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BEFORE THE CALIFORNIA ENERGY COMMISSION

In the Matter of:) Docket No.: 15-IEPR-07
2015 Integrated Energy Policy)
Report Lead Commissioner Workshop)
)

SOUTHERN CALIFORNIA ELECTRICITY RELIABILITY

UNIVERSITY OF CALIFORNIA, IRVINE

STUDENT CENTER, BALLROOM C

IRVINE, CALIFORNIA

MONDAY, AUGUST 17, 2015

10:00 A.M.

Reported by:

Martha L. Nelson

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Michel P. Florio, California Public Utilities Commission

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Rexford Wait, Nevada Hydro Company

Brian Theaker, NRG Energy

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P R O C E E D I N G S

10:00 A.M.

IRVINE, CALIFORNIA, MONDAY, AUGUST 17, 2015

(The meeting commenced at 10:06 a.m.)

MS. RAITT: Hi. Good morning and welcome to today's IEPR Lead Commissioner Workshop on Southern California Electricity Reliability.

I'm Heather Raitt, the IEPR Project Manager. So today we're offsite at UC Irvine and having to do some workaround with our sound system and -- which is happening right now. So please bear with us as we work out the technical details that may be going on during the day.

A few housekeeping items. There's restrooms out the door to the left, down the hall. Upstairs on the second floor there's a food court with lots of food options and coffee. And we'll be taking a lunch break around noon for folks to go up there. There's stairs you can get to and elevator if you want to go upstairs directly to the right as you exit.

Materials for the meeting are on the tables as you enter. And Shawn Pittard in the back of the room will be taking blue cards. If you wanted to make comments, we'll be doing public comments at the end of the day, limiting comments to three minutes. And after we hear from folks in the room we’ll be hopefully taking folks’ comments from WebEx.

Written comments are welcome. The instructions for providing comments are on the public notice for the workshop which is available -- all the materials are available online. And written comments are due August 31st.

So with that, I’ll turn it over to the Commissioners.

COMMISSIONER MCALLISTER: Great. Thank you, Heather. So just to be clear of the rules, can people hear me right now? Okay. So I have to use that phone that phone, as well. Yeah. Okay. All right. Well, that’s the rule. Okay. Thanks for sacrificing your -- your cell phone here. Okay. So I’m hoping this is going to get a little -- we’ll just see.

So I’ll try to speak into two microphones at once here. And we’re getting a little feedback. If you could turn off the audio from this phone being piped back into the room, that would be great.

(Colloquy)

COMMISSIONER MCALLISTER: We still need to get rid of the audio back in the room. We still need to have it not piped back in the room.

THE COURT REPORTER: I need you guys all to be on mike because I’m recording from these mikes.

COMMISSIONER MCALLISTER: Uh-huh.

CHAIR WEISENMILLER: Oh.

COMMISSIONER MCALLISTER: Okay. Okay. Stay tuned, everybody. We still have some technical difficulties.

(Pause)

MS. RAITT: Okay. We're continuing to have some technical issues we're trying to work out. So we'll need a couple more minutes.

And also I neglected to mention that we are recording this, so there will be a written transcript. And you're being -- I just want parties to know they're being recorded. Thanks.

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

(On the record at 10:20 a.m.)

COMMISSIONER MCALLISTER: Okay, so let's get started. My name is Andrew McAllister. I'm the Lead Commissioner on the 2014 Integrated Energy Policy Report. And this is now our -- one of our keystone events, really, in California within the IEPR process. We know how important Southern California reliability is with San Onofre and OTC rules coming up, and for -- and a whole host of other reasons with renewables and integration of them, all sorts of demand-side resources, localized generation, etcetera, etcetera. There are so many interesting trends today in the electric sector. And we need to make sure that we're checking all the boxes we need to for reliability and for planning and for creating the conditions for cost-effective approaches to evolving our electric sector to make all those pieces fit together.

So I'm gratified to be here today with the dais, certainly Chair Weisenmiller, Commissioner Florio from the CPUC, Steve Berberich from the ISO, Barry Wallerstein from So Cal AQMD -- or South Coast rather, sorry, and Jonathan Bishop from the State Water Resources Control Board. Thank you all for being here.

I want to acknowledge the Chair and Chair's Office for really driving and putting this together, as well, this session.

President Picker and Chairman Nichols it looks probably will not be with us today, so they send their regrets.

Given that we're already 20 minutes into our day I'm not going to make any significant opening comments. We'll pass the microphone to the Chair so that we can keep proceeding moving and not shortchange the panelists who have a lot of interesting things to say.

So Chair Weisenmiller?

CHAIR WEISENMILLER: Thank you. Thank you, Commissioner McAllister. As you indicated, this has become an annual event ever since San Onofre went down. We’ve had a workshop in Southern California to examine reliability issues. This workshop has been -- I think Commissioner Florio has been, I want to say at every one of them so far, as I have, and as has Steve Berberich, and as Barry Wallerstein. So this has certainly been an interagency effort. It’s not easy but we are saying on progress to really monitor how we’re doing on getting the resources in place. We have a pretty ambitious plan, particularly every reliance on preferred resources. And we need to every year visit our progress to date. And I look forward to any sort of corrections we need to do.

Again, thanks everyone for being here, either physically or on the phone.

COMMISSIONER FLORIO: Thank you. A pleasure to be here today at lovely University of California at Irvine. The PUC has really moved from the planning stage to the implementation stage on these critical issues. And it makes it vitally important that we keep track of how well we’re doing. So today as a check-in, are we on track or do we need to up our game? And looking forward to some very interesting presentations today.

(Colloquy between Commissioners)

COMMISSIONER BERBERICH: Good morning, everyone. I’m Steve Berberich, the CEO of California ISO.

Commissioner McAllister, I appreciate you having me here today.

I think the representation here at the dais says everything about the import of reliability here in Southern California and the economic engine down here representing the water agencies, air agencies, reliability organizations, the PUC and the California Energy Commission coming together to make sure that we responded to the reliability needs down here.

As it relates to that, and per request of Chair Weisenmiller and Commissioner McAllister, today I think really points to a highlight of what we're dealing with. Today we expect probably the record loads for the year, about 45,000 megawatts across the state, very heavy loads. As everyone notes as they sweated as they walked in this morning, it's hot down here. And I think it just highlights again that we need to pay close attention to this. Representatives from the California ISO will talk about many of the upgrades that have been made on the system. As Commissioner Florio said, we're really in implementation phase at this point.

But for those listening, it looks like reliability will be okay today. It will certainly be tight. The good news is we don't have a lot of cloud cover over the solar fields, as opposed to last time when we -- when we were hot when we had monsoonal flows and we had very diminished solar activity at that point. So we should be close today, but we'll keep a close eye on and it think everything will be fine.

COMMISSIONER WALLERSTEIN: Good morning, everyone. I'm Barry Wallerstein, the Executive Officer of the South Coast Air Quality Manager District.

And I want to extend a very sincere thank you to the Commission for the invitation to join you again and, most importantly, the real spirit of partnership at which the CEC is proceeding on this IEPR. I think it's incredibly important. We're at a very important juncture and time relative to planning and air quality. The federal government has just promulgated new standards for greenhouse gasses for new power plants, as well as for the existing power plant. And so it's important that we look at the air issues, as well as the energy issues and how they interact.

Not only that, as I've mentioned in previous meetings, we have a major update of the Regional Clean Air Plan that will be submitted to EPA in about 11 months. So it's very important that the strategies that our agency brings forward with the California Resources Board that could increase energy demand be incorporated into our energy planning efforts here in the state of California. So I'm looking forward to the day and the information that's going to be shared with everyone.

COMMISSIONER BISHOP: Good morning, I'm Jonathan Bishop with the State Water Resources Control Board. And I also appreciate the opportunity to be here today and to be able to hear what's going on.

It is 2015. The first compliance dates for the once-through cooling are in a few months, the end of this year. And then they ramp up in 2017 to 2020 with most of the plants.

And so we are in the final stages. We've been -- the rules have been out there for about five years. And now it's time for them to come in -- come into compliance which potentially has a big impact on reliability. And it's important for us to understand where things are as we move forward.

Thank you all very much.

MS. RAITT: So our first speaker is Mike Jaske.

(Colloquy)

MR. JASKE: Good morning, Mike Jaske, Energy Commission Staff. Thank you for those comments. I will try to abbreviate my slide presentation here in the interest of getting us on time so that we can focus on the more technical presentations of the rest of this morning's panel.

So really the principle thing to say on this slide that hasn't already been said is that we're really anticipating, as Mr. Bishop said just a minute ago, that we would be having to deal with all of the same OTC retirements in San Onofre's potential retirement, or however it is it might have had to comply with OTC policy. It's just that the San Onofre issue came so much sooner than expected and sort of had, frankly, probably consequences that had never been fully examined since we hadn't had those two units down perhaps ever since their initial start date.

An important dimension of what you're going to hear today is that this is an ongoing project that sort of extends beyond the normal proceedings of all of the affected agencies listed agencies listed at the bottom of this slide, Energy Commission, PUC, ISO and ARB. Those technical staffs of those agencies, plus the assistance of the utilities and the air districts, put together that preliminary plan back in the last summer of 2013 and had that IEPR Workshop in September of 2013. That preliminary plan was never turned into a final plan, but the essence of that plan has been carried on since then through the collaborative efforts of the staff of the agencies. And these periodic workshops, as Mr. Florio said, are a way of apprising you of all -- all of you, as well as the public, about the status or any issues.

This slide, of course, is just in your package to give a little location for facilities if we end up talking about individual facilities here today. We're only talking about L.A. Basin and San Diego as the area directly affected by SONGS. The Ventura Big Creek area up there with Mandalay and Ormond Beach is not electrically connected in a way that is affected by the SONGS outage.

So the essence of this slide really is that all of the agencies are pursuing sort of their natural activities. But in addition, we have this whole contingency mitigation effort that cuts across the agencies in which we're working on in a collaborative manner. And we'll get into a lot of these details about that aspect of where things are in the presentations this afternoon, both where we are to date and some of the remaining issues yet to be overcome.

I think the first bullet, you know, can be exemplified in the example of the synchronous condensers that the ISO approved to be located across the freeway from the SONGS site. That land was controlled by the military. They chose not to allow that to happen. So that synchronous -- that pair of synchronous condensers was split into two, one located on the SONGS plant site itself, and one, I believe, up at Santiago. So that's an example of where, you know, within a category of activities, you know, there was a workaround that was found that is functional. And that may well be the case in other areas, if we observe that we're having shortfalls and we can find substitute programs within preferred resources, for example.

But where that's not feasible, where the shortfall may be something more significant, we're working on developing these mitigation measures, either OTC compliance date deferral or actually authorizing, permitting and getting operational a new gas-fired project. And how to go about that will be the focus of this afternoon.

And again, this slide will -- you'll hear me talk for probably half-an-hour on the this subject this afternoon, so I will just pass it by.

So today, as several folks on the dais have said, we're trying to understand progress to date, trying to assess where we are. We're going to be talking about these mitigation options, understanding where we are in that process. We're certainly going to absorb the input we have heard by the end of the day today, continue our monitoring, of course, and then at some point report to the energy principals about whether developing these more complex mitigation measures if the appropriate next step. Thank you very much.

MS. RAITT: Thanks, Mike.

Next is Michele Kito.

COMMISSIONER BERBERICH: Heather, if I might --

MS. RAITT: Oh, I'm sorry.

COMMISSIONER BERBERICH: No, no. Go ahead, Michele.

I just wanted -- some terms were used, synchronous condensers as an example. Many in the room, I know, know what synchronous condensers are. But just for clarity's sake, they provide voltage support. And as you need more power from outside the area into the area you get voltage sag and synchronous condensers help prop up that voltage. That's why they're important. San Onofre used to provide that voltage support. So we're going about replacing some of the things. You'll hear more about that from Tom Doughty. But just to make sure everybody is on the same page.

MS. RAITT: Go ahead.

MS. KITO: First, I just want to thank the CEC for hosting this and for inviting Energy Division Staff. My name is Michele Kito and I'm the Supervisor of the Resource Adequacy and Procurement Oversight Section. I'm just going to talk about our authorizations that went out, and then also the status to date. So most of you are already familiar with this, so I won't take too long.

Next slide please. Oh, I can do it here? Oh, thanks. Okay.

The reason we have this slide up is the long-term procurement plan process is where we do our authorizations for new resources. The LTPP looks ten years forward and looks at system and local reliability needs. It also considers alternative futures, so they'll have different renewable portfolios, different transmission scenarios, and also different demand and supply.

So the reason we're looking at 2012 LTPP is because this is where the major authorizations came from. So the -- there were two decision that came out of the LTPP. The Track 1 decision was primarily addressing the retirement of the OTC unit. So that was focused just on what we need to replace the OTC. During that process the -- we had the premature retirement of SONGS. And hence, we did the Track 4 of the LTPP, and that looked at any additional authorizations that we needed to meet the local capacity needs stemming from the retirement of SONGS.

So this slide is just to say that not all resources meet all of our needs. So we obviously are concerned about reliability, as well as state policy objectives. And I would also add to that, repair costs.

So some resources are GHG-free. Some resources provide more reliability. But it probably takes a mix of resources to meet all of our needs and objectives. I would just add that this slide is only illustrative. It's not definitive. I've already gotten two calls to say that I should change these a little bit. But just consider it illustrative.

So this is the Edison authorization that came out of the two decisions. The first -- well, actually, I'll just go to the -- the bottom line. So the bottom line, basically, is that we've authorized between 1,900 and 2,500 megawatts for the L.A. Basin. And I won't go through all of these but there are various different categories, so preferred resources, storage, gas-fired generation, and then there's additional from any source and additional from preferred. And you guys probably have seen this before.

So these are the SDG&E authorizations. So Pio Pico was actually authorized out of a different decision, but we're just going to put this here for completeness. In addition, the Track 4 decision authorized between 500 and 800 megawatts for a total of 800 to 1,100 megawatts.

So with regard to implementation progress, Edison submitted an application for 1,882 megawatts last November for the West L.A. Basin. And this is just an overview of the selected offers. So there were 20 contracts for energy efficiency, 7 for demand response, 4 for renewables, there were a number for energy storage. And I would just say that there are two kinds of energy storage in that figure. So there's 100 megawatts that's in front of the meter, and 164 megawatts of storage that's behind the meter. So for a total authorization, again, of 1,882 megawatts.

So with regard to the status of that, the hearings are complete. Briefs have been submitted. And the PB (phonetic) is expected, and this is per the scoping ruling, 90 days after the submission of the case, which I understand to be the date of the reply briefs which was the beginning of July. So that would put it around the beginning of October.

So with regard to SDG&E, Pio Pico has been approved, and it's my understanding that it's under construction. The Carlsbad Energy Center was approved earlier this summer. There are six applications for rehearing pending at the Commission. In addition, SDG&E has an all-source RFO that was issued in 2014. And they are -- well, it says where they are. And it's our understanding that the application would come in for consideration in the first quarter of 2016.

So I just wanted to mention contingency contracts because that comes up some. The Track 4 decision did allow the utilities to come in with contingency contracts but it did put some provisions on that, namely that they had to answer a number of questions. And I'll just leave it at that.

But I guess I would note that the staff would say that we are still in the process of examining the applications and authorizing the resources. And even with that the utilities at Edison and SDG&E have additional procurement that still could be done. So Edison will need to procure an additional 100 megawatts of preferred resources to meet their minimum authorization. And with that they still have 518 megawatts, and I put the 400 preferred in the remainder from any other source. So they still have the authorization pending.

SDG&E has approval for the 500 megawatts at Carlsbad, but it has additional authorization for 300 megawatts, 200 of which is a minimum for storage and preferred resources, and that’s 175 for the preferred and 25 megawatts for the storage.

So with that, I’ll be happy to answer any questions. No? Okay. All right. Thanks.

MS. RAITT: Thanks, Michele.

MS. KITO: Sure.

MS. RAITT: Next is --

CHAIR WEISENMILLER: Can you hang on one second?

MS. KITO: Sure.

CHAIR WEISENMILLER: The question I have is the other part of the preferred resources is sort of the underlying energy efficiency programs?

MS. KITO: Right.

CHAIR WEISENMILLER: And I just wanted to get a sense from you of how the underlying energy efficiency programs, what their status was for Edison and San Diego.

MS. KITO: So you mean in the LTPP we assumed additional achievable energy efficiency.

CHAIR WEISENMILLER: Exactly.

MS. KITO: And so are we on track to do that? That is a difficult question.

So on the one hand, when you do measurement and evaluation it's possible that we're not showing as much as forecasted. On the other hand, I would -- I think it sort of gets wrapped into load forecasts, which I think are moderating.

So I would say in some sense, maybe not as much as we thought. But on the other hand, it's not looking as bad as it could be. So I think loads seem to be moderating.

CHAIR WEISENMILLER: Thanks.

MS. KITO: Sure.

MS. RAITT: Okay. Next is Jim Avery from San Diego Gas and Electric.

MR. AVERY: Good morning, and thank you for the opportunity to come once again and talk about what's happening in San Diego, and what our weather forecast looks like and what does this mean for our reason for reliability.

It's kind of been an interesting year, just to start out before I jump into my slides. We have not broken 4,000 megawatts yet. Today we're trending -- our forecast was -- our forecast is still for about 38 to 65 megawatts on the system and we're trending almost 200 megawatts below that. Temperatures in our coastal regions are running in the mid-∘80s, and evening temperatures still running down about 70 degrees.

Inland temperatures are really one of the big trigger marks for us. Inland temperatures are running right about 90 degrees, but the evening temperatures are running in the mid to low ∘60s still. And for us, in order for us to get into peak load conditions we have to have our average temperatures in the region really get closer to about 85 degrees. And once they get to 85 degrees we break the 4,000 megawatt mark. And then for almost every degree above that we go up about 100 megawatts, somewhere between 70 and 100 depending upon how many days into that heat cycle we are in.

So even with the hot temperatures we’ve had over the last three to four days, with the evening temperatures still trending relatively light our temperatures and our loads are still moderate to low at this time of year. For us the time that I usually worry is -- the first week of September is typically the time that I worry the most because by then people are getting tired of the heat and the response in our region is not as robust has been earlier in the year.

You’ve already heard the numbers with respect to the procurement targets that we’ve been running for the region and the authorized level that we have.

With respect to the question as to the uncommitted energy efficiency that you just asked, there's another 300-plus megawatts of energy efficiency that is assumed in the forecast. I don't -- it's too early to suggest how we will -- or what those numbers will actually end up being and what we'll secure. But it is above and beyond the figures that you heard earlier.

Did you hear already the forecast for our solicitation. We issued it in September of '14. We received bids back in 2015, and we short-listed in the June time period. And we'll be having contracts finalized later this year, early next year for submission into the Commission.

You've already heard about what's the status with respect to Carlsbad. It is still scheduled to be online by the November 2017 time period. And Steve Berberich has promised me that once that is online, and he has a good indication it will be online, he'll allow Encina to be retired.

For us, really the secret sauce has been the Sunrise Power Link. I remember when we were pursuing this project we talked about how long it would take to fill the Sunrise Power Link. It ended up coming online in the 2012 time period. And within just a matter of -- well, just a couple of shorts years it has essentially has delivered all -- upon all of its promises. We are delivering well over 1,000 megawatts of clean renewable power across the Sunrise Power Link.

And I am very proud to say I don’t believe there’s been a single application filed at the ISO to take advantage of the capacity that’s made available by Sunrise Power Link to be anything but renewable in nature. And it’s something that a lot of people had asked us to promise. And as everyone knows, a utility can’t promise what other people will do. But it is delivering upon all of the expectations. And it has really been the primary reason that we haven’t had a lot of problems in the San Diego region over the last couple of years.

I’m also proud to say we’ve exceeded 33 percent renewable for SDG&E’s total portfolio. And we still have several projects that are slated to come on later this year, so those numbers will continue to climb through the end of this year and into next year.

And as for what is in store for RPS going forward, there’s a lot of discussions going on in the legislature and throughout the state as to what the future should be for RPS in California. I can say that we’re five years ahead of schedule, primarily because as we saw the falloff for things such as San Onofre, and as well as we saw the opportunities to take advantage of the capacity that’s been made available by Sunrise, we did capitalize on that. And we've been able to promote getting a lot of projects online expeditiously as we possibly could to take advantage of utilizing energy from clean resources to replace energy that was lost from a nuclear facility.

I do want to touch on one quick thing. This is something that we're working very heavily on in the San Diego region. We have now had, I believe it's eight consecutive years where we've received the ReliabilityOne award for being the most reliable utility in the western states. And that doesn't mean that every single one of our customers received the same level of reliability. It means that as a composite the entire system is posting numbers that demonstrate all of the things we've done to ensure reliability.

But outskirts of our area, and Borrego Springs is one of them, if you look on the map, it's the extreme end of our system electrically. I think the number is roughly 70 miles-plus of transmission to get out to Borrego Springs, and low voltage, 69 kV transmission to get out into that region. And it's a region that is susceptible to hailstorms and fires and windstorms. And just all kinds of incidents can take out customers for extended periods of time, so much so that it was not uncommon that a windstorm or an ice storm a fire could take out service into the Borrego region for hours on end, and at times for days on end.

And the Micro Grid Project that we put forth in the Borrego Springs area is one that through the initial phases of that we saw an immediate reduction of the amount of time it took to return service to that region. And with the additional grants that we've received from the CEC, as well as from the DOE, we have expanded that micro grid. So now we have actually covered incidents where we have had times when outages -- or power would have been out for nine to ten hours, yet customers saw less than 40 seconds of outage. And the phases that we've implemented since then would remove any form of outage to some customers in that region, just because the micro grid instantaneously returns or covers service.

And we have had that period where, again, just a few short months ago we had a period where we would have had a period where we would have had a nine to ten hour outage, we were able to serve the entire region of Borrego Springs for that time period with 100 percent of the energy coming from renewable resources.

And with that I just have a short video on this, if I can figure out how to do that, if you will indulge me. And my guess is we probably turned the sound off, so we don't even have a video anymore.

COMMISSIONER MCALLISTER: They can probably hear it on WebEx.

CHAIR WEISENMILLER: You can narrate it. Beautiful Borrego Springs.

MR. AVERY: This is Borrego Springs. I'll tell you what, I'll send this over to everyone. It essentially captures the intent of the Borrego Springs Micro Grid Project, the successes we've had and the things that lie ahead for us in the area, do further automation, integrate. And this is something where it integrates a large-scale utility-scale solar project with rooftop solar, with large-scale utility-scale energy storage projects with distributed energy storage projects and manages all of that to serve the entire region when there are any forms of disturbances on the system.

So with that I'll turn it over and see if there are any questions. I hope you enjoyed the video.

CHAIR WEISENMILLER: Yeah. A couple. I assume I'll see the video when we meet with the Mexican officials on Wednesday.

MR. AVERY: You will get an opportunity to see it. I'm going to show this everywhere, I'm sorry. You're going to get terribly tired of this video.

CHAIR WEISENMILLER: So a couple questions. One was on your RFO. Roughly what was the ratio between bids versus what you asked or what you need?

MR. AVERY: That’s kind of a trick question because when we receive bids we quite often receive multiple bids for the same product in different formats or different structures. So if you look at the total number of bids and the total number of megawatts, it’s many multiples of what conceivably could have come out of that process.

Essentially what we looked at is, when we did the evaluation on the overall solicitation, we looked at what would be the impact on our system, the least-cost, best fit analysis, and made a determination as to how do all of those projects stack up against it. Would it be a negative impact on rates? Would it be a beneficial impact on rates? And we drew the line essentially across those projects that would be beneficial to the grid.

We did receive a lot of projects, a lot of proposals for projects. It was just stuff is not economical. And what was really interesting, we received a number of projects or bids on projects for technologies where the bids were bidding something that the technology doesn’t have the capability to do, which another kind of a problem that we’ve experienced.

I don’t know the exact number of bids that have made it onto the short list. We are still doing some refining on some of the proposals that have come in to make sure that we fully understand what they are, to make sure that we didn’t lose any opportunities out of this.

I would caution and say we’re not going to select the full number of 300 megawatts out of this process. It will be something less than that. But the opportunities to pursue this in subsequent years I think will give us better understanding of what the potential is. But I’m cautiously optimistic that we can meet all of the requirements for preferred resources, or perhaps even far more in the preferred resource category than what we had originally anticipated.

CHAIR WEISENMILLER: Yeah. Obviously, I was trying to get the notion of how robust or at least were viable bids?

MR. AVERY: Very promising, I think is probably the best way to put it. I was concerned when we sent out the solicitation that we would receive a number of bids for -- or the number of bids that we’d receive would suggest there wasn’t a competitive market at this stage. We’ve received a very robust response to this solicitation, and that’s been part of the reason why we haven’t announced where all the contracts are. Because once we go through the process we identify a potential partner in the process. We then go through the contractual stages in here. What we find is that sometimes people bid things not necessarily interpreting it the way we wanted it to be. So we have to go through a little bit of a process to make sure that we sign a contract and we both understand exactly what is being provided in here.

And at the same token, we're depending on this for reliability. So we want to make sure that the contract is robust enough that we have a high level of assurance it's going to move forward. We don't want -- if you remember some of the early days of the PPAs that surfaced as a result of the renewable quest that we were on, we had a number of contract failures. And it was one thing when the contract failure was something that was effecting the availability of energy to meet an RPS goal. But when there's also capacity sitting behind it, we have to be doubly sure that the capacity is actually going to be there and that the resource can perform as it is promised to perform.

We are entering a little bit of a new era here today. This is not a situation where we're sitting with technologies that are very well known and that they're very reliable. To the extent that we have a gas turbine and the gas turbine has a failed component, it's relatively easy to get the replacement parts and get it back online, maybe not the next day but within a short order.

But at the same token, as we start moving on to just energy storage, as an example, energy storage is something that we're still learning as we go through the process. And as I said, we did have some bids that were presented where people bid the technology to do something that the technology does not have the capability to do. And then other bids where they were overly conservative as to what the technology has the capability to do.

And at the same token, we're acting -- we're acting -- asking all of the suppliers to provide assurances to us that if we're contracting for 10, 15 or 20 years that the product will be there for the 10- to 15- to 30-year time period.

So it's taking us a little bit longer to go through that to make sure that we have contracts in place that when we submit them to the Commission we're confident that the -- that the contract has the capability to perform.

CHAIR WEISENMILLER: You know, obviously on the best fit part, I mean, my impression is your -- the way your system operates you may have a lot of solar flowing through. So how are you -- how are you dealing with sort of over-gen types of issues in the evaluation?

MR. AVERY: Well, I'll very quickly respond with that's Mr. Berberich's problem more so than it is mine. But you've raised a very interesting point, though. The Sunrise Power Link provide a superhighway into the San Diego region from the Imperial County. And if I look back to 2004, 2005, before there was any of the new generation in the San Diego region, San Diego was truly a net importer of power. The flower -- the power flowed in from the north through Southern California Edison, and with load-in from the east from Arizona through the Southwest Power Link. With the additional of Palomar we saw really a new paradigm where there were a few hours of the year where power actually was flowing out of us, flowing into Southern California Edison out of system for a few hours out of the year.

Then with the addition of Cal Pine on the system, and then with the addition of the Sunrise Power Link, I would not be surprised that if I looked at our charts that power was flowing through us 8,000 hours-plus a year, flowing into Southern California Edison’s system through San Diego Gas and Electric’s system.

So with more and more of that power being intermittent in nature and that being out in the Imperial County and into southwest portions of Arizona, and that power flowing in through our system into San Diego, and then wanting to find its way into Southern California Edison’s system, it’s created some interesting challenges for our transmission planners as to how do we accommodate that.

The ISO -- and I’m going to talk about this in the next panel, has approved a number of projects to deal with some of that in the form of reactive support to facilitate the flow of energy into us and then out of us.

But also another thing to keep in mind is when you think about San Diego, we peak when there is a Santa Ana wind. While today and the last couple of days we've had some warm temperatures, they really were not as a result of strong Santa Ana winds coming into our region. And also because of the Santa Ana winds coming into the region forming the peak, for the most part that creates a situation where the skies in the Imperial County are usually clear. Now we may have some storm clouds that move over the mountains in the late afternoon hours. But for the most part there's a good correlation of the solar energy in the Imperial County and in the southwest Arizona with the peaks in San Diego. So we don't have quite the same situation where we have peak load conditions and a lack of the solar coming into the region.

But at the same token, our residential customers peak at 8:00 p.m. Our commercial customers peak 1:00 to 2:00 p.m. And our residential customers have peaked at 8:00 p.m. for 20-plus years. It's not a new occurrence on our system. But it creates an interesting dynamic where the overall system peak, because we really don't have any industry left in our region, our overall system peak occurs between the 2:00 and 9:00 p.m. time periods. And if you look at the correlation of the large-scale solar that has tracking on it, it covers a good part of that window. How it obviously doesn't cover the 8:00 to 9:00 p.m. or the 7:00

to 8:00 p.m. time period as well as I'd like it to. But it -- it doesn't create some of the problems, I think, that you might be anticipating.

And also you may remember -- now this is -- I'm going to be treading carefully here because I'm talking about some of the projects that are still up for, I guess, consideration. But I can talk about the fact that we have looked very carefully at every new fossil resource that we have added to the system to assure that it was flexible in nature and that it was not going to be another combined-cycle plant being added into our system.

You may remember that there -- that there were a number of applications that have been filed back in the early 2000s to put more combined-cycle plants in our region. And we have -- we have refused to pursue any of those because we saw and identified this -- I think the ISO has done a wonderful job of putting a name to it, the Duck Chart. Well, Rob O'Brien -- Rob Anderson actually first identified that situation in San Diego in 2007. And that has led a lot of our procurement activities around the idea of getting more peaker generation in the fossil nature so that we could not have some of the same problems of having to turn off generation in the middle of the day because of the abundance of solar power.

Now having said that we still haven't seen it.

And until Encina is gone we're not going to have all the flexibility that I think we need in our region. And that's actually one of the biggest problems with the once-through cooling plants is the lack of flexibility that they create on the system.

CHAIR WEISENMILLER: So my -- if I recall correctly, the PUC, when it -- when it approved the PPA for Carlsbad, directed you to do a study by putting some sort of clutch on it?

MR. AVERY: That was, yes, that was one of the requests that was identified was the opportunity to put a clutch on the facility so that the facility could also be operated as a synchronous condenser. We did have discussions with NRG, the developer of the facility. And as you know, they submitted their applications for the technology in a different fashion, just a conventional peaker type of facility and not contemplating the air emissions that would be associated with trying to operate that as a synchronous condenser.

In addition to that, it is a highly constrained region physically where they're building the facility. In other words, they're trying to shoehorn it in between the property that they have today and the railroad tracks and the highway so that they could fit this into the facility. And they came to the conclusion that they didn't have the permits in place or the permits that were under -- filed to contemplate the idea of changing the technology to include the clutch, number one.

And then, number two, the physical room would not have facilitated the installation of the clutch in their -- in their system.

Now, we do have -- and I'm going to talk about this again on the next panel, a number of projects towards putting synchronous condensers in the region. And in fact, the first one of those went online on Friday at the Talega Substation where two of those synchronous condensers were turned over to the ISO for operation. And my guys report that they have been doing a wonderful job just over the last couple of days in helping to stabilize voltage on the system to facilitate the flow of power through this.

COMMISSIONER FLORIO: We gave you a very tough assignment with this all-source RFO, having to compare very diverse resources with each other. How has that process been for you? And do you feel like you've cracked that nut or are there still some challenges to putting storage and solar and demand-response on in the same measuring stick?

MR. AVERY: I actually think that was -- from an optics perspective it's not an easy thing to explain. Because as you think of a conventional gas turbine you quite often think of it in terms of dollars per kilowatt year, and then you think of the fuel source that goes into it. Well, then when you try to compare it against a battery that has degradation curves associated with it, that deals with different forms of energy to store it, and you deal with the amount of hours it can be operated, it is a challenge. But I think it’s one that we’ve been able to handle in looking at all of the resources and essentially stack those resources up, so regardless of whether it is energy efficiency, demand response, energy storage, gas turbines, we can put it all on a level playing field so you can see side by side the benefits.

And that analysis looks at all factors. It looks at, for example, energy storage, how many hours a day can be dispatched, how many days over the year, if there are a parameters for that changing season by season. At the same token, gas turbines, that’s an easy thing to look at. We’ve been doing it for a long time. But we’re also putting in there, the analysis, energy efficiency, as well as demand response, and putting all of the parameters in so we can stack them up and look at them from a total cost basis.

I know we have a lot of people who wanted us to immediately say, what was the cost of a battery? Well, I can give it to you as the raw cost. But until you factor in all the components it can be a very misleading number. And I think it’s important that we -- it was actually needed.

And I’m glad the Commission gave us the opportunity to take the time and do that analysis. And it is something that we do share all of that with our PRG and the independent evaluators so that they can provide feedback and updates through the process.

COMMISSIONER MCALLISTER: Thanks.

CHAIR WEISENMILLER: Thank you.

MS. RAITT: Thanks, Jim.

Our next speaker is Caroline McAndrews from Southern California Edison.

MS. MCANDREWS: Good morning. Thank you for inviting Southern California Edison here today to talk about the Preferred Resources Pilot. We were not here last year. We were in the formative stages of the pilot. And we recently provided an update, a midyear status report which on the lower left-hand side of the presentation you can go to that link and get the status. I have a lot to say. I’ll try to do it quickly and succinctly. But again, there is more information there, so don’t feel compelled to try to digest it all.

So we spoke about already the drivers of the Preferred Resources Pilot, but I just want to highlight maybe the region. We’re pretty much smack dab in the middle of the region right here at this conference. It’s the southern portion of Southern California Edison’s territory, covering Irvine, Laguna Beach, Laguna Hills, portions of Costa Mesa, Tustin, Santa Ana. And the interesting part about this region is that it's really growing, much like different portions of our territory where perhaps the demand is flat.

We have actually, and I'll show you through the forecast that we've got over 300 megawatts of load growth through the ten-year period, and the pilot is supposed to run through 2022. So we're really addressing the drivers of the peak. This is the commercial and industrial customers between the hours of 10:00 and 6:00 p.m.

And one other thing I think that's key is that this region is coastal. So unlike some of the areas where solar might have a very large role here, we do see a role for solar, however, we do have to balance the coastal environment.

In terms of the phases, we are right now in the demonstration and proof phase. I'll talk a little bit about the -- some of the foundation that was done. There's also a portion in the upper north -- northern portion of the territory where we're really looking to accelerate the deployment of preferred resources in this region. If we acquire the greater than 300 megawatts of preferred resources to serve the load, that would be about a quarter of the load being served by these resources.

This is something that is different than maybe some other areas. Again, it's about 1,600 megawatts when we're done. That's quite a bit. We want to make sure that we can integrate and optimize the use of those preferred resources. So we're using some of the EPIC funds that we have to really deploy advanced technology. And we're also looking at what other types of requirements might we need in order to manage that high penetration of -- you'll notice distributed energy resources, which the DRP has coined that term. And so you could almost call this a DER pilot, but we were around before and we had Preferred Resources Pilot.

So going on to really what's driving us, we need to make a determination of whether or not these preferred resources can actually perform. And if they cannot perform in a way that actually meets the reliability needed, internally to SCE we addressed -- we identified a potential transmission constraint down in this region. And so by addressing the load growth in this region we feel that that transmission constraint will be resolved.

So in order to address that issue, and if the preferred resources cannot perform, we have to set ourselves up on a timeframe. So the first milestone really looks to see if we can acquire -- acquire, deploy and measure those preferred resources within that first milestone through the end of 2017 and make a decision in 2018 as to whether or not gas-fired generation will be required.

And then once we have that determination, really the next phase really goes to just sustainability, what other additional processes might we need to establish in order to fully meet the 2022 need. So the need is actually out in 2022. Until then the area is -- has sufficient resources to meet the customer needs.

So in the first phase, which is the way of the foundation, we really did a local specific analysis to come up with potential portfolios. Those portfolios then would need to be filled in order to establish a pipeline. And so we have an acquisition strategy. The acquisition strategy really goes to, you know, how can we get these resources quickly, what are we authorized for, and really leveraging those types of capabilities that we have proven experience with, and then to test out some new acquisition approaches. So we also developed some grid-level measurements. That's really collecting, again, the very local generation or reductions that would be occurring as a result of preferred resources.

In Phase 2, which is where we are right now, we're continuing to build that pipeline. Some of you may have seen that we announced that we are potentially going to launch another 100 megawatts of an RFO for preferred resources later this year. We had one out that was a PRP-specific DG RFO, that all bids were due on July 10th. And we're in the process of looking through those offers. And then we've leveraged, obviously, some of the other activities that Michele talked about, the LC RFO. That was a very good feeder to at least our first milestone determination.

We were also looking at really the localized grid. Can we -- can those -- that localized grid adopt a higher penetration of preferred resources? Can they adopt a higher penetration of solar? We're looking at the effectiveness of the mix, how do they perform in concert? And really looking at their delivery capabilities.

And then as I spoke about before, the Phase 3 is really the second -- the later part, after we make that determination in 2018.

Looking at some of the foundational work, looking at Johanna and Santiago Distribution Engineering (phonetic), they do an excellent job of predicting the forecasts, what do we need from a system perspective, forecasting that out into the future, out into 2022. You can see in the upper right-hand corner, somewhat in fine print is that additive total of about 317 megawatts of need.

In terms of the peak months, that -- that peak in June through September. And then it's not enough to know what the peak is, but we really need to understand what are the attributes of that need? So if we're trying to offset the growth, that 300 megawatts over the existing 1,200 or 1,100-something megawatts, what does that growth look like and what does -- what are the attributes? So what is the daily megawatt need, the duration, hourly duration, and annual frequency of that need?

So, for example, if our peak need was up at, well, let's say over 80 -- if we've got 300 megawatts, if we have a peak need of the top 20 megawatts being called 15 times a year, DR, as it currently exists today, might not be the most optimal product because customer fatigue might set in. So we really have to look at what are those needs and how do we balance the portfolio.

So one example of a portfolio is listed there in the lower right-hand corner. And just building up from the bottom we have energy efficiency. You'll notice that we anticipate that we should be able to get over 50 megawatts of energy efficiency. It looks like a flat delivery. This is hours, by the way, so it's from the 10 o'clock hour to the 1900, 7 o'clock in the evening hour. You'll look at that, EE looks relatively flat. As time goes on and we develop more measurement information, we will inform it by the load shape for energy efficiency.

So if we've got energy efficiency reducing the load, we've got demand response being called those few times, as it turns out the number of times that we anticipated to be called is about five to six times a year, so demand response could/should serve as a viable resources, we can offset the peak with that light blue, look at the solar which is that red shape, you can see the red shape, it offsets the load, and then energy storage filling in the gaps. This is just one example.

Obviously, as we gather more information, as the cost of energy storage comes down, as we increase the, know, amount of solar that we're able to obtain, these numbers may -- may be able to move.

So how are we doing? I'll just try to give you a quick snapshot. This curve here, it's stilted because it drops off from 2017 and goes up to 2022. We have 113 megawatts toward our current 316 megawatts' target. And why is that current? Because each year we're doing an update to that portfolio design report. And we find, as an example, the first year we started this pilot the growth was about 20 megawatts, 28 megawatts for that year. The next year we did it was 32 megawatts for the year. So load actually grew.

If you are familiar with this area at all, there was this large marine base at Tustin, an air station there. They're fully developing that out with lots of new homes, lots of new businesses. So we -- that's where the growth is coming from. Data centers are coming in here. So lots --

lots of growth. Right now it's at 32 megawatts per year. We're in the process of updating our analysis again and we'll -- we'll see how -- how it moves.

That's -- what's interesting about that is because if we look at how much was actually deployed over that period from an energy efficiency standpoint we had about eight megawatts of what I'll say are the midstream and downstream programs, which the midstream and downstream programs, you know that they're coming into the region, so they are trackable to the region. And with that we still had that growth. So obviously key to that is we got to -- we got to look at what more can we do.

So looking at the first milestone, that's the 2017 timeframe, right now we have about 91 megawatts expected to be deployed by the end of 2017. And you can see, I'm not going to read that for you, the sources of where they're coming from, again consistent with our acquisition strategy which is really in the near term we are authorized through our customer service program, through our DSM portfolio, through the things that are coming through CSI to get these resources deployed very quickly and see them in the system. And that's where that 23 megawatts is coming from.

In addition, that 23 megawatts is also coming from customers just adoption. They're adopting solar, so that's driving the numbers up also.

And then we have the acquisitions which the LCR RFO, we have some contracts coming online, energy efficiency, in 2016 which, again, we're very excited about that because we'll be able to then get some real good measurements and see how is it really affecting the load in this region.

COMMISSIONER BERBERICH: Caroline, could I ask you a question quickly, actually two of them. I want to start with the solar. How -- is that going to be larger or distributed? Do you expect to put it at substations or is rooftop solar? Can you describe what that might look like?

MS. MCANDREWS: Absolutely. So we have a real challenge. We're talking urban area. And we're talking about an area that's growing. And an area that's growing means land is money. And business owners, business property owners, they do not want to tie up their assets. So I will tell you that we are challenged right now getting urban solar in here. So we are serious about it and we did get offers. And so we hope to communicate how serious we are.

It really is going to be things such as carports' rooftop. There is not land really to develop solar.

COMMISSIONER BERBERICH: Okay. That was my question.

MS. MCANDREWS: Uh-huh.

COMMISSIONER BERBERICH: On energy efficiency, what kind of tactics do you plan to deploy to get that kind of low energy efficiency?

MS. MCANDREWS: Okay. So first, energy efficiency, obviously, is a good overall load modifier and so we -- but it's very difficult to translate that into something that we could use for distribution planning. So we expect to just see that in a change in the load growth from year over year.

We have identified, working with a couple of vendors, a potential tactical use of energy efficiency where certain types of customers, building types, energy efficiency measures may be able to be deployed to defer local distribution upgrades. And in that midyear report there's an example that you can look at on how we hope to use that. We could use that both tactically near term once we develop some confidence level. But right now we're looking at probably about five years to see how that -- how that -- how that fleshes out.

COMMISSIONER MCALLISTER: Can I ask a follow-up question on that?

So I'm interested in the methodologies you're using for that. I mean, when you're -- when you have lots of small loads and lots of small impacts, quantifying that in terms -- and then comparing it to some of the larger scale options, supply and demand is a challenge but I think it’s one we have to rise to. And I’m wondering sort of how you’re approaching the methodological issues there and how you anticipate those informing then the forecasting work that we do at the Commission that gets used across the land in terms of quantifying that for AAEE purposes, but also for other parts of the demand forecast?

MS. MCANDREWS: Okay. So I’ll try to -- hopefully I’ll answer your question, and check me if I’m off.

What we really want to do is see both at the AMI and at the substation level the impacts of this type of tactical energy efficiency. And so while we know that if we change out the HVAC we can put sub metering on and see that it’s actually operating more efficient. But behavior has such a large impact on energy efficiency.

So what we’re looking at is what are those predictable types of loads that could actually show a net difference. And to the degree that it informs that -- your forecast, I’m not sure how we’ll factor that in. But I will tell you that we are really looking at the actual megawatt saving that our distribution planning folks can use in their planning process.

COMMISSIONER MCALLISTER: Okay. So thanks.

And then, sort of taking that one step further, there’s a lot of synergy between demand response and efficiency. If you’re going to change out equipment it ought to be both efficient and manageable. So I just kind of want to hear your reassurance that you're making sure that your program designs reflect that, and your investments in those targeted areas do look at all those opportunities and synergies between them to harvest both the demand side, you know, the capacity reductions and the energy efficiency, potentially.

MS. MCANDREWS: Absolutely. We're -- we're promoting and pushing the loading order. So, I mean, energy -- in fact, some of the schools that we've been engaged with, talking with about using some of the Prop 39 money, as an example, many of them have already done the energy efficiency upgrades. We're trying to now see if they can get them to the next level of demand response and solar. And some of the schools are moving -- obviously, a lot of the schools are moving in that direction.

COMMISSIONER MCALLISTER: Thank you.

MS. MCANDREWS: So going on to the deployment page, what you see here is really progress being made, largely through the DSM portfolio and the California Solar Initiative, as well as the distribution generation solar that's coming on through non-CSI.

What we see as a real challenge is demand response, and mostly because there's been a lot of focus down in the SONGS region over the last few years. So there's a lot of saturation associated with signing/enrolling additional customers.

The other part to that is that right now the way the contract -- the program is designed, it doesn't have that long horizon. And when we talk about the need in this area, the need is in 2022. Well, our programs are year-over-year kind of programs. So, you know, we need to think about how do we get the persistence that we need in demand response. And that's where the LCR contracts really are beneficial because we do have those kinds of -- that kind of persistence.

In terms of measurement, clearly this is not the endpoint. This is actually -- if you look at this curve, September 16th last year was our peak day. And while we anticipate that in 2022 the demand is going to be significantly higher, this is an illustration of how we have measured performance.

So the blue is the load. I would say but for -- but for the preferred resources, the load would have been up at that dotted line. And so just dissecting it, we've got solar offsetting it, demand response by the various programs which happened to have been called on that day, and then we have this dotted line which is the energy efficiency. And again, this is the one where we don't have the technical AMI data to prove out that dotted line, so that's why we made it a dotted line. And really that's focusing on the midstream and downstream programs.

COMMISSIONER BERBERICH: Caroline, if I might, and just for the benefit of everyone, I want to give hats -- hats off to Edison. They have introduced quite a bit of demand response in the last 12 months into the ISO markets, and they've been very helpful this summer. And we truly appreciate that and the efforts that you've done. It's -- it's been -- gone a long way to help, which is what we're talking about today, to the reliability efforts. So thank you for that. And we look forward to continuing to grow that.

MS. MCANDREWS: You're welcome. And, yes, we are looking forward to continue growing that also, particularly the BPI customers -- the BIP customers.

Moving on to maybe sort of the summary here, we're really looking to improve the commercial property owners, as well as the institutional customers, because they really can contribute quite a bit in this region increasing their solar and demand response participation. We're also looking just beyond some of the -- some of the barriers that exist. So we know that we have a lot of lease buildings. We have a lot of owners who don't necessarily have access to the accounts.

So customers, the tenants, as an example, tenants aren't necessarily in -- they're in control of their electric bill, but they're not in control of their building. And so what we've done is actually partnered with a local commercial building owner down in this region. We're testing out right now a way in which the owner can directly apply for incentives for energy efficiency upgrades. As we gained -- gain knowledge in this area we're going to broaden that out, both to the PRP area and as we can process -- make it more of a process, out to the larger SCE territory and, obviously, sharing it with our -- our peer utilities.

We're looking at what do we need to do in order to reinforce the grid. And looking at the local reliability products also. This is really key because sometimes -- sometimes the system needs don't always match the local needs, and that's really a challenge. So, for example, you talk about the Duck Curve. In the PRP region we have about three percent or less of solar. We don't have a Duck Curve. If -- from a pricing standpoint it becomes cost effective to charge energy storage during that timeframe. It really exacerbates the problem down locally for us. So we really need to think about how -- Edison is thinking about how do we really optimize these resources so that they can really serve our customers the best.

And then obviously as we collect this measurement information we want to really work on improving our grid planning purposes to -- process to take advantage of these distributed energy resources.

With that I'll hold for questions.

CHAIR WEISENMILLER: Thanks. I had just a couple questions.

First, the general question is: Having gone through what you've gone through so far, what would be your advice for like Jim Avery as they start going into this area?

MS. MCANDREWS: Okay.

MR. AVERY: Careful.

MS. MCANDREWS: You know, when we started we got a lot of input. And there was this -- this idea almost of, you know, shot-gunning out trying things. And we really resisted and tried to be methodical and thoughtful about what we were acquiring, how we were using it. And I don't know if he needs this advice because I think he's probably doing this, but that is exactly how -- I'm glad that we did that, that we didn't try every idea that came up.

CHAIR WEISENMILLER: Yeah. So soon to be chair, channeling Mary Nichols' question, and that is whether you've looked at fuel cells as part of the preferred package?

MS. MCANDREWS: So we have. Fuel cells aren't quite as clean as the resources that we're talking about.

And right now Edison would like to focus on the resources that we've discussed, energy efficiency, demand response, energy storage and DG solar. If it comes down in the future where we can't establish that pipeline, we will then have to reconsider the use of fuel cells. But we don't feel we're at that point just yet.

CHAIR WEISENMILLER: And my last question, and one is, which we are often asked by the legislature, is where our programs are helping the disadvantaged communities, particularly coming out of the CalEPA model. So I don't -- so in terms of just trying understand that component, too, in your activities.

MS. MCANDREWS: So there are about 6,000 or so customers within our -- this region that fall into that low income ESA type portfolio. And as an example, on Friday at was at the OC Community Forum talking about the -- talking about the Preferred Resources Pilot to the stakeholders that outreach to those groups. So we are clearly reaching out to them and really trying to engage everyone. They have opportunities to get free appliances, energy audits, all kinds of things. And, yes, everything counts.

CHAIR WEISENMILLER: Okay. Very good.

COMMISSIONER MCALLISTER: Mr. Wallerstein?

COMMISSIONER WALLERSTEIN: So from an air pollution perspective, it just seems to me that we're maybe going a bit slow on energy storage. And I've had a major power producer come in and speak with me and tell me their ready to go in a cost effective manner to a greater extent than we're pursuing.

And so when I listened to Jim's presentation and what they're beginning to do with energy storage on a micro grid scale, and the ability to expand our renewable generation, and in fact, the governor establishing in his State of the State Address, a higher target, I'm wondering why so low on energy storage?

MS. MCANDREWS: So currently the energy storage numbers that are reflected here came out of that first -- very first acquisition a year ago when the contracts were due.

As I said earlier, we recently announced 100 megawatts that we would be likely pursuing later this year, of which energy storage and energy storage paired with solar are products that we are interested in acquiring. So it's low now, but we don't anticipate it to be low that much longer.

COMMISSIONER WALLERSTEIN: Just -- I just -- you consider 100 megawatts energy storage --

MS. MCANDREWS: So --

COMMISSIONER WALLERSTEIN: -- to be a large -- large amount?

MS. MCANDREWS: I'm only speaking from the standpoint of the Preferred Resource Pilot acquisition needs, not more broadly from an SCE perspective. So our need is 300 megawatts. And if it were -- if it were just in the PRP area, actually 100 megawatts of energy storage would be quite a bit.

So more broadly, I know that we had one solicitation out for energy storage, and it's not going to be the last. So again, Edison continues to pursue and look for the right cost for energy storage.

COMMISSIONER WALLERSTEIN: I just want us all to be mindful that if the fallback position is peaking turbines, that those are going to be hard to locate and permit in the South Coast in all likelihood.

MS. MCANDREWS: I couldn't agree with you more. That's why we have the pilot.

COMMISSIONER WALLERSTEIN: Yes.

MS. MCANDREWS: Thank you.

MS. RAITT: Thanks, Caroline.

Next we'll move on to Transmission. And be hearing from Tom Doughty from the California ISO.

(Colloquy)

MR. DOUGHTY: Good morning, everybody. I'm Tom Doughty with the California ISO.

As I was getting ready to put my remarks together someone in our industry said to me an interesting statement. They said, “SONGS and OTC, aren’t we done solving that?” It was a fascinating question.

And my answer was, “We’re getting there. We are getting there. And we’re on a really good trajectory. And what I want to focus on here today is the path that we’ve taken. And Mike mentioned it, Michele, others, a tremendous amount of collaboration has taken place over the last couple of years, really unprecedented in, I think, in our -- in our industries recent experience. The loss of SONGS, combined with the impact of the OTC plant reductions or retirements or closings has been -- or repowerings has been nothing less than phenomenal.

And I thought I’d start by just bringing up a graphic that’s been used before. But it’s important to frame our conversation. A grid operator has basically three things to do: We need to provide real power, power that powers appliances and industry; we need to provide reactive power, power that strengthens voltages and allows us to import; and we’ve got to be ready to respond in the circumstances of system contingencies.

So with that in mind, we got together with these agencies and deployed a series of immediate solutions to get after the problem at hand. Now these have been covered in a past IEPR discussion so I’m not going to dwell on them. But suffice it to say, these solutions are in place now and they're providing access to renewable generation, like Jim mentioned, for Sunrise Power Link. They're providing voltage support in the case of both Huntington Beach 3 and 4 and voltage support equipment that's been installed in three Orange County locations. They're delivering energy to the L.A. Basin in reference to the 560 megawatt El Segundo Energy Center. And they're mitigating the risk of thermal loading under high load and contingency scenarios in the case of Barry Ellis (phonetic).

These hardware solutions have also been complimented by other solutions that make a big difference. Flex Alerts, they've been an effective resource for us in motivating customers to reduce load during times of system duress. And they continue to be funded through 2015. Demand response, interruptible load programs, other consumer based efforts that reduce end-user consumption in response to high prices, environmental conditions or a reliability issue.

DR plays two really important roles for us, one, in offsetting the need for more generation and, two, as we know, providing system operators with the flexibility they need in managing the system during periods of difficulty or limited supply.

Steve and Caroline mentioned earlier about working with our customers to expand DR. And we're doing a lot of work now to attract additional DR into our market, but also to improve the way that we dispatch it.

And then finally, we're working with our existing fleet, maintaining close communications with our operators and owners to ensure the fleet is, if you will, well-oiled and ready to go for when summer peak loads like today arrive.

So OTC, another big challenge that got dropped on us, one that we are tackling with vigor. From a megawatts standpoint it's much bigger than the SONGS departure. SONGS 2,250 or thereabouts, OTC 5,400, you add that up, that's about 7,600 megawatts of impacted capacity in the Southern California region. And when you draw your eyes to that coastline from El Segundo to the north, on down to Redondo, Alamitos, Huntington Beach, SONGS, Encina, those are the plants that are effected. Of course, SONGS now with the black dot, now that it's retired.

The green dots on the graphic indicate plants that have moved into a repowering stage, either as a full or partial capacity replacement to the -- to that that existed nearby. Encina, for example, there is a good example. At its original size, 965 megawatts, it's being replaced by the Carlsbad project at 500.

Now there's -- there's a thankfulness to this.

There's an opportunity here. The plan for managing OTC retirements is unlike SONGS. It wasn't an immediate issue that dropped on our lap. But given the magnitude of these megawatts and the size of this impact, we can't really overestimate this -- the scope of this challenge. We're continuing to track these new resources as they come online, monitoring plans replacing those that have yet to be replaced.

This message is probably a good example or a good segue to this graphic on our 2014-15 Transmission Plan which was just published. I'm going to try to hit these points as Michele touched on them earlier. We heard earlier that the PUC has authorized somewhere in the order of 3,600 megawatts for Edison and San Diego. If you subtract the total authorized resources from those anticipated to be coming in the next couple years you get about 600 megawatts -- and, Michele, I'll watch your head to nod, I'm hoping I'm the same numbers as you are -- of megawatts needing to be secured. And that's an important element in the tracking program that we've put in place.

The greatest interest to the group is tracking resources that are to be deployed or need to be deployed in the West L.A. Basin. And, of course, energy efficiency that needs to materialize. If either of these don't, as Michele indicated, we'll have to rely on additional procurement up to the authorized amount, of course, and or repurpose some existing DR to respond more quickly under a contingency situation.

The upshot of this graphic is we're carefully tracking this. And within the ISO's transmission planning process we're conducting additional LCR studies for the years 2021 when OTC plants are to be retired or repowered, and 2025, which is the end of our current ten-year planning cycle. These studies are going to help inform whether existing procurement and upcoming procurement us adequate for the intermediate and long-term planning horizons.

That takes me to my final graphic. And this sets the stage for where does this go from here? When I began I noted that this is not old news. This is going on now. Draw your attention to the yellow circles or lines there, and those are indicative of the projects that are under development now. Jim mentioned just last week SDG&E completed work on the Talega synchronous condensers. Just below the black dot is SONGS there. Great to see those online.

In January 2016 we intend to renew the contracts at Huntington Beach for the synchronous condensers. Now those will fall offline once a set of voltage support, transmission and generation projects are completed.

Between June 2017 and June 2018 voltage support projects are going to be completed at San Luis Rey, Miguel, the SONGS site, and Santiago.

So now complimenting those voltage support projects are a series of additional transmission projects, Sycamore-Penasquitos is a 230 kV line scheduled for June 2017. The Imperial Valley Phase Shifter, June 2017. And the Mesa 500 kV Loop-In, there you can see it kind of the upper left.

For each of the projects that I've talked about today the agencies are tracking six milestones, from authorization to in-service. We meet biweekly. We talk more frequently than that just to make sure we've got great progress against the plans.

So I'll close with this, from the ISO's vantage point we don't see issues that cause an immediate alarm. But we continue to track closely every single project until it's completed. As Mike said, we're reporting to the energy principals.

I think it's a monthly, is that when we send, Mike?

So this really is a moment to acknowledge the work that's been done. It's a tremendous collaborative effort. But also to redouble that our diligence needs to continue until the final project is complete.

Thank you.

CHAIR WEISENMILLER: So, yeah, I just wanted to follow up on Flex Alert status.

MR. DOUGHTY: Yes.

CHAIR WEISENMILLER: So what happens after 2015?

MR. DOUGHTY: After 2015 we have a proposal to have the ISO pick up ownership of Flex Alerts. And we would do that in the future with no paid media. We believe the Flex Alert brand has become strong enough that with our existing communication structures we can get the word out to the consumers that needs to get out. So beginning January 1 the ISO will own the Flex Alert brand, will own the Flex Alert network and the Flex Alert URL. It will maintained and managed, but we just won't have the paid media element along with it.

CHAIR WEISENMILLER: Okay. So how much was the paid media element?

MR. DOUGHTY: I think $10 million. Does anybody here no the number better than me? $10 million.

CHAIR WEISENMILLER: Yeah. I guess the question I would ask from folks back to the PUC, I've heard President Picker a number of times question the effectiveness of the PUC's $1 billion Energy Efficiency Programs. And so the question is where this fits in that.

MR. DOUGHTY: Okay. We'll make sure we take that back to the conversation. Thank you.

COMMISSIONER FLORIO: We’ve got a number of synchronous condensers being installed. And I’ve had generators tell me that they have the capacity to provide the same kind of voltage support, but there’s no way for them to get paid for that. Is that something that the ISO is looking at is using existing generators for VAR support?

MR. DOUGHTY: Absolutely. We looked at a number of different generator configurations, including the clutch model we talked about. We have not yet actually brought any of those into service.

Steve, do you want to add anything to that?

COMMISSIONER BERBERICH: Yes. Commissioner Florio, I think you touch on a specific issue, but also a broader issue. The specific issue is that if the existing power plants provide that reactive power, which they’re capable of doing, you have emissions, obviously, associated with that. With a synchronous condenser, depending on how they’re deployed, you don’t necessarily have that. So that’s the opportunity you have there.

On a broader perspective, though, as you have higher and higher penetrations of removables on the system the grid resources that we were receiving from traditional conventional plants now have to be provided by something else. And it is likely that we will be evolving our market to price things like voltage support and things like that as you look down the road. So I think you do touch on, I think, on a macro issue that will have to be -- but specifically in that running them would increase emission which would be counterproductive.

MR. DOUGHTY: Thank you.

MS. RAITT: Thank you, Tom.

So our next speaker is Jim Avery again from San Diego Gas and Electric.

MR. AVERY: If I may, I'll just touch real quickly on that last question as it relates to just synchronous condensers since the bulk of these are being installed in the San Diego region.

Virtually all of the generation in the San Diego region is under contract to SDG&E. And to the extent that any of the equipment has the capability to provide reactive support, it's compensated through the contracts it has with SDG&E to provide that support. So I don't think there's any lost opportunities here as it relates to that. And Steve Berberich is exactly correct, that to the extent you would operate a generator for the purpose of operating as a synchronous condensers, there are clearly emissions associated with doing that.

If you -- I'm going to focus first on the ISO transmission planning process from 2012-2013. There were three major areas that SDG&E was directed to move forward with. The Talega synchronous condenser, I already mentioned that came online last Friday and it is providing a significant reactive source into our region.

I'll draw you back to our system and point out, essentially, if you look at San Onofre, while it sits in the northwest portions of San Diego, electrically it looks more like it's in the L.A. Basin than it does in the San Diego region.

Talega is the first node beyond the San Onofre bus into our system to the north and extending over to the east. And San Luis Rey is the first node extending to the south out of the system. And a synchronous condenser is slated to go in service in that substation, as well. The Encina facility is located just south of the San Luis Rey.

So all of these transmission and generation assets are located primarily on the corridor that connects San Diego to the L.A. Basin. And that largely has been the focus for why those are strategic areas to deal with some of the voltage constraints in that region.

The second project that has been identified by the ISO is the Sycamore to Penasquitos 230 kV Transmission Link. This is a project that was originally identified as part of the Sunrise Power Link. But it was deferred from that project until a later date and clearly became identified by the ISO in the 2012-13 time period. And that project is slated to come online in the 2017 time period.

The other synchronous condenser project that was identified was the synchronous condenser at the San Onofre bus. Originally two were identified there. But in working with the ISO, Southern California Edison and SDG&E worked to split that into two separate projects, one of the synchronous condensers being located at SONGS within the existing switchyard, and the second one located in Edison's substation up at Santiago.

In the 2013-2014 transmission planning process there were four projects identified here. One is the synchronous condensers located at San Luis Rey that I mentioned just a few moments ago. Site development work is beginning. And in-service date is scheduled for 2017.

The other project is one that has been looked at for probably over 20 years now but identified and approved in the 2013-14 horizon. It is the Imperial Valley Phase Shifter Project. As you start moving bulk power into the region, into San Diego across the Sunrise Power Link and the Southwest Power Link, under different flow configurations or flow conditions we can create problems in the neighboring systems in CFE and Imperial County. And the Phase Shifter is designed to mitigate the potential -- the potential for some of those problems.

And the Miguel synchronous condenser is another project, again slated to be in service in 2017.

And the last project is the Suncrest Static VAR Compensator. The ISO awarded that to a third party and it has been identified and needs to be in service for the 2017 window of time, as well.

That covers for San Diego.

And any questions?

COMMISSIONER MCALLISTER: Yeah, I have a question. So I missed the first half of your -- your presentation, so I'm sorry, you might have talked about this already a little bit. But I guess, you know, having had a front row seat to the Sunrise proceeding when I was living in San Diego, I guess I'm wondering, lessons learned, you know, how you might manage that process differently? Or, you know, I know there was a reticence to kind of commit to what kind of energy was going to flow over that line. And I kind of, you know, can understand some of that. But I guess I just -- how it was sort of managed with the community relations and kind of the technical underpinnings and the long-term plan for the line, I guess, you know, I'd like to hear some lessons learned from the permit using your perspective.

MR. AVERY: Well, I'll touch on the reticence for committing to resources to the facility. As you are aware, a lot of groups suggested that they could get behind and support the Sunrise Power Link if, in fact, it was being built for the development of renewable resources.

As you also know, though, SDG&E is not in a position to commit to what other people can and would use the transmission line for. We did say early on that this was about the development of renewable resources. And we did say that it was our plan to use this line for renewable resources.

What I did mention this morning, and unfortunately you did have to step out, is that it is now several years -- it’s over ten years since we first proposed this project. It’s been service now for three years. And to date, 100 percent of the resources that have filed an application at the ISO to take advantage for the capacity made available by Sunrise has been renewable in nature. So in fulfilling what we had said was our plan, all of that has come to be the case.

There were a number of special interest groups who opposed the Sunrise Power Link for some very valid concerns and valid reasons. But there were also a lot of people who were stirring up that this was all about dirty power from Mexico or this is about dirty coal power. And none of that has come to pass. None of that is real.

The truth is this is about renewable power. The truth is it’s delivering renewable power.

COMMISSIONER MCALLISTER: Yeah. So thanks for the answer. And I guess I'm -- obviously, it's easy in retrospect. But, you know, the fact is I think it's a success story for getting renewables harvested and into the grid in a way that's productive; right? But I guess, you know, we don't always have ten years to sort of -- particularly as we want to try to facilitate the building of transmission, how that process might sort of be sped up but still not shortchange the public process.

MR. AVERY: I think it would be foolish to think that under the current process the way it is designed we encourage people to come in and oppose projects just for the sake of opposing projects, that you can shortcut this process into anything shorter than it was. I think to a very large extent these are emotional issues. These are issues that draw opposition.

I think the Commission did a very good job of trying to balance the interests, trying to balance the overall project. I mean, the original route that we had proposed is not what was selected. An alternative route was identified and that route was selected and that route was constructed. Obviously, there are people who didn't want any route or people who didn't want that route over another route.

But I think the process that we went through, the identification of alternatives, the benefits that were identified in here ultimately prevailed. I think it would be foolish to think that we could somehow come up with a process that could have saved us some time here or there. I would love to see that as a possibility. But in reality it's harder and harder to build facilities into any -- any constrained region.

And if you look at San Diego, we're a highly constrained region. To the east I think there's 214 miles of border separating San Diego from the rest of the world, over land. And out of those 214 miles over 200 miles of them are blocked by -- by Native American lands, by State Parks, by National Wilderness, by National Parks, by military bases, which really creates a very small corridor for anything to be constructed. And as a result it limited the ability to look for alternatives into the region.

But I think the team that went through this, I mean, we learned a lot of lessons from the Valley Rainbow days. We put forth a project that had reliability benefits, that had multiple legs to the stool, also economic benefits, and on top of that provided access to renewables. I think it was the overwhelming preponderance of the benefits that the project provided that ultimately made the project prevail.

COMMISSIONER MCALLISTER: Thanks.

MR. AVERY: Thank you.

MS. RAITT: Thank you.

Next is Dana Cabbell from Southern California Edison.

MS. CABBEL: Good morning, everybody. Thank you again for inviting me to come and talk about some of the transmission projects that we are working on.

As last year, I wanted to provide an update on some of the transmission projects that aren't necessarily pertaining to the OTC and SONGS concerns, but also some projects that are integrating and bringing in renewables from outside, but also projects that help to serve reliably the load, the growing load in certain areas.

Corto Lugo (phonetic), I'm sure as everybody is aware of, it was dismissed due to some recent studies performed by the ISO and retirement of some projects up in that -- north of Lugo, part of the grid. There was -- it actually came down to not needing Corto Lugo for deliverability of some resources up in that area. So that project has been dismissed and we've stopped all work on that project to date.

West of Devers, that is a rebuild of some 230 lines west of Palm Springs area. Again, that project is to help integrate some -- mostly renewables from Imperial County, but also east of Palm Springs area. That -- the draft EIR has just been released on that. We're going through that at this moment to determine what the proposals are, the alternatives that are being proposed. And we're going to go forward and provide, obviously, our comments on that. Construction we're hoping will begin next quarter or quarter one of 2016, so that we'll be able to meet our 2020 operating date.

A new kind of a different project that's going on is the Lugo-Mojave/El Dorado-Lugo Series Capacity -- Series Capacitor Project. These are 500 kV lines that go out east of our Lugo Substation, Hesperia area, out towards southern Nevada. They're series capacitors that are on these lines. Series capacitors, essentially, are devices that are put into lines that shorten the impedance of the line so that you're able to bring in more power over the existing conductor. This project was actually approved in the 2012-2013 ISO Transmission Plan. It's policy driven to help integrate renewables from the southern Nevada and Arizona portion of the grid.

So right now we're going through some detailed engineering to be able to upgrade those series capacitors thermally and provide more compensation on those lines. And that's supposed to come in on -- in 2017.

The last two projects are Alberhill and Santa Barbara County Reliability. These are essentially projects to help serve the load in those areas.

Alberhill is Lake Elsinore area. It's a new substation that's going to be built to be able to continue to serve the growing load out in that area.

Santa Barbara County reliability project is actually a 66 kV project. It is to rebuild the 66 kV lines, because with Santa Barbara we have two 230 lines that serve that area. If for whatever reason, fire, landslides because they're up on a hill, if we lose those 230 lines Santa Barbara and that whole area, Santa Barbara County is isolated from the grid. So we're trying to rebuild the 66 lines and help support the local load in that area. And that is supposed to be built and completed by 2016.

So on to some of the projects that have already been mentioned as -- they were identified as needed to help with the OTC retirements and compliance, and also with SONGS.

The first major project that we identified was the Mesa 500 Substation Project. It's rebuilding one of our current substations which is a 230-66 kV substation right in the Montebello area.

And we will be rebuilding that to a 500 kV substation and looping in the Vincent-Mira Loma 500 kV line which was part of the Tehachapi project. So that project, we've submitted a PTC application earlier this year. The draft EIR is anticipated to come out soon. And we hope to achieve the PTC by next year so we can start construction and meet our in-service date of 2020. And this -- the project again, as I stated up here, helps bring in resources from outside to help serve the L.A. Basin for loss of some of the OTC plants on the west side.

As we've talked already, the Santiago Substation, adding the synchronous condenser at Santiago which will help support the SONGS retirement. And this is a turnkey project. The vendor selection is going to be announced in September. And so currently we're on track to meet the 2017 date.

And lastly, I wanted to just give an update on Tehachapi Renewable Transmission Project. This project has been long in the making. It is to help integrate 4,500 megawatts of wind, and now some solar up in that Tehachapi area. All the overhead construction is fully constructed and completed. The only piece that is still underway is the underground portion through the Chino Hills, so three miles portion of the project, it's called Segment 8. That is a 500 kV underground which is the first 500 kV underground in the United States. So it's been a very interesting project, very complicated, very difficult project. But we are on track to have that completed and go online in 2016. So it's been pretty significant construction and some new challenges.

You know, when we -- when we were handed this opportunity to go underground with 500 kV we wanted to -- we wanted to make it the best engineering project and be the most successful engineering project, because it is a vital piece of the entire Tehachapi Renewable Transmission Project to complete that segment into our -- into the basin to bring in that resource.

And I think that's it. Any questions?

COMMISSIONER FLORIO: Yes. On the West of Devers, will that allow more power to come into the basin or it that being done for other reasons?

MS. CABBEL: Yes, it will, the short answer. It does bring in -- I don't think I have a graphic of it -- but the West of Devers, the 230 lines come from what we call our Devers substation into kind of Vista area, which is bringing it further into the basin where it picks up into more of our robust -- robust portion of our grid to bring the resources further in to the load basins.

COMMISSIONER FLORIO: Okay. Thank you.

MS. CABBEL: Uh-huh. Okay?

COMMISSIONER MCALLISTER: Great.

MS. CABBEL: Great.

COMMISSIONER MCALLISTER: Thanks.

MS. CABBEL: Thank you.

MS. RAITT: Thank you.

We'll move on to Generation and hear from Roger Johnson from the Energy Commission.

MR. JOHNSON: Good morning. And again I'll thank the Committee for having me back again. I'd like to -- my name is Roger Johnson, Deputy Director for Siting at the California Energy Commission. And I'd like to update the Committee today on the status of generation permitting in Southern California.

So just a graphic to show you the location of the projects we've been talking about today. We have a new project we'll be talking about, the Puente Project by NRG to the north. And we then show where the El Segundo, Redondo, Alamitos, Huntington Beach, San Onofre, Carlsbad, and then we'll talk about Pio Pico and Wellhead, as well.

So I just want to -- I just want to quickly -- I know where I'm standing, between you and lunch, and so I'm going to quickly go through these projects and just let you know where we are today.

The Mandalay Generating Station Replacement Energy has filed that application with the Energy Commission. It's a 262 megawatt GE-framed 7HA combustion turbine generator. It's located in the city of Oxnard at the existing Mandalay Generating Station. This picture shows an artist's rendering of what the new facility would look like there to the left of the existing facility.

We have an information hearing scheduled later this month, August 27th, down in Oxnard. We're expecting a Commission decision probably June of 2016. And the OTC compliance date on this project is December 31st of 2020. And they do have a Power Purchase Agreement.

The AES Alamitos Project, it's a replacement project. Currently -- last time I was here last year, that was -- AES was proposing 1,950 megawatts of new -- new generation at that site. Since then they've asked us to stop work on the project and they're going to supplement their application for a different configuration project that would match the PPA they received from Edison. And so they're going to propose a 640 megawatt air-cooled combined cycle there at that site. And we understand they're possibly going to add four LMS100s as additional generation that would be permitted at the same time.

We expect that supplement this year, they say anytime now. Probably a Commission decision in 2016. They're OTC compliance date is December 31st, 2020. And they do have a PPA for the 640 megawatts.

NRG El Segundo, we've talked about that a couple times today. The first two units were replaced and started operation in August of 2013. That's a 560 megawatt fast track combined cycle that's dry cooled. It's located in the city of El Segundo. Now they're -- we're looking at a replacement of Units 3 and 4. They have an application with the Commission for 449 megawatts which is a one fast track air-cooled combined cycle and two simple cycle peakers.

We're getting ready to issue our final staff assessment this month. And we're expecting a Commission decision later this year. Their OTC compliance date for that project is December 31st, 2015. And they do not have a PPA for that project.

AES Redondo Beach, a replacement project proposed 496 megawatts, a three-on-one air-cooled combined cycle located in the city of Redondo Beach at the existing power plant. This project started and stopped and restarted now. We had a preliminary staff assessment workshops earlier this year in May. And we're getting ready to file a final staff assessment in the next few months. There will probably be a Commission decision in 2016. OTC compliance date is 2020. And they do not have a PPA for that project.

AES Huntington Beach, we talked about that one, as well. This one is a 644 megawatt air-cooled combined cycle is what they want to change it to. Last year we permitted 939 megawatts at that site. Since we issued that permit they've received a Power Purchase Agreement from Edison for the 644 megawatts. So they're planning now to file a major amendment with the Energy Commission to change that project design to accommodate the new air-cooled combined cycle.

And they’re also considering adding 200 megawatts of LMS100 generation there.

The project, again, located in city of Huntington Beach at the existing Huntington Beach Power Plant. They expect to file their amendment next month. And OTC compliance date is 2020. And they have a Power Purchase Agreement for the 644 megawatts.

Energy Carlsbad, last year this project was still under review. Now I can say it’s been permitted, and we just talked about that earlier today and quite a few people have mentioned that one. Right now what’s happening at the site is they’re removing the -- the oil storage tanks to make room for the project. They started construction on that effort of the project. The actual construction of the power plant is to be determined.

They’ve got some pre-compliance -- pre-construction submittals that have to be provided. OTC compliance date is December 31st of 2017. And they have their PPA for 500 megawatts, although the Commission issued a license for 632 megawatts at that site.

Pio Pico, 300 megawatt simple cycle project. It has started construction, as was mentioned today. And they expect to be operational in September of next year. This is down in Otay Mesa area, three LMS100s.

Wellhead, this is a project that received a project from Southern California Edison. It's 98 megawatts, two LM 6000s. It's proposed to be in the city of Stanton. We haven't seen the AFC yet. We're expecting to receive that after they get their approval from the CPUC for that contract. They have their PPA for their 98 megawatts.

And so here's a summary of the information I've pretty much just presented and showing you that from -- from last year we've added the Puente Project. We've changed the capacity of the Alamitos and Huntington Beach Projects. We've added the Wellhead Project. And two projects have been removed since last year, the Watson 5th Train, it was another combined cycle co-gen project at the Watson Refinery. They've -- they've terminated that certificate. And Quail Brush terminated their 100 megawatt AFC, as well.

So that's the current status of the projects in the Southern California area.

CHAIR WEISENMILLER: Roger, you want to identify any pending solar projects in Southern California?

MR. JOHNSON: We only -- we only have the potential of one solar project that I'm aware of, and that's essentially the Palen Project. It's -- it was initially proposed as a solar thermal trough project. It went through bankruptcy, was picked up by Bright Source and Abengoa. It was proposed through a major amendment to the Energy Commission as a solar power tower project, water -- water boiler. And they withdrew that application for that amendment.

And now they're proposing to come back yet another time, this time Abengoa is the sole proponent of the project. And they're telling us they're going to bring a solar molten salt tower to that same location. So that's the only project that we're expecting.

CHAIR WEISENMILLER: Okay. And then I guess I should have asked you also about any pending geothermal projects in Imperial Valley?

MR. JOHNSON: We have -- we have a couple of projects in Imperial Valley that have been talking to us. One of them wants to come back and do an amendment, that's the Black Rock Project. And then we also have another project that's been talking to us about filing a permit, but they haven't yet decided.

CHAIR WEISENMILLER: Yeah. I was going to say, I think they've been talking to us about as long as I've been Chair. But anyway, we're still waiting for the geothermal to come in.

MR. JOHNSON: Right.

CHAIR WEISENMILLER: Okay. Thanks, Roger.

MR. JOHNSON: All right. Thank you.

CHAIR WEISENMILLER: Actually, while we're transitioning I should also make an observation that we've been talking about transmission. And I would point people to a recent letter for President Picker and I to Steve Berberich that would announce the kickoff of, basically, RETI 2.0 which will be a stakeholder process to come up with what the -- what our transmission plans will be associated with going from 33 to 50 percent renewables. So stay tuned as we roll that out, but encourage Board participation in that effort.

MS. RAITT: Okay. We actually did have a couple questions for Caroline and Southern California Edison that came over our WebEx. So if Caroline could address those that would be helpful.

MS. MCANDREWS: So I'm going to read the question, and then just give my short response.

"Can you speak to the cost benefit analysis for the PRP deployment of preferred resources?"

Regarding the cost, we're really looking at using our existing programs. So our customer service programs, our DSM portfolios, they have a cost effectiveness check. The contracts from LCR, they go through for CPUC approval. And so we expect the costs to be in line with the existing -- existing costs for other resources.

We're not going to look at any one particular cost of a resource. We're going to look at it from a portfolio aspect.

Regarding the cost benefit, the benefit aspect obviously is -- it reduces the greenhouse gas emissions, and so there is a benefit associated with that. But in, you know, the longer term the 2018 timeframe when we pull together all of this information, we will pull together the costs, the measurement, the reliability components and the benefit. So stay tuned for the cost benefit conclusions at that point.

Two, “Can you speak to the assumptions on slide six about forecasted” -- that’s probably slide -- numbered slide five -- “about forecasted load growth in 2022 spike?” That’s the first part.

There is no real spike. The graph on the top portion really shows an increasing load growth of about 32 megawatts per year. So there’s -- there’s no specific spike. It’s a gradual increase. The assumptions that went into that really come from the plans that are submitted to us by developers and businesses, as well as just looking at things such as increase in electrical, vehicle use, and the assumptions that go into the normal forecasting.

The other question -- and maybe to clarify that, why the need is out in 2022, and you’ve heard many comments about the OTC plants getting closed in 2020 is because that’s crossover point in which the load growth exceeds the amount of imports that we are capable of supporting before we hit that transmission constraint.

Part two to this question was, “Are these taking into account ZNE standards, DERs anticipated from the DRP?”

So first I’ll start with DERs, distributed energy resources, coming from the Distributed Resources Plan. The region will serve -- this PRP region will serve as part or as a whole of the demo projects for Demo Projects A through Delta, Alpha through Delta, with C and D Projects being the actual deployment of those resources to meet those demonstration project objectives. So it is accounting for the actual DERs that will be deployed by -- as part of the DRP. Maybe I can throw a few more acronyms in there. So I apologize for all that. Hopefully there will be a glossary.

Also, relative to leveraging the current standards, we do that on a regular basis. We right now do not have ZNE standards, so as those evolve hopefully we can -- we’re anticipating them and hopefully we can influence it through what we’ve learned here. We are really looking forward to the anticipated standards on smart invertors because we see that could potentially provide some support, VAR support, specifically very locally.

COMMISSIONER MCALLISTER: Yeah, I’ll just chime in on that. So we absolutely welcome your sensitive input on the ZNE front, I think to the extent there are some lessons learned that we could use in the Title 24 process, absolutely welcome --

MS. MCANDREWS: Thank you.

COMMISSIONER MCALLISTER: -- and you're very much encouraged to submit that --

MS. MCANDREWS: Thank you.

COMMISSIONER MCALLISTER: -- as part of the process.

MS. MCANDREWS: Thank you.

The third question was, "How does AMI data help inform system reliability in the PRP study?"

Well, first off, we really are doing a bottoms-up type of analysis. It assists us in understanding the end uses of our customers. So therefore we can target EE, DR, PB by knowing the end uses. And we can incorporate that and blend that with a market potential.

Additionally, we're leveraging that information to actually get actual performance and see how that reflects back to the grid level savings at the substation level.

MS. RAITT: Thank you. Those questions were from Mark Costa at the -- from the Energy Coalition.

Did you want to go ahead and break for lunch?

COMMISSIONER MCALLISTER: I think so.

MS. RAITT: So we'll go ahead and break for an hour lunch and be back here at 1:20.

(Off the record at 12:19 p.m.)

(On the record at 1:21 p.m.)

MS. RAITT: All right, we're getting ready to get started again.

So at the end of the day we're going to have an opportunity for public comments. And for the folks on WebEx, unfortunately we won't be able to hear any verbal comments. But you are welcome to use your chat function to write comments or submit written comments. Written comments are always a great way to provide feedback. And again, the way to do that is provided in the notice. And comments are due August 31st.

So with that we'll go ahead and start our afternoon panel on continued update on activities identified in the draft plan. And we have a presentation from Mike Jaske and Lisa Wong -- excuse me, Lana Wong. I don't know why I said that.

MR. JASKE: So good afternoon, Mike Jaske, Energy Commission Staff. I'm going to do about -- well, the beginning and the end of this package. And my colleague Lana Wong will due the middle sections.

We've -- the technical staff of the agencies have been working on this effort ever since the non-taskforce called into being by the governor in the summer of 2013. And the preliminary plan put forward is sort of a basic thrust of how we're trying to deal with the SONGS' issue, as well overall OTC. And we're heard a lot of reports this morning about the sort of status of the resource development efforts that are the real solution to that.

But in addition to that, the preliminary plan called for the development of some kind of contingency measures so that if those preferred resources and -- or the conventional generation could not be developed then, you know, we'd have a backup that would assure reliability. And what I'm going to present today, what Ms. Wong and I are going to present today is a tool that we have developed, that the Energy Commission, with some assistance from the PUC and ISO, that will help us to gauge whether we actually expect to be on track, and if not how might this analytic information support the triggering of these contingency measures. So I think I said that already.

So we call this thing Local Capacity Annual Assessment Tool. And as an initial-ism we call it LCAAT, just for simple reference. And really what we're doing here is developing annual projections of resources versus local capacity requirements in a number of specific areas of Southern California, the combined area itself, the L.A. Basin, the West L.A. subarea within the L.A. Basin, and the San Diego subarea. And this analysis can provide an understanding of timing, as well as the nature of any shortfall in satisfying these local capacity requirements.

Now this is a simplified tool and we don't propose that we would trigger, you know, complex, perhaps certainly expensive or -- or otherwise controversial mitigation measures just on its analysis. And so this is generally -- I think the way to think of this is kind of a screening tool that would, given its results, you know, call upon a more in-depth study, presumably by the ISO, using the normal power flow techniques and stability studies that they do on a returning basis. And then, you know, if that analysis confirmed what LCAAT shows, then we'd be in a stronger position to know that we might need to do something serious.

So again, another chart of the area just showing where we are. Again, we're not doing Big Creek-Ventura now, but we may be doing Big Creek-Ventura in a future cycle.

So a little section here on method and assumptions. So this is a spreadsheet tool. It's relatively easily modified, tweaked, added to. The input assumptions that drive it in the baseline projections are those that were developed for the 2014 LTPP and/or for the 2014-15 TPP. And those two are about 90 percent, 95 percent the same, so there's only some limited differences. We did need to create some methods and supplements and inputs to do the geographic tagging that lets us, you know, pull values into local areas and subareas. And we did also need to create some logic to modify the initial LCR study results so that they could be used in this tool and annualized. So I'll -- I'll go through that more later.

So it does, in the end, produce tabulations of resources versus requirements by five areas on an annual basis. And we intend to update this on an annual basis and then selectively, if and when needed, something major has changed.

And so the way in which that update would generally happen is that in the spring of each year the ISO staff develops One- and Five-Year Ahead LCR Studies. And then in December they typically release a preliminary. And then early in the following -- in like January or February, the final Ten-Year Ahead LCR Study results. And so it's about that preliminary cycle of December that we can have enough of the LCR and all the input assumptions that are drivers for them all together. And that's when we would do an update.

So we're sort of moving toward the tail end of using 2014-15 TPP LCR results. And over the next three or four months, when we get the '15-16 results we'll have those available for a whole comprehensive update.

So, of course, there's always advantages and disadvantages of creating more simplified tools relative to complex ones. Clearly it's easier to assemble these data than the much more load-bust (phonetic) specific data that drives the ISO's tools -- well, let me say models, let me say model for, you know, a sophisticated analytic support tool. And this is -- this is a tool. It's not at the level of a wholly independent model. But also has the advantage that we can make many more runs.

And when we get into the sensitivity study today you're going to see that we can draw some inferences from the ease of using this thing and rerunning it for wholly different sets of input assumptions that -- that the ISO's more complex tool would just not have -- they would not have the bandwidth in order to do all these cases.

So we're losing some accuracy perhaps. There may be some shades of gray that LCAAT can't really distinguish between. Clearly things that are down to the individual load busts, this tool cannot handle -- we need, you know, the power of the actual power flow models to really distinguish those kinds of phenomenon.

And then, of course, sort of the compliment to what I said before, if and when the ISO produces new results we have to bring this tool up to speed in order to be comparable.

So more about where our input assumptions are coming from. The base demand from the 2013 IEPR -- 2014 IEPR, of course, was adopted, I guess officially in early 2015, as well as the AAEE savings that are associated with that. But we’re -- those -- the ISO has not yet released the Ten-Year Ahead LCR Study results using those assumptions, so we’re lagging behind that IEPR cycle. That will come soon.

We are using the results from the 2015, ‘19 and 2024 studies that the ISO has done. And a key assumption that we’re going to return to, probably more than once in this presentation, is that when there are demand-side adjustments, when there are changes in base load, changes in AAEE or -- or the introduction of the preferred resources that Edison is pursuing or the comparable ones that San Diego is pursuing, we’re assuming the LCR changes on a megawatt for megawatt basis. That’s an assumption.

We are conducting a powerful study using a consultant to look at that very question of is there that scaling. And if it’s not found to be one-for-one we’ll -- we’ll bring that parameter into this tool. But for right now we’re assuming that if AAEE falls short a megawatt then there’s one megawatt of LCR requirement not satisfied.

On the resource side, again, we’re -- we’re doing -- what I’m reciting here are basically all of the specifics that were developed for the 2014 LTPP cycle and/or the 2014-15 TPP. So we’re using 2014 net qualifying capacity list. We’re putting in the Power Purchase Agreements that Edison submitted to the PUC that aren’t yet approved. We're assuming that they are approved and on schedule, at least as a baseline.

We're assuming that the RPS portfolios of renewables are following the trajectory case, as did the ISO in its analyses, although we do assess as one of the sensitivities the high DG portfolio.

For retirements, all the OTC plants are following the dates established in the OTC policy by the Water Board, even though the owners of those have some slightly different ideas about what those schedules are. We have age-based retirements of the various kinds of generating technologies using the same formulas that the PUC and mean-age assumptions in the PUC's 2014 LTPP settings. And we are, in those instances where we have that data, taking contract based extensions into account. So if a plant would reach its 40th year in 2016 and it actually has a contract out to 2018, we're keeping it in until 2018.

So the local capacity requirements of the areas are obviously a key input assumption. The ISO uses a very specific set of assumptions when it runs those studies. And what we are doing here is taking those results and in some instances we are adjusting them so that they're on the same basis. So at least the way we understand how 2015 and '19 are reported, they aren't reported exactly the same way as 2024. So we picked one of those two methods and we put them, all three of them, on the same basis.

Those base LCR requirements then are modified by all these load modifiers, energy efficiency, behind-the-meter DG, behind-the-meter storage, and the transmission system upgrades that Mr. Doughty talked about this morning. And so the tool enables by the logic in it, if one of those projects is delayed a year we're able to take that into account in generating slightly different LCR requirements or -- and/or satisfaction of those requirements.

I think I've probably said most of this slide already, but what do specialized factors down there mean? One of the uncertainties that confronts us and has been the subject of a recent decision at the PUC is the migration, transformation, one of those words, of QFs and co-gen contracts into something more like a wholesale generator. And how successful that transformation is, is not clear. And so that's one of the sensitivities that we assessed in this study is a pretty simply way of generating a lower co-gen projection than in the baseline.

Of course, OTC retirement is a very key assumption. That's been mentioned several times before, all of these thousands of megawatts of the existing OTC facilities on the left-hand side and their compliance dates and what is in queue through Power Purchase Agreements to replace them. Obviously, the sum of the OTC column and the sum of the replacement column are quite different, reflecting that we’re pursuing renewables, other preferred resources and storage as part of our transformation of the whole electricity system.

Now this is a slide that you’re not going to be able to see. I don’t expect you to see it. But this is one of the key ways in which the results actually appear. So these tables that look like this are generated for every one of the areas. So you can see all these rows of data, starting with load, the LCR requirements, a whole bunch of different categories of resources. And then the bottom line is literally the bottom line. What is the surplus or deficit of resources versus requirements for all these years? And we’ll show you results in more user friendly ways than that, but everything stems from these initial results.

So one -- one way to --

COMMISSIONER MCALLISTER: There’s a quick question before you go on to your --

MR. JASKE: Go ahead.

COMMISSIONER MCALLISTER: Go ahead, Steve.

COMMISSIONER BERBERICH: Do you have a -- the LCR change from demand adjustments which are negative numbers?

MR. JASKE: Correct.

COMMISSIONER BERBERICH: Does that apply when you have decreasing load?

MR. JASKE: No. It means that’s a negative value which is reducing that line above that called gross local capacity requirements. So it’s -- so pick -- pick a year, like 2021.

COMMISSIONER BERBERICH: So it was a local capacity requirement when you took a demand adjustment that would increase it if you had increasing load, wouldn’t it? And I’m just -- you know, maybe I don’t understand.

MR. JASKE: Look, take 2021 column, because we’ll talk about 2021 a lot, 10,280 of gross LCR requirements. There’s 700 megawatts of reduction due to the reactive power projects that we talked about this morning. And then there’s an 1,110 megawatt reduction due to demand modifiers, which --

COMMISSIONER BERBERICH: So that’s energy efficiency?

MR. JASKE: Energy efficiency, all the behind-the-meter things.

COMMISSIONER BERBERICH: I got it.

MR. JASKE: Then that gives a final 8,471.

COMMISSIONER BERBERICH: Okay.

MR. JASKE: So that’s showing -- that’s showing what would have been the LCR requirement modified by those demand and transmission system upgrades. Okay.

So graphical displays are frequently much more effective, so on the left-hand side, sort of almost some of these are the very same things we talked about, the -- the gross local capacity requirements being the blue line, the adjustment -- the adjusted ones from transmission upgrades or demand-side modifiers pushing it down to be the red one, and then the green being the total of all the various kinds of resources and -- which is ISO's to do. And that kind of a chart is wherever the green is higher than the red, then there's a surplus. Whenever the green is lower than the red, then there's a deficit. And this slide shows for L.A. Basin that a deficit appears in '21 and shrinks out to 2024.

And then the right-hand graph is just showing that different between the green and the red of the left graph, so that you can actually see the surplus and the deficit.

So this is not intended to focus on the results. This is sort of -- these are the visual and numeric ways of displaying results.

So at this point Ms. Wong will take over and walk you through baseline and sensitivity studies.

MS. WONG: Hi. I'm Lana Wong, Energy Commission Staff. And I'm going to walk you through the baseline results and our sensitivity and scenario studies.

So this -- this table shows simplified L.A. Basin results. And if highlights a few key years and a few key variables from that other summary table, just so that you could clearly see this. So we have our base load forecast adjusted by the load forecast modifiers that -- that we talked about, like AAEE. And then that take you to a managed load forecast. Then we have another block in that summary table that is the gross local requirements adjusted by the transmission upgrade impacts, the load modifying impacts, and that gets you to the adjusted local requirements. And then that is compared to our total resources. And that produces the last line which is our surplus or deficit in the area.

So if you look at the last row, we're included the years 2020 and 2021 because in the early years you can see there is a surplus, about 1,500 or so megawatts in 2020. But by the time we get to 2021, due to the OTC compliance, we end up with a deficit in 2021. And the full table matching this data appears in the CEC Staff report.

So this is --

COMMISSIONER MCALLISTER: Can I just ask a clarifying question? So if you could go back to that other table?

MS. WONG: Whoops.

COMMISSIONER MCALLISTER: One more back.

MS. WONG: Okay.

COMMISSIONER MCALLISTER: There you go.

So you said that the AAEE, you know, the initial efficiency is in -- is already built into the managed load forecast?

MS. WONG: Right.

COMMISSIONER MCALLISTER: So it's --

MS. WONG: It's built into the managed load forecast. It's -- the AAEE is part of the load forecast modifiers.

COMMISSIONER MCALLISTER: Yeah. So then down -- and in the assumptions that Mike talked about. Then further own you've got load modifiers. You've got transmission system upgrades which produces it somewhat, and then you've got load modifiers --

MS. WONG: Right.

COMMISSIONER MCALLISTER: -- which are behind-the-meter DG -- or DR, and behind-the-meter DG, and EE is in also there.

MS. WONG: Right. The AAEE, yes.

COMMISSIONER BERBERICH: So distributed gen is in that number? Rooftop solar is in that number?

COMMISSIONER MCALLISTER: In the load modifiers?

MS. WONG: Right. So it includes some of the behind-the-meter DG. So specifically what's in there is like from the Edison RFO results for the preferred resources, there's some behind-the-meter DG that's part of the RFO. We've included it in there.

COMMISSIONER MCALLISTER: And the storage is also in there, did you say that?

MS. WONG: Behind the meter -- if there's behind-the-meter storage, yes, that's included in there.

COMMISSIONER MCALLISTER: So I guess my question is: Is this EE that also fits in the load modifiers below in addition to AAEE or is it another part of AAEE? Because if AAEE is up there in the load modifiers, then I'm assuming this would have to be additional to that?

COMMISSIONER BERBERICH: I think it's double counted.

MS. WONG: Right. No. And it is in the load modifier impact. So we have our gross local requirements. And that's before accounting for any energy efficiency, before accounting for the AAEE. So we are looking at sort of a higher level of gross local capacity requirements. And then that is adjusted by the transmission system upgrade impacts and the load modifiers, including the AAEE. And that gets you to the adjusted local requirements.

The upper portion that's showing the managed load forecast, at this point it is sort of for informational purposes. It's not being counted in the gross local --

COMMISSIONER MCALLISTER: Okay. I get it. So really there's sort of -- there's sort of a heavy black line between managed load forecast --

MS. WONG: Right.

COMMISSIONER MCALLISTER: -- and those local requirements?

MS. WONG: Right.

COMMISSIONER MCALLISTER: Those are two separate things?

MS. WONG: Right. Right.

COMMISSIONER MCALLISTER: Got you.

MS. WONG: So when I look at the summary table, which I know the earlier slide was busy and hard to see, and this -- you know, the first block is just showing you what the base load forecast is, what the load forecast modifiers are, and what the managed load forecast is. So it’s in there as information for you. But then the next block is the gross local capacity requirements, then adjusted by the transmission upgrade impacts, the load modifier impacts, and then the -- then that brings you down to the adjusted local --

COMMISSIONER MCALLISTER: Got it.

MS. WONG: -- capacity requirements.

COMMISSIONER MCALLISTER: So 1385 and 1384 are basically the same number?

MS. WONG: Right. Exactly. I know, I noticed and it’s like, okay, I know that’s probably rounding or somewhere in producing the numbers but, yes.

COMMISSIONER MCALLISTER: Thanks for that.

MS. WONG: Okay. So this chart shows us the results for the baseline case. And it's showing the surplus and deficit, or deficit results in megawatts. And so we've got the combined area in dark blue. The L.A. Basin is in red. The West L.A. subarea is in green. And then we've got San Diego in sort of light blue, and it's off on its own.

So once we produced our first set of results the one thing we did was we said, okay, how do our results look and how do they compare to the ISO results? So that was one of the first things we did was we took a look at the 2024 results and we said, okay, our 2024 result for the combined area is in line with the ISO's most recent 2014-15 TPP results. So we felt good about that.

And then we went through basically a QA/QC process to look at all of the individual components that go into creating the surplus and deficit. You know, basically we wanted to make sure, okay, are these results reasonable? You know, do we have confidence in this? And after going through the process what we saw, there may be some slight differences in assumptions here or there, but pretty much, you know, our results seem in line with the ISO published results.

So what you can see on this chart is that for the three areas that are the L.A. Basin, San Diego, L.A. Basin and West L.A. Basin, they all tend to have the same shape. You could see the surplus in the early years, and you can see the drop off in 2021 due to the OTC retirements. And for some areas, like L.A. Basin is in red, you can see it has a larger deficit in 2021 that shrinks, basically, to 2024. And for the combined area, which is in a dark blue, there's a slight deficit in 2021 that grows a little bit out to 2024.

So one of the key points when looking at the results here is that the deficit that the ISO identified in 2024 is actually occurring earlier in 2021. And so when you look at the combined area shape in the latter years compared to the L.A. Basin and the -- the slopes of the lines are slightly different, what you could see is that some areas have their greatest deficit in 2021. And it decreases in time, while others are the reverse. And it may make finding a solution common to all three more difficult.

COMMISSIONER BERBERICH: Lana, quick question for you, just for clarification. Are these one-in-two or are these one-in-ten loads? What --

MS. WONG: It's based on the one-in-ten loads. So the local capacity requirement studies are based on the one-in-ten loads. So the load that is in here is based on the one-in-ten loads.

COMMISSIONER BERBERICH: Thank you.

MS. WONG: Okay. So the one thing I didn't mention on the prior chart, I'll flip back up there, was the San Diego area. So San Diego is off on its own. And what you can see is there's a surplus in San Diego. And we do account for the retirement of Encina and the addition of Carlsbad in these results. And that surplus slowly shrinks over time out through 2024. And I think our results may have a slight deficit in 2024.

COMMISSIONER FLORIO: So can a deficit in --

MS. WONG: Let's --

BOARD MEMBER GLICKFELD: Can a surplus in San Diego help cover a deficit in L.A.?

MS. WONG: For -- for the combined area, I believe it does have an impact. So the combined area of L.A. Basin and San Diego is a bigger geographic area. And the surpluses in one area could -- because everything gets combined. So what you could see is that L.A. Basin in red has a deficit, San Diego has a surplus, but the combined area in 2021 is -- has a slight deficit.

So it appears that, yes, when the whole geographic region is combined, if you're looking at that broad region, then it could help.

COMMISSIONER BERBERICH: Commission Florio, can I make a final point on that?

COMMISSIONER FLORIO: Yeah. That's really a transmission question.

MS. WONG: Right. And I was going to say, but if you look at the individual areas like San Diego or L.A., then it's a different --

COMMISSIONER BERBERICH: Well, my comment here is that these are local capacity. So by definition they're transmission constrained areas. So you can't assume a surplus in San Diego that there's enough transfer capacity to get into the L.A. sub region. So I think that, you know, you can't assume that.

MS. WONG: Right. And maybe the key point is when we're looking at these individual local areas like L.A. Basin, West L.A. Basin subarea or the San Diego subarea, that the requirements need to be met for these local areas, as well as the combined L.A. Basin-San Diego area. You know, there are requirements, different requirements defined for each area, and they need to be met.

Okay, so when we looked at the L.A. Basin results and we saw the upward trajectory, that it had a deficit in 2021 that slowly shrinks, as we dug into the results what we found is that one of the key drivers is the growth in the AAEE savings. So there's a ramping of AAEE in the latter part of the study period that contributes towards that upward slope. And the one thing that we wanted to add here is that there are uncertainties that exist within the overall AAEE projections and their allocation to specific load busses within the L.A. Basin local area.

So by interagency agreement the low-mid level of AAEE was agreed upon to be used in the local capacity requirement studies where locational specificity is more critical. And the mid-level case of AAEE is used for bulk transmission studies. And so this whole mapping of AAEE to the specific load busses has been performed by Energy Commission Staff for the last four annual cycles. And there's just uncertainty in that allocation.

COMMISSIONER MCALLISTER: A comment and a question. So in my mind that, certainly, the fact that AAEE is a driver and sort of the scenario that you model here --

MS. WONG: Uh-huh.

COMMISSIONER MCALLISTER: -- and I think what you're saying, basically, there's -- there's a broader uncertainty band around that, and there may be in some of the other resources --

MS. WONG: Right.

COMMISSIONER MCALLISTER: -- it highlights to me the fact that we just need to put together the analytical tools with granular enough data behind them to be able to track actually what's going on. And I think that's the direction we're aiming with the forecast as it evolves. So we're going to be much more, I think, assertive of them doing that kind of analysis and getting the underlying data from utilities and whoever else needs that data. So that's one.

I guess presumably this EE ramp-up in that same time period is happening in other local capacity areas, as well. It's just in the case of L.A. it's making the deficit go down faster. But is that a fair statement? I mean, there's lots going on in there that dictates the slope. You know, several -- many factors dictate the slope. So I'm wondering if EE is really special in L.A. as opposed to another area.

MS. WONG: Right. That -- you know, I am not sure about how the ramping in the L.A. Basin compares to San Diego. I mean, San Diego's AAEE also does ramp up by a few hundred megawatts. But with the surplus in San Diego, it doesn't stand out as much. And so I'm not, you know, absolutely certain how the other areas compare with the ramping. But I do believe in our forecast for AAEE, that we do have AAEE ramping in the latter part of the forecast period.

Okay. So now to talk about some of our --

COMMISSIONER MCALLISTER: One more question here.

COMMISSIONER FLORIO: One more before we move to --

MS. WONG: Okay.

COMMISSIONER FLORIO: -- sensitivity cases.

Looking back at slide 16, the transmission systems upgrade impact, but those seem to be growing year by year. And I think Mr. Jaske indicated those are mainly from the voltage support projects.

Is the Mesa Loop-In counted in here anywhere?

MS. WONG: Yes, it is counted. So the Mesa Loop-In comes in at the end of 2020. And so that contributes to the increase that you see occurring in 2021.

COMMISSIONER FLORIO: And only 300 megawatts. Thank you.

UNIDENTIFIED FEMALE: You may have said this earlier, apologies if I missed it, but does your baseload forecast account for electric vehicles (inaudible) and consistent with (inaudible) and the Governor's plan for California?

MS. WONG: Okay, so now on to the sensitivity results.

So as previously mentioned, the baseline assumptions are primarily based on PUC, LTPP assumption, and the ISO TPP assumptions. And over the last several years or several cycles of the PUC's LTPP rule making we've spent a lot of time on the baseline assumptions and coming up with alternative scenarios, and mostly examining the supply site assumptions. And so we recognize that these assumptions are subject to uncertainty.

After the ISO published its results for the 2014-15 TPP analysis and showed a shortfall in the combined region, what they identified is a DR is a potential mitigation measure. And what we realized is that, okay, we better include sensitivities for this higher level of DR. You know, our baseline DR was the same amount as in the ISO studies. And we wanted to be able to capture these alternative assumptions.

And so that led us down this path of looking at key variables and what the potential impact of those variables could be on the surplus and deficits. So we looked at plausible ranges around the baseline assumptions to come up with our sensitivity analysis.

So this and the next slide lists the 11 different sensitivities that we studied. And it includes changes to demand-side and supply-side assumptions. And of these 11, 7 of the sensitivities provide upside potential, basically improving the outlook for surplus and deficits, while four of them capture the downside potential or worsening the outlook for surplus and deficits.

And I've picked a few sensitivities to cover in more detail that I'll cover in the next few slides. But just to quickly go over these -- the other ones, I'll just go through this list.

So the first one, when we looked at the 2014 IEPR demand forecast and compared it to the 2013 we saw that it was slightly lower. So we thought we should do a sensitivity that captures that lower forecast.

The second one I'm going to cover in the next slide, so we'll go on to number three, transition of CHP QFs to wholesale gens. We understand that the CHP industry is undergoing transformation and that there's a new market for CHP. Some parties believe that the viability of CHP is questionable. I think everyone is in agreement that the old dirty CHP units are likely to retire. So this sensitivity just captures some of that downside or retirement of CHP facilities.

Four and five, DR, I'll cover in the next slide.

Number six, a higher demand growth in the CEC forecast. So the mid-level demand forecast is used for planning purposes. And we thought we should look at a higher demand forecast than what's currently in the model. So we basically took a two percent higher forecast in 2024 than the mid-level case. And that's about half the difference between the mid and high CEC demand forecasts that are -- have been produced over the last two IEPR cycles.

And then seven is the mid-AAEE savings

projections. As I mentioned earlier, by interagency agreement for local capacity studies, the low-, mid-level AAEE is used due to the locational uncertainty of the AAEE savings. And some parties believe we should be more aggressive in energy efficiency. So we thought we should include a higher level of AAEE. So that's what that sensitivity captures.

Then eight is RFO performance below nominal. As you've heard, Edison submitted numerous small contracts to the PUC for approval. This was out of their RFO solicitation. And so there's a question: Will all those contracts be approved, and if they're approved will all they -- will all of them be developed on schedule? Will they perform as expected? And so this sensitivity captures some of the downside risk of that uncertainty.

Nine, RPS, I'll cover in the next slides.

And then the last two sensitivities on storage. So in the baseline assumption the PUC decision isn't explicitly included. ISO has indicated that they would use storage as a mitigation measure if -- if they found any problems. So we just wanted to include higher levels of storage that basically partially meet or satisfy the PUC storage decision.

So that's the list of the 11 sensitivities that we conducted. And what I could say about coming up with the data for these, that some of the sensitivities were fairly straightforward to come up with, such as the mid-AAEE levels, because the Energy Commission already publishes those forecasts so it's easy to take that data.

But other uncertainties, such as the transition of CHP QFs to wholesale generators, it was more difficult to quantify and really hasn't been fully assessed. So we used simplified assumptions to come up with sort of an at-risk portion. So like for that sensitivity what we did was we changed the retirement assumption from 40 years down to 35 years for that assumption. And so with that I know that other staff at the Energy Commission are in the process of trying to obtain data to do a more thorough assessment of CHP.

So this slide gives you an example of the analysis that we went through to develop the alternative assumptions. We have three levels of DR. And as I mentioned, you know, once the ISO identified this as a potential mitigation measure we knew we needed to include, you know, that full level in our model.

And so the first column, the effective amounts of DR, what that means is effective with respect to location and being quick enough to respond within 30 minutes or less. And so ISO had identified eight substations in the western L.A. Basin that are most effective for mitigating the contingencies. And they provided that information to PUC Energy Division Staff. And the Energy Division Staff assisted with mapping these programs to these areas, looking at response time. And so that's how the quantities of the effective amounts were determined.

And then the full amount of DR on the far right column, that's basically all of the programs, including those with longer response times and in less effective locations. And then the moderate case in between, we basically took, I believe it was half of the less effective locations and just considered half of the DR.

And so when the ISO mentioned this repurposing concept, what they're really meaning is that they have certain operational characteristics that the DR programs need to meet in order to account for local capacity. And so an example is that these programs need to respond within 20 minutes. So that's part of what this repurposing means.

So this slide goes over alternative AAEE projections. So the first block we've got our baseline AAEE projections for the low-mid case. And a recently published PUC report basically an EM&V report that documents the actual savings found from IOU programs implemented in 2010 through 2012. What we found in the those studies is that the peak savings per unit of energy savings is below the level assumed in developing the AAEE projections. So for example, the report shows that 844 megawatt net savings were achieved, whereas the gross goals were 1,537 megawatts. That’s a shortfall of about 45 percent. So with this sensitivity we used a 40 percent reduction. It’s basically capturing the shortfall and peak savings.

And then here’s another example of how we developed another sensitivity. One of the questions that was asked is: Is there another RPS portfolio that could resolve this shortfall? I remember getting asked that question.

So, you know, when -- the PUC and Energy Commission for the past several years have produced RPS portfolios and delivered them to the ISO for study. And Energy Commission Staff, we’ve taken those RPS portfolios and we’ve mapped them to the local areas. You know, we’ve used latitude and longitude, sometimes wet bus ID (phonetic) if we have that available, so we could see how these portfolios impact the local area. And so what I found was the only portfolio that would have an impact in the high DG portfolio.

And so what you can see here, we split out DG and central station renewables. And you could see, with central station renewables there’s not much difference in the local areas. And that’s because the central station renewables tend to be located outside the basin. So it’s the DG, all of those solar PV that is bound to impact the local areas. And in this case there's almost a 700 megawatt higher amount by using this high DG case.

Okay, so now to look at some results. So this chart shows the combined area, L.A. Basin and San Diego, for selected sensitivities. And so, you know, as I mentioned, we ran 11 different sensitivity cases. And it's hard to show all of them on a chart without things getting too busy. So what we did was we -- we picked the two cases that formed the boundaries. So the blue line is the baseline case for the combined area. And then this shows a slight deficit in 2021 that increases to 2024. The green line shows the impact of the two percent higher demand -- peak demand case, which makes the deficit worse. And then the orange line shows the benefit of the mid-AAEE assumption which eliminates the deficit in 2021 and we see a surplus.

So the sensitivities, when you look at this they have -- basically have the same shape as the baseline case. So there's surpluses in the early year. And we really do see the impact of the OTC retirements occurring in 2021.

These are the results for the L.A. Basin area for some selected sensitivities. This chart is a little busier but still shows a range of impacts for some of the sensitivities. And what I found interesting about the sensitivities is that there were seven that provided upside potential. But what I found was that there were only two sensitivities that really eliminated the deficit in 2021. And that's the DR full sensitivity which is the dark blue line on cross with the crosses. And the purple line right below it is the high DG sensitivity. So those two eliminate the deficit in 2021 and then continue to provide a surplus in the area.

And then the light blue line in the middle is the mid-AAEE case. And that case still had a slight deficit in 2021 and then provides a surplus after that. So what's interesting about that case, the mid-AAEE case formed a boundary for the combined area. But when you look at the L.A. Basin area, it isn't the case that forms the boundary conditions.

So, you know, as I mentioned earlier when we were looking at the slopes of the lines for the areas, and I mentioned finding a common solution to all the areas may be a little more difficult, well, this highlights that. You know, you won't end up with the same sensitivities that form the boundary conditions for each of the areas. It may be different sensitivities.

And then the bottom case, the dark blue line with diamonds, is the co-gen sensitivity. And what that -- by changing that retirement assumption to 35 years from 40 years results in a loss of capacity in this latter part of the study period. And that just increases the deficits that we see between 2021 and 2024. So looking at this chart overall we still continue to see the surpluses in the early years and the impact of the OTC retirements at the end of 2020, leading to the decline in the surplus in 2021.

So just some observations from looking at the sensitivities. They all seem to have a similar shape to the baseline. It just seems like the results tend to move up or down from the baseline case. Some -- some variables will improve the surplus deficit, while other variables make things worse.

As I mentioned, sensitivities may have different impacts on the different impacts on the local area subareas. That's why you'll find that certain sensitivities will form a boundary for one area; it may not be the same sensitivity that forms a boundary for another area.

And then, again, pointing out that 2021 is a critical year due to the OTC retirements.

And then another finding that we had from conducting the sensitivity analysis is that we know ISO identified DR as a mitigation solution, but it also highlighted that, okay, there could be other solutions, like storage. So our storage sensitivities can also be a potential mitigation solution.

Okay, so now that takes us to our scenario results. So after conducting the sensitivity analysis we thought about, okay, maybe we should combine multiple variables together to look at the impact of multiple things happening at the same time. And we recognized that some combination of variables may be offsetting, like you could have a lower demand forecast by using the 2014 IEPR demand forecast, but that might be offset by a 40 percent reduction in AAEE.

When we created these scenarios what we wanted to do was sort of create bookends. That was our initial goal, to create an optimistic bookend where we're picking variables that all move in the same direction. And the pessimistic bookend, you know, all the variables we picked, they move all in the same direction, so that we could look at a wider range of impact to the surpluses and deficits. And then we came up with two in-between scenarios, markets cooperate and incentives fail, that have a less extreme departure from the baseline case.

And so in the scenario development we chose certain variables to include in each scenario to create a plausible scenario. But the tool is easy to use, and other combinations could be developed.

COMMISSIONER MCALLISTER: Hey, Lana, I wanted -- I wanted to chime in. I'm going to take a little bit of issue with the market cooperating and not having any energy efficiency in it. Energy efficiency is sort assumed to fail but not assumed to actually over-deliver, for example. And I understand why you chose those. But, you know, we have a lot of activities on the efficiency front --

MS. WONG: Right.

COMMISSIONER MCALLISTER: -- beginning to stimulate markets so that they actually do go out there and generate more savings. And, in fact, there's a governor's goal out there to double the savings associated with our existing building programs.

MS. WONG: Right.

COMMISSIONER MCALLISTER: So -- so there are some policy -- there's reasons to believe that the upside is also a possibility, as well.

MS. WONG: Right.

COMMISSIONER MCALLISTER: So I wanted to just point out that the scenarios -- I'd like to see the scenarios including target efficiency and, you know, smart ways to do that, but also, I think, in capacity needs.

MS. WONG: Okay. So the one thing I wanted to add to the scenario development, these are variables that are on top of our baseline assumptions. So the baseline assumption includes the low level of -- or low-mid level of AAEE. So it does have energy efficiency in it, it's just the baseline assumption. So the fact that we don't have an additional energy efficiency variable just means we don’t have a higher level than what’s assumed in the baseline case.

COMMISSIONER MCALLISTER: No, I understand. That. I guess the fact that, you know, for the low-low assessment you already kind of selected a conservative --

MS. WONG: Uh-huh.

COMMISSIONER MCALLISTER: -- efficiency, you know, it’s not the mid-mid, it’s the low-mid. But let’s also look at what happens if, you know, somebody figures out what the special sauce is ad is able to really go out there and sell target efficiency that -- that works at -- on the capacity front in the local -- local area, as well, and see what that -- what that does.

MS. WONG: Okay. So I’ll make a note of that. So our optimistic bookend, that’s certainly something that could be included is including the mid-AAEE level.

Okay, so the first chart we’re showing the surplus deficits for the combined area. And so the baseline case is the middle line in sort of dark blue. And so that’s our combined L.A. Basin-San Diego area. And then we have -- the red lines are optimistic scenario. The green lines, the pessimistic scenario. And the other two lines in between are the markets cooperate and the incentives fail scenario which are providing a narrower spread around the baseline case.

So what we can see here is that we still, under these scenarios, have surpluses in the early years. And then due to the OTC retirements we see that drop off again in 2020. So the surplus is reduced in 2021. The thing to point out, the two upside scenarios, the optimistic and the markets cooperate, that the surplus is maintained throughout the latter part of the study period.

Let's see, the shape of the scenarios tends to be the same shape as the baseline case. And pointing out again, the loss of the OTC continues to dominates the results in the shape of this.

COMMISSIONER BERBERICH: Lana, a quick question, and maybe this goes back to assumptions, and I'm sure you built this into the forecast. But what kind of assumptions do you make around like electric vehicle charging?

MS. WONG: So the electrification assumptions that are assumed in the base demand forecast are incorporated in these results. So if you consider that the mid-level demand forecast that we're using for planning purposes, that includes electrification. And I believe it includes the governor's goals in that forecast.

COMMISSIONER BERBERICH: But in the, you know, particular in the L.A. Basin, I know Dr. Wallerstein has some significant challenges ahead of him to reduce overall emissions, put aside carbon itself. And I didn't know if there were some -- you know, maybe you can comment on this, on kind of what the objectives are. But clearly there's going to have to be very heavy reliance on electrification of transportation, particularly in the L.A. Basin. And we wondered if we had the slide to that adequately there.

Barry, I don't know if you have any --

MS. WONG: Well, one note about our higher demand growth sensitivity, we use a two percent higher demand growth. And in part, higher electrification could be one of the contributing factors to the higher growth in that sensitivity. So that's something that, you know, we considered when we were coming up with the higher demand growth, we thought, okay, that is a plausible scenario, higher electrification.

COMMISSIONER WALLERSTEIN: So the 2019 to 2023 time period is the critical time period for air quality in Southern California. And we've had federal particulate and ozone standards that must be met. And by 2023 we're going to have to reduce the baseline NOx emissions north of probably about 55 percent. And the California Air Resources Board and our agency will come out with a draft plan this fall.

And in parallel to that, CARB is developing its sustainable freight strategy. And the most important emissions source category for us to get clean air is what to do with trucks. And so we're going to need a great deal of electrification well beyond what the governor has in his current goal is we're going to get to clean air, at least by the way we look at the data.

In addition to that there is, as you probably are aware, a lot of movement in the port area to electrify. And so, you know, I would encourage you all to update this analysis once that information is available in the fall in terms of what, at least at a staff level, we think is necessary.

MS. WONG: Uh-huh.

COMMISSIONER WALLERSTEIN: Because I think it's going to have -- potentially have a significant impact.

COMMISSIONER BERBERICH: I think it could be -- I think it could be -- I think it could be a bookend scenario that you could look at, because I know that there are some serious attainment issues in the L.A. Basin. And I'm curious, you know, if you have to -- let's say you convert 30 percent of the transportation fleet, including the truck fleet, to alternate fuels, what that would -- might look like. And is it 2,000 megawatts, 3,000 megawatts? I don't know.

COMMISSIONER MCALLISTER: So I was going to suggest, to the extent you've taken the forecast sort of as given, without breaking that out, maybe it would be good to go back a step and break that out and then do scenarios specifically on that piece. Because there, you know, there is a lot of uncertainty about where the penetration is going to be, just on the natural.

MS. WONG: Right.

COMMISSIONER BERBERICH: And that's driven by policy in large part --

MS. WONG: Right.

COMMISSIONER BERBERICH: -- but also driven by markets, and so you never quite know how that's going to pan out. But those scenarios I think would be very useful.

MS. WONG: Right. And that's certainly something we could go back and look at, like you said, breaking out electrification and seeing if we could do more research on coming up with an assumption that doesn't just take a broad two percent higher demand growth.

COMMISSIONER MCALLISTER: Yeah. And that could actually inform policy. It's like, oh, that scenario actually makes a difference, so let's go out and try to make that happen or --

MS. WONG: RIGHT.

COMMISSIONER MCALLISTER: -- that would be sort of a helpful action.

Oh, did you want to say something, Bob?

CHAIR WEISENMILLER: I was just going to say something very quickly and then hand it back to Barry.

I was just going to point out to everyone that the governor's recent executive order on Sustainable Freight Strategy certainly has pretty aggressive goals. It's had its first meeting. But that's sort of the other aspect to keep an eye on. We certainly encourage people to participate in it.

COMMISSIONER WALLERSTEIN: I was just going to say that for us this is one of those which comes first, the chicken or the egg, that we may have vehicle technologies available but not have the proper infrastructure for the electrification that is needed to support those technologies. And so it's critical to us that this part of it gets taken care of. And it's something that my governing Board has been very, very concerned about in terms of continued investment in electric-based vehicle technology, as opposed to supporting things like natural gas vehicle technology.

COMMISSIONER MCALLISTER: I remember -- I remember your plan and how controversial it was with respect to electrification. So you're going to have to visit that in Part B, maybe. Okay.

Any questions? Okay.

Go ahead. Are you --

MS. WONG: Okay. Just wanted to mention that I drive an electric car, so I'm doing my part. Okay, I'm not in the L.A. Basin area. I'm the Sacramento area. But -- okay.

So this chart shows the surplus deficits for the L.A. Basin area. And again, we see the surpluses in the early years. And then the drop off in 2020 due to the OTC compliance. And we see that impact in 2021, that 2021 is still a critical year. And so again, we could see for L.A. Basin that upward sloping trajectory for the baseline results in the middle. You know, it's driven by the ramping of AAEE.

So just like in the combined area, changing the assumptions tends to move the results up or down from the baseline case. But the scenarios tend to have the same shape as the baseline.

And then the last chart we have for San Diego. And so for the San Diego area, again we include the loss of Encina at the end of 2017 and Carlsbad coming online. But there are surpluses in the San Diego subarea that essentially decline due to load growth and fewer resources being added. What's interesting about the two pessimistic scenarios, the pessimistic and the incentives fail scenario, what those two cases do is it moves the slight deficit in 2024 that we saw in the baseline study, it moves it earlier to the 2022 timeframe.

So this is a table that's just showing you the range for the optimistic and pessimistic cases. So you can see the numbers, like how wide the range it. So, you know, we're really created these bookend cases for the optimistic and pessimistic case. You know, the optimistic case is providing 1,400 megawatts of upside potential, while the pessimistic case has around a 1,700 megawatt downside potential. And then the two scenarios in the middle, the markets cooperate and incentives fail, are -- are basically in between.

So what did we find by conducting the scenario analysis and comparing it to the baseline? That basically none of the scenarios show a departure from the baseline case. You know, the shapes tend to be the same. 2021 is still a critical year. The bookend cases have a wide range.

And the last thing to note is LCAAT is simpler to run than a full power flow model assessment. And, you know, coming up with other scenarios would be easy to do. And I say that, given the -- using the sensitivities that we've created. But as mentioned, if we do an electrification sensitivity, that would actually be doing some research on electrification, coming up with a plausible set of assumptions, and then sort of enhancing the model to add that sensitivity to it.

So that concludes my presentation. I'm going to turn it over, back to Mike Jaske for findings and conclusions.

COMMISSIONER BERBERICH: May I -- may I ask you one final question?

MS. WONG: Sure.

COMMISSIONER BERBERICH: I know these are not power flow models. Is there -- sorry I didn't follow this earlier -- is there some plan to run power flows on this to see how they might depart or --

MS. WONG: Well, so, you know, the idea of LCAAT as a screening tool, the snapshot years are based on the power flow modeling results. So 2015, '19, 2024 are based on power flow model results. And then the intermediate years we've created the results in the data to build out the intervening years.

We consider this a screening tool that if you look at the results that have been created for the intermediate years, if you see something that is a red flag or sending you a warning signal, that's where we would go back and say, you know, we're finding that 2021 is a critical year and we should go back and do power flow assessment. So that's how this was --

COMMISSIONER BERBERICH: But you do have -- you do you have snapshot years through this where --

MS. WONG: Yes.

COMMISSIONER BERBERICH: -- you have run power flows?

MS. WONG: Right. Exactly.

COMMISSIONER BERBERICH: Did you run power flows on all the scenarios?

MS. WONG: No.

COMMISSIONER BERBERICH: Just the base?

MS. WONG: Right, the baseline set of assumptions. And so the caveat there is there isn't power flow assessments for all the sensitivities. I think if you looked at every single year and every single sensitivity, I mean, that would be like 150 cases which -- or something like that, which we know is just impossible to run power flow.

COMMISSIONER BERBERICH: And I'm not, again, I'm not offering to run power flow.

MS. WONG: I know.

COMMISSIONER BERBERICH: I'm just making sure I understood it --

MS. WONG: Yes.

COMMISSIONER BERBERICH: -- where we were on that.

MS. WONG: And so probably what --

COMMISSIONER BERBERICH: Because, you know, the spreadsheets I think gives you data points, but it doesn't necessarily mean you can electrify it, which is something we need to make sure everybody understands.

MS. WONG: Right. Right. Exactly. You know, that if there's a warning sign about a particular year, that we should go back and run power flow models. And as I understand it, ISO is planning to run 2021 which I think, you know, our results are showing that that is a critical year with the OTC retirements.

COMMISSIONER BERBERICH: Is that right, Bob?

CHAIR WEISENMILLER: Yes.

COMMISSIONER BERBERICH: Thank you.

MS. WONG: Okay.

CHAIR WEISENMILLER: So I had a question which maybe either one of you could -- one of the -- the other part that's in the model is looking at the data on sort of substation loads and giving us a way to see basically what's going on out there, sort of looking at load growth, net of, you know, DG and everything else. And I just thought it would be good if you or Mike could give sort of a simple summary on where we seem to stand at this point in this -- in this soft footprint area.

MR. JASKE: Okay. So having more granular and more immediately available load data was thought to be an important method of essentially monitoring what's going on. And obviously those data all by themselves don't explain why you get what you get. But if they are different than the forecast in the short-run period, that's a subject of concern and needs investigation.

So we have arranged to get all of the individual substation data from Edison and San Diego on an hourly basis. And we had -- already had some history from -- from Edison. So we went back and got also a number of years of history from San Diego. We're now getting hourly interval data every quarter, lag 30 days. So our initial -- and we've been doing that essentially for a year now. So we have paid some attention to the Edison data. And we are focusing in particular on Orange County, given its previous identification of being important. And so far we are not finding anything that seems grossly at odds with the forecast.

So the comments that Caroline McAndrews made earlier today, that Orange County is growing a little bit faster than the rest of the L.A. Basin, that seems to be showing up in these data. And there's, you know, variability among the substations in terms of when they're peaking, what days they're peaking, you know, they peak at different hours. So it -- which reflects different mixtures of residential-commercial-industrial customers.

So we're not using that data directly in LCAAT at this time. But it's -- we're massaging it and trying to come up with supplemental explanatory variables for those particular individual substations or groups of them that would explain this differential growth rate. But we're sort of doing that at this point in parallel with LCAAT, not directly in LCAAT.

CHAIR WEISENMILLER: No, that's good.

I think the one thing I just want to have here on the record, I'd ask Ms. Kito, we already knew about what was going on in terms of all the additional energy efficiency load growth. And just to the extent we're looking at sort of the net and keeping an eye on that, that that's important for us as we try to track how nervous we should or shouldn't be.

MR. JASKE: There are some ways that the PUC staff has been working to produce granular results of the normal EM&V evaluation process. But I don't know that it's yet gotten to the stage where it's linked to -- or aggregated by substations. I think it's groups at SIC codes at this point. So there's -- that's another source of data that could be brought to bear to help explain. Ok

So two short sections to wind up this presentation, and then any concluding questions you'll have.

So we had findings and conclusions about the LCAAT tool itself. And I think Ms. Wong has pretty much identified, you know, all of these, that -- that these baseline results are consistent, at least in the individual study years, with ISO power flow study results, which they should be since that's where the LCR values come from. We have, of course, several times identified this '21 out to '24 period for all of the areas that involve L.A. Basin, and that San Diego is different, and that alternative assumptions can either eliminate those deficits or increase the surpluses, depending on which ones.

So I think the way we would characterize what we would found with using LCAAT is that these deficits are a source of concern, they're not a source of alarm. There are identified things that could be pursued that would resolve these deficits. The ISO, you know, in its 2024 analysis itself did that very thing. They -- they sort of bridged the gap by talking about repurposing DR. Storage is another option. Several other things, you know, could be done individually or in combination.

And so when this was written we did not know that the ISO was going to say that it was going to do a 2021 power flow study. I only heard that late last week when the ISO's slides were produced. Our information heretofore had been the ISO was going to study 2020. And we were urging them separately to do 2021 because of what we had been finding. We're very happy to hear that the ISO is agreeing to do 2021. And we'll be happy to help them, you know, assemble inputs for that year, should they require any assistance from us.

We think the PUC needs to think about the local capacity issue in this time horizon, five to eight years forward, and not just focus exclusively on ten years forward as if there's no problem because here and ten years out, because we at least, you know, have some reason to believe things are not fully satisfactory in those intermediate years.

And the Joint Reliability Plan proceeding, although it didn't move forward with Track 1 to require the RA process to move out to years two and three as a mandatory obligation, the Track 2 process, although not very visible, is I think continuing. And this tool that we've developed, particularly if expanded to the other local areas, you know, could be an adjunct to that whole Track 2 effort. So we have been keeping the Energy Division staff working on track two informed. And, in fact, we've given them our report a week or more ago.

And finally, of course it's critical that we monitor all these demand-side savings and use realistic ranges of assumptions. And if, in fact, it's credible to say that AAEE could fall short, we need to either be refuting that by newer EM&V results or figuring out how to strengthen programs so that we can actually achieve that or higher levels.

So one very last little section on how we might then use this tool to trigger mitigation. I think you've heard us probably say throughout this presentation that we're -- we've now got this tool. We're going to update it and run it periodically. We'll update it and run it if some kind of new significant information becomes available. We're going to communicate these results to the staff of the other agencies that we're in close contact with through this overall Southern California Reliability Project. If we find deficits, as we have now found, we're going to see if there's any other independent sources of information that can help inform a decision. The ideas that we would brief, the managements of the agency through the energy principals, requests to ISO to conduct a power flow study if they haven't already agreed to one, and in this instance it looks like they have. And then provide, you know, those powerful results in the right package to the principals that will then lead to individual agencies deciding how to pursue any appropriate course of action.

And this is a slide with these two separate sides that give you an idea how the two different tools that we have been talking about and that I will get into in more detail in the next presentation, how we might choose among them using these results.

So on the left-hand panel, this chart is showing the same basic pattern of -- what color do you have -- dark blue is the original LCR results. The green is the modified ones by virtue of transmission upgrades and load modifier effects on LCR requirements. The purple-ish line which has a steep plunge in '21 shows the deficit in that one year and then bounces up and stays above the green line.

If you go over to the right-hand panel, that's the kind of projection that would say perhaps an OTC plant deferral is the right mitigation. There's only a one-year issue. You might delay that deferral or that compliance for a project by one year, solve your problem, and not invest in a bunch of hardware that is only needed in one year.

In contrast, the red line shows a case where that is that same steep plunge, it goes a little deeper and then stays below. And so that might be the kind of instance where if power flow studies confirmed it we might actually have a much more serious problem and might actually want to consider a new generating facility.

So that's the way in which this kind of analytic tool can help in the process of choosing between different kinds of mitigation measures. So whether it's large or small amounts, whether it's a limited amount of time, and perhaps also the particular area in which the deficit is to occur. And I think I've probably mentioned all these other things that would be taken into account.

So that's the end of our presentation on the projection tool. Are there any questions?

COMMISSIONER MCALLISTER: So I think we have to move on.

MR. JASKE: All right. There are a few from the audience, so I will -- that have been chatted in, shall we say.

So Micah Berry of Chevron asked,

"Does the base load forecast account for electric vehicle demand growth consistent with CARB and the governor's forecast?"

This base level forecast from the 2014 IEPR, I believe had 1 million electric vehicles. That's not consistent with the governor's new goal of major reduction in transportation emission. So things have evolved from the period of time of the 2013 IEPR to where policymakers are now moving the ball right now.

Some more technical questions from Jaleh Firouz who, by the way, is a consultant to the city of Redondo Beach in numerous activities at the PUC.

"Since the load forecast used in the study is one-in-ten, which means the higher load could possibly only occur one year out of the next ten years, what's the justification for assuming higher load sensitivity? Isn't that building conservatism on conservatism into the assumptions? Shouldn't -- shouldn't an alternative sensitivities be a lower load forecast than the one-in-ten?"

My answer is that there's a lot of policy initiatives pushing toward lower load. We wanted to test the consequence of higher load, and we picked two percent just, you know, as a starting point without any kind of real attribution as to what caused it. And the dialogue here is identified, a variety of things that one can name and then perhaps try to quantify their actual specific inputs or consequences. That's probably for a next round of study.

And another perhaps more comment from Ms. Firouz,

"It's not reasonable to call a case that has a one-in-ten load forecast as a base scenario. That case is already a pessimistic scenario."

I think I disagree. If I understand the ISO's practice of a one-in-ten load forecast and two overlapping contingencies, that's a method of satisfying FERC and NERC planning standards. So in that context this one-in-ten forecast is the appropriate assumption to use. And one can imagine a worse forecast than that, maybe a 1-in-15 or a 1-in-20, as well as a less stringent one.

And finally, another comment from Ms. Firouz,

"Through the use of real-time pricing, couldn't peak load be shifted to non-peak hours, thus reducing the peak forecast?”

Yes, clearly that’s true. And in the current 2015 IEPR cycle, that very question of electric vehicle load and charging is being investigated.

Again, from Ms. Firouz,

“The baseline is supposed to show the expected case. The expected case should be based on the expected load forecast, not on a one-in-ten load forecast. A one-in-two load forecast is used in optimistic or pessimistic scenarios could be built around that.”

Again, I disagree. The essence of the NERC and WECC standard is that you’re supposed to have adverse load, not -- not expected.

CHAIR WEISENMILLER: You know, that’s been asked and answered.

MR. JASKE: Okay.

CHAIR WEISENMILLER: So let’s move on.

MS. RAITT: So we have another presentation from Mike Jaske.

COMMISSIONER MCALLISTER: I’m going to ask you to be as quick you can here. That last presentation was only scheduled for half-an-hour, it went a quite bit longer than that. So we’re now running quite a bit longer.

MR. JASKE: Okay. I will try to satisfy that direction.

So we're here to talk about developing these contingency mitigation measures. Some terminology, you can read the terminology for yourself. The whole context of this is that we're doing this enhanced monitoring, we're doing the kind of assessment that I've just described in the previous presentation. We're trying to understand where we're headed. If those kind of analytic tools suggest we end up with problems, we need to have -- or the idea is to have measures that are on the shelf, ready to be triggered. And the two that we're going to talk about here are OTC deferral and new conventional generation.

First, OTC deferral. So the OTC policy itself recognizes the possibility of needing to shift compliance dates. And so it builds into the policy two forms of deferral, a 90-day kind of an emergency that the ISO can trigger, provided the Energy Commission and PUC don't object. And then if there are proposals for longer delays, then that goes through the independent body called SACCWIS which is the Statewide Advisory Committee on Cooling Water Intake Structures. And SACCWIS has representatives of six state agencies, as well as the ISO, so seven body -- or persons on this body. And it's to review specific requests and provide a progress report at least annually to the Water Board. And the Water Board will choose how to respond. But the policy says the Water Board will give it considerable weight if the Energy Commission and the PUC don't object. So it calls for a method of dealing with disagreement among SACCWIS.

So we've -- Mr. Bishop made a fairly complete description orally at the workshop a year ago. And we have talked with Water Board staff and Mr. Bishop a number of times since then and we have tried to pull together more specifically how this whole OTC deferral process would work. And these five items are sort of the key things that he identified a year ago and we fleshed out a bit more how they might work.

So specificity, you need -- from the Water Board perspective receiving a deferral request, they want it to be specific. They want to know what unit you're talking about. They want to know the rationale. They want to know why it is -- you're coming to the Water Board for deferral versus not doing something else. They want to know how compliance will eventually be assured. They don't want a request that just says, well, we need to defer things three or four years until we sort it out. They want to have a proposed solution brought to them. We're asking for deferral for two years for this specific plant for this reason, and at the end of two years this will be the solution.

Of course, since the OTC policy incorporates this whole SACCWIS process, they would like the SACCWIS to be used, not some other mechanism. They want the -- any such deferral requests to be timely. They don’t want it to come at the last second so they’re, you know, feeling pressure to engage in excessively rapid decision making. Maybe they’re tired of doing that as a result of all the water conservation efforts they’re having to do.

And there are consequences built into the policy. I believe the first time the dates were amended was this notion that if you -- if you push them past ‘22, 2022, then you have to do something more than what the original policy called for. So you’re going to -- you have to be careful about what you ask for.

And I -- personally I think the assure compliance, you know, is the -- is the most critical of all of these. They -- from all the conversations we’ve had, they really do not want to be put in a spot of saying, yes, we’ll delay it for some indefinite period for some vague policy outcome. No. We’ve been at this for a number of years. We owe it to them to be specific.

So this is the timeline that we’ve worked out with the Water Board staff. The first step here has quite a large range of what amount of time it might take. And it really is all pre going to SACCWIS. And it’s on -- probably on the shoulders of the agency staffs to be doing this work if there’s new analyses required.

Once it gets to be a proposal and goes from the technical staff of the agencies to SACCWIS, then there's all these steps that follow. And they will take roughly a year, could be accelerated a little bit if need be. But that's the kind of process that the Water Board would like to follow so as to give an opportunity to all the effected stakeholders to have their say along the way.

I think there are really two issues, and the last is probably the most important. But the first one is how far ahead of the official compliance dates should we really be making such a request? Some instances I think it's going to be clear that there's a problem and we could communicate that there's a problem, but we don't yet know what the solution is. So if you were to convey a request early you wouldn't really be able to so clearly satisfy that assurance requirement that we've been talking about. If you wait a little bit longer then you might well have an opportunity to understand what exactly that deferral date or how that ultimate compliance will be satisfied, but that will chew up some time. So that's the issue we may still need to wrestle with.

More importantly is who's submitting a deferral request? We've had deferral requests initiated by the owner-operator in the case of LADWP. We haven't had any initiated by anyone else. Most of how the SACCWIS processes work to date, it's the technical staff of the agencies sort of going through and trying to assess whether any of these facilities, you know, is an issue, and so there's -- there's a request initiated by the agencies. And it's not completely clear in all instances how the owner-operator of a facility might like or not like in such a deferral request. So that's a loose end that needs some further thinking.

Are there any questions about this OTC issue before I move on to --

COMMISSIONER BISHOP: No. I think you did a good job of summarizing our discussion over the last year.

MR. JASKE: Thank you.

Okay, so the new generation option. So in thinking about how you might have new generation in a contingency mode, Michele Kito this morning identified that the key PUC procurement decision allows Edison and San Diego to have contingent projects. It lays out a bunch of questions that would have to be asked, presumably in an application or some other filing to the PUC. And of course then the whole kind of approval process, we presumably want, in thinking about how to design new generation mitigation measures to minimize the amount of elapsed time from when you actually decide you want to trigger this option to when it's operational, because if you don't do that then that means you’re relying on further out, you know, lead time on your analytics and they’re sort of inherently fuzzy.

You have to deal with cost recovery for project design and permitting costs. And if you’re permitting something and then you’re going to put it on your shelf and not ever hope that you’ll never build it, who’s going to get paid for doing all that work? Presumably the one doing it wants to be paid.

You want to think about market power for whatever projects might be involved or would respond to an RFO.

And you want, of course, the project that’s waiting to be triggered to satisfy whatever the reliability problem is that you’ve identified. And if you have one or two things on the shelf, given their location and their design they may not be the optimal solution. So how can you deal with designing things, given these considerations?

You’ve got three options that we’ve identified so far.

The utility does an RFO and puts the burden on the developers to come forward with proposals. And I think, in part, the utilities are interested in this from the perspective that it puts some burden on the developer to say how to allows the costs between the sort of slump-cost part of designing and permitting and getting a PPA for a project that might never be built versus then if it is built, how do you pay -- figure out what to pay it, because in a normal project all that stuff gets rolled together in a single financial transaction.

Option two, the utility itself pushing the project into the permitting and process. And only when it's triggered you turn it over to a developer.

And option there is -- which is a new one that we have only identified in the last few months, which is to rely on a pool of projects that are already permitted but that don't have PPAs. And Roger Johnson this morning identified that there may well be some of those in the pipeline in the next few months, and more later.

So the essence -- I'm going to have three slides that go through each of those in a little bit more detail. There are really two stages to each of these options. There's the stage where you're developing the measure, and then the stage where you're implementing the measure if you ever decide you need to.

So the first option, the utility RFO option. The utility issues an RFO. They get proposals. They choose a developer. The developer is the one that initiates permitting. The utility submits some kind of a PPA, maybe a two-stage PPA to the PUC. The agencies process that permit and the PPA as far as they can go. And we're going to find out from the Air District people later this afternoon some issues about the permitting side of that and what that line is between as far as you can go and a final permit.

In stage two, if it's ever triggered, then the project has to finalize its permit, finalize its PPA if not already done so in some contingently approved manner. And when those two things have been approved using, you know, the normal processes at the Energy Commission and the PUC, then the project gets its go-ahead and it gets constructed.

Option two, keep the developer community out of the game initially. The utility designs the project. They select a site. They initiate the permitting and some kind of PPA dialogue with the PUC. Those processes carry themselves out as far as they can go. And then that sort of sits on the shelf, waiting to be triggered. If it's triggered then -- then utility brings utility brings the developer community in by saying we have this partially permitted project. You know, who wants to carry it to fruition. They get bids. Developer may need to tweak that project design, so there's a little extra time for this option because of that step. The developer submits the proposed project into the permitting process to be finalized and to get a final PPA. And if both of those are approved, then the project goes forward.

The third option, of course, is quite different. There isn't a stage one that already require -- that is going part of the way through the permitting process. The essence of this option is to rely upon the fact that developers have already got projects permitted and that they've already invested money into a project. So we simply monitor what this pool of projects are. And because of the aging of permits and the need -- and the issues that the Air Districts will tell us about in a few minutes of permits getting stale or maybe having, in fact, finite lifetimes, perhaps with renewal and other kinds of updating, they -- this pool of potentially useful projects may change over time, may have new additions and it may have dropouts.

If it's ever -- any of these projects are needed because of the analytics, then the utility uses some RFO process to select from among the pool. The developer submits whatever it needs to, to get the project permitted at the Energy Commission or other agencies. The utility submits a PPA to the PUC. And then again, if both are approved the project can go forward.

This is a chart that tries to compare these three. So there's three columns of -- one for each of the three options. A variety of attributes. Not -- there's no clear winner here. There's pluses and minuses from each of these perspectives. And the -- and the staff paper that Ms. Wong and I authored that's on Energy Commission IEPR website, you know, goes through this all in more detail, of course.

But important is that there are differences, even in the stage two time for approval and construction. So for example, that's the least amount of time it would take to, once triggered, get the project through all the final approval and physical construction so it would be online. So we're having to be projecting forward at least three to four-and-a-half years to be consistent with -- with these lead times, and probably more than that. There's a bunch of differences in all these other things.

And let me point your attention to the very last row, which is the amount of time to develop the option itself, not to trigger and construct it but just to develop it. There's a lot of months to do options one and two to carry them part of the way through the process. For option three we don't have that. So we can have option three as a viable mitigation measure somewhere in early 2016, most likely. Not so for options one and two. A big difference there.

So what are the next steps? We'd be pleased to receive input from stakeholders today and through the comment process. The staffs of agencies will, of course, be consulting among each other about where to go and making a recommendation at some appropriate appoint to the energy principals. And depending on what they decide there will be some effort to convert one of these options or something else into a real mitigation measure so we actually have a tangible option.

Questions?

CHAIR WEISENMILLER: Yeah. Well, first I wanted to thank both of you for the analysis here. I think obviously one thing we've always been doing is trying to make sure we're tracking what's going on, and we have contingency planning. I think I'll make a few statements. I think in the interest of catching up on schedule, I'll probably not ask too many questions.

But in terms of statements I'm just going to say, first, certainly your analysis shows that the future is pretty uncertain. I was going to remark back to when I think back on the Sunrise Transmission Line siting case, a few of the scenarios -- there were dozens of scenarios literally done. There was no scenario that ever considered no SONGS, which obviously is the thing that has made Mr. Avery look like a genius, you know, in that case. And at the same time there was no scenario that really took into account what photovoltaic costs were.

MR. JASKE: Uh-huh.

CHAIR WEISENMILLER: So having said that, I think it's pretty clear that it's important to look across a wide range of things, which you've done. And it's important for us to keep monitoring things. But certainly none of the forecasts per day to date sort of allow any cause for concern or us trying to start scrambling to do anything on the resource side.

I think you sort of framed initially the two choices. One is, as you said, there's a short window, you know, some sort of once-through cooling delay. I think I tend to personally put -- believe very strong that we should comply with the Water Board's standards in moving forward, so it's a pretty high threshold. And frankly, a lot of these plants are pretty old.

MR. JASKE: Uh-huh.

CHAIR WEISENMILLER: So again, if it's a very short delay, that's one thing. But, you know, thinking that some of these plants were built between '59 and '73. So by 2015 they were already pretty old, if not reliability challenged. By 2020 they certainly make me more nervous. And by 2025, you know, again, it's not a good idea.

So that gets you back to what one might do. And certainly in the comments, if people have specific ideas on cleaner projects than peakers, again, we'd like to get those comments. Realizing the reality is peakers run about five percent of the time. So that a lot of our more typical 24/7 resources, if you run back in frequently the cost could be pretty amazing. And you're also assuming, even with these long lead times, that we don't need a transmission line. So if we were to need a transmission line along with a project, you could be adding another ten years. So again, for some kind of fast-acting backup, adding a transmission line on top doesn't really get us there.

So -- but again, I really want to encourage people to think about some of the options. And certainly, as I said, if we're going to be having these sort of annual meetings, and I, you know, assume over time more options are going to come up. And certainly storage costs are going to come down. A bunch of other options will really become much more the mix as we go forward in terms of potential contingency plans. And, you know, hopefully technology choices will be good.

But again, I just want to emphasize to people, the future is very uncertain. Certainly based upon today's conversations there's no -- you know, there's no need for panic. But, you know, again be ready -- suggestions are appreciated, and we'll be back again next year.

So again, thanks for both of your work.

COMMISSIONER WALLERSTEIN: Can I ask a question?

COMMISSIONER MCALLISTER: Sure.

COMMISSIONER WALLERSTEIN: I've been very struck by the last two presentations as relates to how we do contingency planning in the air pollution world. And we have a defined set of measures and we work up those measures, and then they get triggered by various mechanisms.

But I'm wondering whether or not the CEC has a matrix or could put together a matrix of the no-pollution options and various key parameters related to those options like cost and time and so on, and kind of update that matrix annually so that as you move to a point where you feel something needs to be triggered, that it's all sitting there or you as Commissioners to make your decision and to do it in a fashion that obviously takes into consideration a local air plan, what the governor and CARB are going to do on -- with you all on the scoping plan, and an interim GHG target between 2020 and 2050 so that -- you know, for me it's not a lot of time when I think they're talking six years from now.

CHAIR WEISENMILLER: Yeah, right.

COMMISSIONER WALLERSTEIN: And we have to go through public process and do everything.

So I would just encourage us to have something that's a living document that's moving forward, because otherwise the fallback is simply going to be the request and extension of the OTC.

CHAIR WEISENMILLER: Now that, that's a very good idea. We should do that.

I think the other -- the other basic message here is I think the last time we looked at maybe we would have a peaker and preferred resources. I think what we concluded is we were going to keep our foot to the metal on preferred resources, and the notion somehow we would hold them off until we might need them later. Because the more we do them now the less likely we get to contingency plans; right?

COMMISSIONER WALLERSTEIN: Yeah. I had thought of that.

CHAIR WEISENMILLER: Yeah.

COMMISSIONER WALLERSTEIN: And you don't want to take the foot off the pedal. But you also don't want to find yourself on the other end.

CHAIR WEISENMILLER: Yeah. So, yeah.

COMMISSIONER MCALLISTER: You're advising us to basic create a brighter line where we know, okay, well, we -- these conditions have been met, therefore we should try to move forward with the delay, or sort of make it clear what the criteria actually are?

COMMISSIONER WALLERSTEIN: There are so many things that you all have to line up here. And the consequences of not getting it right ultimately are so severe that to me you invest more up front, and that's a cost of frankly doing societies business properly. And when I look at -- and I'm making arguments at CARB about the Greenhouse Gas Reduction Fund and how those monies are spent. And I'd like to see them -- and my board would like to see them spent a little differently. Some of this could and should be part of that as you integrate what the state is doing on GHG with this element, in my view. Because you're talking about investing in the future of the state, is what we're really talking about.

COMMISSIONER MCALLISTER: Yes, Michael?

COMMISSIONER FLORIO: Well, I do find the analysis somewhat sobering. I thought we were in better shape than these numbers are showing that we are. And certainly there are a lot of things in the works that we hope will pan out. But, you know, these numbers don't give me a great deal of confidence about that.

One factor that does give me some confidence is that -- and I'm just repeating what was in the record of one of our proceedings -- there was some suggestion in the Edison RFO that more energy storage might have been cost effective, but there were a number of barriers that led Edison to conclude that they should limit the in-front-of-the-meter storage to 100 megawatts. And that's a contested issue in that proceeding. But storage is certainly something that doesn't take, you know, three-and-a-half to five years to deploy. So we do have some comfort there, but it does -- all of this leads me to think that maybe we went a little short when we did our authorizations.

MR. JASKE: Well, Mr. Florio, Commissioner Florio, I think just to reiterate from a slightly different angle your point, there are, at least for storage and DR --

COMMISSIONER FLORIO: Yeah.

MR. JASKE: -- ongoing proceedings at the PUC that would cause these higher levels to come forward.

COMMISSIONER FLORIO: Right.

MR. JASKE: And perhaps we're in a circumstance where this kind of analysis can help give some guidance to those proceedings at the PUC so that they understand better the timeframe --

COMMISSIONER FLORIO: Yeah.

MR. JASKE: -- in which it needs to be on the -- operational. That guidance may not exist so much --

COMMISSIONER FLORIO: Yeah.

MR. JASKE: -- the way the proceedings are organized.

COMMISSIONER FLORIO: Yeah.

MR. JASKE: So that's another way we can achieve mitigation.

COMMISSIONER FLORIO: Yeah. Well, we're certainly trying to put the pedal to the metal on demand response but it's, you know, challenging.

COMMISSIONER MCALLISTER: Yeah. So I guess I wanted to just build on that general idea. You know, again, okay, storage has some barriers. So maybe it wasn't quite ready for prime time. So Edison sort of used -- is going to look at this 100 megawatt experience, learn from it and hopefully be able to scale it. And you can say the same kind of thing about DR efficiency. As we do things different -- differently we could hopefully learn and give a scale.

So, you know, there's a little bit of a chicken-and-egg problem here where, you know, if we -- if we kind of -- if we're not sure that they're going to substitute in some meaningful way from traditional resources, then we kind of have to do both. And so, you know, that's not -- that's not a true optimization.

COMMISSIONER FLORIO: Correct.

COMMISSIONER MCALLISTER: So, you know, I continue to feel like we need to develop the analytical tools and really look at each of those barriers. Say in demand response it's the market issues that are associated with demand response. So we need to solve those and then enable the technology that already exists to come through for all those services.

Storage is in a little bit of a different arena. You know, I think people are more comfortable that it could work because it's kind of a more centralized sort of approach. But the technology and cost issues have to be fixed.

Efficiency is a whole different set of issues;

right? We've got markets. We've got lots of third parties out there that are service providers. But the dynamic overall, I think you could draw some analogies that depending on the kind of resource you're looking at, accounting for it and quantifying it requires more sort of analytical tools and underpinning data than the traditional utility and business model would normally assume.

And so I think that I just keep hearing this theme. And I just feel like, okay, let's identify the barriers and let's go after them and let's really proactively try to solve those -- those problems so that we can actually put the pieces of the puzzle together in a way that does truly favor our resources as much as we can.

So anyway, I'll get off my soapbox. But I'm seeing some head nodding, and so that's good.

So we're a little bit behind schedule.

Thanks a lot, Mike. I appreciate you speeding it up a bit.

And we need to move on to the Air Quality, Panel 3.

MS. RAITT: Okay.

COMMISSIONER MCALLISTER: So I'm going to pass it back to Heather.

MS. RAITT: Okay. So we're not going to take a break and we'll just move on to the environmental agency considerations.

And on Air Credits in the South Coast Air Basin and San Diego we have Mohsen Nazemi from the South Coast Air Quality Management District.

One moment. There you go. Yeah, that one.

MR. NAZEMI: Good afternoon, and thank you for inviting South Coast Air Quality Management District to talk at this conference. I think -- I'm Mohsen Nazemi. I'm Deputy Executive Officer for Engineering and Compliance. And I think Mike and others mentioned a lot about contingencies. And I think that's really where we should focus more on, given what we are facing in terms of the drought and other temperatures in California that is like breaking records that has never been broken before. And so I'm not sure one-in-ten is pessimistic. It may be even optimistic.

With that, I'd like to go over a few things real quick and try to catch up with our timeframe here. I think Michele covered this very well. I just want to highlight that the proceeding that was approved, Track 4, by PUC allowed for additional 100 to 300 megawatts of any -- from any resource. And so that raised natural gas-fired potential generation up to 1,500 megawatts.

Now what does that mean in terms of other obstacles? You just talked about the storage issue. There are other proceedings that are pending in front of the PUC referenced by -- or filed by Sierra Club or California Energy Storage Alliance, Office of Ratepayers Advocates and others that deals with other issues. And they're looking at from a different angle that, you know, a minimum of 1,000 megawatts is what Edison should have gone for and not 1,280 megawatts that they did sign contracts with AES.

Or the other proposal which, actually, we have some concerns with, too, that somehow re-characterize Edison by distributed generation. But basically what it really looks at is using backup generator as preferred resources. I think our agency has been very clear that we are not interested in bringing back backup generators as a solution to this, but we'd rather have good planning, as Barry was just talking about, so that we can initiate and trigger construction of whatever source of energy, even a central generation, rather than start to look at backup generators, and other proceedings that specifically deal with a particular issue.

Just to give you a quick wrap of what the status of once-through cooling and other power plants are -- Roger already covered this very well, but I just wanted to take another look at it. We had AES Alameda who applied for replacing 1,950 megawatts with 1,936 megawatts. But because of their LPP with Edison they actually canceled all their applications in February and now they’re going to file new applications. We haven’t received those yet.

The Redondo Beach, again, it’s a relatively controversial project. We had a public meeting end of June and there was a lot of opposition raised by, actually, the city of Redondo Beach and their consultants. This project has been issued a preliminary determination of compliance by South Coast. But now we have to look at some new information relative to the EPA’s New Clean Power Plant Regulations. Also some additional modeling that AES just submitted to us on August 7th that needs to be re-analyzed for commissioning and startup periods.

AES Huntington Beach, the replacement of Units 1 and 2, we had issued final determination of compliance. But again those applications were canceled in February. And AES has indicated that either the end of -- by the end of August or sometime in September they’ll file new applications. We haven’t received those yet. Units 3 and 4 have already been removed for permitting of the Walnut Creek Edison Mission Energy which is now an NRG plant in the City of Industry.

And NRG El Segundo, as again you heard, the Units 1 through 3, 1 and 2 basically, but also part of 3 have been repowered. And Units 3 and 4, ultimately the FDOC has been revised just last month. And we are going to have to now go back and look at that project again, also because of the EPA’s New Clean Power Plant Regulations.

As far as units that are not under CAISO, these are LADWP projects for units that have OTC removal data of 2029, those are the LADWP Harbor and a couple of the units from the Haynes plus some turbines, we have no application. So there is nothing for us to do in order to get those up and running. The Units 5 and 6 at Haynes had applications filed early. They repowered it because they were also under a settlement agreement with our agency due to some of the violations that they had back in the 2001 energy crisis relative to their exceeding of reclaimed allowances.

The Scattergood Project, we have just reissued the revised FDOC this month, earlier this month. And they wanted to increase their megawatts by about nine megawatt because of the turbines that they installed actually were more efficient than they thought they would be. But for Unit 2, we have no applications. And again, that’s a 2024 deadline.

Besides those, we also have some local municipalities and some other IOUs that have not filed any applications. And we’re not certain about whether or not they are going to be re-powered. There’s a total of 847 megawatts associated with those projects. But they don’t typically get analyzed here at this point relative to once-through cooling.

So what has South Coast done about permitting power plants? We already had a rule in place for a number of years relative to incentivizing projects that have old utility boilers that are inefficient and dirty to replace them with new state-of-the-art advanced gas-turbine technologies. And that rule has, excuse me, has been used in the past for a number of projects. The issue related to that is that those projects have been permitted with an exemption from offset requirements, but the district still has to provide those offsets from our internal bank.

So a couple of years ago our governing board adopted a regulation that requires a mitigation fee to be paid for these projects so that the fees can be invested in environmental benefit for local communities. In fact, we just received the first payment from LADWP for that project that I mentioned earlier at the amount of about a quarter million dollars.

So with that in mind we looked at what will be needed or future. And looking at the governor's task force and other contingency recommendations that came out of that report, we are in the midst of proposing and adopting new rules. And I'll give you a quick synopsis why we're doing that.

If you look at the availability and costs of emission reduction credits for PM10 in the market, if we look at back in 2000 the percentage of ERCs available has dropped by more than 60 percent, yet the price of ECRs have increased by 2,500 percent. So that not only is -- makes it unaffordable and impractical to build a power plant that requires PM10, but it also shows that they are not even available in the market if somebody wanted to pay for it because not all of these ERCs are actually available for sale. There may be holders that need them for their own future projects.

So we're in the midst of developing two new rules, 1304.2 for investor-owned utilities for new generation, greenfield-type projects, and also 1304.3 for local publicly-owned electric utilities servicing their native rules -- sorry, native loads for both new and increased capacity.

The objectives of these two rules is again to implement Governor's Grid Reliability Task Force Report in terms of contingency measures, but also to promote preferred resources, the loading order, the CARB AB 32 Scoping Plan, and the District's own energy policy that our board has adopted.

We want to make it a level playing field for new generation and existing generating capacities, that if there's a better project at a better location that they don't be disadvantaged or not being able to use our internal bank offsets.

And also want to make sure projects are put in places that it helps grid reliability and it not just go back to the same old locations if they're not going to help with grid reliability.

And, of course, our intention is also to help our attainment strategy. As Barry mentioned, we are going to file a new Air Quality Management Plan, and that's part of -- an important part of that plan.

These projects -- or these proposed rules also include use of a mitigation fee approach to address the immediate surrounding community that will be seeing these new projects going in. And, again, to use the money in terms of preferred resources for energy efficiency, demand response, energy storage, renewables. Also to look at what Air Quality Management Plan reduction needs are, to address those, and as well as to enhance and develop, again as Barry mentioned, the new zero or near-zero emission vehicles and charging infrastructure.

So these are a comparison between these two proposed rules. But what I want to highlight here is that this is still a process in development. These are our thinking as we speak today and they may change by the time they're adopted by the board. Again, 1304.2 for IOUs is for new construction only. And the native load municipalities, both for new and expansion, in order to be able to utilize our offsets we are requiring in this proposed rule to establish a need using the LTPP approved by PUC for IOUs, and some sort of approved integrated resource planning by the local community -- local municipality, and also to show that it's only to serve native load and reliability of the grid.

As far as how they determine this megawatts needed, again for IOUs we are relying on PUC's approval of the long-term procurement procedures and on integrated policy resources plan for the local municipalities.

Some of the other requirements that I just will quickly highlight is that for IOUs a contract would be necessary in order to actually withdraw the credits. They have to still look at a good-faith effort to provide offsets if they can get them from ERCs. And our proposal at this time only covers sulfur oxides and PM10 offsets, which are the two scarce commodities that we believe are in the market. For the other pollutants there is available ERCs in the market that can be used.

We're also requiring a final CEQA document, whether it's a CEC approval of an AFC project or a local municipality going through their own CEQA procedures. And, of course, we have a new source review tracking rule that EPA had required us to adopt and approved into the SIP. And we have some projections in that rule that allows us to show that we're not going to run out of offset credits in our internal bank. So these projects have to be consistent with those projections. We have some minimum limits that we put in here that we want to make sure we don't drop below those levels. But we don't think we're going to drop below those. But these are just some -- some backstop provisions.

And then finally, requirements to actually get a permit would be to have the certified CEQA document and make a payment for those mitigation fees. We have two options right now in the proposed rule. You can either pay an upfront fee for all the credits that you want to withdraw from our account, or you can just pay a first-year payment for -- for the credits and wait until you complete construction, and after the first year of operation pay the subsequent years.

So with that, the schedule for adoption is slipping a little bit behind. But we are -- we've already held an informal meeting, three workgroup meetings. A fourth workgroup meeting is going to be coming towards the latter part of summer or early fall. And we believe that by the time we finish all the associated econ and CEQA analysis for this rule we will be looking at the first quarter of 2016, unless Barry changes that date to an earlier date.

So in conclusion, what are we looking at? There is 4,025 megawatts of once-through cooling required to be replaced under CAISO that has not yet been permitted. There is also 1,411 megawatts under LADWP that requires to get permits. And there's also 847 megawatts that I mentioned that are non-once-through cooling but they are either IOU or local municipalities, that those all are very, very old boilers and need to be replaced.

And assuming that the procurement allows for 1,500 megawatts of new generation which it doesn't -- you know, we already know that AES Huntington Beach and Alamitos got about 1,200 of those -- that would add up to a total of 7,783 megawatts. So do we have enough credits in our bank to supply credits for a worse scenario where they have to build 7,783 megawatts of gas-fired generation? And the answer is yes.

This report is going to go to our board on September 6th, which is our final equivalency to demonstration with new source review requirements. And as you can see, it shows that there is adequate offsets for all pollutants, even if they were all going to be withdrawn from our accounts, which they're not for the new rules. They would only be for SOx and PM. But for 1304.2, Utility Boiler Replacement, it would be for all pollutants, that it demonstrates that there will be adequate credits in our internal bank to cover those. Plus we are putting some backstop measures in the proposed rule to make sure we don’t get to a point where we don’t have enough credits.

And that concludes my presentation.

CHAIR WEISENMILLER: Thank you. I just have one question, which Barry had referred earlier to the overall attainment. It that like 11 months out? I’m just trying to see how this fit into your overall actions, your next step on regulations.

COMMISSIONER WALLERSTEIN: We have attainment dates for the Federal Clean Air Standards in the 2019 timeframe for particulates. And then we have -- I’m sorry.

COMMISSIONER MCALLISTER: Oh, sorry.

CHAIR WEISENMILLER: Sorry. I’m sorry.

COMMISSIONER WALLERSTEIN: We also still need to meet the one-hour ozone standard which will be in the 2022 timeframe. And 2023 is the 80-hour 80 PPB standard. And then we have -- the upcoming plan is really directed at meeting the 75 PTB standard in 2032. And then the federal government in the next month is supposed to finalize a new ozone standard which will likely be in the range of 65 to 70, and it will have an attainment date of 2037.

So from our perspective the most important thing is to meet those near-term standards, 2019, 2022, 2023. And that will put us on the right glide path to meeting the standard in 2032. And in our view what is likely needed to meet the ozone standard of 2032 will be very much the same measures as to meet the governor’s goal for 2030.

MS. RAITT: Ready?

CHAIR WEISENMILLER: Thank you.

MR. NAZEMI: Thank you.

MS. RAITT: Thank you.

Our next speaker is John Annicchiarico from the San Diego Air Pollution Control District.

MR. ANNICCHIARICO: Good afternoon. I’m John Annicchiarico from San Diego APCD. And thank you for inviting us to participate. I’ll be providing an overview of the San Diego APCD and how we -- how we do permitting and how our permitting process might interact with the mitigation options, the generating mitigation options that were discussed earlier.

So this is what we do to protect the public, achieve and maintain air quality standards. We like to have community involvement and we try to do that in a cost effective manner.

So just a couple quick slides on what we’ve been doing. And ozone levels are decreasing in San Diego. It shows we still have a little ways to go.

Toxic emissions, this is a chart of the ambient cancer risk at two of our monitoring stations. So this represents about a 75 percent decrease over that period.

These are just the state regulations that provide the framework for our permitting process. So what we do is we evaluate applications that are submitted for compliance with the local, state and federal regulations that we've been delegated. At that point we issue, if they comply, we issue an Authority to Construct with operating conditions that assure compliance, and we have to ensure compliance. We can't issue a permit unless we -- we know it's going to be in compliance.

So once it's -- the emission unit is constructed the AC becomes a Temporary Permit to Operate until the District inspects, and then we issue what's called a Startup Authorization, and we can test at that point. And once we get the report back we ensure that -- before we issue a permit we ensure it meets the -- all our requirements.

So the process is a little bit altered for when CEC has jurisdiction. The CEC application for certification, the AFC is what we consider equivalent to an application for a district, Authority to Construct, so we publish a PDOC. And then later the final FDOC is provided to CEC. And so the FDOC has all the conditions that ensure compliance.

So our regulations state that an initial ATC is allowed one year for construction. We are allowed to grant a longer period if it's required for construction. ACs, including any extension, can be for no longer than five years. So this is directly out of our rule, Rule 17. These rules vary by district. This is what it is for San Diego. So we -- we would then need to reevaluate any time an extension is granted prior to granting that extension.

I think I'm off maybe by one slide. So these are the things that we would evaluate before an extension is granted. I'll go through each of them. So best available control technology, lowest achievable emission rate, these are moving targets as technology advances and can be effected by decisions by us or other districts, other states or EPA. So this is fairly common. This happened with Pio Pico. After an extension we did reevaluate for BACT and we did make a more stringent determination that was based on a PSD determination by EPA.

So AQIA, Air Quality Impact Assessment, could be revised depending on new data and new emission factors. NO2 to NOx is one factor. The new source test information, new ambient air quality standards, we -- we have had that happen. That happened with Carlsbad Energy Center, new modeling guidance from EPA which is currently -- currently EPA has proposed new modeling guidance and the actual model.

Health risk assessment, same thing, new emission factors, new modeling guidance. There -- there has been recent new -- new guidance from OEHHA or revised health --

health values. Could be new reference exposure levels, toxicities of -- of a pollutant.

So any of these regulations, if they change we would need to reevaluate. The District NSR is currently being revised. It probably wouldn't impact power plants, except for the larger combined-cycle plants. And that could affect the availability of offsets for the larger power plants because offsets need to be racked adjusted at the -- at the time they're used. That -- that's a possibility for an impact there. We would also look at any NSPSs or NESHAPs that were delegated.

So PSD, in San Diego there's two flavors of PSD in our District regulation, Rule 20.3, and then there's Federal PSD which is implemented by EPA. So APCD San Diego couldn't implement Federal PSD unless we had a rule approved by EPA or delegation by a Federal PSD from EPA, so we have neither. We did attempt to have a rule that EPA could approve. However, due to some court cases that EPA will be addressing we need to rescind that request for approval. But we do plan to, in the future, adopt a rule that EPA could approve.

So therefore, any projects subject to a PSD has to receive a Federal PSD permit from EPA and an FDOC/ATC from the District. We have in the past received site-specific delegation from EPA. But because of -- since our rules don't contain the required greenhouse gas and PM2.5

requirements that EPA has, delegation is not likely in the near future.

So the District PSD is required by our rules. It’s -- it can’t be rescinded because of SB 288. That’s the Protect California Air Act that -- that doesn’t allow backsliding of districts’ regulations. So our District PSD is consistent with the Federal PSD of about 1995. So this will continue to be enforced and incorporated into ATCs.

So I just wanted to go over an example. This is the Carlsbad Energy Center. And it sort of resembles the mitigation options. CEC approved the six turbines, but PUC only approved five. So the District ATC isn’t effected. So the applicant could install six if they elect to. But if we need to extend that Authority to Construct what we do is reevaluate for all those things I just mentioned.

So one of the things that would change would be the NOx offsets. It could be that -- because this is a re-power it could very well be that no or very few offsets would be required if they elect to only install five.

So that’s -- that’s my presentation. If you have questions --

Thank you.

COMMISSIONER MCALLISTER: Thank you very much. We appreciate it.

MS. RAITT: Thank you very much for that.

Our next presentation is over WebEx from Lisa Beckham from the USEPA Region IX. And I'll go ahead and get that presentation.

MS. BECKHAM: Okay. And can everyone hear me?

COMMISSIONER MCALLISTER: Yes.

MS. RAITT: We're muted, so --

MS. BECKHAM: Okay. So I'm Lisa Beckham and I am with the Air Permits Office at EPA Region IX in San Francisco. And in the Air Permits Office I do oversight of the Air Permitting Program in Region IX. That includes Southern California, South Coast and some of San Diego. And I also do some of the PSD permitting for EPA, as well as some title permitting. And I'm wanting to focus on what happens if you have -- and my presentation is moving on its own speed. I don't know if we can back it up. Okay, that works, sorry. I don't know why it's doing that.

Yeah, so I'm just going to focus on how, if you happen to be lucky enough to need a PSD permit from the EPA, how that -- how that works, and sort of thinking about how to tie it into the timelines that Mike was discussing earlier under those three options, some recommendations, considerations and my contact information.

So we can go to the next slide.

So I know that if you are already getting a permit from your local agency, why would you also need a second separate permit from the EPA that will probably have the same requirements? I think John at San Diego APCD kind of put it pretty well, and it's because you don't have an approved program, instead you have to get a permit under the Federal PSD Program. I won't go into too much more detail, I think John covered it, but there are a couple different scenarios for how you trigger the PSD program. It does vary based on whether you are a combined-cycle or simple-cycle facility. And if you're an existing major storage there are also different thresholds that are -- that are lower.

And John also talked about the ability to get a delegation agreement. If you have -- if you don't have a SIP approved program. And while San Diego does not have a delegation agreement, South Coast does and they've had that in place for a very long time.

Onto the next slide.

And so what happens is when you have to get a permit from EPA there are some additional requirements that have to be met. I think you need to go back a couple of slides. There we go. And one of those, the big ones is Part 124 which is -- we call that the regulation that it is, but it's our administrative procedures. And this includes our administrative appeal process, the EAB, EPA's Environmental Appeals Board. And what happens is if a permit decision is appealed to the EAB it stays construction until that process is complete. And that can also include a remand proceeding back to the region before you can begin construction.

And then once you get over that hurdle there's the federal judicial appeals process either to Region IX or appealed to the Ninth Circuit Court of Appeals. You can go ahead and begin construction but you would do so at your own risk. And those decisions can take literally years to get.

And in addition, if you're also getting a federal permit there are some other sort of requirements, like ESA and environment justice requirements that you have to meet that we've included probably in a guidance document. And these would probably generally be redundant with some of the CEQA requirements. But they are separate federal requirements that do need to be met.

And the next slide. There we go.

So how long does it take to get a final permit from EPA? The answer is it can vary. And here I show our three most recent TOC (phonetic) projects, Four Corners, Pio Pico and Palmdale. You can see that Four Corners was relatively short, I would say, by a miracle of some sort. There was no EAB appeal. Pio Pico was appealed to the EAB and remanded back to us, and that added about seven months of those 34 months, so that includes the seven of those 34. And Palmdale was 42 months. And I would say that Four

Corners was not necessarily an easy PSD project. Even though it had a very short timeframe, we actually did some extensive public outreach and received a lot of comments. And we're fully expecting EAB appeal, but that never materialized.

And onto the next slide.

So what should you be thinking about if you happen to be lucky enough to need a permit from EPA during your process? And I would say ideally EPA would only have an oversight rule where your project would not trigger the TOC program. You know, while we can delegate the (inaudible) down to the local agency, you still have to meet all of those other federal requirements.

And the other consideration that is important is that the Clean Air Act is really designed for projects that are ready for construction because of that one-year deadline from when we receive a complete application to when we have to make our decision. And that applies to both EPA issued permits and state and local issued PSD permits.

And, you know, after you've gone through that 30 or 40 months permitting process for your permit, you then have -- under the federal program you have that 18-month period until you commence construction. And I think people were curious about whether or not you can then extend the permit, and the answer is, yes, assuming it's justified.

Typically, I think typically it’s an 18-month extension, only because I’ve never seen anyone ask for more than 18 months. It’s actually not specified in our regulations.

But again, this is a federal action if we extend the permit, and that can be challenged in federal courts. And the last one that we did for the Avenal Energy Project was, in fact, challenged. It was dropped once the permit was vacated. And so we do expect any future extension requests to also be challenged in federal court.

And I just also recommend that when you submit a request for extension that you’re providing us with really specific information that we can use if you were defending the request decision in federal court.

And onto the next slide.

And so should you let your EPA PSD permit sit on the shelf? Again, the Clean Air Act is really designed for projects that are ready to construct. And so our ability to extend the PSD permit is on a case-by-case basis. If it were to be challenged there’s a good chance that that extension would expire before we even got an answer from the courts. And it also -- think about that if you took, you know, 30 months to get an initial permit, then maybe you got 36 months of -- you know, 18 months and then another 18-month extension, that’s a total of about 66 months. And so after that period of time the analysis that -- you know, the original determination is probably stale, and probably you need to restart analysis anyhow.

And so do I have any recommendation for how to reduce the time to get a final permit from EPA? And the quickest way to do that is to not need one from EPA in the first place. I think John said that San Diego may be working on a rule for the future. South Coast, I'm not sure that they have any plans for an approved program. But, I mean, they've had a delegation agreement in place for a really long time. And I'm not aware that they've actually ever had a permit challenged to the EAB. But I do think that -- I think that approving more programs in California, our typical commenters are realizing that they need to follow the -- the local process in order to get involved in the challenging of particular projects.

And so -- but if you do have to get a permit from us, we encourage early upfront and ongoing engagement that's keeping us in the loop. And we try to do our best with the resources we have.

And on the next slide I just have my contact information. All of our recent TOC permits are online. And I did not provide anything from the Clean Power Plan, but I think ARB is going to cover that next. I'm on the Clean Power Plan Group here at Region IX. But Ray Saracino is the main contact for California.

And I will take any questions.

CHAIR WEISENMILLER: Bob Weisenmiller. I wanted to congratulate you on the Clean Power Plan now.

MS. BECKHAM: Thank you. We're extremely excited.

COMMISSIONER MCALLISTER: This is Andrew McAllister. And I wanted to reiterate that. It's been a long time coming. And I think California is really happy for your leadership and -- which I think you're probably hearing from many states, they're not -- they're not so happy about that, but we are in California -- in California. So thank you very much.

MS. BECKHAM: Yes. That's -- that's definitely what we've been hearing from California. And we're really excited to work with California as they get started.

COMMISSIONER FLORIO: Good morning and congratulations from California Public Utilities Commission.

I had one question about the -- the EAB appeals process. Does -- does that not apply in the case of the South Coast or is it just that it hasn't been exercised?

MS. BECKHAM: I think it's just that it hasn't been exercised in the past. There could have been an issue in the past that I don't know about. But I don't know about any recent projects that have gone to the EAB from the South Coast.

COMMISSIONER MCALLISTER: Thank you very much.

MS. RAITT: Our next speaker is Tung Le from the California Air Resources Board.

Use that to advance.

MR. LE: Okay. Thanks.

My name is Tung Le. I’m the Manager in the Industrial Strategies Division of the California Air Resources Board. As you just heard a minute ago, EPA released some power plant rules that are intended to regulate carbon dioxide emissions. There are actually two rules that are out there that I’ll be kind of giving an overview about this afternoon, one that covers new and reconstructed plants, and the other that covers existing power plants.

So first, a little bit of background and context on where these power plant rules are coming from.

Back in 2013, President Obama released his Climate Action Plan. That plan identifies area that the nation could take to reduce greenhouse gas emission. As a part of that plan the president looked at power plants and asked his cabinet and his agencies to go ahead and look at ways to accelerate renewable energy permitting, upgrade and modernize the grid, help the electrons move around a little easier, and also directed EPA to go ahead and look at power plant rules and how we can reduce emissions from them.

So first I’ll go ahead and cover the new and reconstructed rule, which we also call 111(b). During the draft proposal there were actually three rules, one to cover new, one to cover modified, and one to cover the existing. When EPA took its final action they decided that the modified rule wasn't workable in its present form, so they're going to go back and work on it some more.

And so now we ended up with two rules, the first being for new and reconstructed units. So that -- so this rule was released a couple of weeks ago. It was released concurrently with the existing source rule. It applies to units built and reconstructed after January 8th of 2014. So anything that's in the pipeline right now that is going to be built after January 2014 would be subject to the 111(b) standard.

For natural gas-fired units, which is what we're mostly concerned about here in California, EPA's sort of rule universe is whether or not the unit is a base load unit or a non-base load unit. And so there's a definition in there in the rule that we're still trying to get our minds around. The rules -- each of the rules were over 1,000 pages long. Staff are still going through it. We're still trying to figure out, you know, what does this mean for us? How is this going to affect power plant permitting in the state? So, well, I'll talk about that a little bit more, you know, some of the work that they're looking at going forward.

So the emission limit for base load natural gas-fired units is 1,000 pounds of Co2 per megawatt hour gross. This is pretty much in line with what we would expect a base load unit to be able to do. So, you know, this is not anything that we're expecting to cause any issues, at least for natural gas-fired power plants in California.

If you're a non-base load unit they have to meet an input base standard. That input base standard is based on the amount of heat input that they take. So it's -- so they -- so the limit there ends up being a 120 pounds of Co2 per million Btu of heat input for a unit.

Whether or not a unit is a base load or a non-base load is dependent upon a sliding scale, sort of equation calculation the EPA has put into the rule. It's based upon the percent of electricity sales versus the net EGU efficiency. And so what the sliding scale does is that it incentivizes the installation of more efficient units because more efficient units basically get to run more or sell more electricity to the grid before their considered base load and subject to what we believe right now is the more stringent limit of 1,000 pounds.

Any questions on the new, before I go on with the existing? Okay.

So with the existing standard it's similar in structure, but there a lot of familiar aspects to the final roles compared to the draft rule. It sets emissions rates dependent on the individual units. And so in sort of summary, how those units add up provides the state targets.

Credit is given for renewable energy programs, so that stayed in the final version of the rule.

And one of the more interesting things that we saw so far is that EPA has put a tighter focus on interstate trading of emissions in the final rule.

So if you remember from my presentation last year, there were actually four building blocks that EPA had proposed. Those four building blocks have now been knocked down to three in the final rule. The fourth building block concentrated on energy efficiency. That has been removed from the final rule. EPA, again, didn't think that that was workable in the final version of the rule, so they concentrated on the first building blocks. And another way they applied the building blocks, too, is that they looked at the regional interconnects. So there's a Western Interconnect, an Eastern Interconnect, and ERCOT (phonetic). And so they've applied the three building blocks to the three interconnects rather than looking at it on a regional basis as they had in the draft.

COMMISSIONER MCALLISTER: Tung, I want to jump in here --

MR. LE: Yeah.

COMMISSIONER MCALLISTER: -- and clarify something.

So they left the building block and the energy efficiency off of the goal setting process?

MR. LE: Off of the goal setting process.

COMMISSIONER MCALLISTER: But they're still going to let it be a core activity for compliance purposes?

MR. LE: Yes, absolutely.

COMMISSIONER MCALLISTER: So that's -- that's a pretty important distinction --

MR. LE: That's right.

COMMISSIONER MCALLISTER: -- because you can't use energy efficiency to comply.

MR. LE: That's right. As long as -- as long as the state is able to show that those energy efficiencies are able to be counted, they're able to be enforced, then they can certainly be a part of its compliance plan.

So what did California's final targets end up looking like? The EPA actually calculated and mass-based targets in the draft rule. They only proposed rate, and so they kind of left it up to the states to figure out how they were going to convert that to a mass.

Well, in the final rule they went ahead and did that for us. There was a whole bunch of different ways that you can do that. EPA chose a certain methodology that's in the rule. The calculation is actually in there if you're interested in looking at it. But for California's baseline 2012 emissions, we're at 963 pounds as far as rate. The mass equivalent of that is 46.1 million short tons. And our 2030 final compliance target is 828 pounds per megawatt hour or 48.4 million short tons. And that's not a typo. We're actually, according to EPA's values, already complying with the rule. We're lower than what our 2030 targets are going to be.

I've got a caveat. This slide right here with -- you know, Staff have already noticed that EPA left off a significant number of units that we think should be in the rule. So we're going through that list right now and trying to figure out which units were left off EPA's inventory for California, what units we think should be included, and that will adjust these values. But overall, you know, the message is that we're in pretty good shape. California is going to be able to comply with this rule and probably over-comply.

So the compliance schedule, they made it real simple this time. Compliance plans are due by September 6th of next year. If we don't have a complete plan together than we can just do an initial submittal and say, well, this is what we have together so far, EPA, we're going to go ahead and ask for an extension. California is not going to do that, actually. We are planning to have our rule in, in time for the first submittal date. But this is an option that EPA is allowing in the final rule.

States that do take advantage of the extension request have sort of a progress report that is due to EPA in 2017. And then again, final compliance plans for states that ask for extensions is in September of 2018.

So some of the next steps, some of the things that we're working on, I've got Staff working like crazy with the Energy Commission Staff, with PUC Staff, and we're going to be consulting with the ISO to make sure that everyone is on board and we all understand what the rule says and what it means for California.

There is going to be a joint state agency workshop, right now tentatively planned for late September or early October where Staff are going to go ahead and present our findings, what we think of the rule, how it's going to affect California, you know, and talk about some of the ways that California is going to show compliance. That's actually going to be the harder part. We're pretty sure that we're going to comply. I mean, it's -- you know, that's -- California has been a leader in renewable energy and doing all the good things to reduce emissions. But how we show that without implicating our state programs and making them federalized is the -- is the tricky part. And so we're going to be working on that and be presenting to folks during that first workshop there.

We're going to continue to communicate with EPA. Region IX actually got the rule the same day we did. So they're actually still, you know, reading it and trying to understand it as well. We are going to be in constant contact with them to make sure, again, we're reading the rule the same way they are, we're understanding the rule the same way that they are, so that that way at the end when we turn in our plan and Region IX has to review it and approve it, we don't have any surprises.

We're going to continue to work with other states, as well, through the Center for the New Energy Economy. It's a group out of Colorado State the Governor Ritter has put together. That group collaborates with the western half of the United States, or I should say the Western Interconnect in California, and has been an active participant in that group.

So here are some resources that you can look at if you're interested in learning more about the Clean Power Plan and the 111(b) for new rules at the very bottom. ARB has its own website for updates about, you know, some of the things that Staff are doing, some of the documents that will be put out. So I'm asking Staff to go ahead and update that right now, to go ahead and look at that and make sure the information that we need for the September workshop will be posted. So keep an eye on that website for updates.

And these are the team contacts. Again, I'm Tung Le. I'm the Technical Lead for the 111 Rules. Craig Segall, who couldn't be here today, is our overall Lead 111 Project Coordinator. And then you have our contact information there if you have any questions or would like to chat about what the rules mean and what we're working on.

COMMISSIONER MCALLISTER: Thank you.

MR. LE: Okay.

CHAIR WEISENMILLER: Thank you.

MS. RAITT: You need to --

CHAIR WEISENMILLER: Come up to the microphone.

MS. RAITT: You need to come up here, please.

CHAIR WEISENMILLER: Why don't you use that one?

MR. NAZEMI: Thanks, Tung.

So ARB has not -- is not going to pursue a multi-state plan submittal at this point; is that pretty much decided?

MR. LE: Yeah. So at this point we are not pursuing that. We are, again, speaking with other states. And so far there just really hasn't been an interest to collaborate in a multi-state sort of plan. And I think that as the conversation develops more there may be interest from other states to do that. But right now I think the easiest way that most states, you know, really are kind of looking at is that, well, how can we comply with this going at it alone? You know, to collaborate with other states will involve a huge amount of time and resources. And if a state can go at it alone, that probably makes the most sense as far as time and resources go.

But again, as the conversation develops and we continue to interact with other states, if there are opportunities for collaboration we are certainly keeping our minds open to that.

CHAIR WEISENMILLER: Thank you.

MS. RAITT: Okay. Okay. I think we're ready to move on to public comment then.

So when we -- so Commissioner McAllister will be reading blue card names. So when he calls your name, if you could come up here to make your comments --

COMMISSIONER MCALLISTER: Do we have any other blue cards? I've got three.

So Robert Smith?

MR. SMITH: I'm just going to start, huh?

MS. RAITT: Yeah. Go ahead.

MR. SMITH: Thank you.

MS. RAITT: Actually, it's right here. So go ahead and just --

MR. SMITH: Oh, okay.

MS. RAITT: Yeah.

MR. SMITH: Okay.

Well, thank you. Good afternoon, Chairman, Commissioners and gentlemen. My name is Bob Smith and I'm the Vice President of Transmission Development for TransCanyon. Thank you for the opportunity to provide comments on the Southern California Electricity Infrastructure Assessment as part of the CEC's process to develop the 2015 IEPR.

TransCanyon commends the CEC for its commitment to working with the CPUC, the ISO, the Air Resources Board, and other agencies and stakeholders to ensure the successful development of energy infrastructure needed to assure the future reliability of the electric system serving Southern California.

TransCanyon is an independent developer of electric transmission infrastructure for the Western United States. It is a joint venture equally owned by the BHE US Transmission and Bright Canyon Energy. BHE US Transmission is a subsidiary of Berkshire Hathaway Energy. And Bright Canyon Energy is a subsidiary of Pinnacle West Capital Corporation and a sister company to Arizona Public Service.

TransCanyon has been an active participant in the CAISO transmission planning process since 2010 when it sponsored the Delaney to Colorado River Transmission Line as an economically driven transmission project. Our team of experts has a deep understanding of the unique challenges the state faces in meeting its increasingly ambitious renewable energy and greenhouse gas emission reduction goals, while ensuring that the reliability of the electric system is maintained.

We are committed to working closely with the CEC and other California agencies to help develop cost effective transmission solutions, taking into account local environmental concerns that will facilitate the state's implementation of these broader policy goals and ensure the reliability of the electric system.

TransCanyon supports the CEC's efforts to track energy resource development and electricity demand and to identify contingency mitigation options, if necessary, to assure electric system reliability in Southern California. We appreciate the opportunity to participate as a stakeholder with the CEC and the other agencies. We understand the limits on the amount of detailed power flow analysis that CAISO can perform and applaud the CEC staff's development and utilization of a local capacity annual assessment tool. We also support the preliminary findings and agree with the need for more detailed studies by the CAISO of 2021 when the loss of substantial OTC resources is scheduled to occur.

And in addition to the two contingency mitigations discussed today, the ISO has identified several alternative transmission solutions as mitigation if the anticipated resources do not develop, future demand exceeds current forecast, or energy efficiency goals are not realized. TransCanyon recommends that the CAISO continues to develop these alternatives in order to select a preferred alternative in the near term.

Further, given the time required and magnitude of development dollars at stake, we recommend that CAISO consider a process where early development of that preferred transmission alternative could begin, but the CAISO and other pertinent agencies could preserve the right to issue a Construction Notice to Proceed until it is determined that a reliability solution is, in fact, needed. This approach or something similar could provide a meaningful contingency response that could be acted in a time to address reliability issues that may emerge in the future.

In essence, commencing with some preliminary development work of the preferred transmission solution would enable a relatively quick and efficient response should the preferred resources not materialize. This is similar to the new generation options that Mr. Jaske had subscribed earlier.

Thank you for the opportunity to comment. TransCanyon looks forward to continuing working with the CEC on this and other important initiatives, such as the New Renewable Energy Transmission Initiative.

CHAIR WEISENMILLER: Thank you. I was going to encourage you to participate in the RETI 1.0 process.

MR. SMITH: We'd love to. Thank you.

CHAIR WEISENMILLER: Thank you.

COMMISSIONER MCALLISTER: Thank you very much. Rexford Wait?

MR. WAIT: Good afternoon, Commissioners. Thank you guys for your time and coming down to Orange County today. My name is Rex Wait. I'm with Nevada Hydro Company.

How many of you at the table today support large storage? Anybody? No one brave enough to stick their hands up.

Well, the reason why I'm here today is LTPP 4 was nice enough to lay out 550 megawatts for large storage. RFP went out with Edison. RFP went out with San Diego. You saw the results of that today. And not one pump storage PPA has been let thus far. I suspect in the future probably none either.

I believe it's an important technology. It doesn't require emissions credits. It's probably been the best assets that have ever been involved in the state, looking at Castaic and Helms. And I would certainly like to see that 550 megawatts eventually go out to just a project. Thank you.

COMMISSIONER MCALLISTER: Thank you.

Robert Smith?

MR. SMITH: I already spoke.

COMMISSIONER MCALLISTER: Oh, I'm sorry. Sorry.

MR. SMITH: Long day.

COMMISSIONER MCALLISTER: Yeah, long day. And multi-tasking, actually, in fact, I have to admit.

Brian Theaker?

MR. THEAKER: So which way do I have to --

MS. RAITT: So you just kind of face this way.

MR. THEAKER: Okay.

MS. RAITT: That will be good.

MR. THEAKER: Okay. Okay. Thank you.

MS. RAITT: Whoops. Hold on.

MR. THEAKER: Okay.

Good afternoon, Commissioners, Mr. Bishop and Mr. Wallerstein, it has been a long day. Thank you. Brian Theaker, Director of Regulatory Affairs for NRG Energy.

We appreciate this -- this opportunity to discuss these issues. We applaud the Commission's commitment to reliability. We think that NRG has also demonstrated a commitment to reliability in Southern California with

Carlsbad, with Puente, with El Segundo. But we've also demonstrated a commitment to preferred resources through our awards and the Edison RFO, as well as 1,200 megawatts of operating solar and about 1,000 megawatts of operating wind.

So what I want to just talk with you today about is we support very much Staff's efforts to look at contingency planning for conventional generation as a backup.

Chair Weisenmiller, you said it best, things happen.

A couple of years ago, you know, at the Carlsbad proceeding, I don't think we anticipated where things were going to take us. So things happen and options are good.

Speaking of options, you know, we currently have three projects at the CEC in licensing process. Two are re-powers, a continuation of our successful project at El Segundo involving conventional generation, combined-cycle and peaking generation. We think that the final staff assessment is due out on that very soon and we think it's on track for a decision in 2016, so that's in good shape.

San Gabriel is a project in less good shape. That is a repowering at Etiwanda. As you're aware, these brownfield projects have immense advantages. First, they have access to air credits under Rule 1304. They can be repurposed for synchronous condensers as the need arises. But most importantly, they utilize the existing gas and transmission infrastructure which is very important.

So we have a third project also in the queue at the Energy Commission, Sun Valley, that's a peaking project similar to what we've deployed, we plan to deploy Carlsbad, and have deployed already at Walnut Creek.

So we applaud the Commission's commitment to reliability. We appreciate that you're looking at options for contingency planning. And just encourage you in this time of uncertainty to keep your options open. Thank you.

COMMISSIONER MCALLISTER: Okay. Thank you very much.

Anybody else in the room want to speak? No?

Do we have anything on -- I'm not sure how we would --

MS. RAITT: Yeah.

COMMISSIONER MCALLISTER: -- we would allow them to speak.

MS. RAITT: No, I'm afraid on the WebEx we're just encouraging folks to please submit written comments, and they're due by August 31st.

COMMISSIONER MCALLISTER: And I apologize for any of the glitches today that were unforeseen.

CHAIR WEISENMILLER: I would say that -- I was just going to fill in the glitch problem. I mean, all of us, on the one hand, like to get down to Southern California. We get real feedback here. The reality is that in this case when we did, you know, we discovered that the AV system isn't quite up to snuff. So anyway, we certainly apologize to the public on the line. It's sort of one of those things that certainly good intentions didn't work as well as we hoped today. But anyway, hopefully next time we come down we need to get past this situation.

COMMISSIONER WALLERSTEIN: I'd like to invite you to use your auditorium.

CHAIR WEISENMILLER: I know. We've done that before. That's very good.

COMMISSIONER MCALLISTER: And that will be great. I've been there too. It's a really good facility.

CHAIR WEISENMILLER: Thank you.

COMMISSIONER MCALLISTER: Yeah. And those -- those, you know, who are at UC Irvine, we really thank them for allowing us to be here and lending their facilities. But I think the -- if you don't do this for a living it's kind of hard to set these things up. And we're learning that, I think, on occasion as we try to move around the state and do this sort of outreach and get closer to folks of interest, rather than doing everything in Sacramento. So, obviously, in this case it's Southern California reliability. We want to get down here. We appreciate the UC helping us out with the venue. But a little -- a little more care with the details I think would be good next year when we come on down here. So great to be here.

Yes, thank you, Barry.

COMMISSIONER WALLERSTEIN: Thank you.

COMMISSIONER MCALLISTER: So I think any final comments from the dais?

I think it's been very productive. Thanks to all the -- all the presenters. The CEC staff obviously carried a lot of load today, and that was great. And all our friends from the other agencies and utilities, we appreciate all your input.

We look forward to written comments on -- Heather, do you have the date?

MS. RAITT: Yeah. August 32st. And the slide provides information. And the details are in the public notice for the workshop.

COMMISSIONER MCALLISTER: Great. So now I'll pass the microphone to the Chair.

CHAIR WEISENMILLER: I was just going to make note of one other event that's going on. Next -- I am both a scientist on the Commission and responsible for some of the climate issues. And next Monday and Tuesday in Sacramento we're having an event of scientists on the climate issues and how that's effecting California.

Certainly, for all those who wonder about reliability of one-in-ten, the basic message is our climate is changing very fast in ways that make us pretty nervous. I think the last thing I saw from Scripps is forecasting for Sacramento that the minimum temperatures in the summer will go up four degrees. The maximum will go up two degrees. And this year we've certainly hit the worst temperatures in history in California, along with the drought.

So the bottom line is it's going to be a very interesting conversation on Monday and Tuesday on the science of climate change, in Sacramento.

COMMISSIONER MCALLISTER: Any further comments from the dais?

Well, thank you all for coming. And thanks, Heather, and the IEPR team. We're adjourned.

(Whereupon the 2015 Integrated Energy Policy Report Lead Commission Workshop adjourned at 4:32 p.m.)

CERTIFICATE OF REPORTER

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

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

IN WITNESS WHEREOF, I have hereunto set my hand this 8th day of September, 2015..

Martha L. Nelson

MARTHA L. NELSON

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

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I certify that the foregoing is a correct transcript, to the best of my ability, from the electronic sound recording of the proceedings in the above-entitled matter.

Martha L. Nelson

MARTHA L. NELSON, CERT**367

September 8, 2015