as aggressive an approach as possible to using this tool, SB 100, and these policies to be as aggressive as we possibly can in reducing our carbon. Not relying, I think, on carbon sequestration, but really reducing our carbon demands.

You know, we're looking at the scenarios and we'll comment on the scenarios approach as we consider the different opportunities. We'd love to see kind of an equity scenario. What would a scenario look like? What would our resources look like in our demand, et cetera, in the most equitable framework we can imagine, from an affordability side and from an environmental justice side.

We'll do some thinking on that, but we'd love the Commission to consider that as well.

MR. GUNDA: Thank you so much, Phoebe. Any thoughts, comments to what Phoebe had to say? Okay, Matt, do you want to respond to the no combustion that kind of Phoebe mentioned?

MR. FREEDMAN: Sure. I think the concerns of disadvantaged communities should be front and center in the implementation process. My comments were not meant to suggest a devaluing of the concerns of people living in heavily impacted communities, but rather to say we

are attempting the total transformation of the electric grid. Something that has not been done. It is the heaviest of all lifts. And all options should be on the table as we think about the long game plan.

My suggestion is not that we run out and order the procurement of a lot of new combustion technologies, but rather that we keep all the tools on the table as we think about how to get from here to the end goal.

And really, the next steps along the way, in my view are the ones that are already occurring. We know we need more solar. We need more wind. We need more of the technologies that we already know about. We need more storage. We should start doing those immediately.

And we should avoid the temptation to wait until a much later date to do things because they get cheaper in the models. Everything looks cheaper ten years from now. I would much rather have the i-Phone that is available in ten years than the one that I bought three years ago.

I would much rather have batteries that are going to be available in 2030, than today. But that is a prescription for perpetual inaction and we need to be careful about that.

So, I think on the combustion front it's just

keep everything on the table. And the market's going to let us know what technologies are available at what costs and whether it's going to make sense.

MR. GUNDA: Just to quote Matt from his kind of talk, he said: No regret solution on an actionable horizon is what he said. This was very eloquently put together.

So, I would like to just kind of ask each of the panelists if there is one thing that you can think of that's no regrets in an actionable time frame, and what would it be?

MS. BRAND: Are we going in order? Okay. I mean, I think that one thing that stands out across the research that we've done is the potential role of solar on the utility scale side. And so, we don't know how much projections will change, but we'll need a lot more than we have today.

So, the investments that we're making now into figuring out where to site it, how to remove barriers, how to create incentives so that we can have low impact deployment of large scale solar at the pace and scale needed I think is lest regrets strategy.

MS. BADI: Yeah, I want to echo that. And then, also, just reiterate that we're going to need a trained workforce in order to implement this. And so, it will

be really important to fund partnerships, fund training, and build that at the onset.

MR. FREEDMAN: Answer my own question. I think the action items in the next couple of years are to make sure that we are engaging in additional procurement of new resources so that we're not taking too much of a breather while we think about the long game plan. That we should develop much better protocols around greenhouse gas accounting, and particularly looking at out-of-state. And how we as a region measure progress. If you're going to regulate it, first you have to measure it. And I think there's a missing piece there and that's part of a long term game plan.

DR. WARA: I'm going to just -- I think that the continued procurement, even in the current context is really important to keep the forward momentum. At the same time, I think that we do need to be thinking about a long-term path that evolves toward a more regional energy market. The EIM is a really important start. The EDAM that will be, you know, moving forward this year as sort of a deepening of that.

And I actually think that those tools or those new markets are ways to solve some of the accounting challenges that Matt has mentioned. There's been a very constructive dialogue -- well, at times. Yeah, there's

been a very constructive dialogue between the ARB and the ISO on these accounting issues with respect to the EIM. And it's led to different approaches that are more sophisticated and more nuanced, and they take account of the market factors to which Matt is referring to some degree. Not perfectly, but to some degree.

And I think we need to keep working on those accounting questions as a way of deepening our regional connection. We have these regional connections. They're going to become increasingly important to achieving a cost effective mix of renewables as we move forward. And I think, as I've said, you know, because of the challenges we face, cost effectiveness just has to be central to getting to the goals.

MS. SEATON: Yeah, I think on the accounting side and kind of the analysis side, having a full, very transparent understanding of how we're calculating our greenhouse gases throughout, in addition to the other elements of environmental justice in terms of the working into our analysis the air quality impacts, and benefits, water, et cetera, and community engagement -- community cohesion and engagement.

And I just think, I think where we have flat in our climate policy on the transparency side, and that needs to change immediately.

MR. GUNDA: Thank you. I have one question.

COMMISSIONER MCALLISTER: Can I actually jump in real quick?

MR. GUNDA: Yeah.

COMMISSIONER MCALLISTER: I guess, so really appreciate your being here, this is great. And all your perspectives really complement each other quite nicely. It's a really nice panel overall and very stimulating.

I wanted to kind of draw out what I think -- I'm not sure if it's a difference of opinion or just sort of the way you stated it, but between Dr. Wara and Mr. Freedman.

And, you know, I think, you know, Mr. Freedman you've heard this before from me. And, you know, you -- I totally understand with your ratepayer advocate hat on you're like don't rely on time-responsive rates. You know, I get that.

Like, I mean I feel like there are equity concerns that absolutely have to be addressed. And maybe it is that we're not mostly talking about residential and we're talking about other pieces of the economy.

But I guess I wanted to kind of ask both of you, and feel free to expand on this anybody. In terms of -- and then, just, you know, we've mentioned carbon signals

and, you know, sort of the carbon content of the grid, and going hourly. You know, what is the role of that ecosystem in our view of like taking signals from what the grid needs, reliability, carbon content, you know, whatever. Whatever, what we're trying to achieve with SB 100, and putting those in front of the consumer really at every level, all the way down from the supply down to the consumer. Like that ecosystem, how powerful of a tool do you see that as being as forming part of the solution?

You know, there's a lot going on in both of our Commissions along these lines, and load management and, you know, some legislation we're implementing, and building standards and, you know, many, many fronts.

And I'm hopeful that that ecosystem can help us. That those tools, and particularly the digitization, you know, sort of evolution of those tools.

But I also don't want to get out of our skis and, you know, use it in -- if it's not going to be really a core tool.

So, I guess I'm curious as to how, you know, your feelings are evolving about that? I don't know, si that a clear enough question for you?

MR. FREEDMAN: I think I understand the question, Commissioner.

COMMISSIONER MCALLISTER: Okay.

MR. FREEDMAN: Thank you. And let me just clarify, my point in raising rate design was not to knock on time of use or dynamic rates, but simply to respond to what I understand to be some of the commentary coming up recently that if we just fix rates, rate design, we've solved the affordability problem. And this is a different issue. It doesn't make everything cheaper, it just moves money around.

If we change the rate design for all of us here at this table, some of us are winners and some of us are losers. That was my point.

Now, the role of time-of-use rates is a really interesting topic. And we're actually facing this really fascinating challenge where time-of-use rates are being designed based on wholesale costs. But that's not matching up with environmental impacts.

So, if you wanted to design rates to take into account greenhouse gas emissions, they would look quite different than the time-of-use rates and the dynamic rates that are being developed today. And in fact, they may be so complicated that nobody would be able to respond to them unless it was completely automated.

One thing that a lot of us have talked about is the idea that the optimal form of customer response is

kind of set and forget it, rather than customers having to pay attention to when rates are changing. Because at least at the residential level customers are overwhelmed and confused about pricing.

And so, you want to have everything designed to be kind of opt in. Where customers, to the extent that they have shiftable load they make a decision once, and they kind of forget about it, and their load shifts automatically.

And there are some opportunities for that and we definitely need to design rates to encourage customers to do that.

We also want to be careful about setting rates with such high expectations that everyone is going to opt in and join it that we end up getting a lot of free riders.

There's a large diversity of customers at the residential level with different load profiles. And every time you set a really attractive rate, with very, very deep off-peak discounts, there's a bunch of big users who are structural benefiters and will see huge savings just by opting in without changing their behavior at all.

So, the challenge of rate design is how do you construct these interesting rate options to incentivize

incremental behavior. I think that's the holy grail and I'm not sure we've figure it out, yet, but that's what I think we should be looking at.

And then, one more thing would be sort of the opposite is the proposal to just create mega-fixed charges. What if everybody just pays the largest of the fixed charge, a hundred bucks a month and usage is free. Well, that creates its own set of really big problems and I would not encourage us to go down that route.

COMMISSIONER MCALLISTER: Great, thanks.

COMMISSIONER RANDOLPH: I'm just going to kind of make a little bit of an editorial comment. I really appreciated the conversation about kind of no regrets steps for now because I think it's really important that we have this discussion to consider the limitations of this report. Right. To Matt's point, you know, this is not -- you know, we cannot project out to 2045. We can just try to understand where we are now and where we see ourselves going.

And the legislation says every four years we're going to go through this exercise. So, I think it's really important not to get too bogged down into sort of assuming that we're going to be able to map it all out.

Like, you know, as an example one of the resources we have on our list for RPS Plus is gas

generation with carbon capture and storage. And as we heard at the last panel nobody is thinking -- you know, nobody is thinking about that here for our, you know, gas-fired generation resources in the state. So, to me that's sort of part of the bucket of some of the things that we need. Like, longer duration storage that can be more locally sited. You know, things like that that would -- we need to be thinking about what we need. And we have to be comfortable with the fact that maybe we don't have it at this moment, but we need to be trying to work towards it.

So, I -- but we also need to be thinking about the short term. So, I appreciated the no regrets conversation. That was very helpful to hear.

DR. WARA: I'll just respond quickly to your question, Commissioner McAllister. You know, I think it's very odd to have a market with a vertical demand curve. Right. And we need to -- whatever we can to move away from a vertical demand curve benefits everyone.

The challenge I see, I think there are sort of twofold. One -- or the opportunities, maybe. One is to push consumer device manufacturers to build in exactly the kind of technologies that Matt referred to where -- and I'll just give examples from my personal life. We

have two electric vehicles in our family. One is entirely programmable to gain the time of use rate. The other requires me, out in our driveway at eleven o'clock at night, or midnight before I go to be, to plug the car in. And we could -- you know, or to buy a separate charger that costs several hundred dollars more.

And I think to the degree that we can push the device makers to make things as, you know, plug and play, like sort of set it once and forget about it as possible, the more successful we will be in moving from a vertical to a sloped demand curve for electricity consumption.

The challenge there, though, is equity. Right. I mean the people that are going to be most able to purchase these kinds of devices are people like me who are, you know, very fortunate and just straight up lucky, and have the resources to purchase things like electric vehicles. And it's going to be harder to put those devices in the hands of folks who have fewer resources and are struggling to afford life in our state. And I think that's just a -- you know, that's a question that goes back to where do we -- how do we pay for these kinds of things and how do we create the right set of incentives. And I know that both of you are working hard to focus the incentives of the state on

lower and moderate income individuals. And I think that's a really important challenge.

But I guess I am very optimistic. I look around the ecosystem at Stanford and I see enormous numbers of companies that are trying to figure out exactly how to do that in way that maintains cyber security that minimizes the computational load for grid optimization and is actually, you know, set once and forget for the customer. So, that they might actually want to do it, as opposed to having to get up off their couch at 8:30 at night, which no one is ever going to do. So, that's --

MR. GUNDA: Thank you, Dr. Wara. Any other questions from the Commissioners? Okay, with that I would just like to thank the panel. That was some thought-provoking ideas and some clearly articulated questions that we ought to be studying moving forward in the study. So, thank you.

I think we would request you to just stay in your seats as we have some public comment.

MS. GALLARDO: Here we go. Noemi Gallardo, Public Advisor for the Energy Commission. I have a few people lined up for comments. Julia from the Bioenergy Association of California. After her will be Nancy, from the California Wind Energy Association. Then, Ben

from the California Solar and Storage Association. And fourth would be V. John White from CERT.

MS. LEVIN: Good afternoon Commissions, Julia Levin with the Bioenergy Association of California. I want to pic, up on a few things I've heard this afternoon that I think are really, really critical to the success of SB 100 and our climate and clean energy programs more generally.

The previous panel, I think all of the speakers talked about diversity. They may not have used that word, but essentially the need to balance our portfolios.

The original RPS legislation, which Matt, Nancy Radar and I, you know, let the campaign to pass. Matt and Nancy were the brains and I was the loudmouth. The very first finding in that legislation is the purpose of the RPS was to increase the diversity of California's electricity supply and that was to protect ratepayers. It was also, obviously, to protect the environment.

But diversity is really, really critical in any complex system and I would say energy is about as complex a system as you could ask for. And we need to keep that in mind.

And so, to Matt's point about we're not ready to ban combustion. There may come a time when we are.

When we have sufficient technologies, fuel cells, others that can replace combustion, but we're not there and we shouldn't be foreclosing options.

In the case of bioenergy, I think I agree with a lot of what Phoebe said. There are some very polluting bioenergy facilities in the United States. And the goal for the last decade has to move away from those first generation, very large direct combustion facilities to community scale, more advanced technologies that provide far greater benefits to the gird with far fewer impacts. We really need to accelerate the development of those.

And particularly, Commissioner Randolph, under the BioMAT program, we're eight years in from the passage of the legislation that created it, SB 1122, and we've only procured 20 percent of the megawatts, and only a small handful of projects are actually online. So, we've got to accelerate the next generation of bioenergy which will provide far greater benefits.

In addition to the importance of diversity, we need bioenergy for climate reasons, more than any other resource. Bioenergy is the only form of electricity that can reduce short-lived climate pollutants. It is critical to meeting our 2030 climate goals. Nothing else we do in the energy sector is going to have any

impact on the climate in the next decade, or five.

Reducing short-lived climate pollutants is the only thing we can do that will make a difference right away in terms of energy.

It's also important for our midcentury goals. Lawrence Livermore National Lab released a report a few weeks ago. I left you executive summaries of it. That say that we can get to carbon neutrality with existing technologies and very cost effectively my midcentury. But to do so, we need to invest a lot more in carbon negative emissions. Bioenergy is the only form of electricity that can provide carbon negative emissions.

So, for all of these reasons we need a diverse portfolio. We need to move to the cleanest possible sources and we need to continue to invest in bioenergy. Thank you.

MS. RADER: Good afternoon, Nancy Rader, California Wind Energy Association. A lot of interesting comments today. I want to direct to a couple I just heard, and then one actually from the first panel.

First, I just want a word of caution on Nature Conservancy's recommendations. The type of screening that Erica talked about resulted in the prohibition of virtually all win energy in the California desert, as a

part of the Desert Renewable Energy Conservation Plan, the DRECP. The problem is that this high level modeling precludes the analyses of impacts at the site-specific level. And that's very, very important not to do this planning from 50,000 feet, but to actually allow the evaluation of particular sites which may perfectly appropriate for a wind energy project.

Second, I wanted to support basically everything Matt said, but in particular on behind-the-meter solar. And just wanted to note, Matt, I'm not sure if you're aware that for this SB 100 evaluation they are -- they did say earlier that BTM solar would be treated as a candidate resource. Which is different from what we've got on the IRP that's currently on the table, where very high levels of expensive BTM solar are being baked into the portfolio. So, I was very glad to hear that this morning.

And lastly, I just wanted to put forward for consideration a modeling scenario that would shed more light on resource diversity and that relates to a lot of the points that have been made. When we talk about resource diversity, there's the diversity that results from properly accounting for indirect cost and the declining capacity value of a dominant technology.

And the proposed methodology gets at that. It

captures all those indirect costs and the declining value of resources as they increase penetration.

But if that doesn't produce much of a diverse portfolio, there's still the risk reduction value of resource diversity. Diversity sort of for diversity's sake. That addresses a number of risks, technology risks, operational risks, and other risks that will exist in a portfolio that's dominated by a couple of technologies.

There's also benefits that come from some of this technologies, as Julia just mentioned.

So, my thought is that it would be useful to look at sort of an insurance premium scenario. What would it cost us to get a little bit more diversity in the portfolio? Or, bring up in time some of the diversity that maybe shows up in 2045. But maybe we start, like Delphine said, start testing some technologies now that may be needed later. I think Matt also touched on that.

So, that's different than the way we're looking at it. Really, all the modeling that is being done now is looking at the least cost portfolio. Least cost under this assumption, least cost under that assumption. But we're not looking at, gee, could we buy a little bit of diversity for a relatively small premium. And I

would hope that maybe that would be a scenario that could be looked at. Thank you.

COMMISSIONER MCALLISTER: Thanks Nancy.

MR. DAVIS: Good afternoon, Ben Davis, California Solar and Storage Association. Thank you for the opportunity to provide comments.

Distributed generation solar doesn't really plan a role in the current modeling, but I wanted to provide a couple reasons for why we should consider it moving forward.

First, it is my understanding that the current modeling does not link the cost of new clean power production with the cost of new transmission and distribution infrastructure. And as we electrify buildings, and as we electrify the transportation sector, which will cause loads to skyrocket, distributed generation is one way to largely avoid the cost of transmission and distribution infrastructure upgrades.

Second, in order to hit the SB 100 goals, we obviously need the build out of renewables everywhere. It sounds like we need three or four Yosemite's worth. And in terms of solar, one advantage of rooftop solar, as folks know, is that it uses the built environment and does not contribute to society's footprint on our natural spaces.

Third, this probably goes without saying, but the more behind-the-meter solar and behind-the-meter solar and storage we have, the less total energy needs to be produced by or produced on behalf of the utilities. And, therefore, the less clean energy utilities need to produce. And that's important because it makes it easier to hit the state's clean energy goals.

So, forgive my layman simplification, but if California's total energy needs in 2030 is 500 terawatt hours, but 100 terawatt hours are behind the meter, that means you'll need 60 percent of 400 terawatt hours to be clean, rather than 60 percent of 500 terawatt hours to be clean.

And then, fourth there seems to be some ambiguity on what it means that renewables need to supply a hundred percent of retail sales. And there's some discussion, I think, on whether the clean energy that we lose from line loss and from energy storage can be made up with dirty energy.

One, this seems a little backwards. Whenever a clean energy is lost, we should need to make that up with clean energy.

And then, two, this also I think very much speaks to the importance of customer sited solar because

with that we don't have the line loss issues.

Thank you.

MR. WHITE: End of the day, Commissioners. It's been a good day. Lots of interesting comments. I'll try to be brief.

I wanted to make a point, though, that was mentioned earlier that the idea that somehow the SB 100 process is separate and distinct from the IRP. In fact, the SB 100 process is building on the platform of the IRP. And to the extent the IRP gets things wrong, it's going to affect everything.

So, I want to point out that we filed our comments at the PUC on the second phase there or P decision in this docket. And we're going to file on a proposed decision from March 12th from this docket. And we hope you'll pay attention to these comments because they're important in terms of where we see things headed. And I don't want to commit an ex parte violation. But I'll just say that one of the suggestions that we made in that docket filing was the lack of engagement, which you all corrected today, across the different LSEs.

The IRP process is focused primarily on the investor-owned utilities. There's some reference to the

CCAs, but the POUs are not involved.

And one of the things I'd like to see for purposes of one of your next meetings is hear from all the LSEs. Maybe just do Southern California and have Edison, LADWP, and the Southern California Clean Power Alliance, and just say what do you all see and how do these things fit together.

Because I think as we saw in the LADWAP presentation, they're going about things in a very different way. They don't have RESOLVE. They have scenarios. And they are looking at distribution, transmission, generation, demand response and so forth in a more integrated, holistic fashion than others.

So, I think it's important to bring the LSEs together and see how these pieces might fit. Because it's not just that we want to get everybody's IRP to be the same, we want to see how they fit together and how we can share.

For example, if SCE and LADWP both are pursing these same goals, there's going to be crossover that we need to take account of.

I want to also thank Matt Freedman for raising the issue of equity on behind-the-meter solar. I think that one of the things we're going to have to do is to reinvent net metering, time of use rates, and demand

response. Right. Flexible demand is a really crucial thing. But time of use rates connote something narrower.

I think one of the solutions to the solar behind-the-meter dilemma is that the solar folks ought to be paid for the value they create and the services they provide that the grid needs.

Most of the -- and I'm a big fan, worked on the Million Solar Roofs Initiative, and so forth. But we don't have the same circumstances now that we had when we started.

And so, for example, if you have the ability to send power to the grid, when the grid needs it, you should get paid. But if you're sending power to the grid when the grid doesn't need it and you're getting paid retail that doesn't work, okay. And that's not fair to the other customers. But more importantly, it doesn't send the right signal about what we want to do in the future.

So, lastly, I think that the idea -- I want to commend Commissioner Randolph for initiating a proceeding on the transition for natural gas. I think we need a just, equitable, orderly transition. But we also need recognize at this moment we're kind of heading the other way with once-through cooling and some of the

others things.

But a planning process for the transition to gas is important for some of the reasons that Matt mentioned. Thank you.

COMMISSIONER MCALLISTER: Thanks.

COMMISSIONER RANDOLPH: And John, just to be clear, I wasn't trying to say that IRP and SB 100 were separate. It's just that IRP is necessarily more granular and goes up to 2030, as opposed to this sort of longer-range planning exercise.

Because I take your point that, you know, we need to be consistent and heading in the correct direction either way.

MS. GALLARDO: We have a few more comments. Next up is Kaela Shiigi. And apologies if I've pronounced that incorrectly. Then, Roger Lin, and then Diane from CHBC.

MS. SHIIGI: Hi, my name is Kaela Shiigi and I'm from the UC Berkeley Environmental Law Clinic. Thank you for this house today.

I actually have a question for our panel. How do you propose accounting for or addressing the social cost of carbon when planning for the future? Does anyone want to go? Go ahead.

DR. WARA: I'll take a pass at it. You know, I

think that to most -- for most purposes, the social cost of carbon is not incorporated into resource planning in California. But, certainly what is incorporated is expectations about future carbon prices within the Cap-and-Trade Program, which are mostly upward. Maybe not as fast as some of us would like but, nevertheless trending upward.

And so, over time the price of carbon will affect decisions, as long as we get the accounting right. As long as there's no way to game the system, and to sell your coal to someone else and ship hydro in, in its stead.

MR. FREEDMAN: Yeah, I'll just emphasize that. I think turning everything into a greenhouse gas metric for purposes of planning is very tempting. It's like one concept to rule them all. Right. One metric that drives every decision. But it does motivate some pretty unusual gaming strategies. Not everyone is a good actor and there are ways to manufacture compliance that don't look like they're the next steps forward towards the total transformation of the system that we're looking for.

So, I just want to provide some caution on using greenhouse gas emissions as the single determinant for planning.

MS. SHIIGI: If no one else has comments, thank you for your time.

MR. LIN: Roger Lin with U.C. Berkeley and the DAC Advisory Group, again. Thank you panelists for your time. And this is more of a comment than a question for you all. Sorry.

But the state's climate policy does require the consideration of when we go to cost effectiveness, which I agree should be at the heart of these inquiries for SB 100. The state's climate policy does require the state, and especially ARB, who unfortunately are not here, to consider the social cost of greenhouse gas emission reduction strategies.

On that note, a common theme that's emerged today is equity, which is great. But another common theme on top of that is that the burden is on the equity organizations or individuals to actually provide suggestions on how to meet equity. And I think it should be reversed and there should be some proposal given to the public for us to then comment on.

And a good starting place, again in ARB's absence, it's not first, but a good starting place would be for ARB's work on the social cost of greenhouse gas emission reduction strategies. The 2017 Scoping Plan provided some estimates and that was subject to being

reworked.

We heard today that this -- part of this proceeding is a rulemaking, and to also determine the 2021 scoping plan.

So, the Disadvantaged Communities Advisory Group is looking at this issue. It's a priority issue. And it would be nice to have at the next meeting of ours, or a subsequent meeting or ours an update on where ARB is on that question.

COMMISSIONER MCALLISTER: That sounds like a good suggestion. I'm not sure how we carry that forward but, yeah, great.

MS. MOSS: Hi, Diane again from CHBC. Just apropos of our discussion this morning about including zero carbon hydrogen as an eligible form of storage and electricity generation in the implementation of SB 100, I don't know if folks saw this across their emails, but I did, that Senator Nancy Skinner just released SB 1122 today. That would clarify that the Energy Commission, and the PUC, and ARB should consider green hydrogen as a zero carbon emitting resources in any plans developed to help California reach 100 percent zero carbon electricity by 2045.

And her press release does call out electric utilities like LADWP, which are now experimenting with

-- I'm just reading off her press release -- with repowering existing natural gas peaker plans to operate on green hydrogen instead of gas.

And it was really heartening to hear today that there's already some willingness to consider this type of application of hydrogen in SB 100 implementation. And instead of, you know, just waiting for legislation to spell it out as a mandate. And it's also great to hear that hydrogen fuel cells are considered in the capacity mix as a flexible dispatchable resource.

So, CHBC, of course stands ready to help, to answer questions, to address concerns. All of this is sort of nascent and new, and there's a lot of work on plates, so I think certainly we're here to help.

And I'll just lastly say that there seems to be broadening consensus among the last two Obama Energy Secretaries, the DOE, Bloomberg New Energy Finance, it just seems like there's a report every couple of weeks now that points to the great potential to see cost reductions, because we don't want to see just, you know, overblown costs in all of this transition, of renewable hydrogen in particular. And in particular electrolytic hydrogen with renewable electricity can -- that resource, the electrolytic hydrogen prices can also fall.

But all of these actually do point the policies are going to be necessary. So, that is something that we entrust the wise people in this room to undertake as their job. And like I said, we're here to help. Thank you so much.

MS. GALLARDO: No more comments in the room. I'll hand it over to Terra for phone calls.

MS. WEEKS: Great. It looks like we don't have any comments by WebEx, so we're going to go ahead and -- this thing is always a little risky, but unmute all the phone lines. So, we'll see if we have any comments from anyone joining by phone.

If anyone on the phone has a comment, please go ahead and speak up now.

Okay, hearing none, thank you all so much for your comments today. I'm going to hand it back over briefly to Siva for some closing remarks, and then final closing statements from the dais.

MR. GUNDA: Thank you again for being here today. And I will just kind of at a high level summarize some of the next steps for us as a team here. I would like to thank all the speakers and stakeholders who were present here, and for Commissioners for your time to helping guide this discussion.

I would also like to thank all the interagency

team who have tirelessly worked to put this together, but also been working behind the scene to take all your input into consideration as we develop the first report.

As Terra mentioned today, this is the first of several reports to come over the next 25 years. And the joint agency report goals at a high level, we wanted to meet the statutory requirements, provide some clear direction to the electricity market, coordinate planning processes across the different agencies, but also develop a consensus on the interpretation of the statute. And all of them seem to be moving forward in earnestness.

A huge part of meeting these goals, though, is to establishing a good interagency coordination process, developing a well vetted, comprehensive analytical tools to which most of the commenters, the panelists, the stakeholders today talked about a real need for a comprehensive analytical tool that can answer a variety of different questions.

And most importantly, the way to get to the goals of our collective agencies is to really have a good public discourse like today. And I would just like to take a moment one more time to thank everybody for being here.

And so, we'll continue to work on all three of

them. And just as we move forward, just kind of reminding the spirit of the analysis we all embarked on. At a high level, we would like this to be a clear process that establishes a comprehensive, robust analysis that stands the test of time. And as we develop each report we take into account, in a timely fashion, the emerging trends in the market. So, that's something we're going to work on.

But having said that, there are some clear things we are not able to do this very first report. And there are huge gaps in some of the tools we have. But we take into account all the different perspectives that were said today, and then figure out how best to approach them qualitatively this year, but definitely in a more quantitative basis moving forward.

I also want to just touch upon a very high level interaction between the demand and the supply side. So, the demand scenarios that we used today or we are using for the first report have been developed a couple of years ago, and it's going to be consistent with what IRP has done, and also what TNC has presented today, and a number of other studies.

But it's becoming more and more clear that these scenarios will rapidly change as we move forward and also has a huge supply side implication. So, that's

something as a team we are thinking about carefully as to how best to devise these scenarios on a regular basis.

We're also going to continue to develop models that can better support the resource portfolio development, taking into account land use considerations, but also equity and some of the main questions that were brought up today.

It is, however, important that for -- just kind of put it out there that we are working against three agencies and we are trying to form an analytical background and backbone that doesn't confuse different proceedings, and make sure that each of the proceedings plays out themselves.

So, it's important for us to figure out how best to develop the scenarios and analysis, and put in the public domain that actually advances the conversation.

Also want to thank TNC, LADWP, Hawaii in the past, and SCE for some of the innovative work that they're doing, and provide some thoughts for how best for us to move forward in the future.

An important remark that was made by Commissioner McAllister today is to just improve our ability to become more accessible as we develop this comprehensive analysis. We have a variety of

stakeholders that are really interested in this and will impacted in this analysis. So, we will attempt, as we are doing right now, to better make the analysis more accessible.

To this end we had a couple of meetings with the environmental justice group before this workshop to just help them understand what the analytical tools are able to do, and how to better articulate their questions so we can do something about it in this particular cycle. So, that's something that we're going to endeavor moving forward.

And also, I just want to -- before I close, I just want to make sure I acknowledge the limitations of the work that we are doing in this particular report, in the first one. But we'll continue to develop better analysis.

But also, the other side of the limitation is this SB 100 bill is for the electricity side. It's important to make sure we cross over and interlink a variety of different sectors and analyses that different agencies are looking into, but we also want to make sure the scope of this work is clearly defined and let the other proceedings play out as they are.

One big part of this report is going to be recommendations. And the recommendations is where we

would really like stakeholder engagement on. That really pushes forward and sets the framework for the future analysis. And also, develop recommendations specifically for those to be tackled in IEPR at CEC, IRP at CPUC, and the Scoping Plan that CARB is embarking on right now.

In closing, please make sure you continue your engagement. This is phenomenal. And we are all on the same team, pulling together to make California's transition more equitable, and as carbon free as possible.

And just to highlight the timeline, so we have a results workshop coming up late spring, and a draft report coming up late summer. And the report is due January 1st, 2021. And as we mentioned earlier today, we might pull together a working webinar to just kind of provide a kind of a status on the different scenarios we might end up doing for this year.

With that, thank you, and I'll pass it on to the dais for closing remarks.

COMMISSIONER MCALLISTER: Well, thanks Siva that was great. You didn't rob too many of my talking points.

But seriously, this has been a great day. I want to thank all of you for coming. All the panels

were terrific in their own way.

I want to thank Commissioner Randolph for coming over and visiting us from the PUC. And there's more to come on this. This is going to become a routine that one of our agencies or the other will be gathering regularly. And certainly, my fellow Commissioners here, and Chair Nichols via Rajinder. I really want to thank them for coming as well.

A big lift is analytical. I mean I think those of us who like data and, you know, a big wonkiness, this is a great, you know, this is a career making endeavor. We're going to be back here for the next 25 years.

But it also is -- it really behooves us to keep it real. You know, to keep it grounded, to keep it communicable, and to keep it accessible, as Siva said. So, I think we have to work doubly hard to do that, because it's not easy. It's very complex. It doesn't have to be as complex as sometimes maybe we make it, but it is inherently complex.

In particular, you know, I think how malleable demand is going to help us solve some of these problems. Because it's not just about -- the reason I asked the question before was really to get viewpoints on how much it can actually reduce costs. If it's just shuffling money, you know, money here and there, redistributing,

it's not actually -- that's not the main point. The main point is to reduce overall costs for everybody. If we can use demand, we can be more flexible with all this digitization technology we've got, storage, you know, to not just mitigate the operational challenges of the new grid, but also reduce costs overall and not have to rebuild the whole darn thing as we go forward.

So, you know, it needs to reduce the cost to the customer and certainly not exacerbate the equity issues. I mean, I think that's really what we have to pay attention to as we go forward or we're done. I mean we're just not going to reach our goals and we're not going to -- it's not going to be good policy. So, I think that's really, you know, how to use technology and automation, but serving people. I think that's really the challenge we have to keep in mind for the long term. And that's at all scales, right.

So, in any case, nothing more to add. I just want to again extend my thanks to staff, and Terra, fearless leader of this SB 100 effort at the staff level, and from Chair Hochschild's office.

And all of your contributions from all the agencies, and all of you in the room who've come and been with us all day, I think we're going to need more of that going forward. So, please, you know, just let's

keep at it, and let's build a good team, and let's all row roughly in the same direction whenever we can. Okay. And thanks a lot for everybody.

I think, are we adjourned or --

MS. WEEKS: We are adjourned.

COMMISSIONER MCALLISTER: All right great.

MS. WEEKS: Thank you so much.

COMMISSIONER MCALLISTER: Thanks everybody.

(Thereupon, the Workshop was adjourned at 4:29 p.m.)

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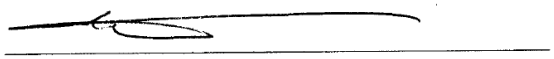

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